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PUBLIC SERVICE COMMISSION

Via Courier and Electronic Mail

August 6th, 2012

Mr. Jeff Derouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

**Re: Sierra Club Response to Commission Staff Requests for Information
Docket 2012-00063**

Dear Mr. DeRouen:

Enclosed for the filing are an original and ten copies of Sierra Club's response to Commission Staff's initial request for information, including verification pages. Copies of this letter and all enclosures have been served on each of the persons listed on the attached service list.

Sincerely,

James Giampietro
Sierra Club Environmental Law Program
85 2nd Street, 2nd Floor
San Francisco CA, 94105
Office: (415)977-5638

CERTIFICATE OF SERVICE

I certify that on August 6, 2012 I served an electronic and paper copy Sierra Club's response to Commission Staff's initial request for information to Sierra Club on the below parties of record:

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James Giampietro

____
James Giampietro

VERIFICATION

STATE OF MASSACHUSETTS)
) SS:
COUNTY OF MIDDLESEX)

The undersigned, Rachel Wilson, being duly sworn, deposes and says that she is an Associate with Synapse Energy Economics, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Rachel Wilson

Subscribed and sworn before me
on this 3 day of August, 2012

Notary Public

JANICE CONYERS
Notary Public
Commonwealth of Massachusetts
My Commission Expires
July 27, 2018

VERIFICATION

STATE OF	**)**
	) SS:
VERMONT	**)**

The undersigned, Dr. William Steinhurst, being duly sworn, deposes and says that he is an Associate with Synapse Energy Economics, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

William Steinhurst

Subscribed and sworn before me
on this 2nd day of August, 2012

Notary Public
ANNABEL L GONYAW
NOTARY PUBLIC, VERMONT
MY COMMISSION EXPIRES FEB. 10, 2015

Commonwealth of Kentucky
Before the Public Service Commission

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL OF ITS 2012 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, FOR CERTIFICATES OF PUBLIC CONVIENENCE AND NECESSITY, AND FOR AUTHORITY TO ESTABLISH A REGULATORY ACCOUNT.	)	Case No. 2012-00063

BEN TAYLOR AND SIERRA CLUB'S RESPONSES TO COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION TO SIERRA CLUB

Intervenors Ben Taylor and Sierra Club hereby submit their responses and objections to the Kentucky Public Service Commission Staff's First Requests for Information.

RESPONSES

Request No. 1

Refer to the Direct Testimony of Rachel S. Wilson ("Wilson Testimony") at pages 8-9, lines 18-4. Provide copies or sources of documents referred to in list items A-C.

Response to Request No. 1 – Respondent: Rachel Wilson

Please see the attached files.

Resource Adequacy Implications of Forthcoming EPA Air Quality Regulations

December 2011

U.S. DEPARTMENT OF ENERGY

Table of Contents

Executive Summary

This report presents the results of an independent assessment by the U.S. Department of Energy (DOE) of the adequacy of U.S. electric generation resources under air pollution regulations being finalized by the U.S. Environmental Protection Agency (EPA). This report does not estimate the economic impacts of EPA regulations, nor does it provide detailed reliability assessments that planning authorities and other stakeholders will need to conduct to ensure deliverability of power and grid reliability during implementation of EPA rules.

This report considers two EPA regulations, the Cross-State Air Pollution Rule (CSAPR) and the Mercury and Air Toxics Standards (MATS), that are widely expected to have the greatest impact on the electric sector between now and 2015.[1] CSAPR creates multiple trading systems to control the emissions of NO_x and SO_2 from electric generators, and MATS imposes emissions rate standards on coal and oil-fired electric generators for mercury, acid gases and particulate matter. The trading systems for CSAPR begin in 2012, with the limits tightening for sources in some states in 2014. The first year of compliance for MATS is 2015, subject to potential extensions discussed in this report.

In some cases, compliance with the new rules, particularly CSAPR, may be achieved through the use of existing controls, shifts in dispatch, purchase of allowances, and fuel switching. In other cases, compliance with new rules will require installation of new pollution controls and may motivate the construction of replacement generation, which can sometimes take multiple years to complete. Assuming prompt action by regulators and generators, the timelines associated with new construction and retrofit installations are generally comparable to EPA's regulatory compliance timelines. If delays occur and if it is necessary to address localized reliability concerns, the Clean Air Act provides multiple mechanisms to extend these deadlines or bring sources into compliance over time on a plant-specific basis.

This report examines a Stringent Test Case, where, in addition to CSAPR requirements, each uncontrolled electric generator is required to install both a wet flue gas desulfurization (FGD) system and a fabric filter to reduce air toxics emissions. If such installations are not economically justified, this scenario assumes that the plant must retire by 2015. In reality, power plant owners will have multiple other technology options to comply with the regulations – options that typically cost less than installations of FGDs and fabric filters. *Therefore, this scenario should not be viewed as an estimate of the expected impacts of CSAPR and MATS, but rather as a stress test used to bound resource adequacy implications of these rules under conservative assumptions.* Specifically, this report focuses on whether, under the Stringent Test Case, there would be sufficient generation

[1] Two other regulations, the Coal Combustion Residuals rule and the 316(b) Cooling Water Intake Structures rule, have been proposed, and the final rules may differ significantly from the proposed rules. New Source Performance Standards for greenhouse gases have not yet been proposed.

capacity to meet electricity demand in each NERC region, before constraints on deliverability are considered.[2] This is known as *resource adequacy*, and it is one determinant of grid reliability.

In the Stringent Test Case, a total of 29 GW of coal capacity would be retired by 2015 (21 GW over the Reference Case). DOE examined resource adequacy in this case compared to the planning reserve margins for each region. The analysis finds that target reserve margins can be met in all regions, even under these stringent assumptions. Moreover, in every region but one (TRE), no additional new capacity is needed to ensure resource adequacy in the Stringent Test Case beyond what is projected in the Reference Case. In TRE, the analysis finds that less than 1 GW of new natural gas capacity would be needed by 2015 beyond the additions already projected to occur in the Reference Case. This analysis also finds that the total amount of new capacity that would be added by 2015 is less than the amount that is already under development, only some of which is reflected in the Reference Case.

DOE's analysis also considered impacts on available generation capacity of plant outages due to pollution control retrofit activity. Once construction of a new pollution control system is completed, a plant will pause operations for a short period as the system is connected or tied-in to the plant. For fabric filters, this has typically been accomplished during planned outages for routine maintenance that often last about one month, and the tie-in period for FGDs may extend for a few weeks beyond this typical period for maintenance outages. These planned outages are generally scheduled for the fall and spring seasons when electricity demand is well below peak. In the Stringent Test Case, taking into account projected capacity additions, DOE found that resources would be sufficient in all regions even when outages to tie-in pollution control retrofits were incorporated.

While the Stringent Test Case examined by DOE indicates that resource adequacy would not be compromised under CSAPR and MATS, retirements of power plants or other factors could lead to grid reliability challenges in some cases. Federal and state governments can use available regulatory and planning tools to address such reliability concerns as needed on a case-by-case basis. DOE is committed to providing technical assistance and working with stakeholders to ensure that the electric grid remains reliable as we strive to modernize the power sector.

In summary, this report concludes:

- Assuming prompt action by regulators and generators, the timelines associated with the construction of new generation capacity and installation of pollution control retrofits would generally be comparable to EPA's regulatory compliance timelines.

- A Stringent Test Case more conservative than the anticipated implementation of CSAPR and the proposed MATS rule showed the overall supply-demand balance for electric power in each region examined would be adequate; however, further iterative analysis will be warranted to assess local reliability considerations as the rules are implemented.

[2] NERC is the North American Electric Reliability Corporation. See Appendix A of this report for a map of NERC regions. See the technical supplement to the introduction of this report for limitations of this analysis and restrictions on its interpretation.

- Mechanisms exist to address such reliability concerns or other extenuating circumstances on a plant-specific or more local basis, and the Department of Energy is willing to provide technical assistance throughout this process.

Chapter 1. Introduction

The U.S. Environmental Protection Agency (EPA) has finalized or is in the process of finalizing several rules that will regulate a variety of environmental pollutants produced by power plants in the United States. Congress assigned authority to promulgate the rules to EPA, which must meet statutory deadlines and in some cases court-ordered deadlines.

This report considers two key EPA regulations, the Cross-State Air Pollution Rule (CSAPR) and the Mercury and Air Toxics Standards (MATS), that are widely expected to have the greatest impact on the electric sector between now and 2015.[3] CSAPR creates multiple trading systems to control the emissions of NO_x and SO_2 from electric generators, and MATS imposes emissions rate standards on coal and oil-fired electric generators for mercury, acid gases and particulate matter. The trading systems for CSAPR begin in 2012, with the limits tightening for sources in some states in 2014. The first year of compliance for MATS is 2015, subject to potential extensions discussed in this report.

Compliance with new rules will require installation of new pollution controls on some plants and may motivate the construction of replacement generation, which can sometimes take multiple years to complete. Assuming prompt action by regulators and generators, the timelines associated with new construction and retrofit installations are generally comparable to EPA's regulatory compliance timelines. If delays occur and if it is necessary to address localized reliability concerns, the Clean Air Act provides multiple mechanisms to extend these deadlines or bring sources into compliance over time on a plant-specific basis.

Beyond questions of timing, this report considers the issue of resource adequacy. Resource adequacy is the aspect of grid reliability that examines whether there is sufficient electricity generation capacity to meet demand before constraints on deliverability are considered. This report highlights several findings related to resource adequacy that would be valid under many alternative compliance pathways available to industry, and the analysis is intended to inform a broader discussion about how to manage the electric power sector's response to new pollution rules. Since the scenario examined in this analysis is more conservative than the anticipated response to CSAPR and MATS, results of this analysis should not be viewed as an estimate of the expected impacts of any final or forthcoming EPA rules or combination of rules.

Resource adequacy is one necessary component of grid reliability, and it can be evaluated for a relatively broad region. However, it does not ensure delivery of power to end use consumers or the ability to recover from events such as the unexpected loss of a generator or transmission line. These aspects of grid reliability depend on transmission adequacy and provision of other ancillary services, which depend strongly on the local details of the electric power system. This report does not

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[3] Two other regulations, the Coal Combustion Residuals rule and the 316(b) Cooling Water Intake Structures rule, have been proposed, and the final rules may differ significantly from the proposed rules. New Source Performance Standards for greenhouse gases have not yet been proposed.

attempt to identify or assess any aspect of reliability beyond resource adequacy.[4] However, several flexibility mechanisms provide tools to federal and state governments and other stakeholders to manage local reliability challenges that may arise after more detailed analysis is conducted. The U.S. Department of Energy (DOE) recognizes the role that regional transmission organizations (RTOs), independent system operators (ISOs), state public utility commissions (PUCs) and others will have in conducting and reviewing these detailed analyses.

In summary, this report concludes:

- Assuming prompt action by regulators and generators, the timelines associated with the construction of new generation capacity and installation of pollution control retrofits would generally be comparable to EPA's regulatory compliance timelines.
- A Stringent Test Case more conservative than the anticipated implementation of CSAPR and the proposed MATS rule showed the overall supply-demand balance for electric power in each region examined would be adequate; however, further iterative analysis will be warranted to assess local reliability considerations as the rules are implemented.
- Mechanisms exist to address such reliability concerns or other extenuating circumstances on a plant-specific or more local basis, and the Department of Energy is willing to provide technical assistance throughout this process.

The remainder of this report is divided into two sections. Section 2 provides an overview of EPA's regulatory timeline and describes how various potential compliance pathways align with this timeline. Section 3 uses a version of the National Energy Modeling System (PI-NEMS)[5] to explore resource adequacy implications of a test case in which potential future plant retirements, additions and pollution control retrofits are considered. The following technical supplement to this introduction is intended to describe the limitations of this analysis, recommended restrictions on its interpretation and the steps that could be taken to address those limitations or expand this analysis in the future.

1.1 Technical Supplement

The primary purpose of this report is to examine, for each North American Electric Reliability Corporation (NERC) region in the U.S. (see Appendix A of this report for a map), how the volume of retirements and pollution control installations prompted by constraints more strict than CSAPR and MATS requirements would affect the planning reserve margins and available capacity for that region. Two main cases were developed in this study: A Reference Case and a Stringent Test Case. For each of these cases, a low natural gas price sensitivity version was also considered. The resulting four cases were modeled using a version of the National Energy Modeling System (PI-NEMS) based

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[4] See technical supplement below for a discussion of the limitations of this analysis and restrictions on its interpretation.

[5] The version of NEMS utilized in this report has been run by OnLocation, Inc. with input assumptions determined by DOE. Since this analysis was commissioned by DOE's Office of Policy and International Affairs (PI) and uses a version of NEMS that differs from the one used by the U.S. Energy Information Administration (EIA), the model is referred throughout the document as PI-NEMS. The results described in this report do not necessarily represent the views of EIA.

on EIA's 2011 Annual Energy Outlook.[6] These cases are not intended to capture the full set of possible outcomes related to resource adequacy under the implementation of EPA rules. However, the adoption of conservative assumptions implies that results of this study likely overstate required compliance actions by the utility sector and that the qualitative conclusions about resource adequacy in 2015 would not change under many other potential scenarios.

The following limitations of PI-NEMS are most relevant for the interpretation of resource adequacy results:

- The electric sector in PI-NEMS is modeled as 22 distinct regions. All electricity generated in or imported into a given region is assumed to be deliverable within that region, with explicit costs associated with that delivery. In other words, there are no transmission constraints within a given region, and flows of power between regions are constrained by a simple pipe flow representation of existing transmission capacity, with potential to build new transmission capacity between regions when it is economically justified.
- Natural gas is assumed to be deliverable where it is needed for generation, and the delivered cost varies by region.

These limitations imply that statements about resource adequacy should not be interpreted to imply that electric power or natural gas is deliverable within a given region, even when supply is adequate. Local studies will need to be undertaken to assess deliverability when appropriate. In addition, planning margins are one of several metrics available to evaluate resource adequacy. More focused studies could be carried out, when appropriate, using deterministic methods similar to the ones employed here or using alternative stochastic methods.

The following types of analyses could be performed in the future to examine other aspects of grid reliability beyond those examined here:

- Stochastic evaluation of resource adequacy (e.g., to evaluate loss of load probability)
- Transmission adequacy analysis using (DC power flow) production cost models with explicit representation of the full transmission system
- Static and/or dynamic AC power flow analysis to evaluate reactive power support, system stability, etc.
- Survey of plants providing relevant ancillary services in a given area

Many of these analyses require knowledge of the actual units being removed or added to the system, including specification of their location and connection to the transmission network, as well as an explicit representation of the overall system topology. Therefore, these analyses are most appropriate to conduct on a more localized basis, once particular units are identified for retirement, extended maintenance or new construction.

[6] Specific modeling assumptions related to the cases are described in Section 3 of this report.

Chapter 2. Alignment of potential compliance pathways with regulatory deadlines

This section gives an overview of the requirements and regulatory deadlines associated with two key EPA air quality rules. It then discusses the main compliance options available to generator owners to satisfy these requirements and evaluates the alignment between implementation timelines and regulatory deadlines.

2.1 Regulatory deadlines

This analysis considers two major EPA power sector regulations that will have been finalized by the end of this year, namely the final Cross-State Air Pollution Rule (CSAPR) and the proposed Mercury and Air Toxics Standards (MATS).[7] Two others, the Cooling Water Intake Structures Rule and the Coal Combustion Residuals Rule, are not examined here, as the details for their final requirements and implementation timelines are more uncertain.[8] EPA is also expected to release proposed New Source Performance Standards (NSPS) for greenhouse gas emissions from new power plants in coming months, but it is not possible to evaluate their impact at least until proposed rules with clear compliance options are offered by EPA for consideration. This study recognizes the significance of regulatory uncertainty in contemporary decision-making, and as discussed in Section 3.1, it includes a conservative investment payback requirement as a rough proxy for that uncertainty.

The Cross-State Air Pollution Rule was finalized in July 2011, and a proposed update was issued in October 2011. This rule was issued in response to a court order remanding the Clean Air Interstate Rule (CAIR). CSAPR puts in place four regional trading programs that set emissions limits for SO_2 and NO_x in 27 states.[9] EPA issued a Supplemental Notice of Proposed Rulemaking to include six states in the seasonal NO_x program (all but one are covered under another aspect of the program). SO_2 and NO_x are both precursors to particulate pollution, and NO_x is also a precursor to ozone pollution. Both particulate and ozone pollution contribute to premature deaths, non-fatal heart attacks, aggravated

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[7] Both of these regulations are being promulgated by EPA under the Clean Air Act Amendments of 1990.

[8] As proposed, the Cooling Water Intake Structures Regulations (under section 316(b) of the Clean Water Act) would require that cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. Affected power plants would have to demonstrate compliance with a national impingement requirement and work with state and federal permitting authorities to address entrainment on a site-specific basis addressing factors detailed in the proposed regulations. EPA proposed a rule in March 2011 and is under a settlement agreement to issue a final rule by July 2012. Coal Combustion Residuals (CCR) rules proposed in June 2010 under the Resource Conservation and Recovery Act (RCRA) would regulate the handling of CCRs (such as coal ash) from their generation at power plants to final disposal. Depending on whether EPA classifies CCRs as RCRA Subtitle D waste or RCRA Subtitle C special waste, compliance could be required within six months after the final rule or several years later after states adopt the federal regulation, respectively. EPA does not face a legal requirement to issue a final rule by a specific deadline. For information about 316(b), see Federal Register Volume 76, Number 76 (Wednesday, April 20, 2011) pages 22174-22288. For information about CCR, see EPA, "Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities; Proposed Rule" 2011.

[9] The four regional programs cover annual NO_X emissions as well as ozone season NO_X emissions and SO_2 emissions from two separate groups of states.

asthma attacks and acute bronchitis. EPA estimates the annualized social costs of CSAPR to be $0.8 billion and the annualized monetized social benefits to be $110-280 billion in 2014.[10]

The Mercury and Air Toxics Standards were proposed in March 2011, and EPA is under a court order to finalize the rule by December 16, 2011. MATS would set limits on emissions of mercury and acid gases, and it would reduce heavy metals and other toxic chemicals by limiting particulate matter. Mercury causes nerve and brain damage in children and other vulnerable populations. Acid gases cause lung damage and contribute to asthma and other respiratory diseases. Other toxic chemicals controlled by the rule such as arsenic and chromium can cause cancer. EPA estimates the annualized social costs of the proposed MATS rule to be $10.9 billion and the annualized monetized social benefits to be $53-140 billion in 2016.[11]

CSAPR requires fossil fuel fired generators to demonstrate compliance annually. Requirements begin on January 1, 2012 and tighten in certain states in 2014. Starting in March 2013 and annually thereafter, sources must demonstrate compliance by submitting emissions allowances for each ton of regulated pollutants emitted in the previous year. MATS has a statutory compliance deadline of January 2015, subject to the flexibilities described in this report, after which coal and oil-fired generators must meet emissions limits for the pollutants described above.

2.2 Potential compliance pathways

Some existing generation facilities already have sufficient pollution controls to ensure compliance with CSAPR and MATS. Electric generating units not already in compliance with new rules will have a variety of options available to them. Owners will typically choose among available options to comply with the requirements in the most cost-effective way. Given the compliance deadlines associated with CSAPR and MATS and the wide applicability of MATS to the generating fleet, the remainder of this section focuses on these rules.

Available compliance options for CSAPR and MATS may include:

- **Use of existing controls:** Some plants could increase utilization of existing pollution control technologies. Increasing utilization rates can decrease emissions.

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[10] All estimates are in 2007 dollars. The range in social benefits reflects the use of alternate discount rates (3% and 7%) and alternate studies for PM-related mortality. Social costs were also valued at the alternate discount rates, but the estimate is unchanged at this level of rounding. EPA "Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States" June 2011.

[11] All estimates are in 2007 dollars. The range in social benefits reflects the use of alternate discount rates (3% and 7%) and alternate studies for PM-related mortality. Social costs were also valued at the alternate discount rates, but the estimate is unchanged at this level of rounding. EPA "Regulatory Impact Analysis of the Proposed Toxics Rule" March 2011.

- **Shifts in dispatch (relevant to CSAPR only):** Individual plants could comply with CSAPR by decreasing generation since compliance is based on total annual emissions.[12] Other, cleaner plants could increase generation in order to meet electricity demand.
- **Purchase of allowances (relevant to CSAPR only):** Plant owners could purchase emissions allowances from other sources that emit less than their individual limits, in such a way that the total system-wide emissions caps would be maintained.[13]
- **Fuel switching:** Some plants could switch to fuels with a lower pollutant content (such as low-sulfur and low-chlorine coals to comply with CSAPR and MATS respectively). Fuel switching (re-powering) to natural gas could also be possible.
- **Retrofitting units with pollution controls:** Existing generating units could deploy new pollution control equipment to reduce emissions. In some cases, existing controls could be upgraded to provide the necessary emissions reductions.
- **Retiring uneconomic units:** Existing generating units could be retired rather than improved to comply with the rules. Where replacement capacity would be needed, new generating units that meet environmental requirements could be added to the system or demand side measures could be implemented in order to meet expected electricity demand.

The first three options, where applicable, can be undertaken rapidly. Often, fuel switching between coals can also be done quickly. These four options are expected to be the main near-term compliance pathways for CSAPR, whose initial compliance deadlines precede those of MATS. Three remaining categories of options include repowering a plant with natural gas, retrofitting, and retiring a plant altogether. The remainder of this section focuses on the timelines associated with these options.

Table 1 lists technology options to control different pollutants regulated by CSAPR and MATS, as well as other potential measures available to comply with these rules. Typically, several options are available to control any given pollutant, and many control technologies can be used to facilitate compliance with multiple requirements. For example, a wet Flue Gas Desulfurization (FGD) system can facilitate compliance with both CSAPR and MATS by controlling SO_2 and acid gases. As a result of such co-benefits, the number of potentially available pathways to comply with CSAPR and MATS is large.

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[12] MATS will require power plants to meet emissions rate standards, so this option is not generally relevant. However, power plants with multiple generating units may be able to shift generation between units to enable the entire plant to meet the standards under certain circumstances.

[13] In addition, allowances can be banked for future use, so it is also possible to over-comply and accumulate allowances early in the program for use in subsequent compliance periods.

Table 1: Retrofit control technologies and other potential measures available for compliance with CSAPR and MATS

Rule (Status)	Pollutant	Control Technologies	Other Measures
CSAPR (Final)	SO_2	DSI; wet or dry FGD	Shifts in dispatch; purchase of allowances; fuel switching
	NO_x	SCR; SNCR; low-NO_x burners	Shifts in dispatch; purchase of allowances; fuel switching
MATS (Proposed)	Mercury	ACI	Fuel switching
	Acid Gases	DSI; wet or dry FGD	Fuel switching
	Metallic Toxics/PM	Fabric Filter; ESP	Fuel switching

Control Technologies Key:
Wet/dry FGD = Flue Gas Desulfurization (also referred to as wet or dry scrubbers)
SCR = Selective Catalytic Reduction
SNCR = Selective Non-Catalytic Reduction
DSI = Dry Sorbent Injection
ACI = Activated Carbon Injection
ESP = Electrostatic Precipitators
Fabric Filter, sometimes referred to as a baghouse

Pollution control equipment will take time to install. Figure 1 shows estimated ranges for pollution control build times based on past experience from various sources for a variety of technologies. Excluding any necessary regulatory approvals, these technologies should generally require fewer than four years for combined design, construction and start-up, and, in most cases, the amount of time required should be significantly shorter.

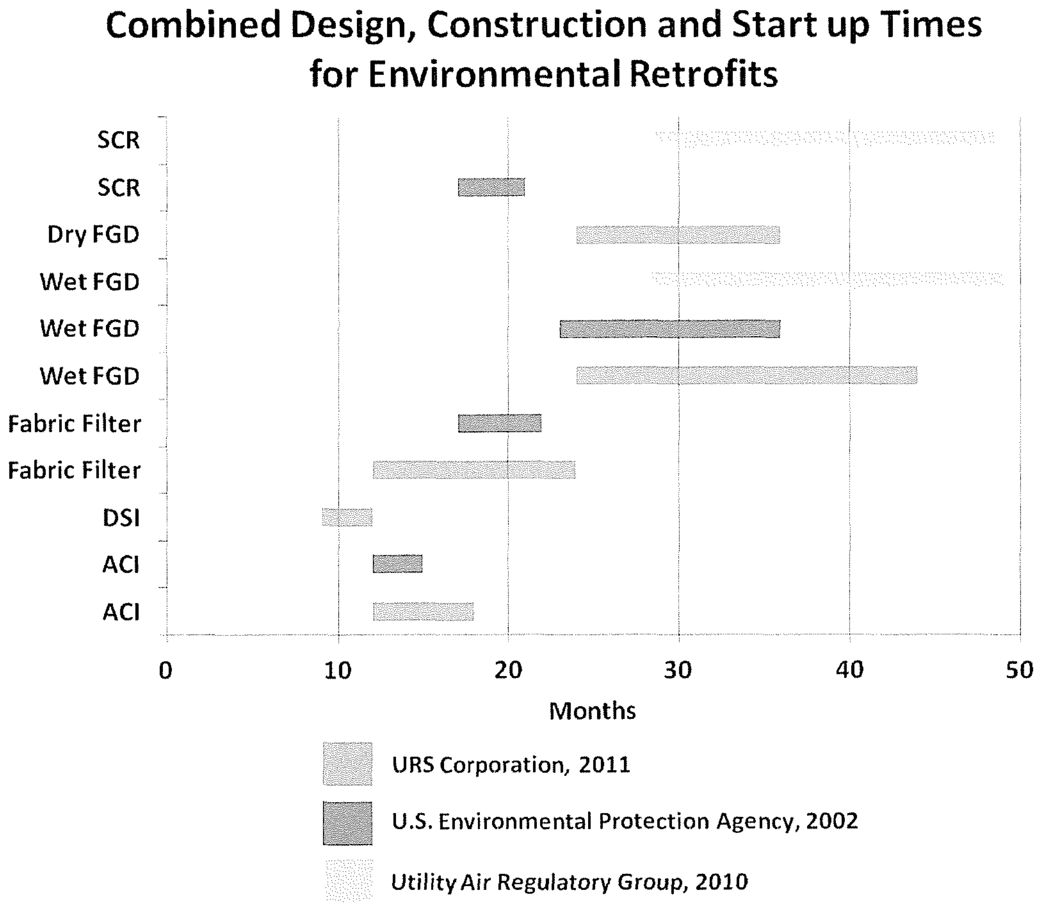

Figure 1: Estimated range of combined design, construction and start-up times for pollution control retrofit installations[14]

All plants installing pollution controls will require construction permits and may require modifications to existing Title V operating permits. In addition, owners of plants in regulated markets may require approval from the relevant public utility commission (PUC) to recover the costs of the retrofits through rates. While some of these additional requirements and approvals may be pursued simultaneously with design, construction and start-up activities, they may collectively extend completion times. For context, Figure 2 provides a breakdown of the U.S. coal generation fleet by ownership and whether or not a generator owned by an electric utility is equipped with an

[14] These estimates assume all installations are for a single generating unit. Design, construction and start-up times could take longer if a single device is installed to control pollution from multiple generating units. Ranges do not include any potentially necessary public utility commission approval, selection of vendors or permitting and assume sufficient materials and labor are readily available. Sources: URS Corp. "Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants" 2011; EPA "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multi-pollutant Strategies" 2002; Utility Air Regulatory Group "Implementation Schedules For Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Process Equipment" 2010.

FGD. Currently, about one quarter of U.S. coal generators are classified as independent power producers. PUC approval is not required for these generators to install pollution control equipment. Furthermore, 44 percent of the generation fleet owned by electric utilities (34 percent of the total fleet) is not equipped with an FGD (the pollution control option with the longest construction time) and may require state PUC approval of any new retrofit investments.

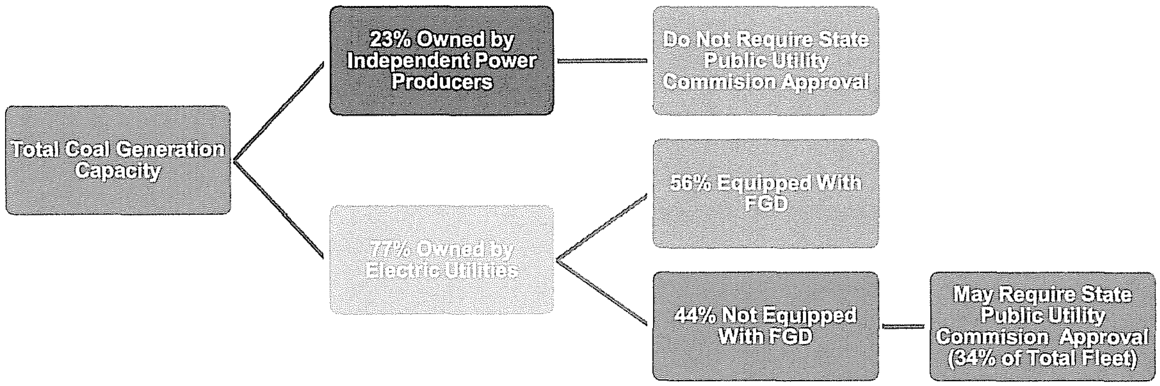

Figure 2: Breakdown of U.S. coal generation fleet by ownership type and pollution control equipment[15]

Recent experience suggests that rapid, large-scale deployment of pollution control equipment is possible in advance of deadlines to meet environmental requirements. Figure 3 illustrates recent historical deployment of retrofit technologies from 2005 through 2010. During this period, nearly 160 GW of pollution control retrofits were completed nationwide. The maximum amount of installations in this period occurred in 2009 when nearly 25 GW of FGDs and over 50 GW of total retrofits were installed. This deployment coincided with the run-up to the first compliance periods for the NO_x and SO_2 trading programs under EPA's Clean Air Interstate Rule. These technologies are among those expected to be used for compliance with CSAPR and MATS. Recent declines in retrofit deployment further suggest that there is readily available manufacturing capacity and labor supply to meet increases in demand going forward.

[15] Energy Information Administration, 2009 Form 860, 2010. Equipment estimates are current as of 2009, and percentages are based on capacity. EIA Form 860 sector definitions are used to differentiate coal generation by regulatory status.

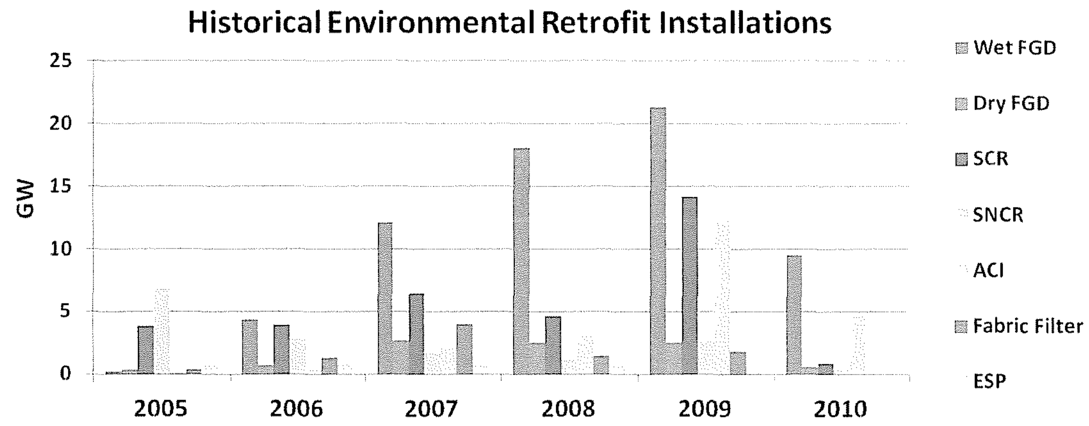

Figure 3: Coal capacity receiving air pollution controls by in-service year, 2005-2010[16]

Even though several retrofit options may be available to comply with the rules, it may not be profitable to install controls on some generating units. In these instances, owners may seek to repower those units with natural gas or retire them. Switching from coal to natural gas would likely require more time than switching between types of coals due to plant modifications and the potential need for new natural gas pipeline infrastructure. Even taking this into account, fuel switching to natural gas could be faster than construction of a new natural gas plant, which might be undertaken to replace the capacity of a unit to be retired. While individual plants can sometimes be retired without adverse impacts on electric system reliability, in some cases, new replacement generation or transmission capacity might be needed. Excluding time for any required regulatory approvals, some natural gas capacity (combustion turbines) could be built in as little as one year, while the construction of new baseload combined cycle natural gas power plants could take from two to four years. Expansion of the natural gas pipeline system to accommodate new natural gas-fired units can generally be undertaken in parallel to new plant construction and also typically takes between two and four years. New electric transmission lines could take significantly longer.

2.3 Relationship between potential compliance pathways and regulatory deadlines

For CSAPR, plant owners have the option to purchase allowances (once a liquid allowance market is established) or to use banked allowances from previous years within each pollution control program to comply in the most cost-effective manner. Along with the flexibility provided by other non-build options such as fuel switching, greater use of existing controls and shifts in the dispatch of generators, this flexibility to trade allowances is expected to help facilitate compliance with CSAPR by the regulatory deadlines without the need for rapid fleet-wide investment in pollution control retrofits. Over the long-term, as requirements tighten, installation of additional environmental controls could be undertaken to maintain compliance with CSAPR.

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[16] EIA 2009 Form 860, 2010 (scrubbers and particulate controls), EPA NEEDS Database 4.1, 2011 (ACI and NOx controls). 2010 values are planned installations.

MATS compliance will require use of additional options. Figure 3 provides a timeline for installation of pollution controls and construction of new generation capacity in relation to the compliance deadline for MATS. Assuming prompt action by plant owners, permitting authorities and (where applicable) public utility commissions, the anticipated completion times for new pollution controls and new generation capacity additions are generally comparable to the compliance period for MATS. Moreover, this figure omits other options such as fuel switching or greater use of existing controls that may facilitate compliance in some cases, and it does not include non-build options such as demand response or energy efficiency programs that might be deployed quickly to help maintain adequate resources when plants retire.

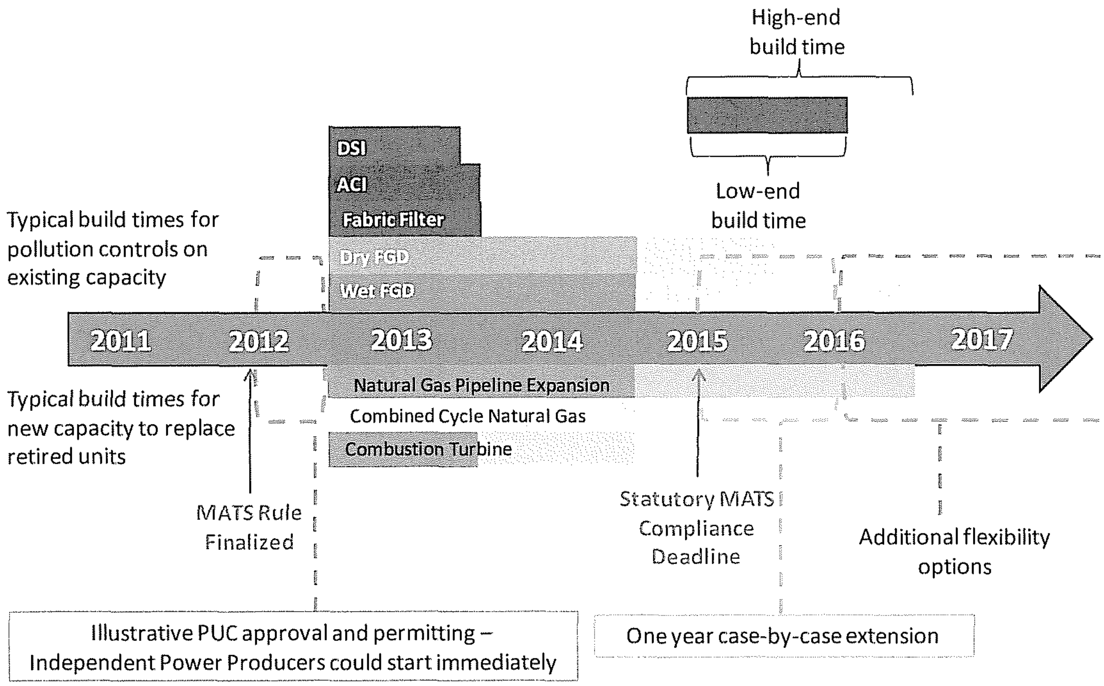

Figure 4: Retrofit and new build timelines in relation to EPA statutory deadline for the MATS rule and potential compliance extensions[17]

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[17] Independent power producers will be able to initiate compliance strategies as soon as the MATS rule is finalized, if not before. Owners of plants in regulated markets may need to acquire PUC approval before moving forward with major investments, which may delay the start time for the installation of retrofits and/or generation. A survey of over 100 recent coal plant pollution control retrofit approvals before PUCs in ten states found that the average approval time across all cases was 6.3 months. Less than 6 percent of all cases took more than one year. See: M.J. Bradley & Associates prepared for SRA International, Inc. "Public Utility Commission Study," 2011. The figure shows an illustrative case in which construction begins six months after rule finalization. Sources: URS Corp. "Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants" 2011; EPA "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multi-pollutant Strategies" 2002; Utility Air Regulatory Group "Implementation Schedules For Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Process Equipment" 2010; Energy Information Administration "Assumptions to the Annual Energy Outlook" 2011; Letters to Southern Company from Transco Natural Gas and Southern Natural Gas 2011; Survey of state and industry natural gas plant construction data by Energetics Inc. 2011, Industry Expert Communication 2011.

Nonetheless, there are likely to be circumstances where delays in PUC approval, permitting or construction push the completion date of a project beyond the 2015 compliance deadline. In such cases, there are multiple flexibility mechanisms available on a plant-specific basis to facilitate compliance. Specifically, Section 112(i)(3)(B) of the Clean Air Act (CAA) allows the EPA or the relevant permitting authority (e.g., a state environmental protection agency) to extend the MATS compliance deadline by an additional year to allow time for the installation of environmental controls. In addition to this one-year extension for compliance with MATS, other flexibility options are available to provide extra time on a plant-specific basis.[18]

Therefore, existing units that choose to retrofit in order to comply with MATS should have sufficient time to do so if industry and state regulatory authorities act swiftly and responsibly, even in instances where completion of a project takes longer than anticipated. Similarly, given timely notification of an intention to retire existing capacity[19], these same flexibility mechanisms might be used to align the timing of retirements of reliability-critical units with new capacity additions.

[18] These options could include administrative orders under Section 113(a)(4) of the CAA (providing up to one additional year for compliance), negotiated Consent Decrees with the appropriate concurrences from the Department of Justice and the courts, or the flexibility provided by Section 112(i)(4) of the CAA.

[19] Current notification lead time to an Independent System Operator is approximately 90-120 days, which could be timely enough to identify a specific reliability standard that could be violated yet not long enough to resolve the issue. Such a case would be a candidate for use of one of the flexibility mechanisms.

Chapter 3. Resource adequacy

This section examines an illustrative, stringent scenario to "stress test" one aspect of grid reliability – resource adequacy. Resource adequacy means that there are sufficient resources, in the form of available generation and demand response capacity, to meet peak electricity demand (and by extension, demand in all other hours of the year) in a given region, before constraints on deliverability are considered. Peak demand usually occurs in the afternoon during the heat of the summer months, although in some regions it can occur in other seasons. The difference between available capacity and normal peak demand is called the planning reserve margin, which is usually expressed as a percentage over normal peak demand.[20]

Although the North American Electric Reliability Corporation (NERC) assigns a default reserve margin of 15% for most regions[21], each region may adopt a standard with a different value. A common standard in electricity system planning is that resources should be sufficient to yield less than one day in ten years of unmet electricity demand[22], and each region may apply such a standard to calculate a target for its planning reserve margin based on its resource mix. This report does not analyze other aspects of grid reliability that must be analyzed locally, such as transmission adequacy, voltage support and system stability.

EPA regulations can affect resource adequacy in two ways. First, they can lead to some additional retirements of existing generation capacity (typically coal-fired or simple cycle oil/natural gas steam capacity) beyond the retirements that would have occurred in the absence of new power sector regulations. Depending on the number and location of these retirements (including the retirements that would have occurred absent new regulations), there might be a need for new capacity in order to maintain planning reserve margins above the target for a specific region. Second, EPA regulations will motivate owners of many of the plants that do not retire to install pollution control equipment. Once construction of this equipment is complete, plants may have to pause generation for a short time to "tie-in" the controls. Whenever possible, these tie-ins are undertaken during or near routine planned maintenance outages and are not scheduled during peak load periods. In the case of certain installations, however, the tie-in period may extend for a few weeks beyond standard maintenance outages, reducing the available capacity to meet demand during those off-peak periods.[23]

To test the potential resource adequacy implications of new EPA rules, this report uses a version of the National Energy Modeling System (PI-NEMS) to examine two stringent scenarios. Planning

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[20] Intermittent resources such as wind and solar are discounted in this calculation, since they may not be available at the time of peak demand.

[21] NERC assigns a default standard of 10% to regions with predominantly hydroelectric sources of generation.

[22] See, for example, North American Electric Reliability Corporation, "Resource and Transmission Adequacy Recommendations" 2004.

[23] See section 2.2.9 of Utility Air Regulatory Group, "Implementation Schedules for Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Process Equipment" 2010. See section 2.2.9

reserve margins are calculated for each NERC region in the U.S.[24] Results from these scenarios suggest that resource adequacy can be maintained in each NERC region in the U.S. under conservative assumptions about available compliance options, as long as some new capacity can be built before 2015 beyond that which is already planned.

3.1 Modeling assumptions

This analysis consists of a comparison, conducted in PI-NEMS,[25] between a Reference Case that does not include CSAPR or MATS and a Stringent Test Case that includes constraints that are deliberately designed to be more conservative (in the sense of offering fewer compliance options and therefore driving greater retirements) than the CSAPR and MATS rules. The specific assumptions associated with these cases are provided in Table 2. The results from the low natural gas price (high natural gas supply) cases are discussed in Appendix B to this report.

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[24] See Appendix A for a map of the NERC regions. PI-NEMS represents the electric power sector using 22 regions, which combine in groups to form the eight main NERC regions in the U.S.

[25] NEMS is a product of the U.S. Energy Information Administration (EIA), which uses it to issue its yearly Annual Energy Outlook as well as to evaluate the impacts of proposed policies. According to EIA, "NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics." Documentation for NEMS can be found on the website of EIA: http://www.eia.gov/forecasts/aeo/. As stated earlier, PI-NEMS refers to the version used in this report, and results expressed here should not be assumed to represent the views of EIA.

Table 2: Descriptions of cases examined in PI-NEMS

Case	Description
Reference Case	Modified[26] version of published AEO 2011 Reference Case with the following substantive changes: • Fabric Filter and ACI costs are increased to mirror EPA assumptions.[27] • Construction and operation of unplanned[28] natural gas combustion turbines and combined cycle units are delayed until 2013 and 2014, respectively, reflecting the construction times associated with these technologies. The existing CAIR rule is included and does not expire.
Stringent Test Case	Identical to the Reference Case with the following additional constraints: • CSAPR SO_2, annual NO_x and seasonal NO_x limits[29] are in place in 2012 with variability limits starting in 2014 only for SO_2. The SO_2 control groups 1 and 2 are treated as a single trading market due to the regionality of PI-NEMS. • 90% mercury reduction requirement is imposed in 2015. • All unscrubbed coal units must retrofit with a wet FGD or retire by 2015. • All units not already equipped with a fabric filter must install one or retire by 2015. • All pollution control capital retrofit technology costs must be paid back over 10 years.
Low Natural Gas Price Reference Case	Identical to the Reference Case above, except that the natural gas supply follows EIA's "High Shale EUR" side case. This increases the amount of shale gas recovered in each well and effectively lowers natural gas prices at any given quantity.
Low Natural Gas Price Stringent Test Case	Identical to the Stringent Test Case above, except that the natural gas supply follows EIA's "High Shale EUR" side case.

[26] The major difference is that the logic associated with interregional capacity transfers has been modified so that the transfer capacity is reflected in the supply/demand balance of importing regions.

[27] See Appendix C for a table of retrofit costs for representative plants.

[28] Unplanned units refer to power plants built based on economic decisions made within the model, as opposed to planned units, which are those reported to EIA as being under construction as of December 31, 2009 as well as an additional 4.3 GW of renewable capacity included in the reference case by EIA.

[29] These are the limits in the proposed update to the CSAPR rule in October 2011. States covered under EPA Supplemental Notice of Proposed Rulemaking are included in the seasonal NOX program.

The Stringent Test Cases in this analysis should not be viewed as estimates of the expected impacts of CSAPR and MATS, but rather as illustrative, stringent cases used to bound resource adequacy implications. In particular, while the assumptions in the Stringent Test Cases result in a power system that would satisfy the environmental requirements of CSAPR and MATS, several other compliance options such as DSI or upgraded ESPs are not included in these scenarios. Such compliance options are commercially available, and in technically feasible situations, they will be more economically attractive than the options allowed in the Stringent Test Case. As fabric filters and wet FGDs are both more time- and capital-intensive than these alternative options, the scenario examined here is intended to be a stress test for resource adequacy, as the electric sector complies with the CSAPR and MATS rules. The inclusion of a 10-year investment payback requirement on pollution control retrofits is 10 years less than the default payback assumed in the Annual Energy Outlook[30] and significantly less than the typical payback requirements assumed in other studies of the electricity system impacts of EPA rules.[31] This assumption adds an additional level of conservatism and acts as a rough proxy for future regulatory uncertainty, including other forthcoming rules.

3.2 Modeled capacity retirements and retrofits

Figure 5 shows the cumulative retirements of coal plant capacity in the Reference and Stringent Test Cases. The amount of capacity attributed to the additional constraints nationally in 2015 is the difference between the amount in the Reference Case and the amount in the Stringent Test Case in that year, namely 21 GW. While the total number of modeled retirements is slightly higher in 2020, the difference remains at 21 GW (not shown). As discussed in Appendix B to this report, natural gas prices can have a significant impact on the number of coal and oil-fired plant retirements.

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[30] EIA, "Annual Energy Outlook, 2011" 2010. See page 48.

[31] For example, see EPA-IPM v4.10 documentation, http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html; "2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations", NERC, October 2010. http://www.nerc.com/files/EPA_Scenario_Final.pdf; "Staying Power: Can US Coal Plants Dodge Retirement for Another Decade?", IHS CERA, April 2011. http://www.ihs.com/products/cera/energy-report.aspx?id=1065929313; "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet ", EEI, January 2011. With the exception of assumptions for independent power producers made by IHC CERA (10 years) and plants with a capacity factor below 35 percent made by NERC, these studies typically assumed pay back periods between 20 and 30 years and always greater than 10 years.

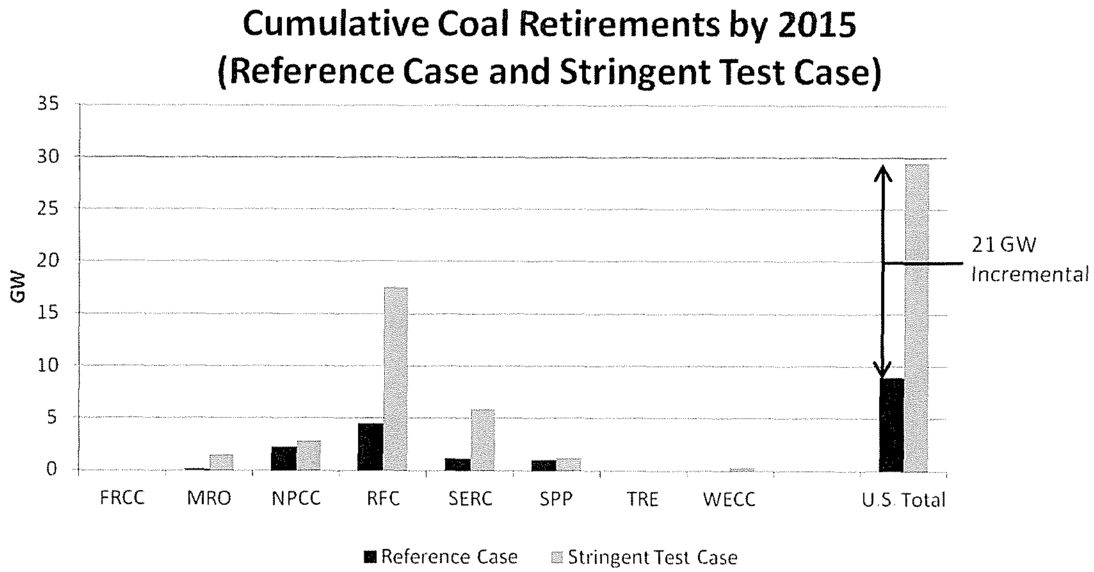

Figure 5: Cumulative coal retirements by NERC region, 2011-2015, in Reference and Stringent Test Cases[32]

Figure 6 shows the total amount of capacity retrofit by 2015 under the Stringent Test Case. Nationally, owners of 253 GW of coal units would install fabric filters, and owners of 110 GW would install wet FGDs. This scenario conservatively assumes that every coal plant that is not retired must have both of these technologies installed. Again, in scenarios with less rigid compliance options, the scale of these installations is likely to be significantly lower than the numbers in Figure 6. For example, some units may be able to install DSI in order to comply with the acid gas limits under MATS and would therefore not need to install a new FGD. Similarly, some units might be able to use or upgrade existing ESPs to meet particulate matter limits and would not need to install a new fabric filter.

[32] U.S. total values in this and subsequent figures include results for the lower 48 states only. In addition to coal retirements, by 2015 there are projected to be 25 GW of cumulative oil/natural gas steam unit retirements (of which 10 GW are incremental) in the Stringent Test Case and a total of 3 GW of natural gas combustion turbine retirements.

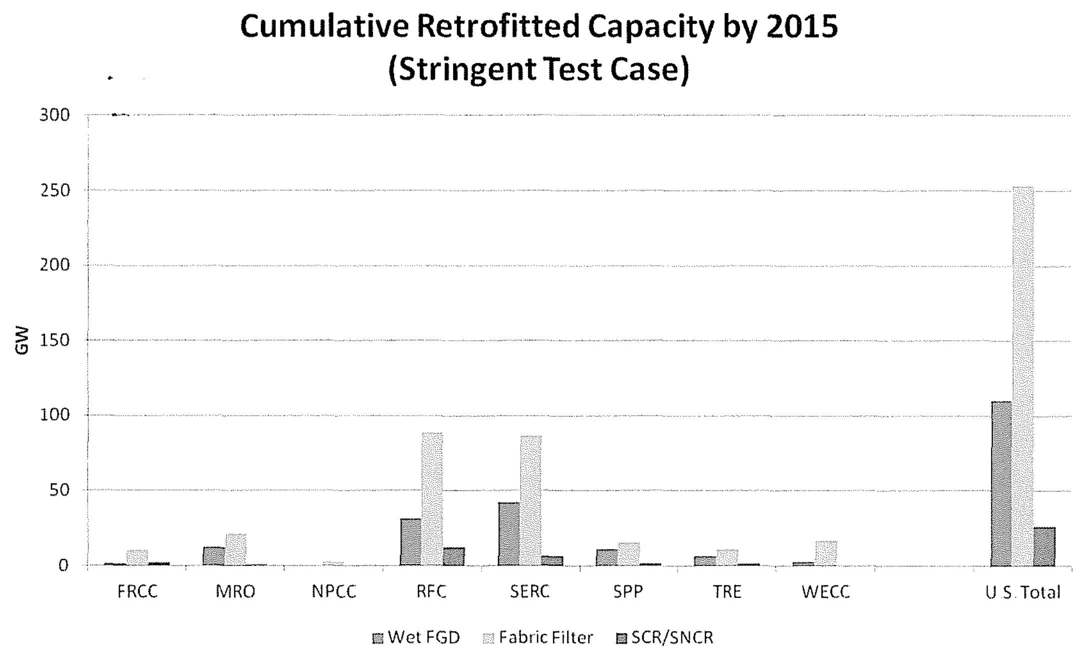

Figure 6: Cumulative capacity retrofit from 2011-2015 in the Stringent Test Case, using three types of control technologies[33]

3.3 Modeled impacts of retirements on planning reserve margins and new capacity requirements

Figure 7 shows the results for both scenarios on planning reserve margins in 2015, the year by which most coal retirements attributed to the Stringent Test constraints would have occurred. In all regions, PI-NEMS will add new generation or transmission capacity if needed to ensure that target reserve margins are satisfied.[34] To quantify this new capacity, Figure 8 shows the modeled cumulative capacity additions in 2015 by NERC region in the Reference Case. Most of these capacity additions are planned additions that are currently under construction or slated for completion no later than 2012. The model adds approximately 8 GW of unplanned renewable energy capacity, primarily wind in the SPP and WECC regions, in anticipation of the production tax credit expiring in

[33] Figure does not include approximately 1 GW of planned dry FGD retrofits. No additional dry FGDs are built because this control technology is not available in the model for anything other than planned retrofits. In the Reference Case, 32 GW of SCRs and SNCRs are installed by 2015 in the U.S. to comply with the CAIR rule. Under the stress test case, 26 GW of SCRs and SNCRs are installed in the U.S. by the same year.

[34] PI-NEMS is designed to always satisfy planning reserve margin targets. These targets are computed internally in the model to reflect the willingness of consumers to pay for additional capacity to avoid unserved energy. Reserve margin targets are calculated in PI-NEMS at the Electric Market Module region level and then aggregated in this report to the corresponding NERC region. To compute the capacity that can count toward planning reserves, the model discounts intermittent resources such as wind to capture the fact that these resources may not always be available to meet demand. The discounting of resources is similar, but not identical to the discounting used by NERC.

2012.[35] A relatively small amount of unplanned natural gas combustion turbine capacity is added by the model between 2013 and 2015 in the Reference Case.

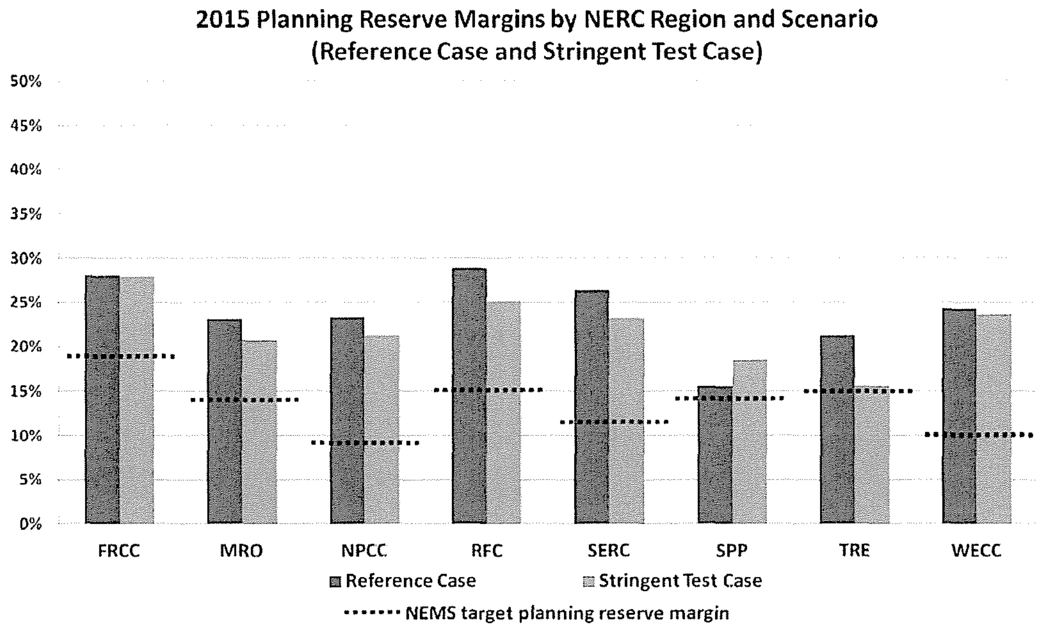

Figure 7: PI-NEMS planning reserve margins and targets in 2015

Figure 9 shows the additional capacity that would be added in the Stringent Test Case, relative to the Reference Case. In most regions in the Stringent Test Case, no significant additional capacity would be built beyond what would already be built in the Reference Case. Most regions have more than sufficient capacity, in the sense that their planning reserve levels remain higher than their target levels. In such cases, there would be no resource adequacy-related reason to replace lost capacity with new additions (although there might be other reasons not captured by this analysis). However, as noted above, in at least one region (TRE), a small amount of new natural gas combustion turbine capacity (0.7 GW) would be required by 2015 to meet target margin levels, and this capacity would be added in 2015.

[35] All of these additions are unplanned and were built by the model based on economic decisions. For context, the average annual amount of new wind added between 2005 and 2010 was 5.8 GW, with a peak of over 9 GW in 2009 (EIA, 2009 Form 860, 2010).

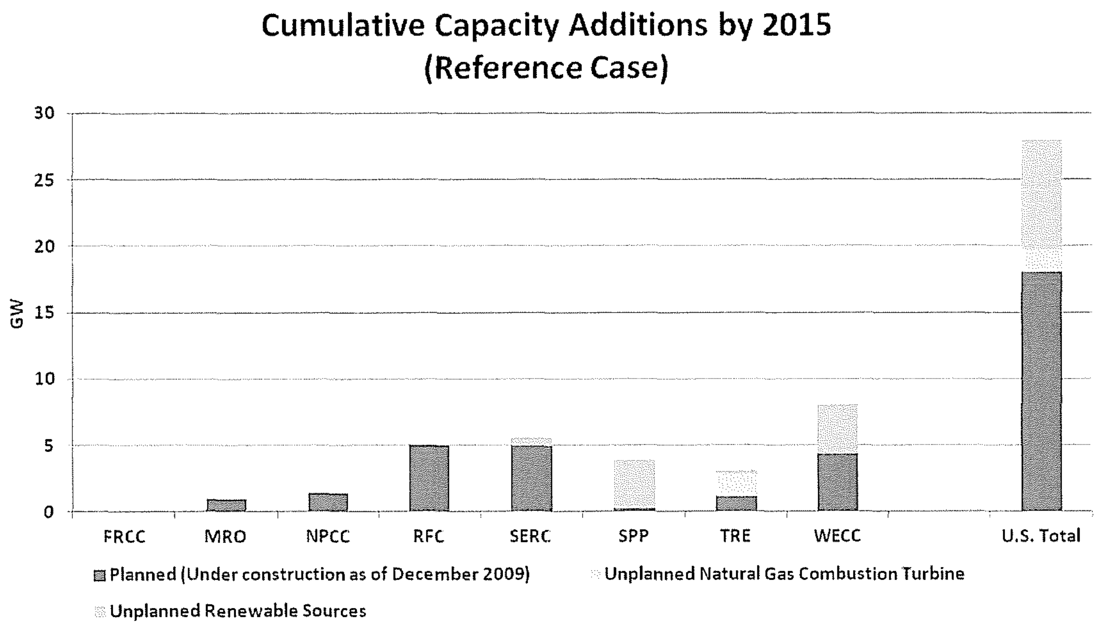

Figure 8: Cumulative regional capacity additions, 2011-2015, in the Reference Case[36]

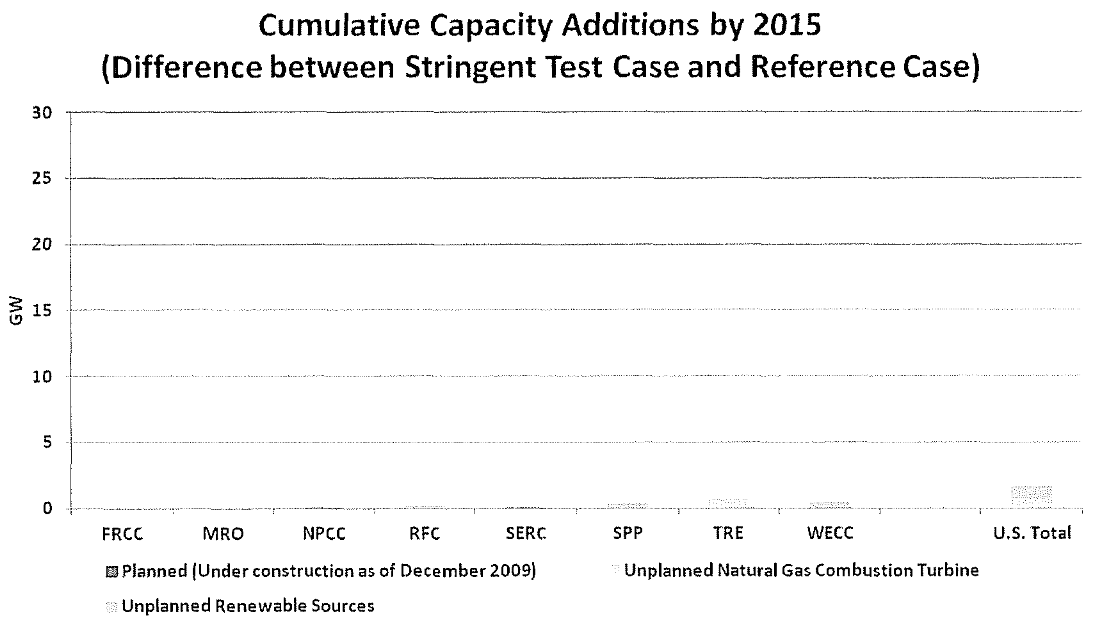

Figure 9: Cumulative regional capacity additions, 2011-2015, difference between Stringent Test Case and Reference Case

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[36] Planned additions are those reported to the EIA as under construction as of December 31, 2009 as well as an additional 4.3 GW of renewable capacity included in the reference case by EIA. Unplanned additions are those that are built for economic reasons according to the model. Most planned additions and unplanned renewable additions are operational before 2013. Unplanned combustion turbine additions occur after 2013.

To put these capacity additions in perspective, Figure 10 compares cumulative Reference Case and Stringent Test Case capacity additions between 2011 and 2015 (the Stringent Test Case column represents the combined capacity additions from Figure 8 and Figure 9) with EIA's most recent Form 860 survey of capacity additions in various stages of development.[37] As of December 2010, over 55 GW of capacity is reported to be in some stage of development and is expected to be operational by 2015. In other words, there is far greater generation capacity in the development pipeline today than the total added in the Stringent Test Cases in this analysis.[38]

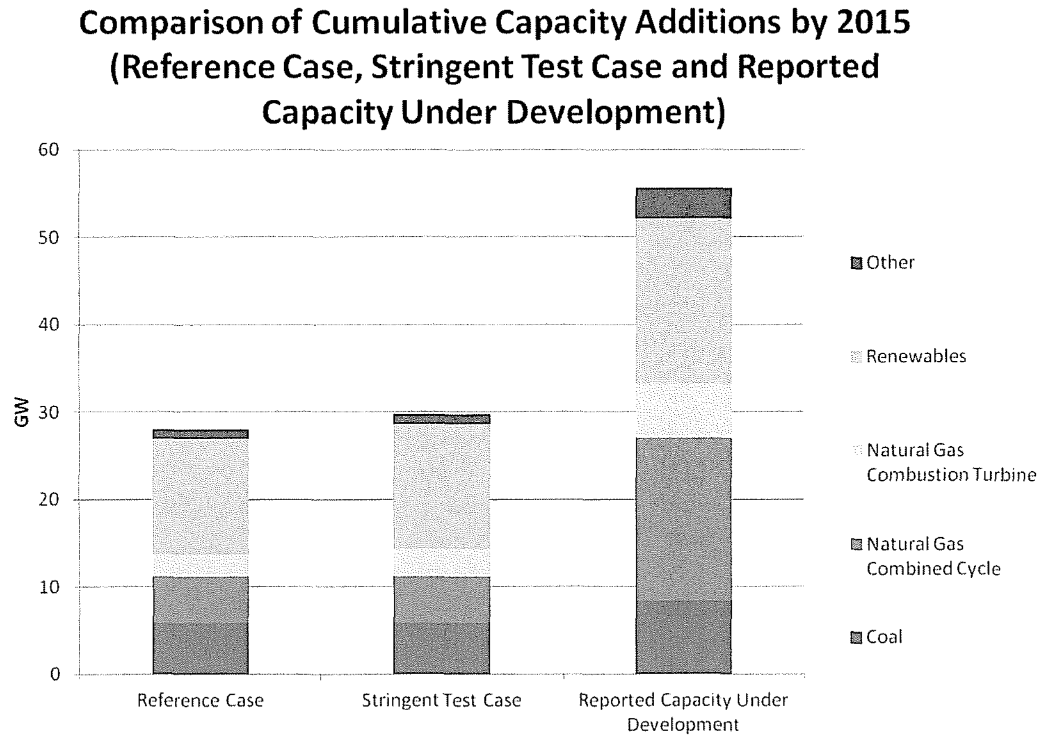

Figure 10: Comparison of reported capacity under development, and cumulative capacity additions under the Reference Case and Stringent Test Case, 2011-2015

3.4 Modeled impacts of pollution control installations on availability of generation capacity

While it can take multiple years to complete construction of some retrofits, their connection and configuration requires plants to be turned off for a significantly shorter period of time. This "tie-in"

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[37] Reported capacity additions considered here include all capacity that has either received or is in the process of receiving permitting and regulatory approvals, is undergoing construction or has completed construction but is not yet operational. Capacity reported as "planned" that has not initiated the regulatory approval process is not included. Capacity under development is expected to be operational by 2015. All data are current as of December 31, 2010. "Other" primarily consists of petroleum and nuclear capacity. EIA, 2010 Form 860, 2011.

[38] Total cumulative capacity reported as under development and expected to be operational by 2015 is comparable to or exceeds Stringent Test Case 2015 cumulative capacity additions in all NERC regions except TRE. In TRE, Stringent Test Case additions were 1 GW greater than reported capacity under development.

time usually takes less than eight weeks and often can be completed during regular planned maintenance outages. A survey of outage times related to tie-in is provided in Figure 11.

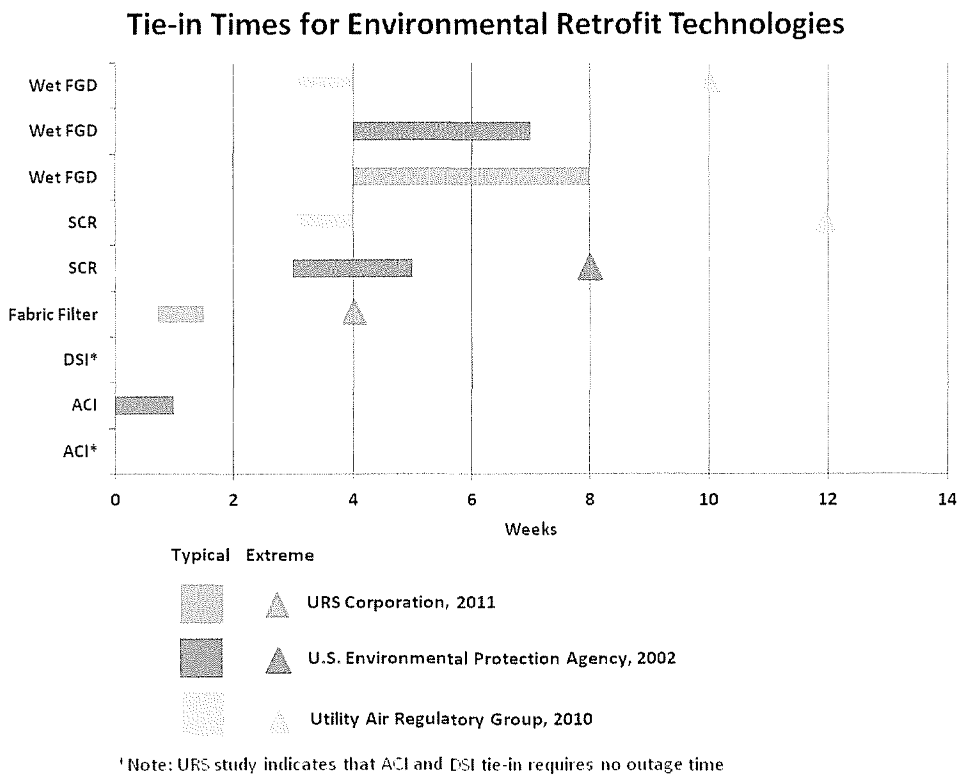

Figure 11: Estimated range of plant tie-in times associated with pollution control retrofit installations[39]

Within PI-NEMS, coal plants are taken off-line for approximately one month each year for scheduled maintenance. These scheduled outages often occur in fall and spring when demand for electricity is lowest. In some regions, they can also occur in other seasons. These scheduled maintenance outages are included in the model when computing available capacity to meet load, but extended outages for retrofit tie-in are not taken into account. However, the effect on available capacity can be estimated outside of the model by assuming that wet FGD retrofit tie-in outages take eight weeks and are evenly distributed over the fall and spring months of a single year. In the Stringent Test Case, fabric filters are the most widely deployed retrofit (see Figure 6), but they require relatively little tie-in time and are assumed to be completed during modeled scheduled outages.

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[39] Tie-in time is for a single unit only. Timeframes could be longer, or tie-in outages could be more frequent if a single device is installed to control pollution from multiple generating units. Ranges do not include start up and commissioning. Sources: URS Corp. "Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants" 2011; EPA "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multi-pollutant Strategies" 2002; Utility Air Regulatory Group "Implementation Schedules For Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Process Equipment" 2010

The results of this estimate are shown in Figure 12.[40] The orange bar is identical to the calculated reserve margin (summer excess capacity relative to peak summer demand) shown in Figure 7. The light blue bar shows the fall/spring excess capacity (relative to peak demand in fall and spring), adjusted downward for retrofit-related outages. The lower demand in fall and spring increases excess capacity, leaving sufficient headroom to take plants off-line to tie-in the needed controls.

This estimate assumes that the outages would be coordinated so that they would be evenly distributed across the fall and spring months. However, a conservative assumption is also made that all FGD tie-in outages must occur in a single year. In reality, it is likely that these outages would be spread across multiple years and that some would take place during other parts of the year.

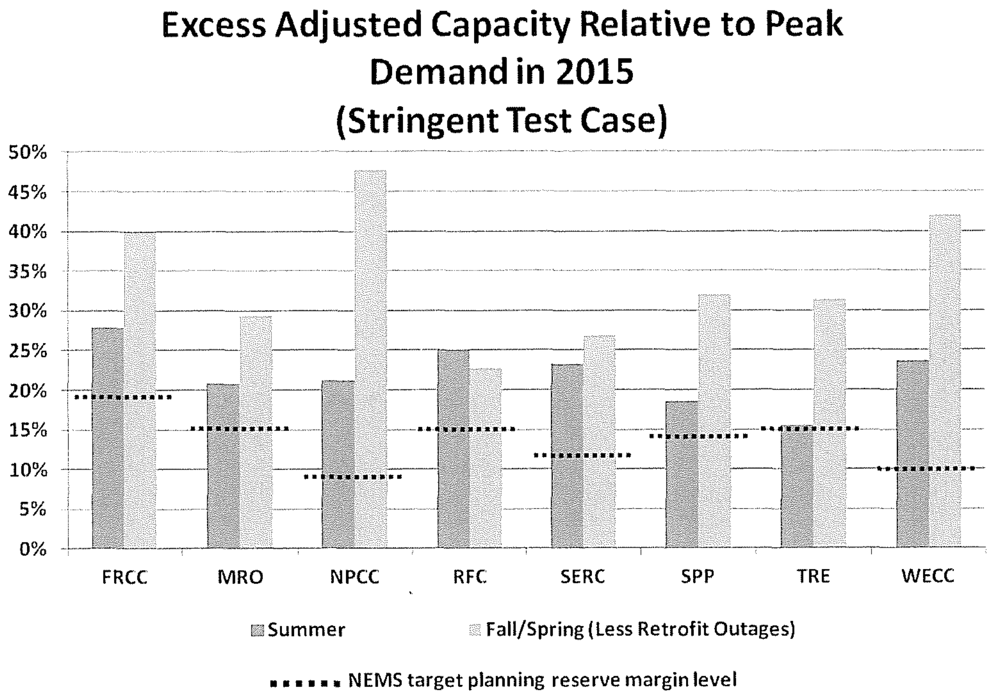

Figure 12: Excess adjusted capacity[41] available in fall and spring of 2015 after outages due to pollution control tie-in are removed

[40] This calculation assumes that if the regularly scheduled outage occurs in the winter, the retrofit outage is assumed to take eight weeks in the fall and spring. If the scheduled outage occurs in the fall and spring, the retrofit outage is assumed to take four weeks beyond the scheduled outage, again for a total of eight weeks.

[41] Adjusted capacity refers to the sum of capacities available in the given season with appropriate discounting for intermittent resources.

Appendix A: NERC regions

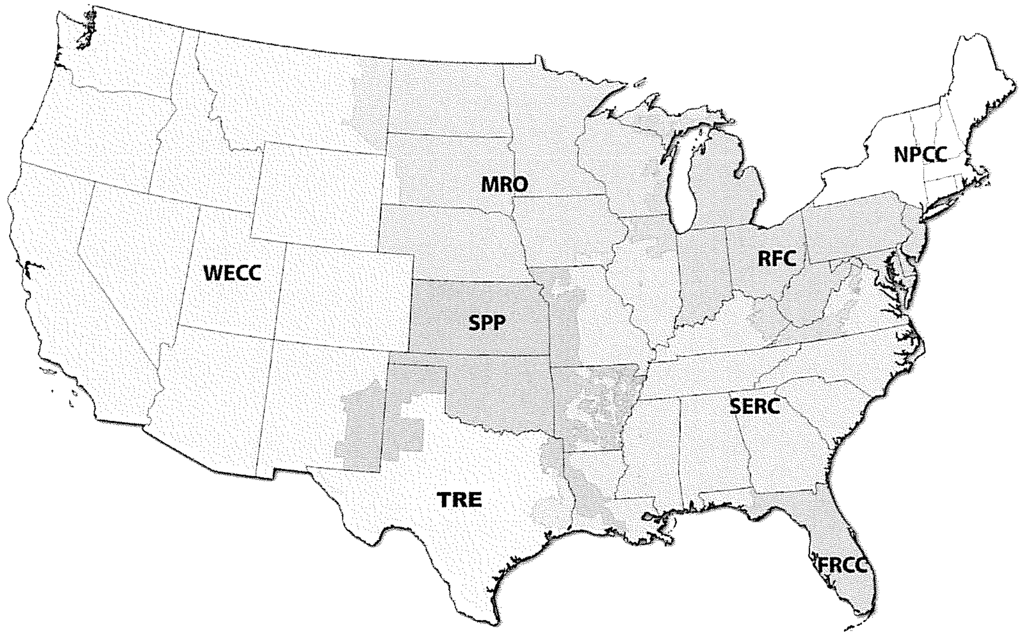

Figure 13: Map of NERC regions[42]

[42] Map generated by the National Renewable Energy Laboratory (NREL).

Appendix B. Low natural gas price cases

The evolution of natural gas prices can significantly change the economics of retiring versus retrofitting existing coal plants. Given the uncertainty about shale gas resources, the U.S. Energy Information Administration (EIA) has done a number of additional cases exploring greater natural gas availability. This sensitivity uses EIA's "High Shale EUR" case[43] which increases the amount of shale gas recovered in each well. Although there is no explicit natural gas supply curve in PI-NEMS, this sensitivity effectively shifts the natural gas supply curve to the right, lowering natural gas prices at any quantity supplied. For context, the price of natural gas delivered to the power sector in 2015 is 4.8 dollars per Mcf in the Reference Case and 4.0 dollars per Mcf in the Low Natural Gas Price case.[44]

The Low Natural Gas Price Stringent Test Case constraints related to the rules are identical to those of the earlier Stringent Test Case. They are deliberately designed to be more conservative (in the sense of offering fewer compliance options and therefore driving greater retirements) than the CSAPR and MATS rules. The inclusion of a 10-year investment payback requirement of pollution control retrofits again adds conservatism and acts as a rough proxy for future regulatory uncertainty.

The results from the low natural gas cases are given in the following figures. The decrease in natural gas prices leads to a greater number of coal retirements in both the Low Natural Gas Price Reference Case and the Low Natural Gas Price Stringent Test Case (compare Figure 14 with Figure 5).

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[43] From Annual Energy Outlook 2011, p. 222: "In the High Shale EUR case, the EUR per shale gas well is assumed to be 50 percent higher than in the Reference Case, decreasing the per-unit cost of developing the resource. The total unproved technically recoverable shale gas resource is increased from 827 trillion cubic feet in the Reference Case to 1,230 trillion cubic feet."

[44] These prices are provided in 2009 dollars. NEMS fuel prices are endogenous and vary by year as well as by scenario.

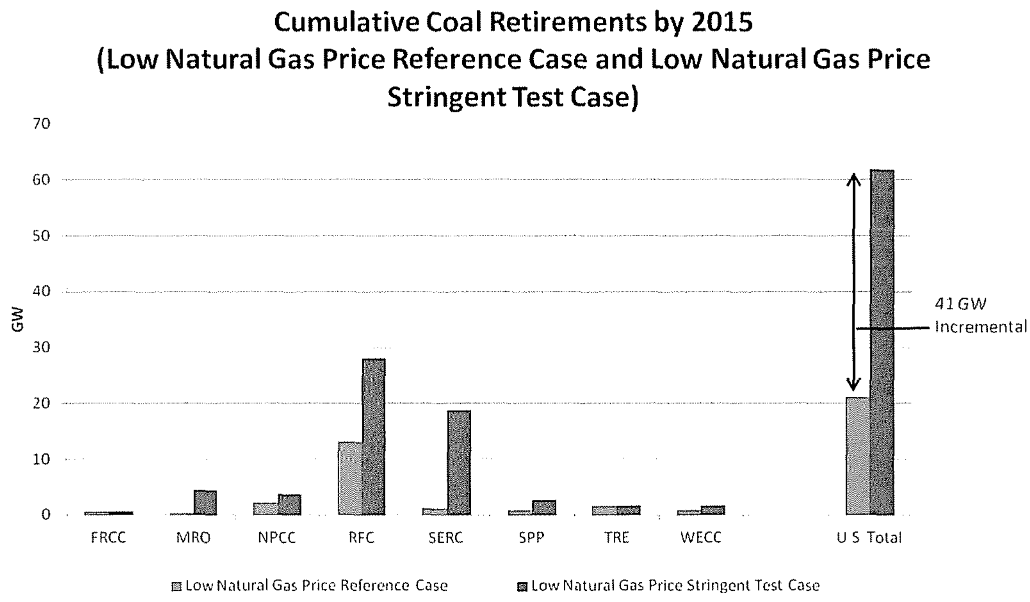

Figure 14: Cumulative coal retirements by NERC region, 2011-2015 in the low natural gas price cases[45]

Figure 15 shows that planning margins are once again maintained in these cases. In the Low Natural Gas Price Stringent Test Case, the number of incremental retirements is higher, since the price of natural gas is lower. As a result, the amount of *additional* new capacity needed in the Low Natural Gas Price Stringent Test Case relative to the Low Natural Gas Price Reference Case (13 GW) is generally higher than the *additional* capacity needed in the earlier Stringent Test Case (2 GW) relative to the earlier Reference Case (compare Figure 16 and Figure 9). This additional capacity is needed to meet PI-NEMS target planning reserve margins, replacing some portion of the higher number of retirements in the Low Natural Gas Price Stringent Test Case. The largest amount of additional new capacity is in SERC, where approximately 4 GW of primarily natural gas combustion turbine capacity is added.[46] Outside of SERC, additional unplanned natural gas combined cycle capacity would be added across several regions, although the additional capacity would be relatively small in any one region. All of the additional natural gas capacity additions would be built in 2014 and 2015.

[45] U.S. total values in this and subsequent figures include results for the lower 48 states only.

[46] Some additional wind is added in SPP, but this is largely driven by the expiration of the PTC (similar to the wind additions in the earlier Reference Case).

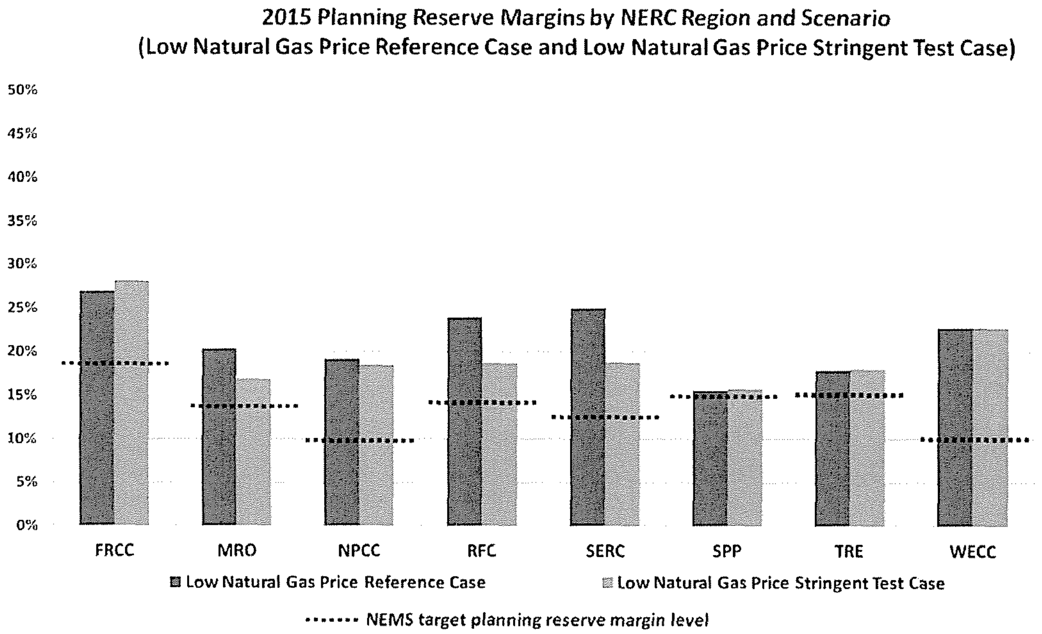

Figure 15: PI-NEMS planning reserve margins and targets in 2015 for the low natural gas price cases

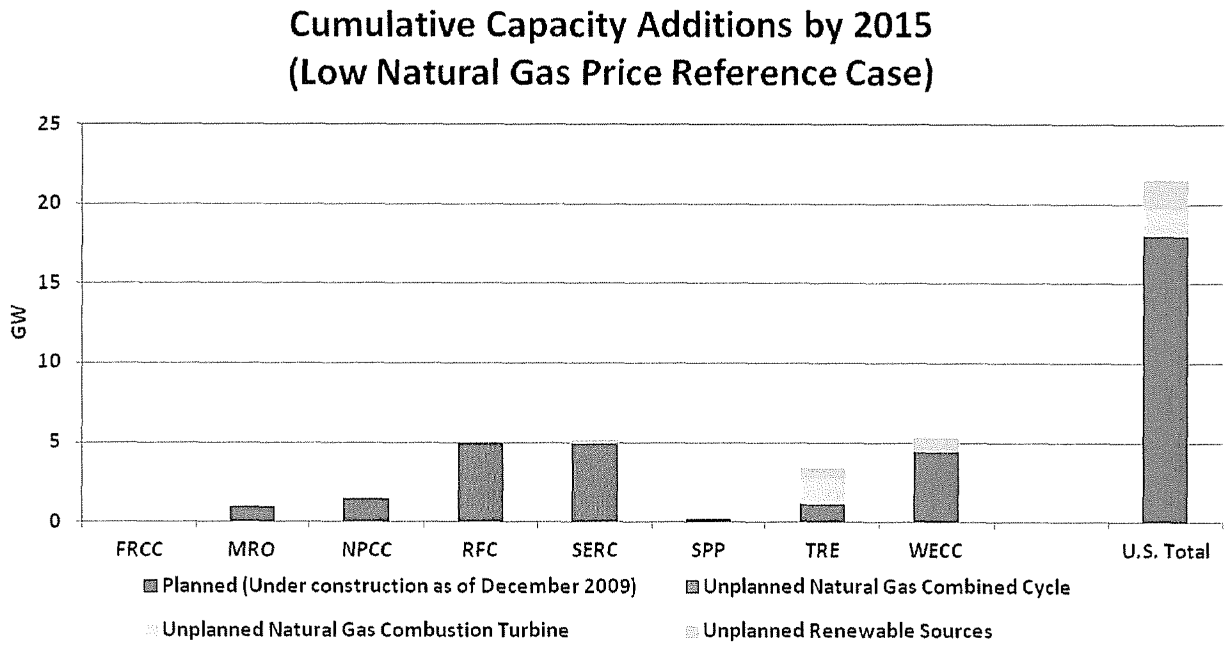

Figure 16: Cumulative regional capacity additions, 2011-2015, in the Low Natural Gas Price Reference Case

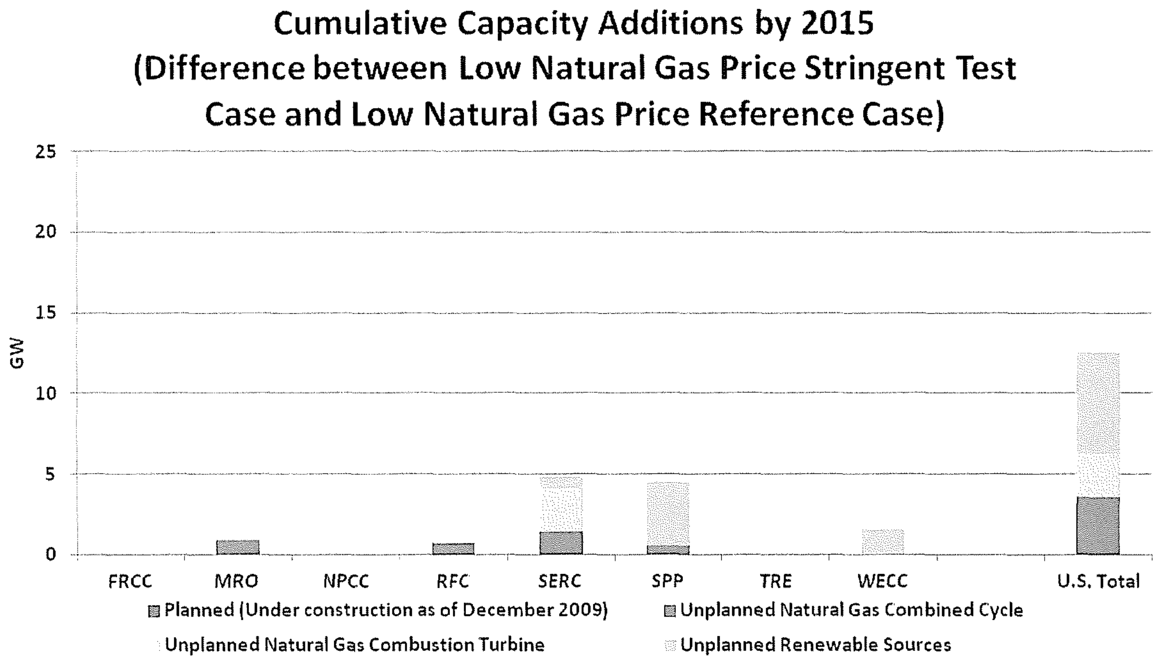

Figure 17: Cumulative regional capacity additions, 2011-2015, difference between Low Natural Gas Price Stringent Test Case and Low Natural Gas Price Reference Case

To put these capacity additions in perspective, Figure 18 compares cumulative Low Natural Gas Price Reference Case and Low Natural Gas Price Stringent Test Case capacity additions between 2011 and 2015 (Low Natural Gas Price Stringent Test Case column represents combined capacity additions from Figure 16 and Figure 17) with EIA's most recent Form 860 survey of capacity additions in various stages of development.[47] As shown earlier in Figure 10, there is far greater generation capacity in the development pipeline today than is added in any of the cases in this analysis.

[47] Capacity additions considered here include all capacity that has either received or is in the process of receiving permitting and regulatory approvals, is undergoing construction or has completed construction but is not yet operational. Capacity reported as "planned" that has not initiated the regulatory approval process is not included. Capacity under development is expected to be operational by 2015. All data are current as of December 31, 2010. "Other" primarily consists of petroleum and nuclear capacity. EIA, 2010 Form 860, 2011.

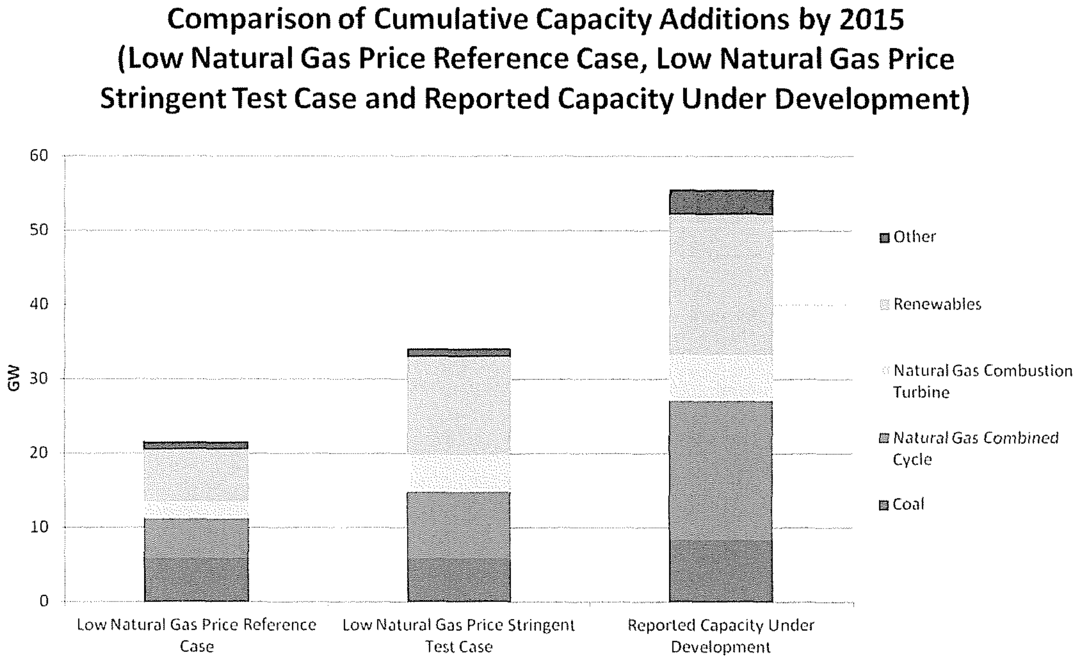

Figure 18: Comparison of reported capacity under development, and cumulative capacity additions under the Low Natural Gas Price Reference Case and Low Natural Gas Price Stringent Test Case, 2011–2015

The number of pollution controls installed in the Low Natural Gas Price Stringent Test Case is slightly smaller than the number in the earlier Stringent Test Case (compare Figure 19 and Figure 6) since there are a greater number of retirements in the former case and thus fewer plants that require controls. Figure 20 shows that, similar to the earlier Stringent Test Case, the outages associated with pollution control tie-in, if staged properly, are not estimated to have a significant impact on available capacity.

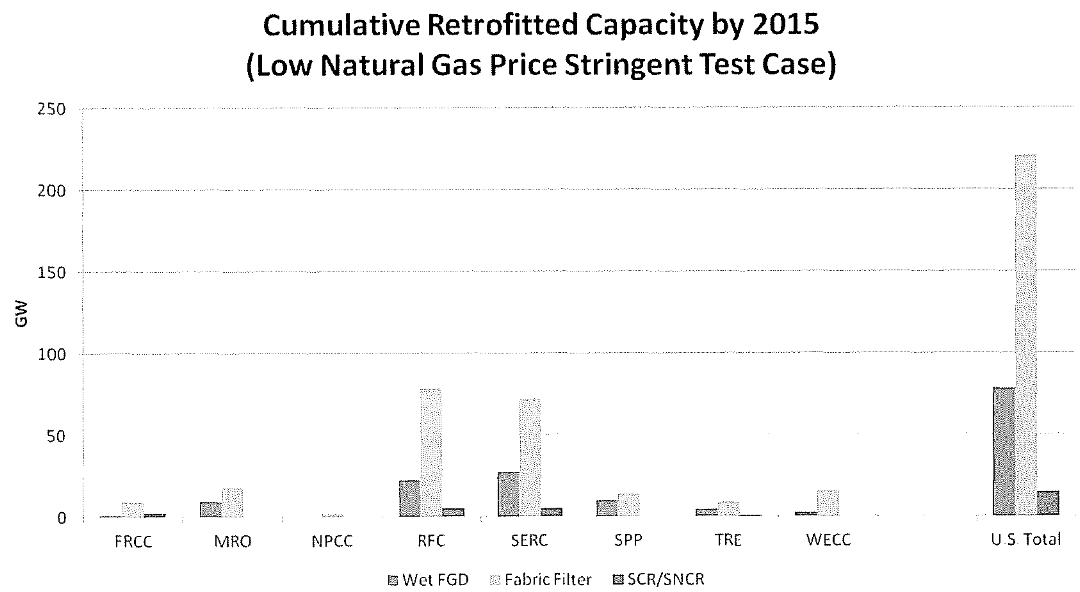

Figure 19: Cumulative capacity retrofit from 2011-2015 in the Low Natural Gas Price Stringent Test Case, using three types of control technologies

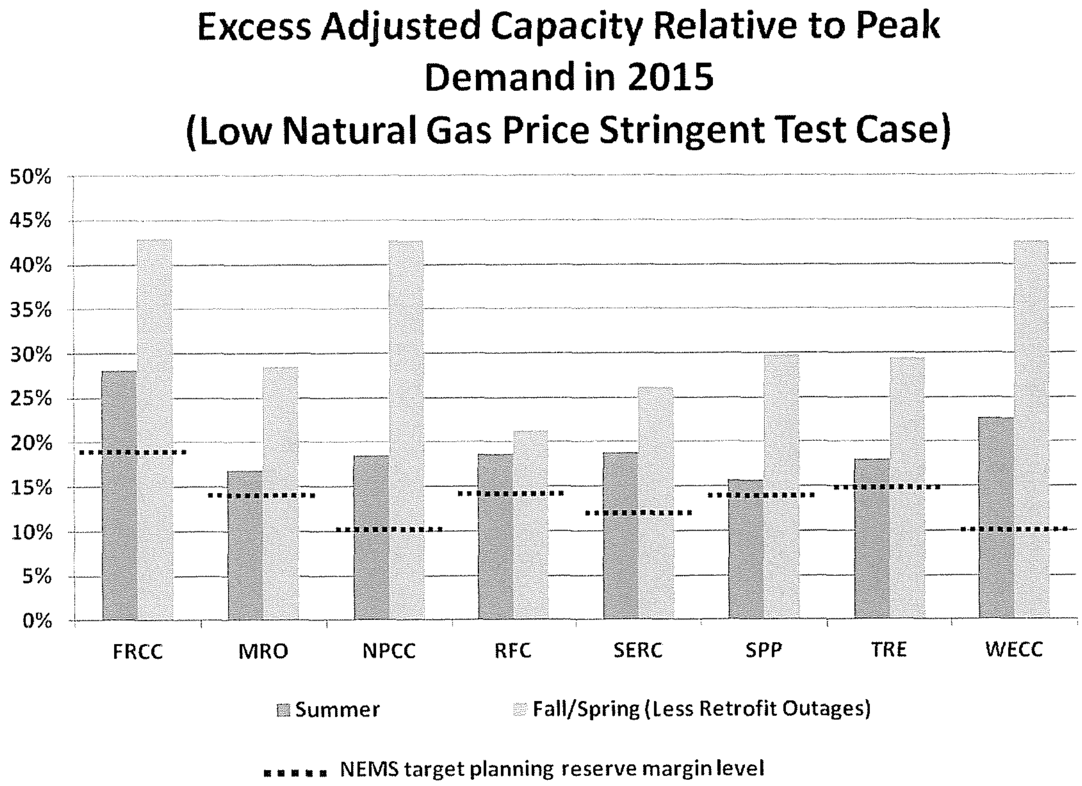

Figure 20: Excess adjusted capacity available in fall and spring of 2015 in the Low Natural Gas Price Stringent Test Case after outages due to pollution control tie-in are removed

Appendix C: Retrofit Cost Assumptions

For retrofit costs, PI-NEMS relies on the same costs as those in EIA's AEO 2011, except that costs for Fabric Filters and ACI are increased to mirror EPA's cost assumptions in its IPM Base Case v4.10. Table 3 provides sample costs for representative plants burning bituminous coal with 9,000 BTU heat rates.

Table 3: Assumed Capital ($2009/kW) and Fixed O&M Costs ($2009/kW-yr) Costs for Representative Plants in PI-NEMS

Coal Plant Capacity (MW)	FGD		SCR		ACI		Fabric Filter	
	Capital	Fixed O&M	Capital	Fixed O&M	Capital	Fixed O&M	Capital	Fixed O&M
300	556	11	179	1				
500	464	8	161	1	12	2	186	1
700	428	8	159	1				

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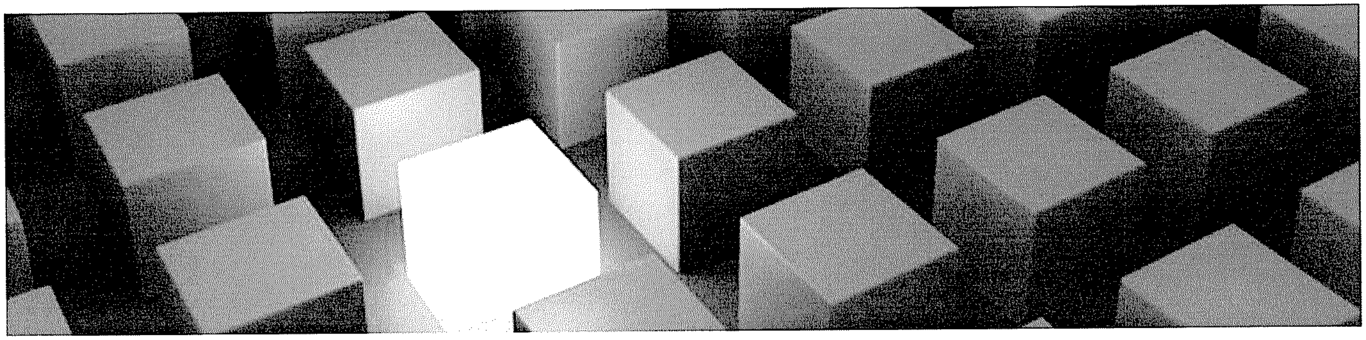

Proposed CATR + MACT

Prepared for:
American Coalition for Clean Coal Electricity

Draft
May 2011

Insight in Economics™

Outline

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- Glossary
- Executive Summary
- Methodology
- Assumptions and Uncertainties
- Energy Market Impacts
- Economic Impacts

Glossary

- Present value (PV) of costs
  - **Present value**, also known as **present discounted value**, is the value on a given date of a future cost or series of future costs, discounted to reflect the time value of money and other factors such as investment risk. Present value calculations are widely used in business and economics to provide a means to compare costs at different times on a meaningful "like to like" basis
- Annualized value (AV) of costs
  - **Annualized value**, also known as **annualized net present value**, is calculated from a given present value as the average annual value in each future year taking into account the discount rate and the number of years over which costs are calculated. Annualized value calculations are widely used in business and economics to compare costs at different times on a meaningful "like to like" basis, particularly when two cost streams have different lifetimes.
- 2010 dollars
  - Constant value of money based on price levels in 2010
  - Costs or prices reported in 2010 dollars for future years control for inflation between 2010 and future years, so any changes reflect real changes in market conditions
- Henry Hub
  - Henry Hub is the pricing point for natural gas used by the New York Mercantile Exchange (NYMEX) and widely used in the industry. It is a point on the natural gas pipeline system in Louisiana.

Summary of Key Results

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- Evaluated impacts of EPA's Clean Air Transport Rule (CATR) and Utility Maximum Achievable Control Technology (MACT) proposals
- Coal unit retirements would increase by about 48 GW
- Electricity sector costs would increase by $184 billion (present value over 2011-2030 in 2010$) or $17.8 billion per year
  - Includes coal unit compliance costs (including $72 billion in overnight capital costs), fuel price impacts, and costs of replacement energy and capacity
- Coal-fired generation in 2016 would decrease by about 13% and electricity sector coal demand in 2016 would decrease by about 10%
- Natural gas-fired generation in 2016 would increase by about 26% and Henry Hub natural gas prices 2016 would increase by about 17%
  - Increased natural gas prices would increase natural gas expenditures by residential, commercial, and industrial sectors by $85 billion (present value over 2011-2030 in 2010$) or $8.2 billion per year
- Average U.S. retail electricity prices in 2016 would increase by about 12%, with regional increases as much as about 24%
- Net employment in the U.S. would be reduced by more than 1.4 million job-years over the 2013-2020 period, with sector losses outnumbering sector gains by more than 4 to 1.

Comparison of EPA and NERA Modeling of CATR and MACT

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	EPA		NERA
Proposed Regulations	CATR	MACT	CATR+MACT
Source of Technologies	EPA	EPA	Electricity companies
Source of Control Cost	EPA	EPA	EPA
Model	IPM	IPM	NEMS
Coal Units			
Retirements by 2015 (GW)	1.2	9.9	47.9
Annual Costs (billion 2010$)	NA	$8.4	$14.2
Present Value of Costs (billion 2010$)	NA	$77-$86	$118
Electricity Sector			
Annual Costs (billion 2007$)	$2.8	$10.9	Not relevant
Annual Costs (billion 2010$)	$3.0	$11.4	$17.8
Present Value of Costs (billion 2010$)	$27-$35	$97-$133	$184

IPM = ICF Integrated Planning Model
NEMS = EIA National Energy Modeling System
NA = Not available

Electricity system costs reflect all generation and transmission costs.

Dollar conversions use the GDP deflator.

EPA CATR projections relate to the preferred policy alternative (state budgets with limited interstate trading).

NERA coal unit retirements and costs reflect medians from Monte Carlo uncertainty analysis ranges developed by NERA for all coal units.

EPA provides annual costs (including annualized capital costs) only for selected years (2012, 2015, 2020, and 2025 for CATR and 2015, 2020, and 2030 for MACT). EPA annual costs in the table relate to 2015. All present values are calculated between 2011 and 2030 as of 2011. Calculation of EPA PV costs include the assumption that costs begin in 2011 at the earliest available annual value. NERA annual costs are annualized costs derived from present values. EPA PV cost ranges reflect discount rates between 11.3% (EPA's capital charge rate) and 6.15% (EPA's discount rate for non-capital costs). NERA annual and PV costs for coal units reflect discount rates of 7% for public units and 11.8% for merchant units. NERA annual and PV costs for the electricity sector reflect a discount rate of 7%.

Energy Market Impacts Summary for 2016

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2016 CATR+MACT Impacts

	Coal Retirements (GW)	Coal-Fired Generation (million MWh)	Elec Sector Coal Demand (million tons)	Gas-Fired Generation (million MWh)	Elec Sector Gas Demand (trillion cu ft)	Gas Price at Henry Hub (2010$/MMBtu)	Avg Retail Elec Price (2010$/MWh)
	2016 Projections						
Reference (No CAIR or State Hg)	5.0	1,910	1,018	603	5.9	$4.50	$87.13
CATR+MACT	52.7	1,658	918	760	7.0	$5.28	$97.18
	Change from 2016 Reference Projections						
CATR+MACT	+47.8	-253	-100	+157	+1.1	+$0.78	+$10.05
	% Change from 2016 Reference Projections						
CATR+MACT	+958%	-13.2%	-9.8%	+26.0%	+18.5%	+17.3%	+11.5%

Notes: Summary results are provided for 2016 rather than 2015 to show the full potential effect on electricity prices.
Electricity price impacts reflect levelized capital costs for environmental controls and new capacity.

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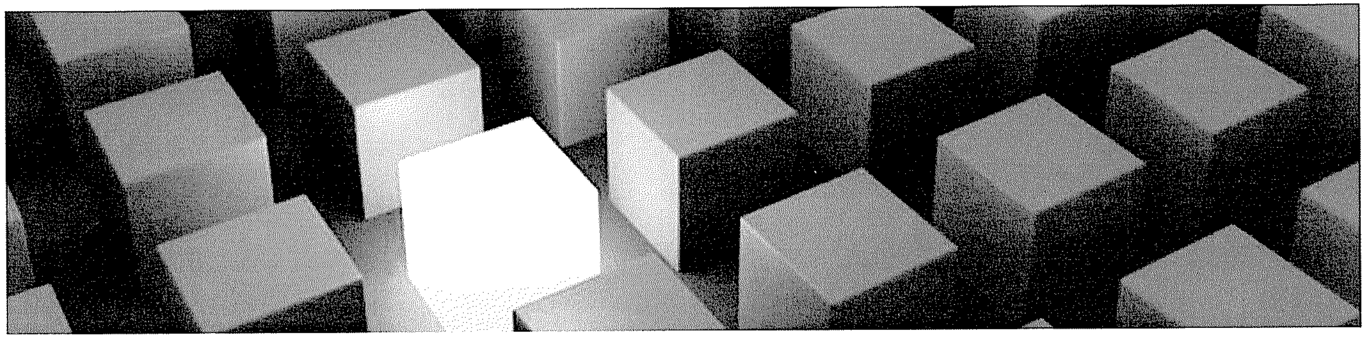

Methodology

Overview of Modeling Methodology (Note: Simplification of inputs and outputs)

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- CATR+MACT environmental control requirements
- EPA environmental control cost assumptions
- EIA fuel price projections
- EIA electricity price projections

Note: Inputs with significant uncertainty have ranges for Monte Carlo analysis

NERA Retirement Model

- Coal unit retirements due to CATR+MACT
- CATR+MACT environmental control technologies/costs

Note: Retirements are based on higher costs than natural gas replacement capacity in 50% or more of Monte Carlo simulations

- Coal unit retirements due to CATR+MACT
- CATR+MACT environmental control requirements/costs
- EIA *Annual Energy Outlook 2011* assumptions

EIA National Energy Modeling System (NEMS)

- Environmental control costs
- Replacement generation units
- Coal and gas production, consumption, and prices
- Electricity production, consumption, and prices

- Environmental control costs
- Replacement generation costs
- Electricity expenditures
- Coal and gas expenditures
- Consumer income effects

REMI Economic Impacts Model

- Employment
- Gross state product
- Disposable income
- Sector impacts
- Occupation group impacts

Overview of Rationale for Models

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- NERA Retirement Model
  - Monte Carlo formulation allows for inclusion of uncertainty in key parameters (e.g., fuel prices) and development of ranges of costs and retirements
- NEMS
  - State-of-the-art model of the energy system
  - Used extensively by EIA and others
  - Not proprietary with NERA in-house modeling capability
- REMI
  - State-of-the-art regional economic model
  - Ability to model impacts in individual states as well as U.S.
  - Used extensively by government agencies and others
  - Not proprietary with NERA in-house modeling capability

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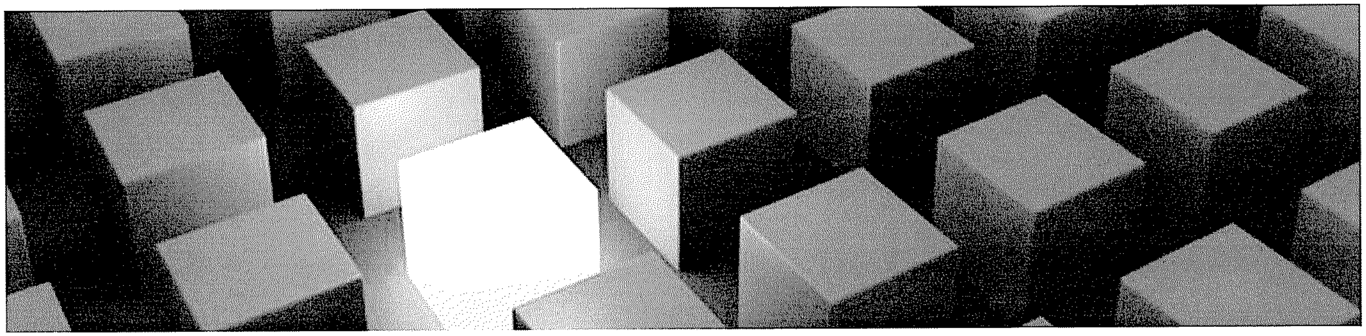

Assumptions and Uncertainties

Control Cost and Penalty Assumptions from EPA and EIA

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	500 MW		300 MW		100 MW	
	EPA	EIA	EPA	EIA	EPA	EIA
Wet Scrubber						
Capital (2010$/kW)	$538	$485	$622	$580	$850	$762
Fixed O&M (2010$/kW-year)	$8.35	$24.99	$11.20	$24.99	$24.40	$24.99
Variable O&M (2010$/MWh)	$2.11	$0.44	$2.11	$0.44	$2.11	$0.44
Capacity Penalty	-1.84%	-5.00%	-1.84%	-5.00%	-1.84%	-5.00%
Heat Rate Penalty	1.87%	5.26%	1.87%	5.26%	1.87%	5.26%
Dry Scrubber						
Capital	$460		$532		$727	
FOM	$6.76		$8.86		$17.71	
VOM	$2.70		$2.70		$2.70	
Capacity Penalty	-1.45%		-1.45%		-1.45%	
Heat Rate Penalty	1.47%		1.47%		1.47%	
SCR						
Capital (2010$/kW)	$201	$165	$217	$184	$268	$225
Fixed O&M (2010$/kW-year)	$0.73	$1.66	$0.83	$1.88	$2.60	$2.25
Variable O&M (2010$/MWh)	$1.38	$0.34	$1.38	$0.34	$1.38	$0.34
Capacity Penalty	-0.58%	0.00%	-0.58%	0.00%	-0.58%	0.00%
Heat Rate Penalty	0.59%	0.00%	0.59%	0.00%	0.59%	0.00%
ACI						
Capital (2010$/kW)	$8	$6	$12	$6	$30	$6
Fixed O&M (2010$/kW-year)	$0.03	$1.71	$0.05	$1.71	$0.12	$1.71
Variable O&M (2010$/MWh)	$0.60	$0.00	$0.56	$0.00	$0.52	$0.00
Capacity Penalty	-0.06%	0.00%	-0.06%	0.00%	-0.06%	0.00%
Heat Rate Penalty	0.06%	0.00%	0.06%	0.00%	0.06%	0.00%
Fabric Filter						
Capital (2010$/kW)	$170	$78	$187	$78	$230	$78
Fixed O&M (2010$/kW-year)	$0.73	$5.97	$0.83	$5.97	$0.94	$5.97
Variable O&M (2010$/MWh)	$0.16	$0.00	$0.16	$0.00	$0.16	$0.00
Capacity Penalty	-0.60%	0.00%	-0.60%	0.00%	-0.60%	0.00%
Heat Rate Penalty	0.60%	0.00%	0.60%	0.00%	0.60%	0.00%
DSI						
Capital (2010$/kW)	$43		$61		$134	
Fixed O&M (2010$/kW-year)	$0.61		$0.94		$2.39	
Variable O&M (2010$/MWh)	$7.70		$7.70		$7.70	
Capacity Penalty	-0.79%		-0.79%		-0.79%	
Heat Rate Penalty	0.79%		0.79%		0.79%	

Notes: Heat rate of 11,000 Btu/kWh is assumed. EIA does not model dry scrubber retrofits.

Assumptions used for Annualization Period

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- Coal unit lifetime assumptions for annualizing the overnight capital costs of control technologies depend on unit age in 2015:
  - Less than 45 years old: 20 years (NEMS baseline assumption)
  - 45 to 54 years old: 15 years
  - 55 years or older: 10 years

Reference Energy Market Conditions: Coal, Natural Gas, and Electricity Prices

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EIA Coal, Natural Gas, and Electricity Prices

	2015	2020	2025	2030	2035
Coal					
Minemouth (2010$/ton)	$33.04	$34.23	$35.11	$35.30	$35.60
Delivered to Elec Sector (2010$/MMBtu)	$2.19	$2.23	$2.31	$2.35	$2.42
Natural Gas					
Henry Hub (2010$/MMBtu)	$4.46	$4.88	$6.05	$6.57	$7.26
Delivered to Elec Sector (2010$/MMBtu)	$4.41	$4.77	$5.82	$6.35	$7.00
Electricity					
Wholesale (2010$/MWh)	$48.35	$49.89	$54.66	$57.05	$59.97
Retail (2010$/MWh)	$87.04	$85.83	$88.47	$89.35	$91.81

Note: Projections reflect EIA's *Annual Energy Outlook 2011: Early Release* (December 2010). Projections are similar in the final version.

Reference Energy Market Conditions: Costs for New Capacity

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Economic Consulting

EIA Overnight Capital Costs for New Capacity (2010$/kW)

Supercritical Pulverized Coal	$2,805
Natural Gas Combined Cycle	$987
Nuclear	$5,283
Wind	$2,402
Solar Thermal	$4,663
Solar Photovoltaic	$4,672

Note: Projections reflect EIA's *Annual Energy Outlook 2011* (same projections in early release and final version).

Input Assumptions for NERA Retirement Model

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Economic Consulting

		Expected Value			Uncertainty Range (Lognormal Distributions with Fat Right Tails)		
	Units	Value	Notes	Source	Standard Deviation	95% Confidence Interval	Source
Control Capital Costs							
Scrubber	2010$/kW	$538	Varies by unit (value for 500 MW)	EPA	15% ($80.70 for illustrative 500 MW)	$403 - $718	NEMS environmental control cost model documentation
SCR	2010$/kW	$201	Varies by unit (value for 500 MW)	EPA	15% ($30.15 for illustrative 500 MW)	$151 - $268	NEMS environmental control cost model documentation
ACI	2010$/kW	$8	Same for all units	EPA	15% ($1.20 for all units)	$6 - $11	NEMS environmental control cost model documentation
Fabric Filter	2010$/kW	$170	Same for all units	EPA	15% ($25.50 for all units)	$127 - $227	NEMS environmental control cost model documentation
Discount Rates							
Public	Rate	0.07	Capital costs annual-ized over 10-20 years depending on unit age	EiA NEMS	0.005	0.06 - 0.08	Historical variation (www.snl.com)
Private	Rate	0.1183	Capital costs annual-ized over 10-20 years depending on unit age	EIA NEMS	0.005	0.109 - 0.129	Historical variation (www.snl.com)
Prices							
Coal (delivered to electricity sector)	2010$/MMBtu	$2.19	2015 U.S. Avg. (inputs are regional)	EIA NEMS	$0.37 (2015 U.S. Avg.)	$1.58 - $3.03	Historical variation (Bloomberg)
Natural Gas Price (delivered to electricity sector)	2010$/MMBtu	$4.90	2015 U.S. Avg. (inputs are regional)	EIA NEMS	$1.30 (2015 U.S. Avg.)	$2.71 - $7.56	Historical variation (Bloomberg)
Electricity Price (wholesale)	2010$/MWh	$48.35	2015 U.S. Avg. (inputs are regional)	EIA NEMS	$2.60 (2015 U.S. Avg.)	$43.52 - $53.71	Historical variation in gas price and relationship between gas and elec prices (Bloomberg)

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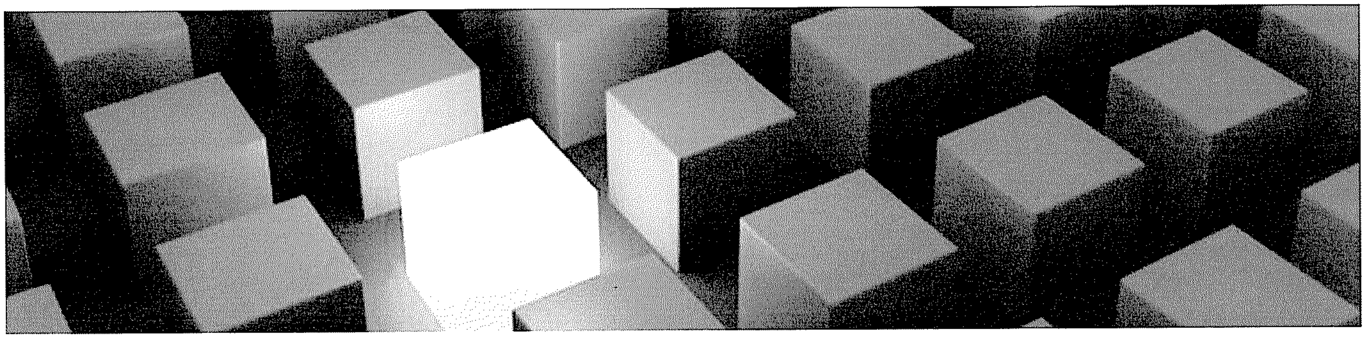

Energy Market Impacts

Context for Coal Units

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Overview of U.S. Coal Units (> 25 MW) in 2010

	Count	Capacity	Generation
All Coal (> 25 MW)	1196 units	318 GW	1875 TWh
Unscrubbed	721 units 60%	136 GW 43%	739 TWh 39%
Unscrubbed & > 40 years	566 units 47%	74 GW 23%	358 TWh 19%
Unscrubbed & > 40 years & HR > 10	454 units 38%	47 GW 15%	221 TWh 12%

Note: CATR and MACT would exempt coal units smaller than 25 MW. There are 193 coal units smaller than 25 MW in the U.S. and their total capacity is 2.8 GW (EPA, MACT RIA, March 2010, p. 7-3).

CATR + MACT Control Retrofits (Net of Retirements)

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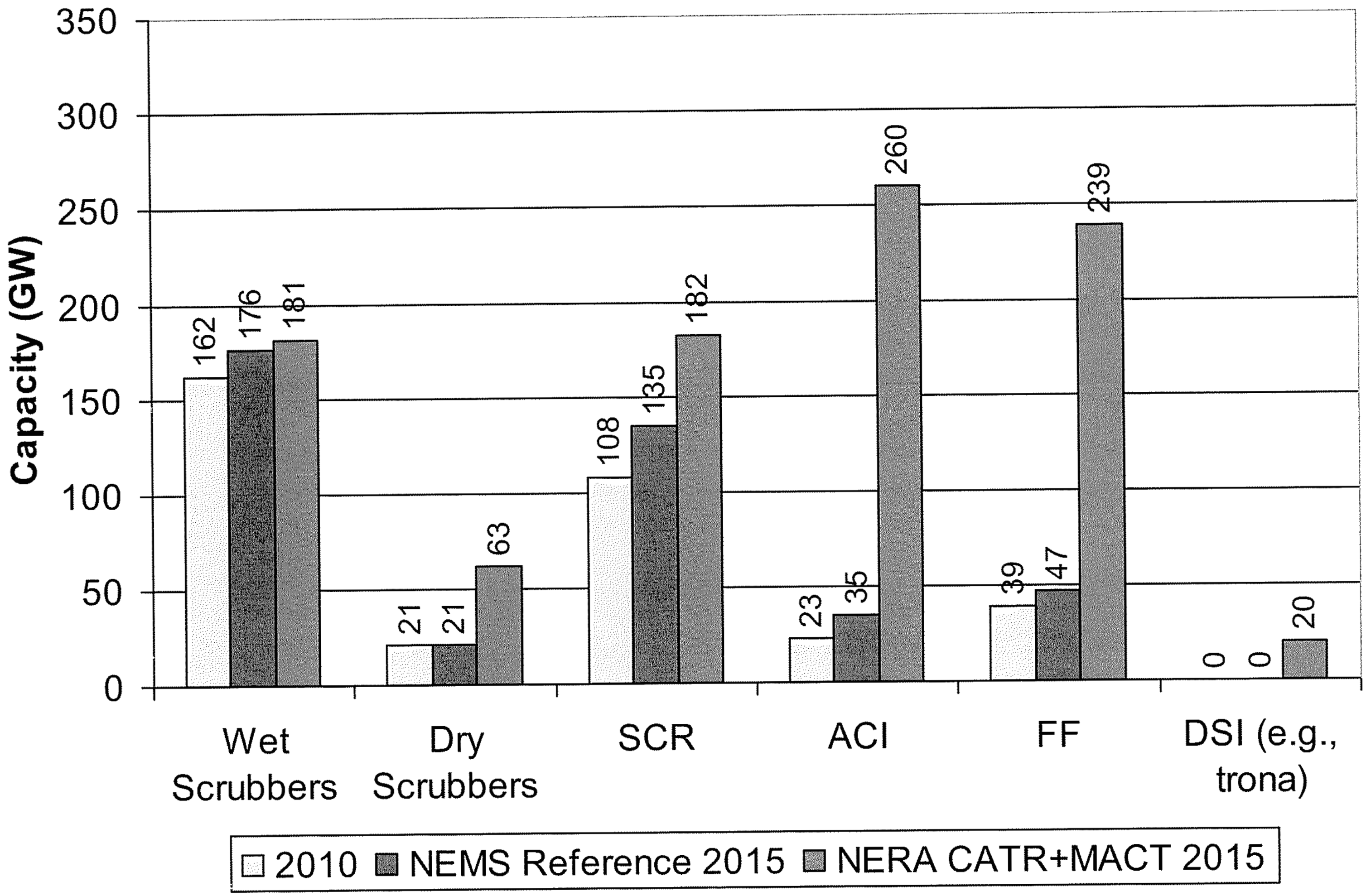

Comparison of EPA and NERA Modeling of CATR and MACT

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	EPA		NERA
Proposed Regulations	CATR	MACT	CATR+MACT
Source of Technologies	EPA	EPA	Electricity companies
Source of Control Cost	EPA	EPA	EPA
Model	IPM	IPM	NEMS
Coal Units			
Retirements by 2015 (GW)	1.2	9.9	47.9
Annual Costs (billion 2010$)	NA	$8.4	$14.2
Present Value of Costs (billion 2010$)	NA	$77-$86	$118
Electricity Sector			
Annual Costs (billion 2007$)	$2.8	$10.9	Not relevant
Annual Costs (billion 2010$)	$3.0	$11.4	$17.8
Present Value of Costs (billion 2010$)	$27-$35	$97-$133	$184

IPM = ICF Integrated Planning Model
NEMS = EIA National Energy Modeling System
NA = Not available

Electricity system costs reflect all generation and transmission costs.

Dollar conversions use the GDP deflator.

EPA CATR projections relate to the preferred policy alternative (state budgets with limited interstate trading).

NERA coal unit retirements and costs reflect medians from Monte Carlo uncertainty analysis ranges developed by NERA for all coal units.

EPA provides annual costs (including annualized capital costs) only for selected years (2012, 2015, 2020, and 2025 for CATR and 2015, 2020, and 2030 for MACT). EPA annual costs in the table relate to 2015. All present values are calculated between 2011 and 2030 as of 2011. Calculation of EPA PV costs include the assumption that costs begin in 2011 at the earliest available annual value. NERA annual costs are annualized costs derived from present values. EPA PV cost ranges reflect discount rates between 11.3% (EPA's capital charge rate) and 6.15% (EPA's discount rate for non-capital costs). NERA annual and PV costs for coal units reflect discount rates of 7% for public units and 11.8% for merchant units. NERA annual and PV costs for the electricity sector reflect a discount rate of 7%.

Energy Market Impacts Summary for 2016

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2016 CATR+MACT Impacts

	Coal Retirements (GW)	Coal-Fired Generation (million MWh)	Elec Sector Coal Demand (million tons)	Gas-Fired Generation (million MWh)	Elec Sector Gas Demand (trillion cu ft)	Gas Price at Henry Hub (2010$/MMBtu)	Avg Retail Elec Price (2010$/MWh)
	2016 Projections						
Reference (No CAIR or State Hg)	5.0	1,910	1,018	603	5.9	$4.50	$87.13
CATR+MACT	52.7	1,658	918	760	7.0	$5.28	$97.18
	Change from 2016 Reference Projections						
CATR+MACT	+47.8	-253	-100	+157	+1.1	+$0.78	+$10.05
	% Change from 2016 Reference Projections						
CATR+MACT	+958%	-13.2%	-9.8%	+26.0%	+18.5%	+17.3%	+11.5%

Notes: Summary results are provided for 2016 rather than 2015 to show the full potential effect on electricity prices.
Electricity price impacts reflect levelized capital costs for environmental controls and new capacity.

U.S. Cumulative Coal Plant Retirements

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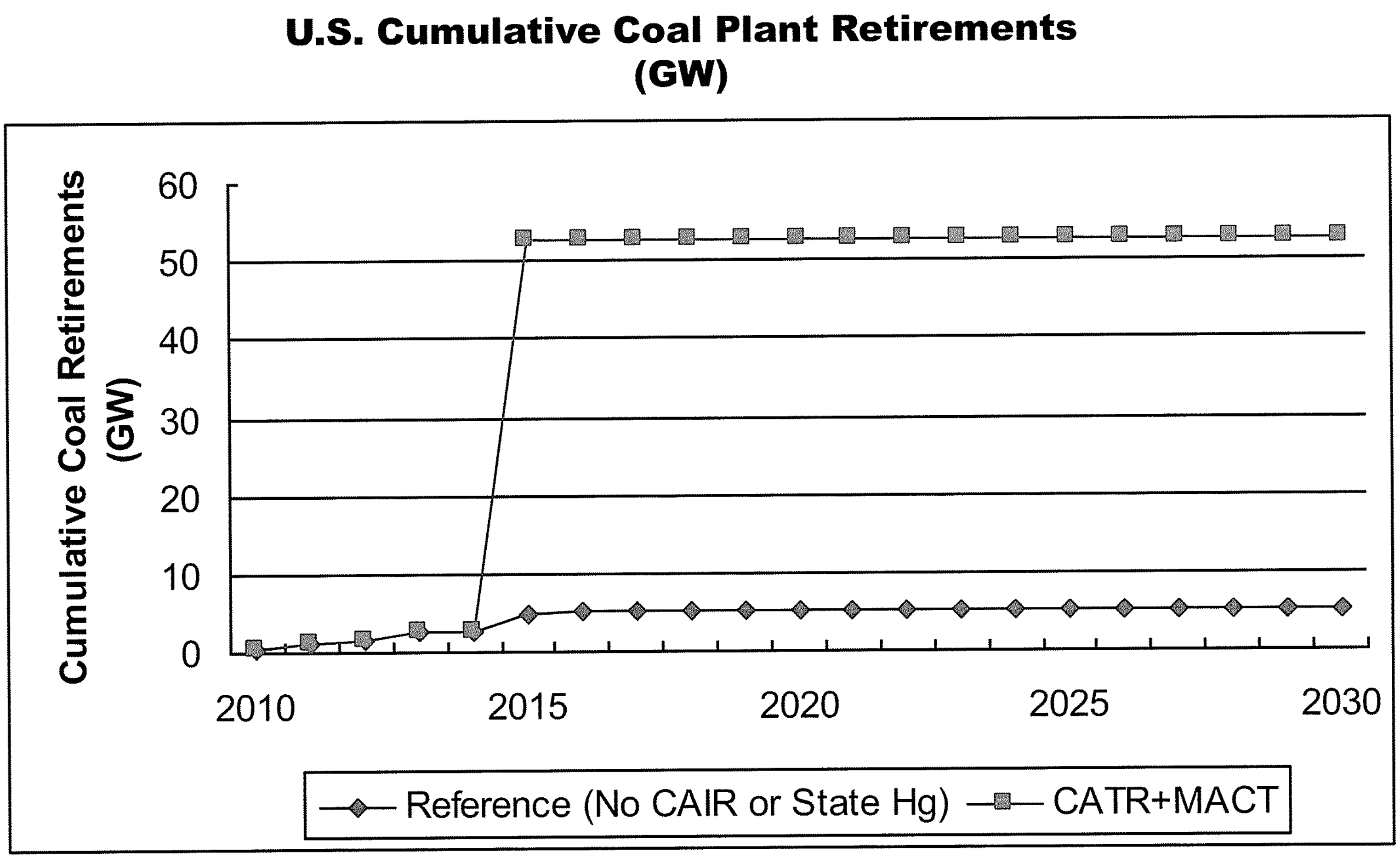

Note: Retirements are cumulative from 2010.

U.S. Coal-Fired Generation

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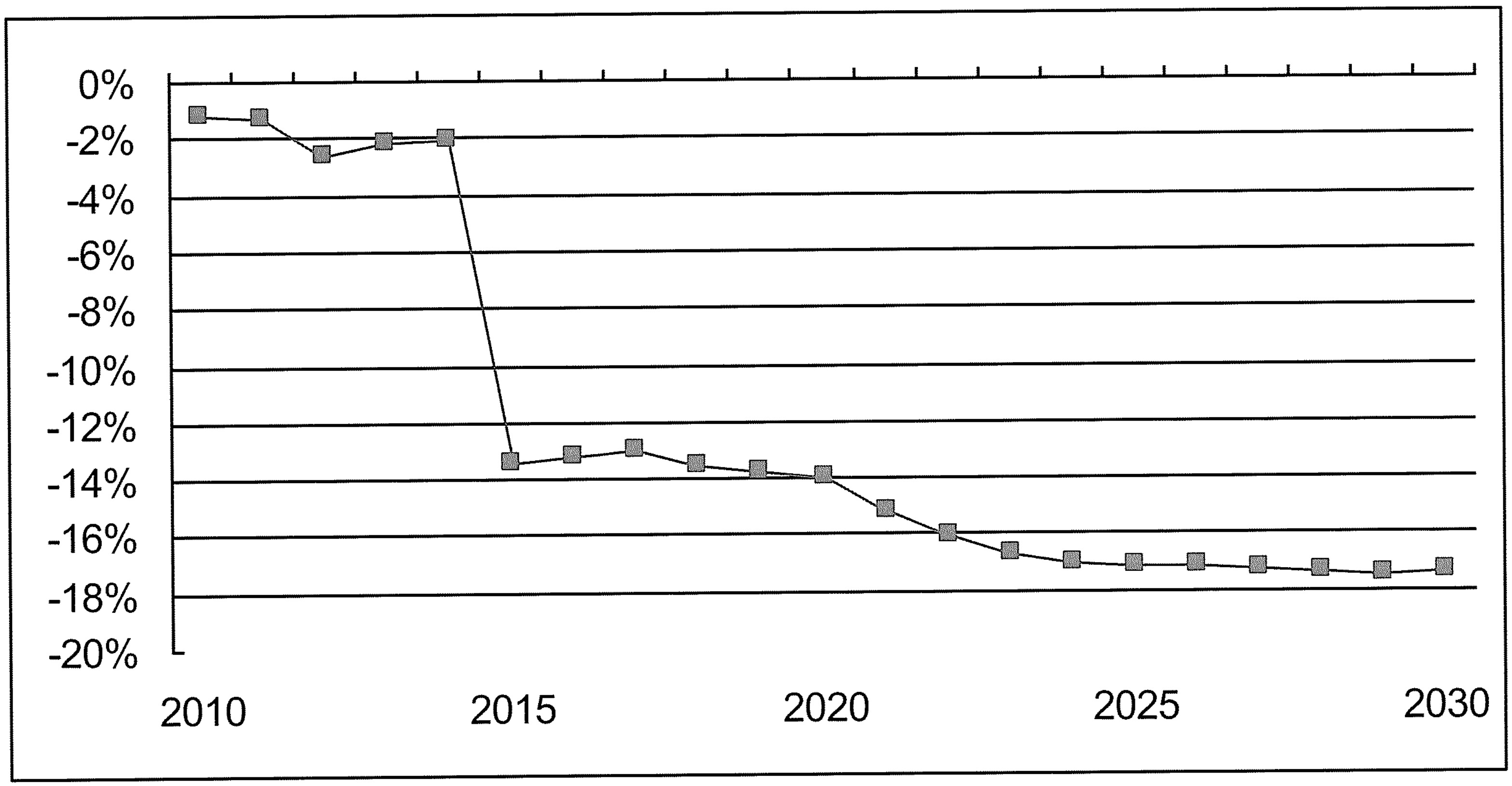
Percentage Change in U.S. Coal-Fired Generation



U.S. Electricity Sector Coal Demand

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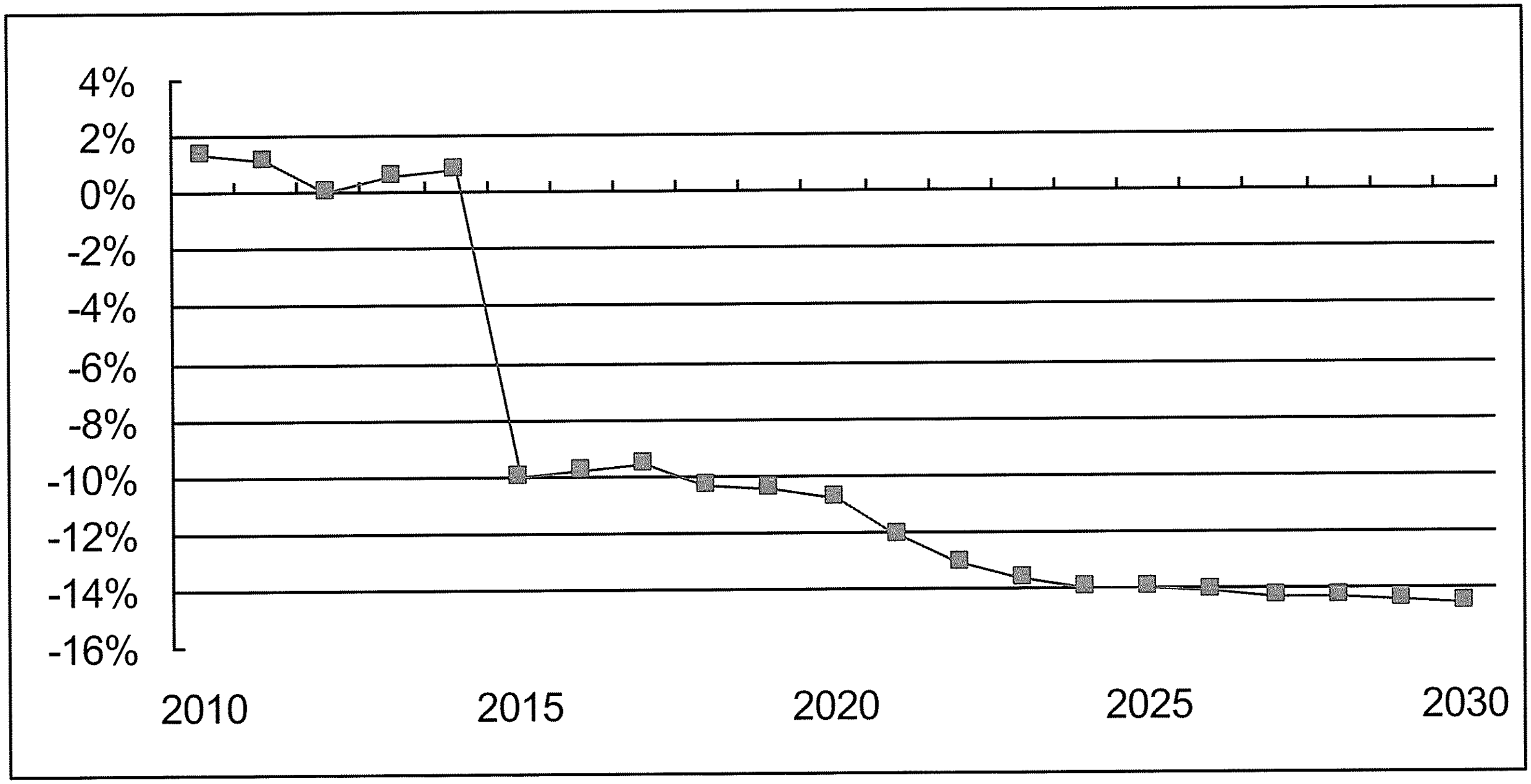
Percentage Change in U.S. Electricity Sector Coal Demand



U.S. Gas-Fired Generation

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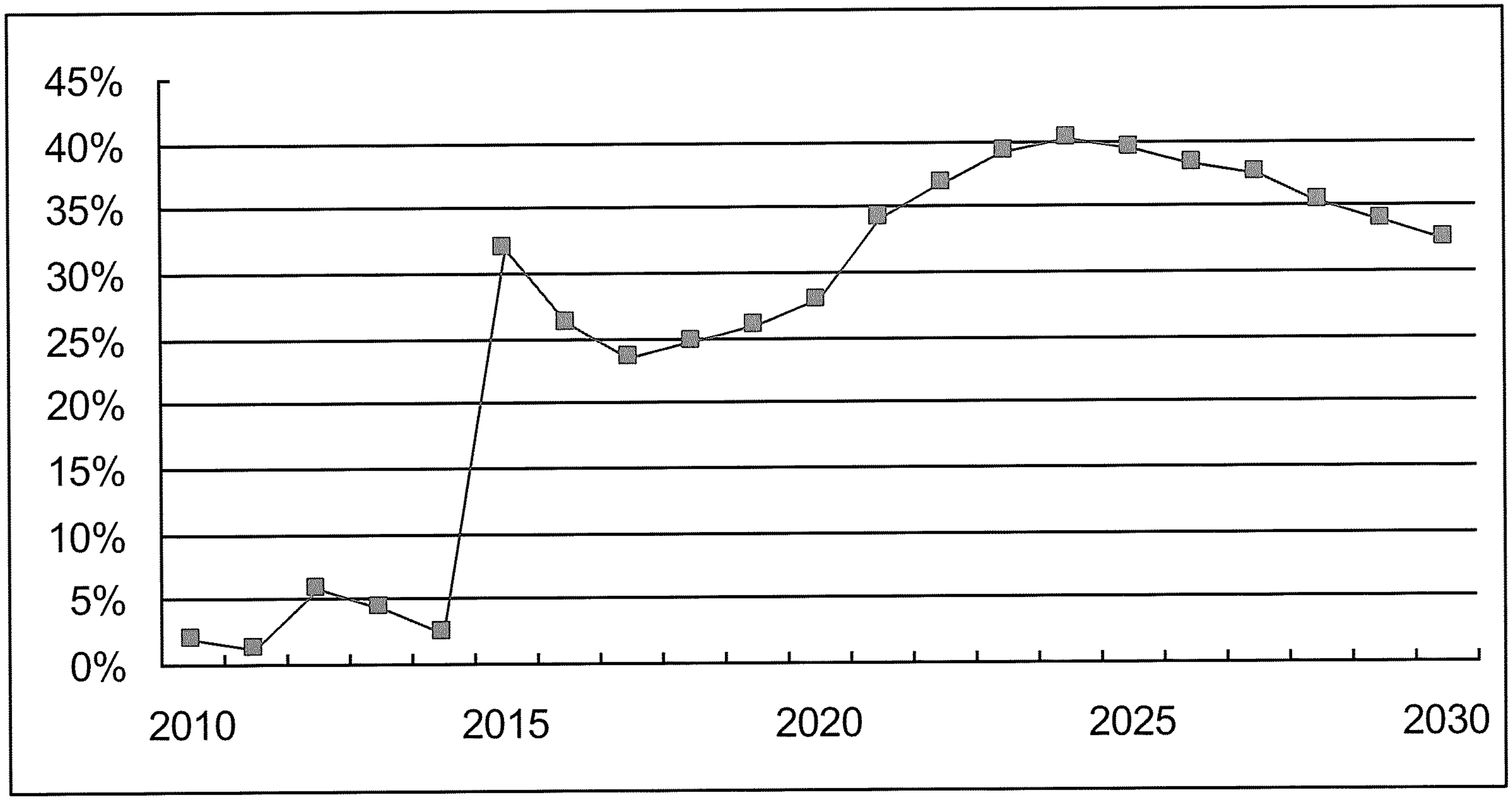
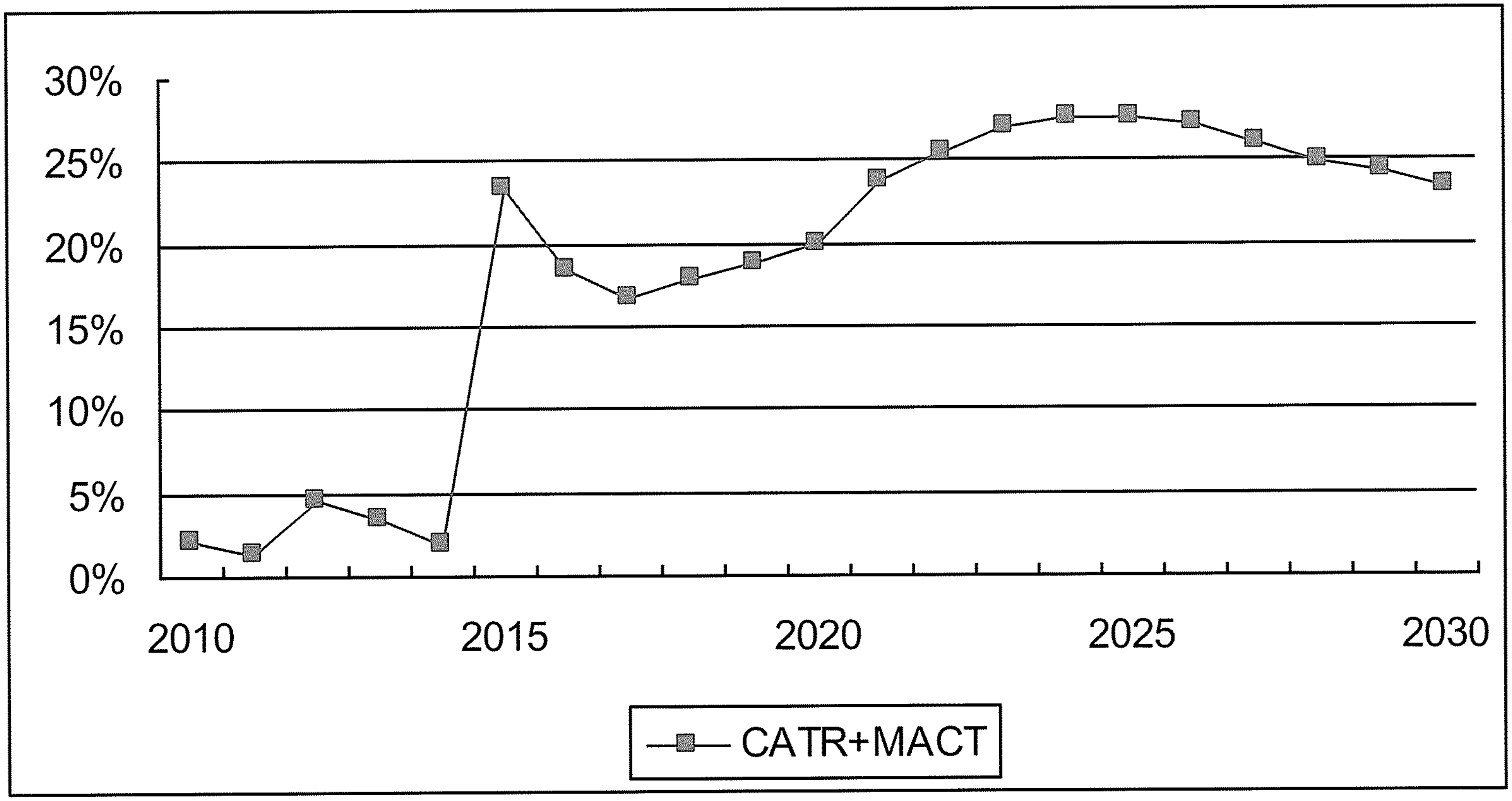
Percentage Change in U.S. Gas-Fired Generation



U.S. Electricity Sector Gas Demand

Percentage Change in U.S. Electricity Sector Gas Demand



Henry Hub Natural Gas Price

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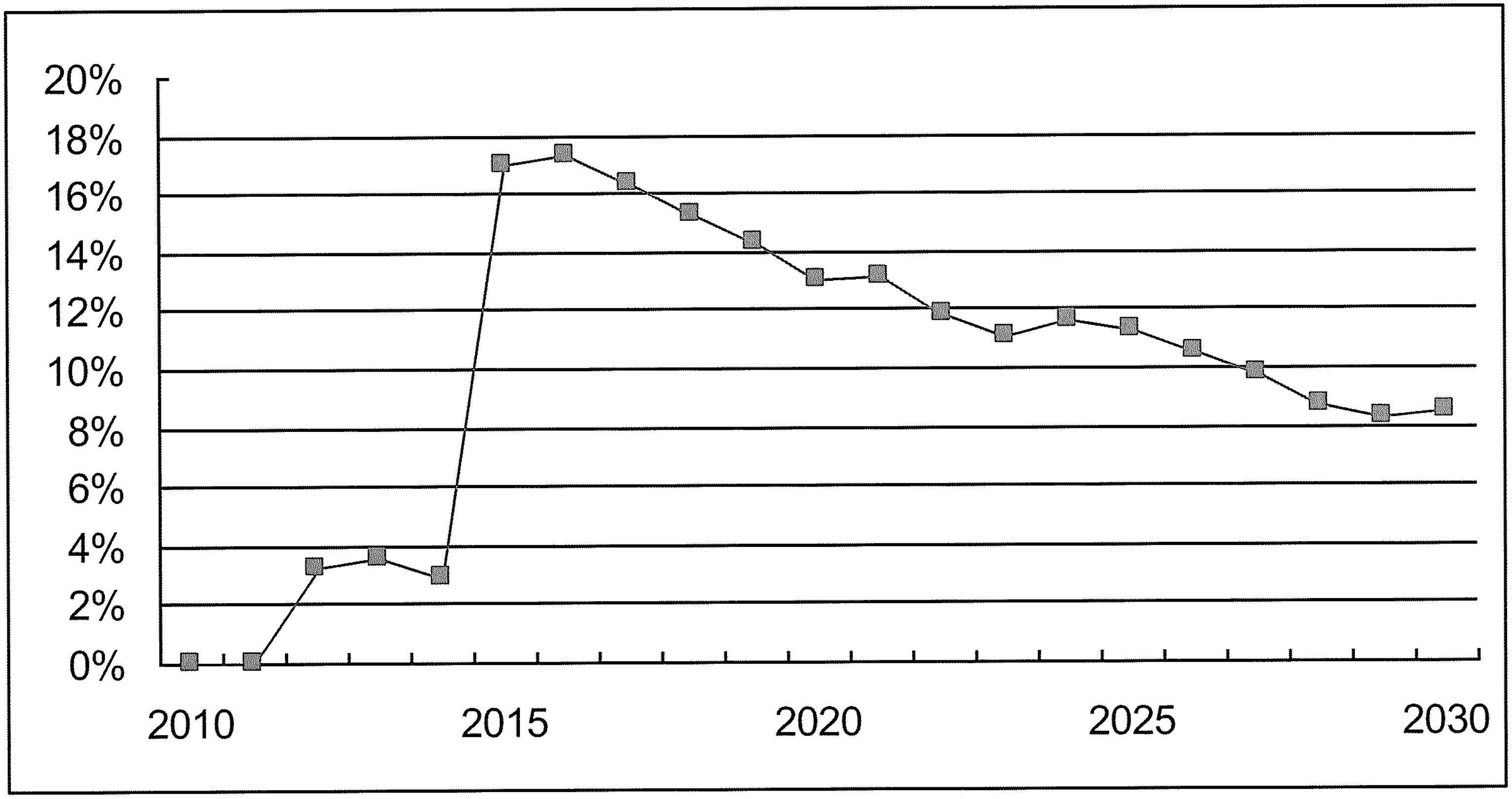
Percentage Change in Henry Hub Natural Gas Price



U.S. Average Retail Electricity Prices

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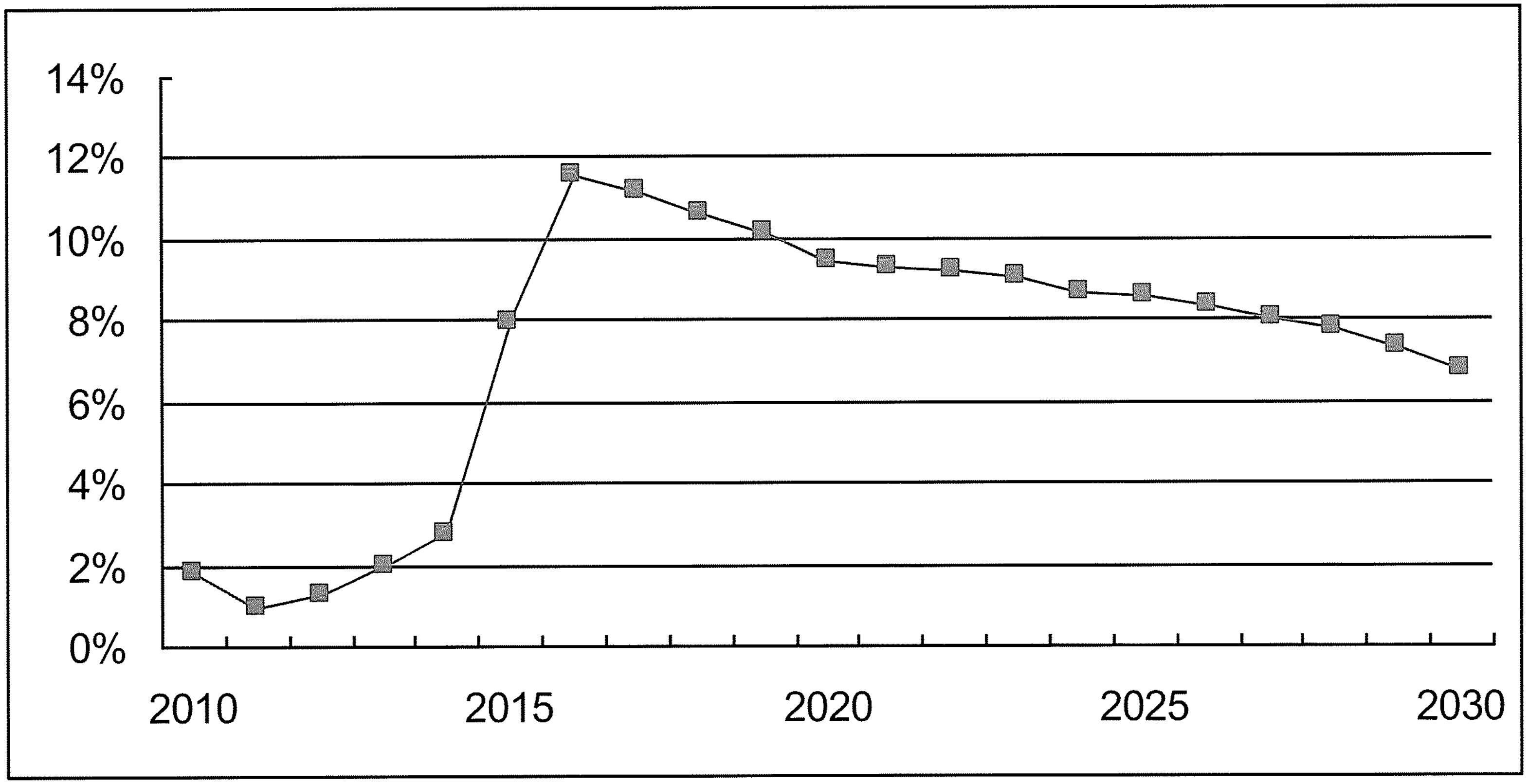
Percentage Change in U.S. Average Retail Electricity Price



Note: Electricity price impacts reflect levelized capital costs for environmental controls and new capacity.

Electricity Regions in NEMS (AEO 2011)

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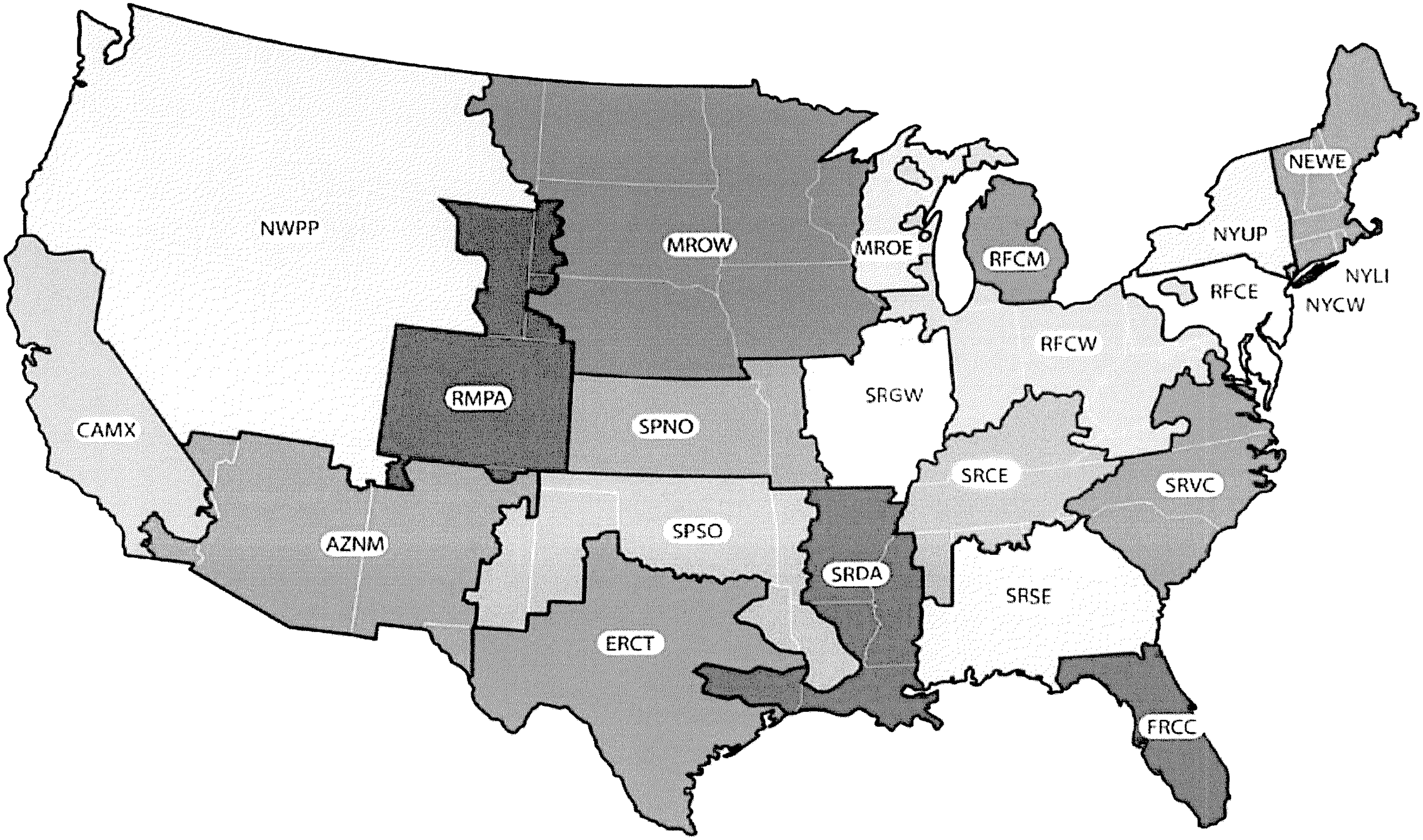

Source: EIA

Regional Retail Electricity Prices

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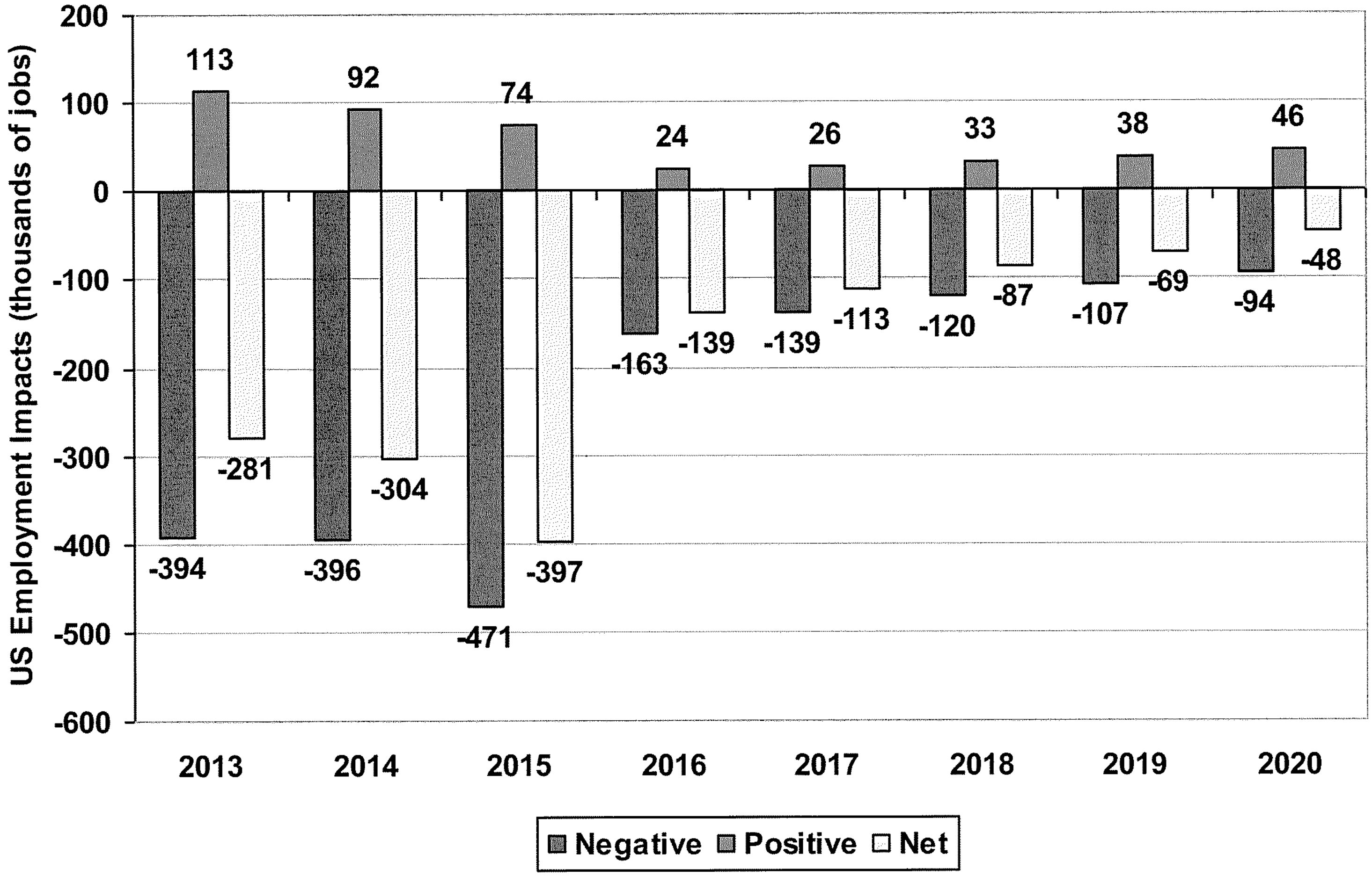
Percentage Change in Average Retail Electricity Prices

		2016	2020	2025
	US Average	+11.5%	+9.5%	+8.5%
NEWE	New England	+7.5%	+7.7%	+5.4%
NYCW	NYC	+5.5%	+5.0%	+7.6%
NYLI	NY Long Island	+6.5%	+4.8%	+6.6%
NYUP	NY Upstate	+8.0%	+6.4%	+8.1%
RFCE	Mid-Atlantic	+17.1%	+9.9%	+7.8%
SRVC	VA & Carolinas	+12.7%	+9.9%	+8.2%
SRSE	Southeast	+14.5%	+9.4%	+9.8%
FRCC	Florida	+8.8%	+8.9%	+8.5%
RFCM	Lower MI	+20.5%	+17.7%	+13.4%
RFCW	OH, IN, & WV	+12.9%	+12.1%	+11.9%
SRCE	KY & TN	+23.5%	+17.8%	+13.3%
MROE	WI & Upper MI	+21.7%	+17.3%	+12.6%
MROW	Upper Midwest	+17.6%	+14.1%	+10.2%
SRGW	South IL & East MO	+23.1%	+18.8%	+16.3%
SPNO	KS & West MO	+12.8%	+12.0%	+14.6%
SRDA	AR, LA, & West MS	+9.0%	+8.0%	+7.5%
SPSO	Oklahoma	+15.8%	+12.8%	+10.9%
ERCT	Texas	+12.1%	+9.4%	+9.5%
RMPA	CO & East WY	+6.1%	+7.3%	+8.8%
NWPP	Northwest	+2.0%	+4.0%	+7.9%
AZNM	AZ & NM	+6.1%	+5.2%	+3.6%
CAMX	California	+1.8%	+1.9%	+0.8%

Economic Impacts: U.S. Employment 2013-2020

NERA Economic Consulting



U.S. Total 2013-2020:

Negative: -1.88 million

Positive: 0.45 million

Net: -1.44 million

Note: Negative employment impacts are the sums of employment impacts in sectors with net losses.
Positive employment impacts are the sums of employment impacts in sectors with net gains.

BERNSTEINRESEARCH

U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?

OCTOBER 2010

EPA emissions regulations will speed coal plant retirements, raise prices – and benefit survivors

Under a court order to regulate hazardous air pollutants from coal-fired power plants by November 2011, EPA is readying tough new emissions standards for mercury and acid gases; the Clean Air Act requires that all coal plants comply by November 2014

To control hazardous air pollutants, the Clean Air Act requires "maximum achievable control technology," a costly combination of emissions controls; for many older, smaller coal plants, the cost of these retrofits will be prohibitive, forcing widespread retirements by 2015

We calculate that plants supplying 15% of U.S. coal-fired generation will cease operation; net of new coal plants coming on line, coal-fired generation could fall by 9% by 2015; utility demand for coal will drop commensurately; gas-fired generation, and utility demand for gas, will rise

This loss of coal-fired capacity will raise prices for energy and capacity, benefiting competitive generators whose nuclear or EPA-compliant coal plants are unaffected: FirstEnergy (FE), Exelon (EXC), Constellation (CEG), Mirant (MIR), PPL (PPL), PSEG (PEG), and Allegheny (AYE)

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We calculate that plants supplying 15% of U.S. coal-fired generation will cease operation; net of new coal plants coming on line, coal-fired generation could fall by 9% by 2015; utility demand for coal will drop commensurately; gas-fired generation, and utility demand for gas, will rise

This loss of coal-fired capacity will raise prices for energy and capacity, benefiting competitive generators whose nuclear or EPA-compliant coal plants are unaffected: FirstEnergy (FE), Exelon (EXC), Constellation (CEG), Mirant (MIR), PPL (PPL), PSEG (PEG), and Allegheny (AYE)

Portfolio Manager's Summary

EPA regulations governing power plant emissions of hazardous air pollutants — known as the Air Toxics Rule — will require the installation of costly emissions controls for mercury and acid gases across the coal-fired generating fleet by 2015. The cost of these retrofits will force the accelerated retirement of many old, small coal-fired units, whose low profitability and short remaining useful lives render the required environmental upgrades uneconomic. The scale of these retirements will have a material impact on the markets for energy and capacity, as well as those for coal and natural gas. Benefiting from the Air Toxics Rule will be competitive generators whose nuclear or environmentally compliant coal-fired power plants are unaffected by the new regulations, but will enjoy materially higher power prices. Principal among these are FirstEnergy (FE), Exelon (EXC), Constellation (CEG), Mirant (MIR), PPL (PPL), PSEG (PEG) and Allegheny (AYE).

Operating under a court order to regulate power plant emissions of hazardous air pollutants by November 2011, the EPA is preparing stringent new regulations for mercury and acid gases. Once the regulations are issued, the Clean Air Act requires *all* sources of hazardous air pollutants to install "maximum achievable control technology," or MACT, and mandates that these controls be installed within three years — implying that all coal-fired power plants must be compliant by November 2014. The Clean Air Act sets a very high standard for MACT, defining it as the control technology that attains "the average emission limitation achieved by the best performing 12 percent of existing sources" of the hazardous pollutant. To achieve such a reduction in emissions, the EPA is expected to require coal-fired power plants to install a costly combination of SO2 emissions controls, NOx emissions controls, and fabric filters.

Of the coal-fired power plants that currently lack such controls, 40% are over 50 years old, some 80% are smaller than 200 MW, and 40% run less than 50% of the time. The capital cost of installing emissions controls on these older, smaller, plants is often prohibitive. In the current environment of low natural gas prices and, hence, low wholesale power prices, the cash flows generated over the short remaining useful lives and limited hours of operation of these units may be insufficient to recover the cost of retrofitting them with costly SO2 scrubbers.

To comply with the Air Toxics Rule, we expect U.S. utilities by 2015 to: (1) install the requisite emissions controls at power plants that today supply 23% of U.S. coal-fired generation, and (2) cease operation at coal-fired power plants that today produce 15% of U.S. of coal-fired generation, or 275 million MWh. This reduction in coal-fired generation will be offset to a significant degree by the output of new coal-fired power plants scheduled to come on line by 2015, which are expected to generate 110 million MWh annually. We thus estimate the net decline in U.S. coal-fired generation by 2015 to be 165 million MWh, equivalent to 9% of U.S. coal-fired generation in 2009. Such a drop in coal-fired generation would nonetheless reduce utility demand for coal by 108 million tons, equivalent to 11% of U.S. coal production in 2009. If this reduction in coal-fired generation were to be offset by a like increase in the output of gas turbine generators, U.S. consumption of gas would be expected to rise by 1.2 Tcf annually, equivalent to 6% of total U.S. demand for gas in 2009 (20.9 Tcf).

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October 12, 2010

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Exhibit 1 Financial Overview

	AEP	D	DUK	EIX	EXC	NEE	FE	PCG
Prices as of Oct. 11, 2010	$36	$45	$18	$35	$43	$55	$38	$47
52-Week Range	$28-$37	$34-$45	$15-$18	$30-$37	$37-$52	$45-$57	$34-$48	$35-$48
Target Price	$39	$38	$18	$37	$45	$51	$49	$52
Market Capitalization ($ billion)	$17.4	$26.3	$23.2	$11.5	$28.6	$22.9	$11.7	$18.2
Rating	M	M	M	M	M	M	O	O
YTD Performance	18.2%	28.8%	12.9%	6.8%	(12.6)%	3.6%	(16.1)%	12.8%
YTD Relative Performance	9.4	20.0	4.2	(2.0)	(21.3)	(5.2)	(24.8)	4.1
SCB EPS Forecast								
2009A	$2.97	$3.27	$1.22	$3.25	$4.12	$4.05	$3.77	$3.21
2010E	$3.06	$3.31	$1.31	$3.34	$3.97	$4.27	$3.45	$3.38
2011E	$3.26	$3.10	$1.34	$2.73	$4.55	$4.28	$4.43	$3.67
2012E	$3.19	$2.88	$1.38	$2.54	$3.40	$4.75	$4.76	$3.93
2013E	$3.35	$2.86	$1.42	$2.89	$3.07	$5.16	$4.85	$4.04
2014E	$3.52	$2.76	$1.52	$3.30	$3.09	$5.56	$3.71	$4.26
EPS Annual Change								
2009A-10E	3%	1%	7%	3%	(4)%	5%	(8)%	5%
2010E-11E	7%	(6)%	2%	(18)%	15%	0%	28%	9%
2011E-12E	(2)%	(7)%	3%	(7)%	(25)%	11%	7%	7%
2012E-13E	5%	(1)%	3%	14%	(10)%	9%	2%	3%
2013E-14E	5%	(3)%	7%	14%	1%	8%	(23)%	6%
Consensus EPS								
2010E	$3.03	$3.34	$1.33	$3.31	$3.93	$4.39	$3.59	$3.41
2011E	$3.19	$3.18	$1.34	$2.98	$4.11	$4.54	$3.62	$3.70
2012E	$3.34	$3.24	$1.38	$2.83	$3.20	$4.79	$3.25	$3.92
2013E	$3.55	$3.46	$1.42	$2.96	$2.86	$5.18	$2.72	$4.12
2014E	$3.70	$3.38	$1.52	$3.30	$2.65	$5.49	$2.98	$4.26
P/E on SCB EPS Forecast								
2009A	12x	14x	14x	11x	10x	14x	10x	15x
2010E	12x	14x	13x	11x	11x	13x	11x	14x
2011E	11x	14x	13x	13x	9x	13x	9x	13x
2012E	11x	16x	13x	14x	13x	12x	8x	12x
2013E	11x	16x	12x	12x	14x	11x	8x	12x
2014E	10x	16x	12x	11x	14x	10x	10x	11x
Diluted Shares Outstanding (mil.)	479	589	1,319	326	661	416	305	391
Yield	4.6%	4.1%	5.6%	3.6%	4.9%	3.6%	5.7%	3.9%
Dividend per Share	$1.68	$1.83	$0.98	$1.26	$2.10	$2.00	$2.20	$1.82

Source: Corporate reports and Bernstein analysis.

Significant Research Conclusions

Introduction

On July 6, 2010, the U.S. Environmental Protection Agency (EPA) proposed a set of regulations, known as the Transport Rule, that would require significant reductions in emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx) from utility boilers in the eastern United States. Additionally, by March of next year, the EPA must propose regulations, known as the Air Toxics Rule, governing power plant emissions of hazardous air pollutants, including mercury and acid gases.

The EPA is not only changing standards for air quality, it is also tackling solid waste. On May 4, 2010, the agency proposed rules to phase out wet ash handling and storage at the nation's coal-fired power plants. Finally, cooling water intake by power plants is subject to regulation by states as well as the EPA under the Clean Water Act. California has recently issued costly new regulations governing cooling water intake, and the EPA is currently preparing national standards for cooling water intake at existing power plants.

The costs of complying with these new regulations — and in particular the Transport and Air Toxics Rules — will accelerate the retirement of many older, smaller coal-fired power plants. The scale of these retirements will have a material impact on the markets for power, coal and natural gas. In this *Blackbook,* we provide the context for the new rules, describe their nature and extent, and estimate their impact.

This chapter will summarize our findings with respect to the Transport and Air Toxics Rules. In particular, we will quantify (1) the extent to which emissions controls must be installed at existing power plants to achieve compliance with the rules, and (2) the potential for the cost of such retrofits to force the accelerated retirement of certain coal-fired units, whose low profitability and short remaining useful life render the required environmental upgrades uneconomic. Our analysis includes company-by-company estimates of the cost of compliance and the percentage of generation that may be lost to plant retirements. We will assess the implications of these plant closures on utility demand for coal and natural gas. Finally, we will assess the impact of the two rules on the power supply curve — and hence on the price of energy and capacity — in the PJM Interconnection. Given the expected impact on prices, we identify those utilities most likely to benefit from the new regulations.

The EPA's Transport and Air Toxics Rules

The Transport Rule governs emissions of SO2 and NOx from utility boilers in 31 eastern states and the District of Columbia. Proposed by the EPA on July 6, 2010, and expected to be promulgated in its final form in the first half of 2011, the Transport Rule sets limits on the SO2 and NOx emissions of each of the 31 states. The limits are imposed in two phases, with the first coming into effect in 2012 and the second in 2014. In aggregate, the SO2 emissions of the 31 states would be cut from 4.7 million tons annually in 2009 to 3.9 million tons in 2012 and then to 2.5 million tons in 2014, for a cumulative reduction over five years of 47%. By contrast, the rule's effect on NOx emissions is likely to be minimal. The NOx emissions caps established by the Transport Rule slightly exceed the actual level of NOx emissions in the region in 2009. The impact of the Transport Rule on power generators, therefore, will be felt primarily through its limits on SO2.

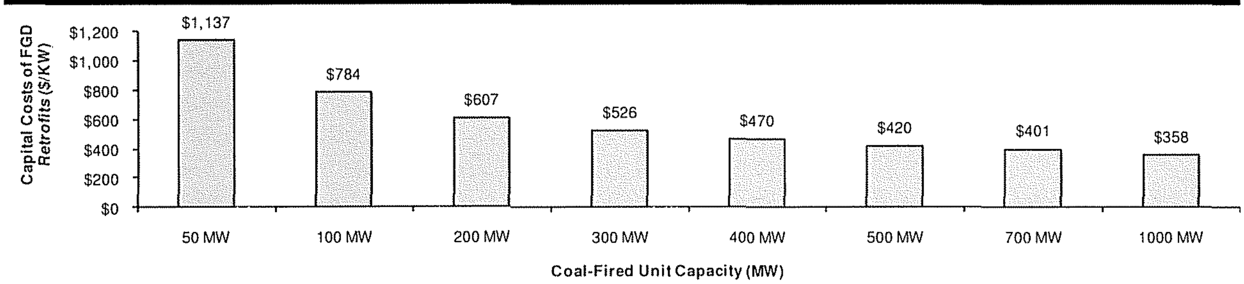
Much wider in its scope, and more severe in its impact, will be the EPA's Air Toxics Rule. The EPA is currently under a court order to regulate power plant emissions of hazardous air pollutants, including mercury and acid gases. Preliminary regulations must be published by March 2011, and final regulations promulgated by November 2011.

The Clean Air Act defines hazardous air pollutants as those that can kill or irreparably harm human beings. The provisions of the Act regulating such pollutants are commensurately stringent. First, the Clean Air Act requires *all* sources of hazardous air pollutants to install "maximum achievable control technology," or MACT, and mandates that these controls be installed within three years — implying that all coal-fired power plants must be compliant by November 2014. The Clean Air Act sets a very high standard for MACT, defining it as the control technology that attains "the average emission limitation achieved by the best performing 12 percent of existing sources" of the hazardous pollutant.

To achieve such a reduction in emissions, the EPA is expected to require coal-fired power plants to install a costly combination of SO2 scrubbers, NOx emissions controls and fabric filters. The cost of such retrofits is likely to force the accelerated retirement of many older, smaller coal-fired units, whose low profitability and short remaining useful life render the required environmental upgrades uneconomic.

Of the required pollution controls, the sulfur dioxide controls, commonly known as "SO2 scrubbers," are the most expensive component. The Electric Power Research Institute, a research institute sponsored by the power industry, estimates the cost of installing an SO2 scrubber at a typical 500 MW Midwestern plant to be some $420 per kW. Due to the economies of scale in design and construction, the cost per kW cost of SO2 emissions controls increases significantly at smaller generating units. Thus, the cost of installing an SO2 scrubber at a 200 MW unit is estimated to be $607 per kW, equivalent to the cost of gas turbine peaker; at a 100 MW unit, $784 per kW; and at a 50 MW unit, $1,137 per kW, equivalent to the cost of a new combined cycle gas turbine power plant (see Exhibit 2).

Exhibit 2 **Capital Costs of Retrofitting Coal-Fired Power Plants with SO2 Emissions Controls ($ per kW)**



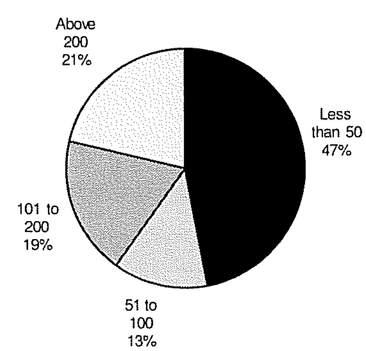
Source: EPRI and Bernstein analysis.

Reflecting the high cost of retrofitting smaller coal-fired units with SO2 scrubbers, the bulk of the nation's unscrubbed coal-fired power plants are precisely such smaller units. Of the coal-fired generating units that today lack SO2 scrubbers, almost 80% are smaller than 200 MW (see Exhibit 3). Almost half are smaller than 50 MW, the point at which the cost of installing SO2 scrubbers becomes comparable to the cost of building a new combined cycle power plant. Most of the unscrubbed units are also quite old. Only 90, or 0.5%, of the 1,740 coal-fired generating units in the United States are more than 60 years old. Of the coal-fired generating units that today lack SO2 scrubbers, 41% are over 50 years of age, suggesting that they are approaching the end of their useful lives (see Exhibit 4). Finally, many of the unscrubbed plants operate at relatively low capacity factors. Of the coal-fired generating units that today lack SO2 scrubbers, 42% have capacity factors of less than 50% (see Exhibit 5). These plants, in other words, tend to operate as load-following rather than base load units.

Our analysis suggests that the capital cost of installing SO2 emissions controls on such smaller, older units is often prohibitive. In the current environment of low natural gas prices and, hence, low wholesale power prices, the cash flows likely to be generated over the short remaining useful lives and limited hours of operation of these units may be insufficient to recover the cost of retrofitting them with SO2 scrubbers.

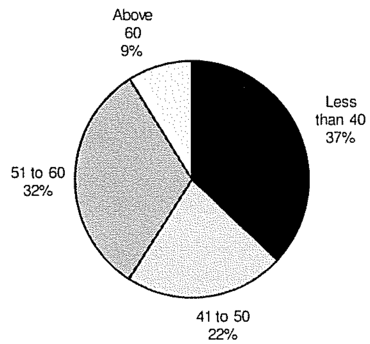
To identify those coal-fired power plants likely to be retrofitted with emissions controls as well as those likely to be shut to comply the EPA's Transport and Air Toxics Rules, we have assessed the economic benefit of installing emissions controls to the plant owners. Specifically, we have compared the present value of (1) the after-tax operating cash flow of these plants over their remaining useful lives, given forward prices for energy and capacity, forward coal prices, and the heat rates of the units in question, with (2) the estimated cost of installing SO2 scrubbers, net of any tax benefits from the additional depreciation expense. We have assumed that emissions controls will be added at those plants where the present value of future operating cash flow exceeds the cost of installing scrubbers. Where scrubber installation costs exceed the present value of future operating cash flow, we have assumed that scrubbers are not installed, and that the units do not operate beyond 2014.

Exhibit 3 Breakdown of Unscrubbed Coal-Fired Units by Generating Unit Capacity (MW)



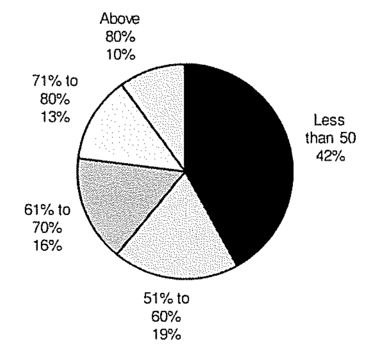
Source: Ventyx and Bernstein analysis.

Exhibit 4 Breakdown of Unscrubbed Coal-Fired Units by Generating Unit Age (Years)



Source: Ventyx and Bernstein analysis

Exhibit 5 Breakdown of Unscrubbed Coal-Fired Units by Generating Unit Capacity Factor (%)



Source: Ventyx and Bernstein analysis.

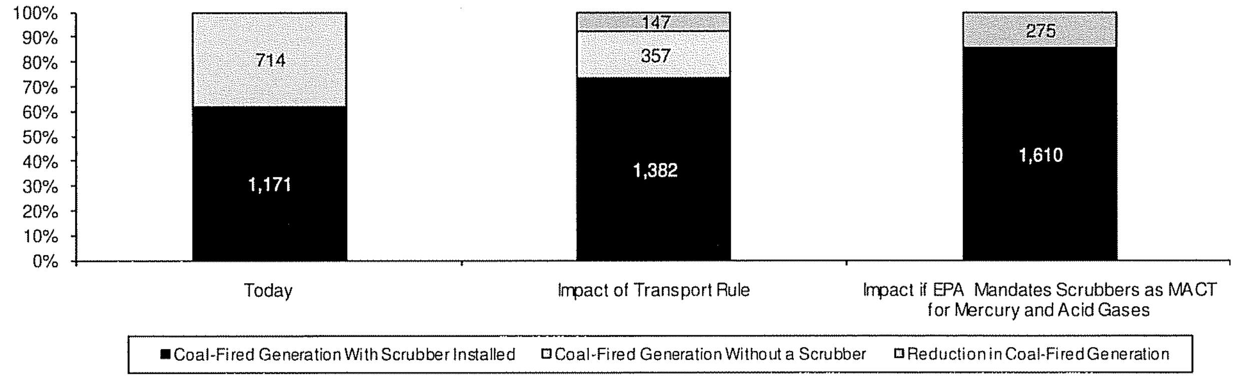
Impact on Coal-Fired Generation and Utility Demand for Coal and Gas

Exhibit 6 presents the results of our analysis. As can be seen there, we estimate that to achieve the Transport Rule target of limiting SO2 emissions in the eastern United States to 2.5 million tons by 2014 it will be necessary (1) to install SO2 scrubbers at power plants that today generate 211 million MWh, or 11% of U.S. coal-fired generation, and (2) to cease generation at unscrubbed coal-fired power plants that today produce some 147 million MWh, or 8% of U.S. of coal-fired generation.

The impact of the Air Toxics Rule is likely to be significantly greater. Assuming that the EPA defines maximum achievable control technology for hazardous air pollutants, including mercury and acid gases, in a manner that requires the installation of SO2 scrubbers, compliance with the Air Toxics Rule would require U.S. utilities by 2015 (1) to install SO2 scrubbers at power plants that today generate 439 million MWh, or 23% of U.S. coal-fired generation, and (2) to cease generation at unscrubbed coal-fired power plants that today produce 275 million MWh, or 15% of U.S. of coal-fired generation (see Exhibit 6).

The reduction in coal-fired generation required to comply with the Air Toxics Rule (275 million MWh) will be offset to a significant degree by the output of new coal-fired power plants scheduled to come on line by 2015. We estimate the increase in coal-fired generation attributable to these new plants at 110 million MWh annually, equivalent to 6% of U.S. coal-fired generation in 2009. Therefore, in a scenario where the EPA determines that maximum achievable control technology for hazardous air pollutants must include the installation of SO2 scrubbers, we would expect the *net* decline in U.S. coal-fired generation by 2015 to be 165 million MWh, equivalent to 9% of U.S. coal-fired generation in 2009.

Exhibit 6 **Scrubbed and Unscrubbed Coal-Fired Generation in 2009 vs. That Expected in 2015 from the Existing Fleet, Given the Transport Rule's SO2 Targets and an EPA Mandate to Install SO2 Scrubbers as MACT for Mercury and Acid Gases**



Source: Ventyx, EPRI, EIA and Bernstein analysis.

By converting this reduction in coal-fired generation into its fuel equivalent, it is possible to estimate the expected reduction in coal consumption by the utility industry. Based on the regional composition of utility coal supplies, and the heat content of the different coals consumed, we estimate that a net decrease in coal-fired generation of 165 million MWh would reduce utility demand for coal by 108 million tons, equivalent to 11% of U.S. coal production in 2009.

Given the regional breakdown of the expected decline in coal-fired generation, and the regional composition of utility coal supplies, we expect demand for coal grades mined east of the Mississippi (eastern coal) to be more heavily affected than demand for coal grades mined west of the Mississippi (western coal). Specifically, we estimate that the Air Toxics Rule could reduce utility demand for eastern coal by 68 million tons, or 16%, by 2015. Utility demand for western coal, by contrast, is estimated to drop by 40 million tons, or only 7%.

It is also possible to estimate the increase in utility demand for gas that is likely to result from these coal plant retirements. As mentioned, we have estimated the net reduction in coal-fired generation as a result of the Air Toxics rule at 165 million MWh by 2015. If this reduction in coal-fired generation were to be offset by a like increase in the output of currently underutilized combined cycle gas turbine generators, utility consumption of natural gas would be expected to rise by 1.2 Tcf, equivalent to 6% of total U.S. natural gas consumption in 2009 (20.9 Tcf).

Company Impact

The economic impact on individual utilities of complying with the Transport and Air Toxics Rules will depend critically on their regulatory status. For regulated utilities, the capital expenditures and plant retirements required for compliance represent prudently incurred and therefore recoverable costs. Indeed, regulators may allow the capital expenditures for environmental controls and replacement plants to be added to regulated rate base, potentially accelerating the growth of regulated earnings.

Unregulated generators, by contrast, enjoy no such mechanism for the recovery of environmental capex, nor any offset to the loss of generation from retired plants. Only to the extent that this loss of generation capacity is reflected in higher wholesale power prices can unregulated generators expect relief. (We examine the potential for this to occur in the PJM Interconnection in the next section of this chapter.)

The exhibits that follow present our estimate of the company-by-company impact of a decision by the EPA that maximum achievable control technology for hazardous air pollutants, including mercury and acid gases, must include the installation of SO2 scrubbers. Our estimate of the net loss in generation likely to be suffered by regulated utilities is presented in Exhibit 7, and our estimate of the impact on unregulated generators is shown in Exhibit 8. We next present our estimates of the capital cost likely to be incurred to comply with the new regulations, for regulated utilities in Exhibit 9 and for unregulated generators in Exhibit 10.

Exhibit 7 **Regulated Utilities: Estimated Reduction in Coal-Fired Generation Due to an EPA Mandate to Install SO2 Scrubbers as MACT for Mercury and Acid Gases**

		Company Total		Regulated Coal-Fired Plants			
		Nameplate	Generation	Reduction in Nameplate Capacity		Reduction in Generation	
Holding Company Name	Ticker	Capacity MW	GWh	In MW	As % of Total	In GWh	As % of Total
CMS Energy Corp	CMS	6,463	12,215	1,780	28%	7,393	61%
Black Hills Corp	BKH	382	1,757	125	33%	762	43%
SCANA Corp	SCG	5,568	26,065	1,832	33%	8,501	33%
Integrys Energy Group Inc	TEG	2,425	9,436	492	20%	2,878	30%
ALLETE Inc	ALE	1,346	7,310	359	27%	2,182	30%
Wisconsin Energy Corp	WEC	6,114	18,513	845	14%	4,260	23%
Southern Co	SO	42,519	182,605	8,698	20%	38,735	21%
DTE Energy Co	DTE	11,754	48,037	2,096	18%	9,093	19%
Great Plains Energy Inc	GXP	5,760	23,740	709	12%	3,962	17%
Empire District Electric Co (The)	EDE	1,235	3,084	88	7%	488	16%
Northeast Utilities	NU	1,094	3,774	100	9%	585	16%
Alliant Energy Corp	LNT	6,419	15,891	792	12%	2,309	15%
American Electric Power Co Inc	AEP	38,239	168,505	5,290	14%	19,972	12%
AES Corp (The)	AES	11,502	40,475	879	8%	3,948	10%
TECO Energy Inc	TE	4,565	18,405	326	7%	1,700	9%
Ameren Corp	AEE	16,482	74,302	923	6%	5,305	7%
Westar Energy Inc	WR	7,292	27,367	281	4%	1,809	7%
Progress Energy Inc	PGN	21,688	90,686	1,446	7%	5,121	6%
Duke Energy Corp	DUK	34,538	132,866	2,545	7%	7,250	5%
Dominion Resources Inc	D	24,314	110,437	1,504	6%	5,938	5%
Xcel Energy Inc	XEL	16,154	68,536	667	4%	2,609	4%
Allegheny Energy Inc	AYE	9,991	31,881	601	6%	243	1%
DPL Inc	DPL	3,648	15,713	414	11%	79	1%
NextEra Energy Inc	NEE	38,814	151,516	27	0%	76	0%
Total United States		**970,280**	**3,722,034**	**51,116**	**5%**	**219,117**	**6%**

Source: Ventyx, EPRI, EIA and Bernstein analysis.

Exhibit 8 **Competitive Generators: Estimated Reduction in Coal-Fired Generation Due to an EPA Mandate to Install SO2 Scrubbers as MACT for Mercury and Acid Gases**

		Company Total		Unregulated Coal-Fired Plants			
		Nameplate	Generation	Reduction in Nameplate Capacity		Reduction in Generation	
Holding Company Name	Ticker	Capacity MW	GWh	In MW	As % of Total	In GWh	As % of Total
RRI Energy Inc	RRI	13,381	23,779	1,465	11%	5,535	23%
Ameren Corp	AEE	16,482	74,302	1,906	12%	11,624	16%
Edison International	EIX	15,198	78,531	2,002	13%	7,925	10%
NRG Energy Inc	NRG	22,997	65,390	1,263	5%	5,856	9%
FirstEnergy Corp	FE	13,381	64,964	1,333	10%	5,492	8%
Dynegy Inc	DYN	17,433	44,128	775	4%	3,611	8%
Allegheny Energy Inc	AYE	9,991	31,881	461	5%	1,121	4%
Duke Energy Corp	DUK	34,538	132,866	1,024	3%	3,405	3%
AES Corp (The)	AES	11,502	40,475	149	1%	959	2%
Pepco Holdings Inc	POM	6,055	4,316	74	1%	47	1%
Public Service Enterprise Group Inc	PEG	16,274	58,916	103	1%	634	1%
Exelon Corp	EXC	27,797	149,257	895	3%	1,233	1%
Constellation Energy Group	CEG	8,713	47,600	136	2%	318	1%
Dominion Resources Inc	D	24,314	110,437	330	1%	666	1%
Calpine Corp	CPN	23,144	89,017	252	1%	332	0%
Total United States		**970,280**	**3,722,034**	**13,815**	**1%**	**55,813**	**1%**

Source: Ventyx, EPRI, EIA and Bernstein analysis.

Exhibit 9 **Regulated Utilities: Estimated Capital Cost to Install Emission Controls to Comply With an EPA Mandate to Install SO2 Scrubbers as MACT for Mercury and Acid Gases**

Holding Company Name	Ticker	Rate Base ($ million)	Capital Cost Required ($ milion)	Capital Cost Required as % of Rate Base
OGE Energy Corp	OGE	$4,752	$1,199	25%
DTE Energy Co	DTE	$10,633	$1,499	14%
Alliant Energy Corp	LNT	$6,424	$853	13%
Xcel Energy Inc	XEL	$15,222	$1,843	12%
Empire District Electric Co (The)	EDE	$1,274	$144	11%
Ameren Corp	AEE	$14,932	$1,525	10%
American Electric Power Co Inc	AEP	$28,047	$2,591	9%
CMS Energy Corp	CMS	$9,387	$509	5%
Integrys Energy Group Inc	TEG	$4,299	$233	5%
Great Plains Energy Inc	GXP	$6,144	$290	5%
Entergy Corp	ETR	$15,778	$555	4%
DPL Inc	DPL	$2,285	$54	2%
ALLETE Inc	ALE	$1,357	$27	2%
IDACORP Inc	IDA	$2,427	$44	2%
Westar Energy Inc	WR	$4,964	$72	1%
Southern Co	SO	$32,273	$361	1%
Progress Energy Inc	PGN	$19,800	$207	1%
Dominion Resources Inc	D	$21,458	$204	1%
Cleco Corp	CNL	$2,749	$18	1%
NextEra Energy Inc	NEE	$32,336	$208	1%
NorthWestern Corp	NWE	$1,854	$11	1%
NV Energy	NVE	$7,755	$42	1%
Wisconsin Energy Corp	WEC	$8,250	$9	0%

Source: Ventyx, EPRI, EIA and Bernstein analysis.

Exhibit 10 **Competitive Generators: Estimated Capital Cost to Install Emission Controls to Comply With an EPA Mandate to Install SO2 Scrubbers as MACT for Mercury and Acid Gases**

Holding Company Name	Ticker	Market Capitalization ($mil.)	Capital Cost Required ($ mil.)	Capital Cost Required as % of Market Cap.
Dynegy Inc	DYN	$444	$349	79%
RRI Energy Inc	RRI	$1,371	$440	32%
NRG Energy Inc	NRG	$5,881	$1,201	20%
Edison International	EIX	$10,983	$2,075	19%
Ameren Corp	AEE	$6,443	$710	11%
American Electric Power Co Inc	AEP	$17,456	$703	4%
Dominion Resources Inc	D	$25,657	$824	3%
Constellation Energy Group	CEG	$6,212	$189	3%
FirstEnergy Corp	FE	$11,495	$345	3%
Public Service Enterprise Group Inc	PEG	$16,393	$188	1%
PPL Corp	PPL	$12,903	$143	1%
Duke Energy Corp	DUK	$22,946	$23	0%

Source: Ventyx, EPRI, EIA and Bernstein analysis.

Impact on Power Prices: The Case of PJM

We also have assessed the likely impact of the expected reduction in coal-fired generation on wholesale power prices in the PJM Interconnection. PJM Interconnection (PJM) is the FERC-recognized regional transmission organization (RTO) that coordinates the generation and transmission of electricity across the Mid-Atlantic region and portions of the Midwest.

We focus our analysis on the PJM RTO for two reasons: (1) because of our expectation that it will experience a significant reduction in coal-fired generation as a result of the Air Toxics Rule, and (2) because of the number of competitive generators operating in this market whose gross margins would be materially affected by the consequent movement in wholesale power prices.

While the RTO is operated by PJM as a single power market, its limited east-west transmission capacity frequently results in wide disparities in power prices across its eastern and western regions. Therefore, for purposes of our analysis, we have divided PJM into two regions, which we call "PJM East" and "PJM West."

To estimate the impact of the Air Toxics Rule on power prices in PJM, we have constructed forecast power supply curves for each of these two regions. These forecast power supply curves reflect the estimated variable cost of operation of each of the power generating units in the two regions in 2015. To estimate these variable costs, we have used currently prevailing forward prices for coal, natural gas and fuel oil; the heat rates of each existing generating unit; and the estimated heat rates for each new generating unit scheduled to come on line by 2015.

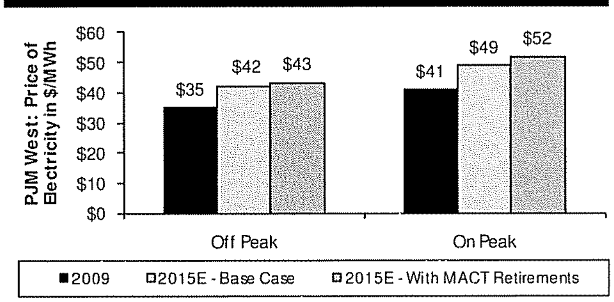
We also have prepared a second set of regional power supply curves corresponding to a scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers across the coal-fired fleet. In this case, our power supply curves for PJM East and PJM West have been adjusted to reflect the withdrawal from operation of those coal-fired power plants that we estimate it would be uneconomic to retrofit with SO2 scrubbers.

To estimate power demand in the PJM RTO in 2015, we have used historical load duration curves for PJM East and PJM West and adjusted these for the load growth forecast by the North American Electric Reliability Corporation (NERC) for its ReliabilityFirst (RFC) region, and more particularly its PJM subzone. The NERC forecast calls for power demand in PJM to grow by 12% through 2015.

Using these forecast load duration curves and power supply curves for PJM East and PJM West, it is possible to match (1) forecast power demand during each hour of 2015 with (2) the variable cost of production at the last plant required to be dispatched to meet demand during that hour. In this way it is possible to estimate the marginal of cost of power supply in each of the two PJM regions during each hour of 2015.

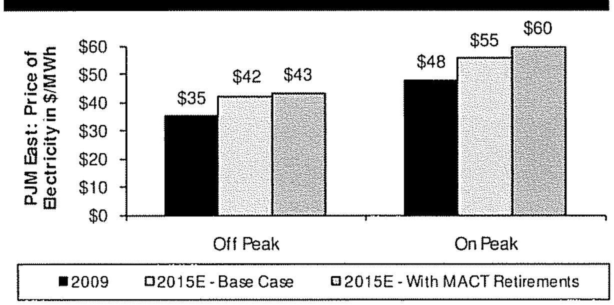
Exhibit 11 presents our power price forecast for 2015 in PJM West in both our base case scenario and in the scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers. Exhibit 12 presents our power price forecast for 2015 in PJM East, again considering the same two scenarios. As can be seen in Exhibit 11 and Exhibit 12, we estimate the impact of coal plant retirements as a result of the Air Toxics Rule will be to raise the on-peak price of electricity prevailing in PJM West in 2015 by $3 per MWh compared to our base case, while the on-peak price in PJM East could increase by $5 per MWh. In both regions, we expect the price of electricity during off-peak hours to rise by $1 per MWh.

Exhibit 11 Two Markets Hypothesis: 2015 Power Price Forecast for PJM West



Source: Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

Exhibit 12 Two Markets Hypothesis: 2015 Power Price Forecast for PJM East



Source: Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

To estimate the impact of these power price movements on the revenues and gross margins of the generators operating in the PJM Interconnection, we have taken into consideration not only our forecast power price increases but also the potential loss of power output that these generators may suffer as a result of expected coal plant retirements. Exhibit 13 presents the estimated gross margin impact by company. In a scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers, we estimate that PPL Corp (PPL) would enjoy a gross margin increase of 8% when compared to their last 12 months' EBITDA, while Mirant (MIR), Exelon (EXC) and Constellation (CEG), would enjoy an increase of 5%; PSEG (PEG) 4%; FirstEnergy (FE) and Dynegy (DYN) 3%; and Allegheny (AYE) 2%. On the other hand, we estimate that RRI Energy (RRI) could see its gross margin in the PJM RTO decrease by 3% and Edison International (EIX) by 1%.

Exhibit 13 **2015 Gross Margin Impact by Company — Assuming PJM Operates as Two Markets During Peak Hours**

Holding Company Name	Ticker	LTM EBITDA ($ million)	Gross Margin Impact ($ million)	EPS Impact	Margin Impact as % of LTM EBITDA
PPL Corp	PPL	$1,666	$133	$0.20	8%
Mirant Corp	MIR	$665	$36	$0.16	5%
Exelon Corp	EXC	$6,835	$323	$0.29	5%
Constellation Energy Group	CEG	$1,778	$82	$0.24	5%
Public Service Enterprise Group Inc	PEG	$3,968	$145	$0.17	4%
FirstEnergy Corp	FE	$2,798	$97	$0.26	3%
Dynegy Inc	DYN	$479	$13	$0.06	3%
Allegheny Energy Inc	AYE	$1,202	$18	$0.07	2%
Duke Energy Corp	DUK	$4,891	$55	$0.02	1%
Dominion Resources Inc	D	$4,219	$35	$0.04	1%
NRG Energy Inc	NRG	$2,695	$11	$0.02	0%
NextEra Energy Inc	NEE	$5,025	$11	$0.02	0%
Calpine Corp	CPN	$1,515	$3	$0.00	0%
AES Corp (The)	AES	$4,524	$4	$0.00	0%
Edison International	EIX	$3,662	$(52)	$(0.10)	-1%
RRI Energy Inc	RRI	$257	$(7)	$(0.01)	-3%

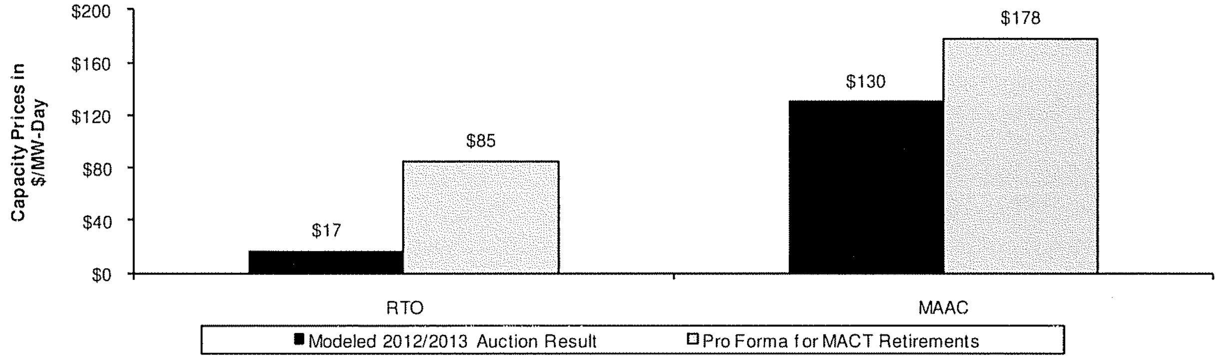
Source: Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

We have also assessed the impact that the expected retirement of coal plants as a result of the Air Toxics Rule would have on capacity prices in PJM. To do so, we re-ran the results of the 2012/2013 PJM capacity auction (the last for which the capacity prices offered by generators have been published by PJM), adjusting pro forma for the expected loss of coal-fired capacity in PJM by 2015 due to the Air Toxics Rule. Exhibit 14 illustrates the impact that the expected retirement of coal-fired capacity in PJM would have had on the 2012/2013 capacity auction. In PJM's "Rest of RTO" region (corresponding broadly to our PJM West), we estimate that capacity prices would have risen from $17 per MW-day in the 2012/2013 auction to $85 per MW-day. In PJM "MAAC" region (corresponding broadly to our PJM East), we estimate that capacity prices would have risen from $130 per MW-day in the 2012/2013 auction to $178 per MW-day (see Exhibit 14).

In Exhibit 15 we assess the impact that such an increase in PJM capacity prices would have on the earnings power of unregulated generators in PJM. We arrived at our estimates by multiplying (1) the capacity price increase in each region by (2) the unregulated capacity in PJM which each utility owns, adjusted for expected plant retirements, and then (3) comparing the result with the utility's EBITDA over the last 12 months.

As can be seen in Exhibit 15, the capacity revenue increases from the PJM auctions could contribute materially to the earnings power of the largest unregulated generators in the RTO. As a percentage of the last 12 months' EBITDA, the utilities that would appear to benefit the most are RRI Energy (RRI), for which the increase in capacity revenues is equivalent to 52% of the last 12 months' EBITDA, Mirant (MIR) with 12%, FirstEnergy (FE) with 11%, PPL (PPL) with 10%, Dynegy (DYN) with 7%, Exelon (EXC), Allegheny (AYE) and Constellation (CEG) with 6% each, and Calpine (CPN), and PSEG (PEG) with 5% each.

Exhibit 14 **What Would Have Been the Effect on PJM's 2012/2013 Capacity Auction If Supply Had Been Reduced by Our Estimate of Coal Plant Retirements in Response to an EPA MACT Standard for Mercury?**



Source: PJM, Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

Exhibit 15 **Potential Impact on PJM Auction Prices on Company Gross Margins**

Holding Company Name	Ticker	LTM EBITDA ($ million)	Gross Margin Impact ($ million)	EPS Impact	Margin Impact as % of LTM EBITDA
RRI Energy Inc	RRI	$257	$133	$0.25	52%
Mirant Corp	MIR	$665	$78	$0.35	12%
FirstEnergy Corp	FE	$2,798	$317	$0.85	11%
PPL Corp	PPL	$1,550	$153	$0.23	10%
Dynegy Inc	DYN	$479	$35	$0.16	7%
Exelon Corp	EXC	$6,835	$405	$0.36	6%
Allegheny Energy Inc	AYE	$1,202	$67	$0.25	6%
Constellation Energy Group	CEG	$1,778	$99	$0.29	6%
Calpine Corp	CPN	$1,515	$75	$0.13	5%
Public Service Enterprise Group Inc	PEG	$3,968	$196	$0.24	5%
Edison International	EIX	$3,662	$126	$0.25	3%
Duke Energy Corp	DUK	$4,891	$139	$0.05	3%
NRG Energy Inc	NRG	$2,695	$30	$0.06	1%
Dominion Resources Inc	D	$4,219	$47	$0.05	1%
AES Corp (The)	AES	$4,524	$29	$0.03	1%
NextEra Energy Inc	NEE	$5,025	$25	$0.05	0%

Source: PJM, Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

Valuation Methodology

Our target prices reflect the results of three alternative valuation methodologies: (1) a multiple-based valuation calculated by applying the median valuation multiples of a group of comparable companies to our estimates of a utility's future earnings, dividends and EBITDA; (2) a discounted cash flow model over the forecast period of 2010-15, and a terminal value in 2015 discounted back to present value at the weighted average cost of capital; and (3) a discounted dividend model over the forecast period of 2010-15, and a terminal value in 2015, discounted back to present value at the cost of equity.

Risks

Our earnings and cash flow forecasts — and thus our price targets — are subject to considerable uncertainty.

For primarily regulated utilities — such as American Electric Power (AEP), Dominion Resources (D), Duke Energy (DUK), Edison International (EIX), and PG&E Corp. (PCG) — our earnings forecasts are driven primarily by our projections of load growth, rate relief and, in the long run, the rate of growth in regulated rate base and long run realized returns on equity. Inaccurate estimates of any of these major variables can have a significant impact on our earnings forecasts, valuations and stock recommendations.

For utilities with significant unregulated generation, such as Exelon (EXC), FirstEnergy (FE) and NextEra Energy (NEE), as well as American Electric Power, Edison International and Dominion Resources in respect of their unregulated power sales, our earnings forecasts are predicated on the currently prevailing forward price curves for power and generation fuels, particularly natural gas, coal and nuclear fuel. Given the volatility of commodity prices, the relationship between these price curves is highly unstable. Changes in the spread between fuel costs and power prices can cause company earnings to diverge materially from our forecasts.

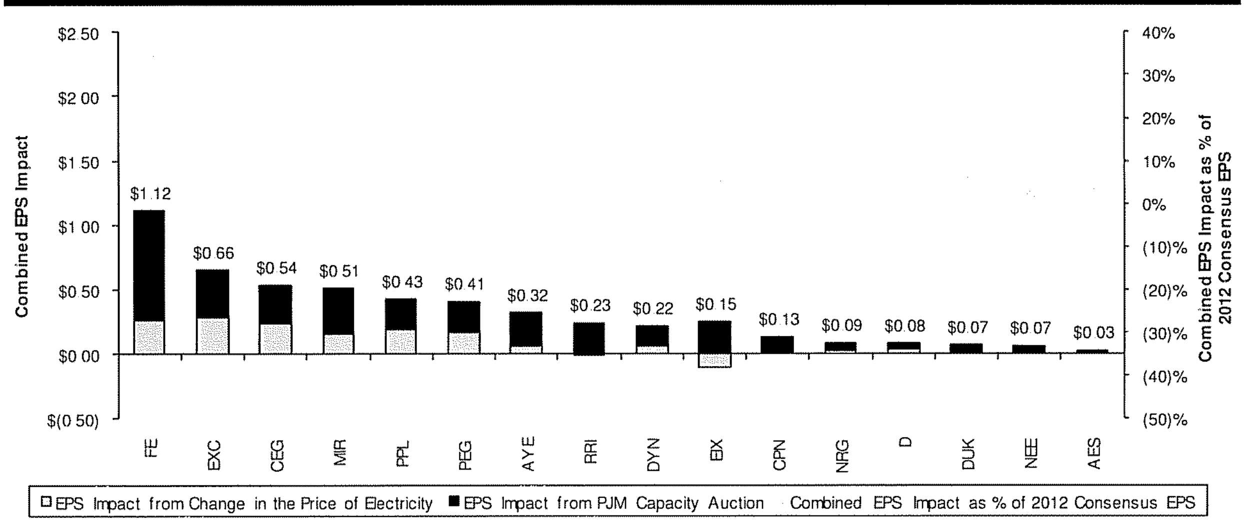
Investment Conclusion

In the PJM Interconnection, the potential loss of coal-fired generation as a result of the Air Toxics Rule is expected to drive on-peak power prices materially higher by 2015, enhancing the revenues and gross margins of those competitive generators that are relatively unaffected by coal plant retirements. We estimate that PPL Corp (PPL) would enjoy a gross margin increase of 8% when compared to their last 12 months' EBITDA, while Mirant (MIR), Exelon (EXC) and Constellation (CEG), would enjoy an increase of 5%, PSEG (PEG) 4%, FirstEnergy (FE) and Dynegy (DYN) 3% and Allegheny (AYE) 2%. The estimated EPS impact on these companies, based on current shares outstanding, is estimated at $0.20 for PPL, $0.16 for Mirant, $0.29 for Exelon, $0.24 for Constellation, $0.17 for Public Service Enterprise Group, $0.26 for FirstEnergy, $0.06 for Dynegy and $0.07 for Allegheny. See Exhibit 13 for a more complete screen.

Many of these companies are also positioned to benefit from the increase in PJM capacity prices that would result from the expected loss of coal-fired capacity in the RTO due to the Air Toxics Rule. The impact on gross margin of the resulting capacity price increases would be material for RRI (52% of last 12 months' EBITDA and $0.25 to EPS), Mirant (12% and $0.35), FirstEnergy (11% and $0.85), PPL (10% and $0.23), Dynegy (7% and $0.16), Exelon (6% and $0.36), Allegheny Energy (AYE) (6% and $0.25) and Constellation (6% and $0.29). See Exhibit 15 for a more complete screen.

To facilitate stock selection, Exhibit 16 estimates the combined impact of higher electricity and capacity prices on the earnings per share of the principal unregulated generators operating in the PJM Interconnection (left-hand axis). By dividing this estimated EPS gain into the 2012 consensus earnings estimate of each company, the chart also presents the percentage impact on each firm's long-run earnings power (right-hand axis).

Exhibit 16 **Combined EPS Impact by Company vs. 2012 Consensus EPS**



Source: PJM, Ventyx, Bloomberg L.P., EPRI, EIA, Thomson Analytics and Bernstein analysis

EPA's Proposed Transport Rule Will Replace the Clean Air Interstate Rule — How Will the Coal Fleet Be Affected?

Overview

On July 6, 2010, the EPA proposed a new regulation, the Transport Rule, which governs emissions of SO2 and NOx in 31 eastern states and the District of Columbia. By March of next year, the EPA is required by court order to issue its Air Toxics Rule, which will govern emissions of hazardous air pollutants — mercury and acid gases — from utility boilers nationally. These two new regulations will result in a significant reduction in U.S. coal-fired generation, as utilities find it cheaper not to run smaller, older coal-fired power plants than to upgrade them to meet costly new air emissions standards. We assess the specific implications of the Transport Rule in this chapter, and analyze the Air Toxics Rule in the next chapter.

Compliance with 2014's SO2 emissions limits set by the Transport Rule will require widespread additional installations of costly flue gas desulfurization equipment, more commonly known as "SO2 scrubbers," at utility boilers across the 31 eastern states subject to the rule. To identify those coal-fired power plants most likely to be retrofitted with emissions controls, we have assessed the economic benefit of doing so to the plant owners. Specifically, we have compared the present value of (1) the after-tax operating cash flow of these plants over their remaining useful lives, given forward prices for energy and capacity, forward coal prices, and the heat rates of the units in question, with (2) the estimated cost of installing SO2 scrubbers, net of any tax benefits from the additional depreciation expense.

We have assumed that emissions controls will be added at those plants where the present value of future operating cash flow exceeds the cost of installing scrubbers. Where scrubber installation costs exceed the present value of future operating cash flow, we have assumed that scrubbers are not installed.

Investment Implications

Based on the assumptions outlined above, we estimate that to achieve the Transport Rule's target of limiting SO2 emissions in the eastern United States to 2.5 million tons by 2014 it will be necessary to:

- Cease generation at unscrubbed coal-fired power plants that today produce some 147 million MWh, or 8% of U.S. of coal-fired generation, and
- Install SO2 scrubbers at power plants that today generate 211 million MWh, or a further 11% of U.S. coal-fired generation.

The economic impact on individual utilities of complying with the Transport Rule will depend critically on their regulatory status. For regulated utilities, the capital expenditures and plant retirements required for compliance represent prudently incurred and therefore recoverable costs. Indeed, regulators may allow the capital expenditures for environmental controls and replacement plants to be added to regulated rate base, potentially accelerating the growth of regulated earnings.

Among regulated utilities, the potential loss of generation due to plant closures is expected to be largest at CMS Energy (CMS), Southern (SO), ALLETE (ALE), Integrys Energy Group (TEG), Black Hills (BKH), and American Electric Power (AEP). The revenues of these companies, however, are a function of their retail sales of electricity, which will be unaffected by the composition of their power supplies. And if the cost of the power purchased to replace the lost output of coal-fired power plants were to increase the cost of power supplied, regulatory mechanisms are in place to pass through this increase to customers. Indeed, it is possible that regulated utilities may benefit from the loss of a portion of their coal-fired generation. If they can persuade regulators to allow the replacement of their unscrubbed coal-fired power plants — generally older, fully depreciated assets — with new generating capacity, these firms may accelerate the expansion of regulated rate base, and with it the growth of earnings.

Also contributing to rate base growth would be the cost of retrofitting existing coal-fired power plants to meet the emissions standards set by the Transport Rule. Relative to existing rate base, we expect these environmental capital expenditures to be highest at Ameren (AEE), American Electric Power (AEP), DTE Energy (DTE), Alliant Energy (LNT) and Integrys Energy Group (TEG).

Unregulated generators, by contrast, enjoy no such mechanism for the recovery of environmental capex, nor any offset to the loss of generation from retired plants. These companies not only face large potential reductions in power output, reflecting the closure of power plants that are uneconomic to retrofit with emissions controls, but several of them will also incur substantial, unrecoverable capital costs to ensure the continued operation of the remainder of their coal-fired fleets.

Only to the extent that this loss of generation capacity is reflected in higher wholesale power prices can unregulated generators expect relief. Most at risk among unregulated generators appear to be RRI Energy (RRI), FirstEnergy (FE), Ameren (AEE), and Edison International (EIX).

The Transport Rule and Its Predecessor, the Clean Air Interstate Rule: Key Differences

Formally titled "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone," the Transport Rule governs emissions of SO2 and NOx from utility boilers in 31 eastern states and the District of Columbia. The Transport Rule is designed to replace the Clean Air Interstate Rule (CAIR), which was issued by the EPA in March 2005 but remanded to the agency in July 2008 by the D.C. Circuit Court of Appeals *(North Carolina v. EPA)*.

The Transport Rule seeks to ensure achievement of the EPA's standards — National Ambient Air Quality Standards or NAAQS — for fine particulate matter and ground level ozone. Breathing fine particulate matter can cause or worsen respiratory diseases, such as emphysema, bronchitis, and asthma, and can aggravate existing heart disease, leading to increased hospitalization and premature death among at-risk populations, particularly the elderly. Breathing ozone, a primary component of smog, can trigger a variety of health problems including chest pain, coughing, throat irritation, and congestion. It can also worsen bronchitis, emphysema and asthma.

The EPA first adopted NAAQS for ozone and fine particulate matter in 1997. NOx is a precursor of ozone, and NOx and SO2 are precursors of fine particulate matter. Because these gases can be borne by the wind for hundreds of miles from their sources, the EPA sought to regulate emissions of the two pollutants on a regional basis. In March 2005, the EPA promulgated CAIR, which mandated significant reductions in emissions of SO2 and NOx across the eastern United States. Compared with 2003 levels, CAIR mandated cuts in regional SO2 emissions of 44% by 2010 and 56% by 2015. NOx emissions were subject to cuts of 52% by 2009 and 61% by 2015, again measured against 2003 levels.

To achieve its targeted reduction in regional emissions, CAIR implemented a cap-and-trade scheme under which the EPA issued allowances to emit SO2 and NOx up to the targeted levels. Allowances were allocated to fossil-fueled power plants in the states subject to CAIR based on their historical levels of emissions. The recipients were free to trade the allowances; consequently, while the aggregate amount of allowances declined over time, individual generators could emit at or above historical levels provided they purchased the allowances necessary to cover their emissions.

In July 2008, however, the D.C. Circuit Court of Appeals vacated CAIR: In *North Carolina v. EPA,* the Court of Appeals found that CAIR's regional cap-and-trade system violated the "Good Neighbor Provision" of the Clean Air Act, which prohibits "any...type of emissions activity [that] contribute[s] significantly to nonattainment in, or interfere[s] with maintenance by, any other state with respect to any [National Ambient Air Quality Standard]" [42 U.S.C. Sec. 7410(a)(2)(D)]. Contrary to the Good Neighbor Provision, the Court found, CAIR permitted power plants in upwind states to continue to emit SO2 and NOx, provided they purchased the allowances to do so, and thus to contribute to air quality deterioration in downwind states. The Court therefore remanded the rule to the EPA, requiring it to measure each upwind state's contribution to downwind states' nonattainment of the air quality standards stipulated under the Clean Air Act, and to promulgate a revised regulation that would eliminate these contributions. (A time line of these events, as well as critical dates related to other key environmental regulations, is presented in Exhibit 17.)

Exhibit 17 **Key Environmental Regulations Time Line**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Ozone	Revised Ozone NAAQS		Reconsidered Ozone NAAQS	Final EPA Nonattainment Designations			Next Ozone NAAQS Revision			
SO2/NOx			NOx Primary NAAQS SO2 Primary NAAQS		NOx/SO2 Secondary NAAQS					
Clean Air Trans. Rule	CAIR Vacated CAIR Remanded	Begin CAIR Phase I Annual NOx Cap Begin CAIR Phase I Seasonal NOx Cap	Begin CAIR Phase I Annual SO2 Cap Proposed CATR Rule	Final CATR Rule Expected	Beginning CATR Phase I Annual SO2 & NOx Caps Beginning CATR Phase I Seasonal SO2 & NOx Caps		Compliance With CATR Rule Beginning CATR Phase II Annual SO2 & NOx Caps			
Hg/HAPS Air Toxic Rule	CAMR & Delisting Rule Vacated			HAPS MACT Proposed Rule in March HAPS MACT Final Rule Expected in November				HAPS MACT Compliance 3 Years After Final Rule		
Water			316 (b) Proposed Rule Expected	Effluent Guidelines Proposed Rule	316 (b) Final Rule Expected	Effluent Guidelines Final Rule Expected	316 (b) Compliance 3 to 4 years After Final Rule	Effluent Guidelines Compliance 3 to 5 years after Final Rule		
PM 2.5	PM-2.5 SIPs due			Next PM-2.5 NAAQS Revision	Next PM-2.5 SIPs due	New PM-2.5 NAAQS Designations				
Coal Ash			Proposed Rule for CCBs Management	Final Rule for CCBs Management		Begin Compliance Requirements Under Final CCB Rule (Ground Water Monitoring, Double Monitors, Closure, Dry Ash Conversion)				
CO2			EPA Regulation of CO2							

Source: EPA, EEI and Bernstein analysis.

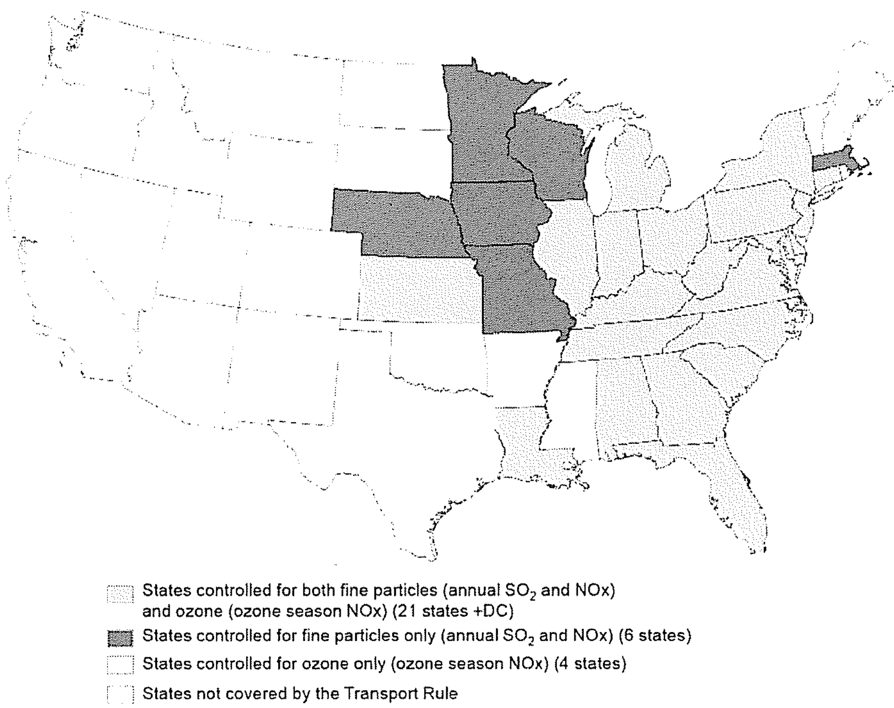
The EPA has sought to comply with this requirement in the Transport Rule by setting a pollution limit (or "budget") for each of the 31 states and the District of Columbia. These state pollution limits are designed to ensure that no state "contribute[s] significantly to nonattainment in, or interfere[s] with maintenance by, any other state" with respect to any NAAQS. States may choose to develop a state plan to achieve the required reductions (a "state implementation plan" or SIP), or they may adopt the EPA's proposed federal implementation plan.

The federal implementation plan, while setting state-specific pollution limits, would permit the operation of cap-and-trade schemes within each state. Thus, each state would be granted SO2 and NOx emissions allowances, up to the pollution limit set for that state, and these allowances would be allocated to the fossil-fueled power plants in the state. The recipients would be free to trade the allowances, but only on an intra-state basis, thereby ensuring that the state as a whole does not violate the Good Neighbor Provision of the Clean Air Act.

The federal implementation plan proposed in the EPA's Transport Rule would make one exception to the intra-state trading rule. The EPA notes that its state-by-state pollution limits are "based on its projections of state emissions in an average year," and are designed to ensure that under average circumstances no state's emissions will contribute to the deterioration of air quality in any downwind state. However, in the EPA's words, "the inherent variability in power plant operations," whether triggered by weather, plant failures or other causes, may cause state level emissions to vary from these average levels. To allow for these fluctuations, the EPA developed variability limits for each state budget. The federal implementation plan therefore sets one-year variability limits (10%) and three-year rolling average variability limits (about 6%) for each state. Inter-state trading in emissions allowances would be allowed up to these variability limits.

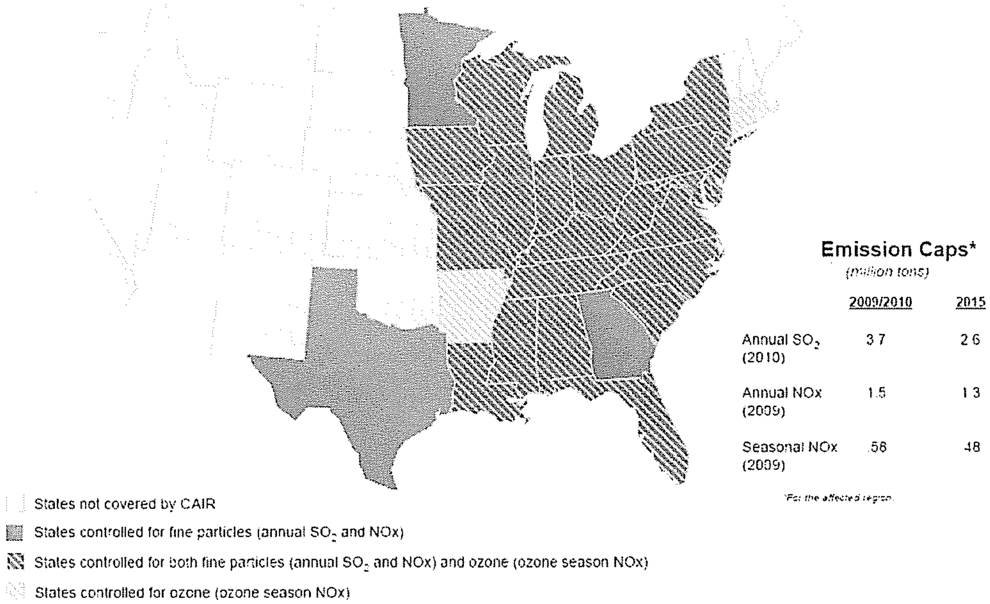
While the most important difference between the CAIR and the Transport Rule is the latter's focus on state, rather than regional, emissions limits, the two rules also differ in other significant respects. First, they do not cover precisely the same states. The Transport Rule would subject 27 states and the District of Columbia to annual limits on SO2 and NOx emissions, and an additional four states to ozone season limits on NOx emissions (see Exhibit 18). CAIR imposed annual SO2 and NOx emissions limits on 25 states, and ozone season NOx emissions limits on three states (see Exhibit 19). Importantly, CAIR imposed annual SO2 emissions limits on Texas, while the Transport Rule does not. Conversely, the Transport Rule imposes annual SO2 and NOx emissions limits on Kansas, Nebraska, Connecticut and Massachusetts, while CAIR did not (see Exhibit 20).

Exhibit 18 **States Regulated Under the Transport Rule**



Source: EPA.

Exhibit 19 **States Regulated Under the Clean Air Interstate Rule (CAIR)**



Source: EPA.

Exhibit 20 **States Regulated Under CAIR and the Transport Rule**

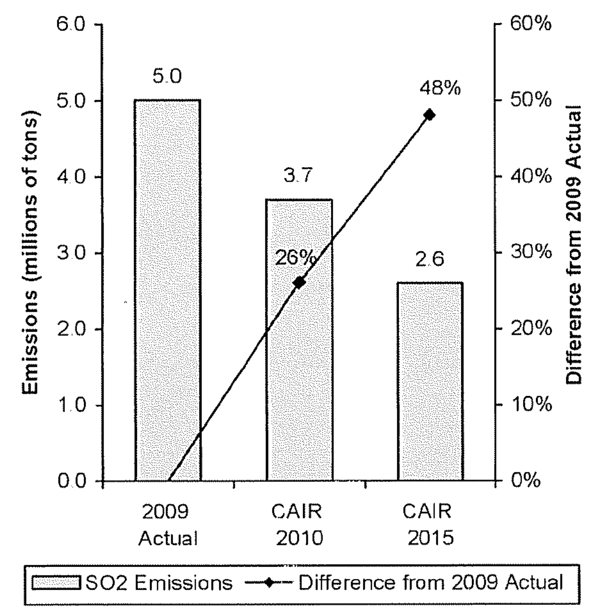
Fine Particles (SO2 and NOx)		Ozone Season NOx Only	
CAIR	Transport Rule	CAIR	Transport Rule
Alabama	Alabama	Arkansas	Arkansas
	Connecticut	Connecticut	
District of Columbia	District of Columbia	Massachusetts	
Delaware	Delaware		Mississippi
Florida	Florida		Oklahoma
Georgia	Georgia		Texas
Iowa	Iowa		
Illinois	Illinois		
Indiana	Indiana		
	Kansas		
Kentucky	Kentucky		
Louisiana	Louisiana		
Maryland	Maryland		
	Massachusetts		
Michigan	Michigan		
Minnesota	Minnesota		
Mississippi			
Missouri	Missouri		
	Nebraska		
North Carolina	North Carolina		
New Jersey	New Jersey		
New York	New York		
Ohio	Ohio		
Pennsylvania	Pennsylvania		
South Carolina	South Carolina		
Tennessee	Tennessee		
Texas			
Wisconsin	Wisconsin		
West Virginia	West Virginia		

Source: EPA.

A second key difference between the CAIR and the Transport Rule are the limits they impose on SO2 and NOx emissions, and the deadlines they set for compliance. Because the two rules cover different states, the emissions caps imposed by them are not strictly comparable. The SO2 emissions caps established by CAIR are presented in Exhibit 21, and are compared with the actual level of SO2 emissions in the CAIR states in 2009. The SO2 emissions caps established by the Transport Rule are presented in Exhibit 22, along with their differences from the actual levels in 2009.

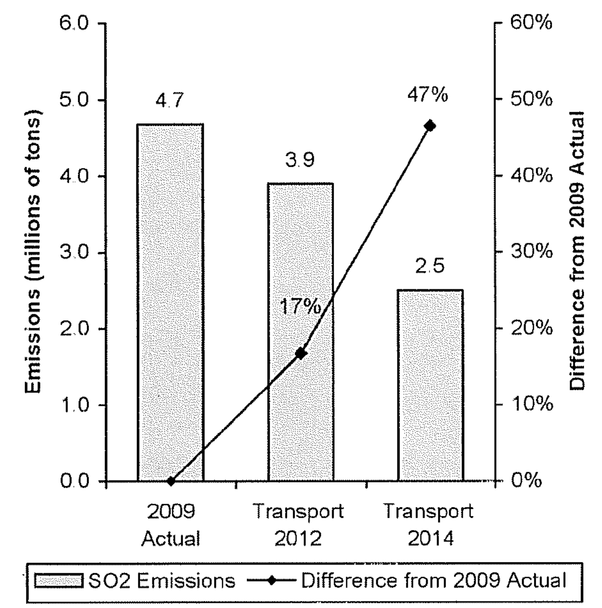
As can be seen by comparing Exhibit 21 with Exhibit 22, the Transport Rule imposes a lower cap on regional SO2 emissions (2.5 versus 2.6 million tons) and an earlier deadline for compliance (2014 versus 2015). As noted above, however, the regions covered by the two rules differ slightly. When the final emissions targets under the two rules are compared with the 2009 level of emissions in the states regulated by the two rules, CAIR appears to require a slightly higher percentage cut.

Exhibit 21 SO2 Emissions Caps Under CAIR



Source: EPA, Ventyx Global Energy and Bernstein analysis.

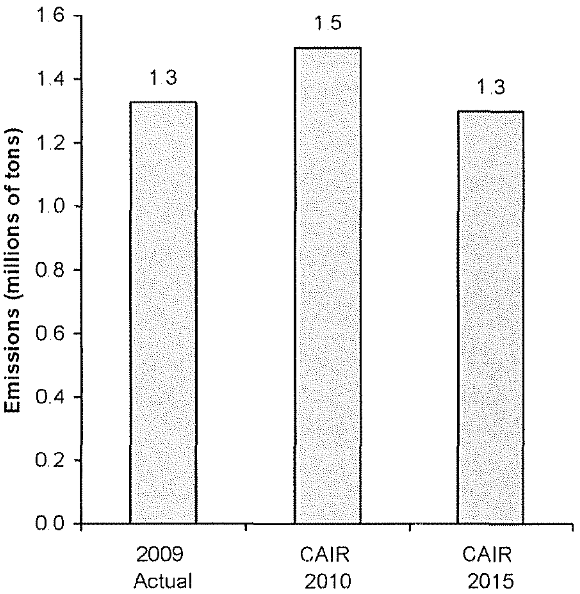
Exhibit 22 SO2 Emissions Caps Under the Transport Rule



Source: EPA, Ventyx Global Energy and Bernstein analysis.

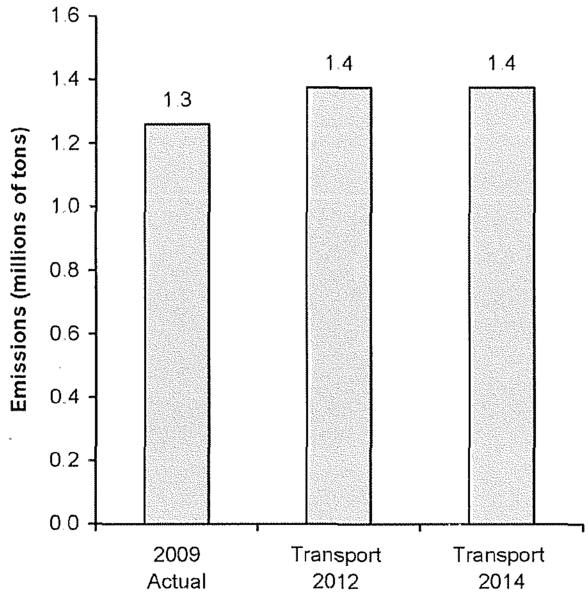
While both CAIR and the Transport Rule would require significant reductions in SO2 emissions relative to 2009 levels, little if any reduction in NOx emissions would be required off the 2009 base. As can be seen in Exhibit 23 and Exhibit 24, actual NOx emissions in the regulated regions in 2009 were at or below the final caps set by the two rules. The impact of the Transport Rule on power generators, therefore, will be felt primarily through its limits on SO2.

Exhibit 23 Annual NOx Emissions Caps Under CAIR



Source: EPA, Ventyx Global Energy and Bernstein analysis.

Exhibit 24 Annual NOx Emissions Caps Under the Transport Rule



Source: EPA, Ventyx Global Energy and Bernstein analysis.

Modeling the Impact of the New Emissions Limits

In this section we model the impact on the utility industry of the emissions limits to be set by the EPA under its Transport Rule — assessing the extent to which utilities will be required to install SO2 scrubbers to comply with the state-by-state limits on SO2 emissions.

Our model makes several simplifying assumptions. First, we have assumed that each state will meet its 2014 emissions cap. Second, we have assumed that in order to do so, states will first require those coal-fired power plants that lack SO2 scrubbers to install them. Third, if the emissions reductions achievable by installing scrubbers are insufficient to meet the state emissions limits set by the Transport Rule, we have assumed that the shortfall will be met through plant retirements.

To identify those coal-fired power plants most likely to be retrofitted with SO2 scrubbers to meet state emissions limits under the Transport Rule, we have assessed the economic benefit of doing so to the plant owners. Specifically, we have compared the present value of (1) the after-tax operating cash flow of these plants over their remaining useful lives, given forward power prices (including both energy and capacity), forward coal prices, and the heat rates of the units in question, with (2) the estimated cost of installing SO2 scrubbers, net of any tax benefits from the additional depreciation expense.

We have assumed that emissions controls will be added at those plants where the present value of future operating cash flow exceeds the cost of installing scrubbers. In cases where scrubber installation costs exceed the present value of future operating cash flow, we have assumed that the scrubbers are not installed, and if necessary to meet state targets, the plants cease to operate.

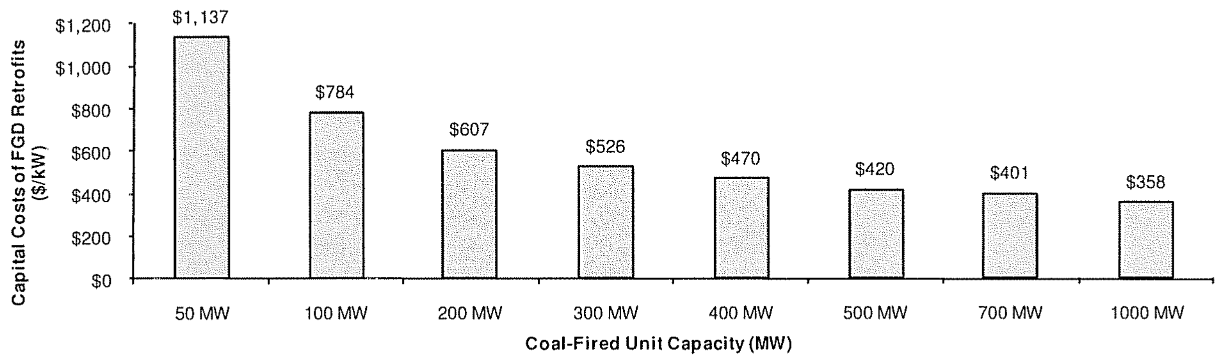
If a state can meet the SO2 emissions limits imposed by the Transport Rule through the installation of SO2 scrubbers on those coal-fired power plants where it is economic to do so, we have assumed that those coal-fired units where retrofitting is not economic remain in service without emissions controls. However, if the requisite cut in SO2 emissions cannot be achieved through retrofits, then we assume that coal-fired units that are not economic to retrofit must be retired until the target is achieved.

We have made several assumptions that are designed to ensure that we do not overestimate plant retirements. First, our estimate of the normal useful life of a coal-fired power plant is 60 years. This is likely conservative, as only 90, or 0.5%, of the 1,740 coal-fired generating units in the United States are more than 60 years old. Second, we have attempted to capture the potential economies of retrofitting power plants composed of several small generating units. As Exhibit 25 shows, the dollar-per-MW cost of installing SO2 scrubbers rises dramatically for smaller units However, where several small units are present at a single site, we assume that the dollar-per-MW cost to retrofit each is the cost typical of the largest unit at the site. Third, regardless of the outcome of our analysis, if a utility has announced plans to install SO2 scrubbers on a power plant over the next two years, we assume these plans are carried out, permitting the continued operation of the affected units.

To estimate the cost of installing SO2 scrubbers, we have relied on estimates prepared by the Electric Power Research Institute (EPRI), a technological research institute sponsored by the power industry. EPRI estimates the cost of installing an SO2 scrubber at a typical 500 MW Midwestern plant to be some $420 per kW — approximately the cost per kW of building a new gas turbine peaker. Installation costs for NOx emissions controls are estimated at a further $116 per kW for a 500 MW plant.

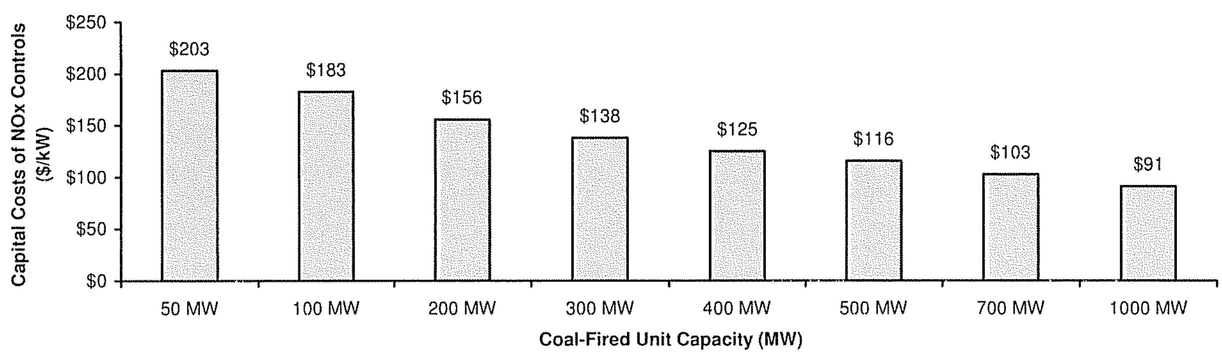
Due to economies of scale in design and construction, the costs per kW cost of both SO2 and NOx emissions controls increase significantly at smaller generating units (see Exhibit 25 and Exhibit 26). Thus, the cost of installing an SO2 scrubber at a 200 MW unit is estimated to be $607 per kW, equivalent to the cost of gas turbine peaker; at a 100 MW unit it is $784/kW; and at a 50 MW unit it is $1,137/kW, equivalent to the cost of a new combined cycle gas turbine power plant.

Exhibit 25 **Capital Costs of Flue Gas Desulfurization Retrofits ($ per kW)**



Source: EPRI and Bernstein analysis.

Exhibit 26 **Capital Costs of NOx Controls ($ per kW)**



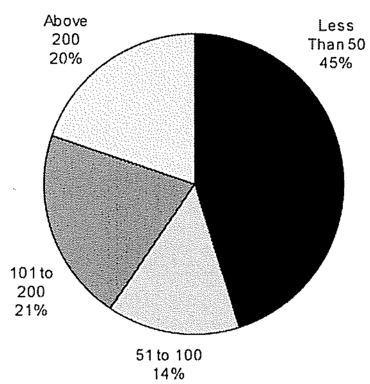
Source: EPRI and Bernstein analysis.

Reflecting the high cost of retrofitting smaller coal-fired units with SO2 emissions controls, the bulk of the nation's unscrubbed coal-fired power plants are precisely such smaller units. Of the coal-fired generating units that today lack SO2 scrubbers in the states affected by the Transport Rule, almost 80% are smaller than 200 MW (see Exhibit 27). Almost half are smaller than 50 MW, the point at which the cost of installing SO2 scrubbers becomes comparable to the cost of building a new combined cycle power plant.

Most of the unscrubbed units are also relatively old. Of the coal-fired generating units that today lack SO2 scrubbers in the states affected by the Transport Rule, 45% are over 50 years of age (see Exhibit 28). Over 69% are over 40 years of age.

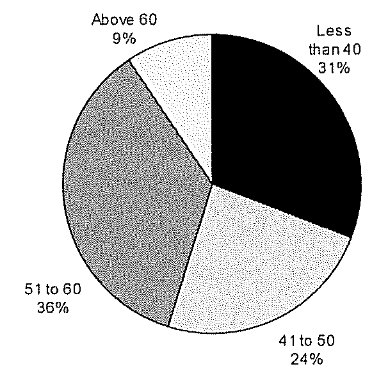
Finally, many of the unscrubbed plants operate at relatively low capacity factors. Of the coal-fired generating units that today lack SO2 scrubbers, 42% have capacity factors of less than 50% (see Exhibit 29). Over 61% operate have capacity factors of 60% or less. These unscrubbed coal-fired plants, in other words, tend to operate as load-following rather than base load units.

Exhibit 27 Breakdown of Unscrubbed Coal-Fired Units in Transport Rule States by Generating Unit Capacity (MW)



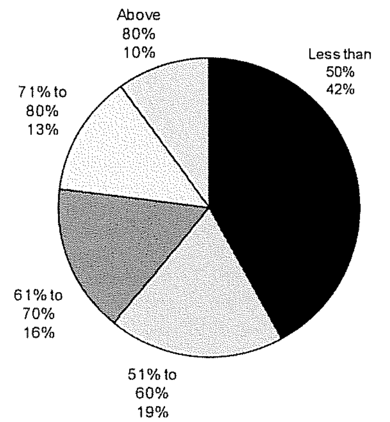
Source: Ventyx and Bernstein analysis.

Exhibit 28 Breakdown of Unscrubbed Coal-Fired Units in Transport Rule States by Generating Unit Age (years)



Source: Ventyx and Bernstein analysis.

Exhibit 29 Breakdown of Unscrubbed Coal-Fired Units in Transport Rule States by Generating Unit Capacity Factor (%)



Source: Ventyx and Bernstein analysis.

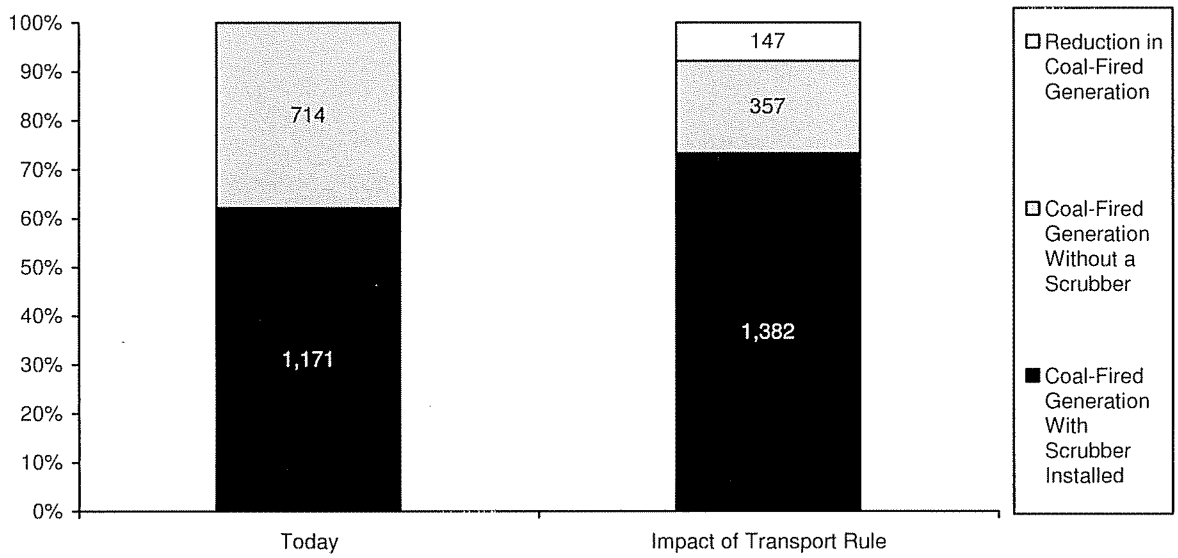
Given the size, age and capacity factors of the nation's unscrubbed coal-fired power plants, we believe the capital cost of installing SO2 emissions controls on these units is likely to be prohibitive. The current environment of low gas prices and, hence, low wholesale power prices, is aggravated by rising forward price curves for coal, particularly Appalachian grades, compressing generation margins. With such a large portion of the unscrubbed fleet comprising smaller units that are costly to retrofit, the cash flows likely to be generated over these units' short remaining useful lives and limited hours of operation may be insufficient to recover the cost of SO2 scrubbers.

Forecast and Conclusions

Using data provided by the Ventyx Global Energy database, we estimate the net generation of the U.S. coal-fired fleet in 2009 at 1,885 million MWh of electricity. Of this total, 1,171 million MWh, or 62%, was produced by units already equipped with SO2 scrubbers or where plans have been announced to install scrubbers in the next two years. The remaining 714 million MWh (38% of U.S. of coal-fired generation) was produced by units where adequate SO2 emission controls have not been installed nor have plans been announced to do so (see Exhibit 30).

Based on the assumptions outlined above, we estimate that to achieve the Transport Rule target of limiting SO2 emissions in the eastern United States to 2.5 million tons by 2014 it will be necessary (1) to cease generation at unscrubbed coal-fired power plants that today produce some 147 million MWh, or 8% of U.S. of coal-fired generation, and (2) to install SO2 scrubbers at power plants that today generate 211 million MWh, or a further 11% of U.S. coal-fired generation (see Exhibit 30).

Exhibit 30 **Scrubbed and Unscrubbed Coal-Fired Generation in 2009 vs. that Expected in 2015 from the Existing Fleet Under the Transport Rule's SO2 Targets for 2014**



Source: Ventyx, EPRI, EIA and Bernstein analysis.

Company Impact from the Transport Rule

The economic impact on individual utilities of complying with the Transport Rule will depend critically on their regulatory status. For regulated utilities, the capital expenditures and plant retirements required for compliance represent prudently incurred and therefore recoverable costs. Indeed, regulators may allow the capital expenditures for environmental controls and replacement plants to be added to regulated rate base, potentially accelerating the growth of regulated earnings. Unregulated generators, by contrast, enjoy no such mechanism for the recovery of environmental capex, nor any offset to the loss of generation from retired plants. Only to the extent that this loss of generation capacity is reflected in higher wholesale power prices can unregulated generators expect relief.

Our estimate of the potential loss of coal-fired generation by regulated utilities as the result of compliance with the Transport Rule is presented in Exhibit 31, and our estimate of the impact on competitive generators is shown in Exhibit 32. We next present our estimates of the capital cost likely to be incurred to comply with the Transport Rule, for regulated utilities in Exhibit 33 and for unregulated generators in Exhibit 34.

Most at risk among unregulated generators appear to be RRI Energy (RRI), FirstEnergy (FE), Ameren (AEE), and Edison International (EIX). These companies not only face large potential reductions in power output, reflecting the closure of power plants that are uneconomic to retrofit with emissions controls, but several of them also will incur substantial, unrecoverable capital costs to ensure the continued operation of the remainder of their coal-fired fleets.

Among regulated utilities, the companies most at risk of plant closures, and the consequent loss of generation, are CMS Energy (CMS), Southern (SO), ALLETE (ALE), Integrys Energy Group (TEG), Black Hills (BKH), and American Electric Power (AEP). Those regulated utilities facing the largest capital outlays to bring their coal-fired fleets into compliance with the Transport Rule are Ameren (AEE), American Electric Power (AEP), DTE Energy (DTE), Alliant Energy (LNT) and Integrys Energy Group (TEG).

Exhibit 31 **Regulated Utilities: Estimated Reduction in Coal-Fired Generation Due to the EPA's Transport Rule**

		Company Total		Regulated Coal-Fired Plants			
				Reduction in Nameplate Capacity		Reduction in Generation	
Holding Company Name	Ticker	Nameplate Capacity MW	Generation GWh	In MW	As % of Total	In GWh	As % of Total
CMS Energy Corp	CMS	6,463	12,215	345	5%	2,149	18%
Southern Co	SO	42,519	182,605	6,596	16%	30,219	17%
ALLETE Inc	ALE	1,346	7,310	191	14%	1,186	16%
Integrys Energy Group Inc	TEG	2,425	9,436	201	8%	1,200	13%
Black Hills Corp	BKH	382	1,757	35	9%	199	11%
American Electric Power Co Inc	AEP	38,239	168,505	4,082	11%	16,819	10%
Northeast Utilities	NU	1,094	3,774	50	5%	291	8%
Alliant Energy Corp	LNT	6,419	15,891	238	4%	1,076	7%
Empire District Electric Co (The)	EDE	1,235	3,084	38	3%	202	7%
DTE Energy Co	DTE	11,754	48,037	583	5%	2,852	6%
Dominion Resources Inc	D	24,314	110,437	1,504	6%	5,938	5%
Duke Energy Corp	DUK	34,538	132,866	2,129	6%	6,633	5%
AES Corp (The)	AES	11,502	40,475	529	5%	1,797	4%
Progress Energy Inc	PGN	21,688	90,686	987	5%	3,253	4%
SCANA Corp	SCG	5,568	26,065	78	1%	514	2%
Ameren Corp	AEE	16,482	74,302	138	1%	745	1%
DPL Inc	DPL	3,648	15,713	414	11%	79	1%
Allegheny Energy Inc	AYE	9,991	31,881	298	3%	112	0%
Xcel Energy Inc	XEL	16,154	68,536	40	0%	199	0%
Total United States		**970,280**	**3,722,034**	**27,882**	**3%**	**117,896**	**3%**

Source: Ventyx, EPRI, EIA and Bernstein analysis.

Exhibit 32 **Competitive Generators: Estimated Reduction in Coal-Fired Generation Due to the EPA's Transport Rule**

		Company Total		Unregulated Coal-Fired Plants			
				Reduction in Nameplate Capacity		Reduction in Generation	
Holding Company Name	Ticker	Nameplate Capacity MW	Generation GWh	In MW	As % of Total	In GWh	As % of Total
RRI Energy Inc	RRI	13,381	23,779	1,465	11%	5,535	23%
FirstEnergy Corp	FE	13,381	64,964	1,333	10%	5,492	8%
Ameren Corp	AEE	16,482	74,302	442	3%	3,093	4%
NRG Energy Inc	NRG	22,997	65,390	392	2%	1,969	3%
Allegheny Energy Inc	AYE	9,991	31,881	386	4%	928	3%
Duke Energy Corp	DUK	34,538	132,866	1,024	3%	3,405	3%
AES Corp (The)	AES	11,502	40,475	149	1%	959	2%
Dynegy Inc	DYN	17,433	44,128	75	0%	404	1%
Exelon Corp	EXC	27,797	149,257	895	3%	1,233	1%
Dominion Resources Inc	D	24,314	110,437	330	1%	666	1%
Calpine Corp	CPN	23,144	89,017	252	1%	332	0%
Total United States		**970,280**	**3,722,034**	**7,820**	**1%**	**28,969**	**1%**

Source: Ventyx, EPRI, EIA and Bernstein analysis.

Exhibit 33 **Regulated Utilities: Estimated Capital Cost to Install Emission Controls to Comply With the EPA's Transport Rule**

Holding Company Name	Ticker	Rate Base ($ million)	Capital Cost Required ($ milion)	Capital Cost Required as % of Rate Base
Ameren Corp	AEE	$14,932	$1,284	9%
American Electric Power Co Inc	AEP	$28,047	$1,761	6%
DTE Energy Co	DTE	$10,633	$657	6%
Alliant Energy Corp	LNT	$6,424	$382	6%
Integrys Energy Group Inc	TEG	$4,299	$233	5%
Xcel Energy Inc	XEL	$15,222	$567	4%
CMS Energy Corp	CMS	$9,387	$320	3%
DPL Inc	DPL	$2,285	$54	2%
ALLETE Inc	ALE	$1,357	$27	2%
Southern Co	SO	$32,273	$361	1%
Progress Energy Inc	PGN	$19,800	$207	1%
Dominion Resources Inc	D	$21,458	$204	1%
NextEra Energy Inc	NEE	$32,336	$208	1%
Wisconsin Energy Corp	WEC	$8,250	$9	0%

Source: Ventyx, EPRI, EIA and Bernstein analysis.

Exhibit 34 **Competitive Generators: Estimated Capital Cost to Install Emission Controls to Comply With the Transport Rule**

Holding Company Name	Ticker	Market Capitalization ($ mil.)	Capital Cost Required ($ mil.)	Capital Cost Required as % of Market Cap.
RRI Energy Inc	RRI	$1,371	$440	32%
Edison International	EIX	$10,983	$2,075	19%
Ameren Corp	AEE	$6,443	$519	8%
Dominion Resources Inc	D	$25,657	$824	3%
Constellation Energy Group	CEG	$6,212	$189	3%
FirstEnergy Corp	FE	$11,495	$345	3%
Public Service Enterprise Group Inc	PEG	$16,393	$188	1%
Duke Energy Corp	DUK	$22,946	$23	0%
PPL Corp	PPL	$12,903	$8	0%

Source: Ventyx, EPRI, EIA and Bernstein analysis.

Black Days Ahead for Coal: Implications of EPA Air Toxics Rule for the Energy and Power Markets

Overview

By March of next year, the EPA must propose regulations governing emissions of hazardous air pollutants from coal- and oil-fired power plants, including mercury and acid gases. The new regulations, known as the Air Toxics Rule, will have a material impact on the markets for power, coal and natural gas. Because it governs hazardous air pollutants, the Air Toxics Rule will require that coal-fired power plants nationally install what is known as "maximum achievable control technology" (MACT) for mercury and acid gases. The MACT standard is expected to require that all coal-fired units install SO2 scrubbers in combination with other costly emissions controls by 2015.

To quantify the impact of the Air Toxics Rule, we have identified those coal-fired power plants that currently lack SO2 scrubbers, and assessed which of these would be economic to retrofit with scrubbers and which would not. Specifically, we have compared at each of these plants (1) the present value of its after-tax operating cash flow over its remaining useful life, given forward prices for energy and capacity, forward coal prices, and the heat rate of the unit in question, with (2) the estimated cost of installing SO2 scrubbers, net of any tax benefits from the additional depreciation expense. We have assumed that scrubbers will be added at those plants where the present value of future operating cash flow exceeds the cost of the scrubbers. Where scrubber installation costs exceed the present value of future operating cash flow, we have assumed that emissions controls are not installed. Because such units would fail to comply with the Air Toxics Rule's emissions limits, we assume they cease to operate in 2015.

Our model suggests that in a scenario where all coal-fired power plants must install SO2 scrubbers to meet EPA emissions standards for mercury and acid gases, plant closures will cause the output of the existing coal-fired generation fleet to decline by 275 million MWh by 2015. This loss in power output, however, will be offset in part by the generation of new coal-fired power plants scheduled to come on line over the next five years. This incremental generation is estimated at 110 million MWh, reducing the net loss to 165 million MWh.

We estimate that this 165 million MWh net decline in coal-fired generation will be reflected in a drop of 108 million tons, or 11%, in utility demand for coal. Consumption of eastern coals will be hit hardest, with utility demand estimated to fall by some 68 million tons, or 16%. If the 165 million MWh loss in coal-fired generation were to be offset by an equivalent increase in the output of the nation's gas-fired power plants, U.S. consumption of natural gas would have to increase by at least 1.2 Tcf, equivalent to 6% of total U.S. consumption of natural gas.

Investment Implications

Most at risk are unregulated generators with a high proportion of older, smaller, coal-fired power plants in their generating fleets. Not only is the cost of retrofitting smaller units markedly higher, but the short remaining useful lives and limited hours of operation of older units also make it difficult to recover the capital cost of a scrubber out of the plant's future cash flows. Our analysis suggests that the unregulated generators likely to suffer the largest drop in coal-fired generation as a result of the new regulations are RRI Energy (RRI), Ameren (AEE), Edison International (EIX), NRG Energy (NRG), FirstEnergy (FE) and Dynegy (DYN). The capital cost of retrofitting existing coal-fired power plants to meet the emissions standards set by the Air Toxics Rule is expected to be highest, relative to market capitalization, for Dynegy (DYN), RRI Energy (RRI), NRG Energy (NRG), Edison International (EIX), and Ameren (AEE).

Numerous regulated utilities may also be forced to significantly curtail their coal-fired generation, including CMS Energy (CMS), Black Hills (BKH), SCANA (SCG), Integrys Energy (TEG), ALLETE (ALE), Wisconsin Energy (WEC), Southern (SO), DTE Energy (DTE), Great Plains Energy (GXP), Empire District Electric (EDE), Alliant Energy (LNT), and American Electric Power (AEP). The revenues of these companies, however, are a function of their retail sales of electricity, which will be unaffected by the composition of their power supplies. And if the cost of the power purchased to replace the lost output of coal-fired power plants were to increase the cost of power supplied, regulatory mechanisms are in place to pass through this increase to customers.

Indeed, it is possible that regulated utilities may benefit from the loss of a portion of their coal-fired generation. If they can persuade regulators to allow the replacement of their unscrubbed coal-fired power plants — generally older, fully depreciated assets — with new generating capacity, these firms may accelerate the expansion of regulated rate base, and with it the growth of earnings. Also contributing to rate base growth would be the cost of retrofitting existing coal-fired power plants to meet the emissions standards set by the Air Toxics Rule. Relative to existing rate base, we expect these environmental capital expenditures to be highest at Alliant (LNT), DTE Energy (DTE), Xcel Energy (XEL), Empire District Electric (EDE), Ameren (AEE), and American Electric Power (AEP).

Hazardous Air Pollutants and the Air Toxics Rule

By March of next year, the EPA must propose regulations governing emissions of hazardous air pollutants from coal- and oil-fired power plants, including mercury and acid gases. The new regulations, known as the Air Toxics Rule, will have a material impact on the markets for power, coal and natural gas.

As defined under the Clean Air Act, hazardous air pollutants are those that "may reasonably be anticipated to result in an increase in mortality or an increase in serious irreversible or incapacitating reversible illness" [CAA Section 112 (a); 42 U.S.C. Section 7412 (a) (1)]. There are three principal categories of hazardous air pollutants: mercury and other toxic metals, such as arsenic, lead and selenium; acid gases such as hydrogen chloride, hydrogen fluoride and hydrogen cyanide; and organic air pollutants, including organic hydrocarbons and volatile organic compounds.

Mercury is a toxic metal that appears in varying concentrations in different types of coal. Mercury enters the food chain when it is transformed into methylmercury by microorganisms in aquatic environments. After oxidized mercury has precipitated out of the air and been deposited into a body of water, it is taken up by a variety of microbes, which attach a methyl group (CH_3) to it during normal biological processes. As it is consumed by microorganisms, crustaceans and fish, methylmercury is not purged from the body but rather accumulates over time. As a result, large fish on the upper end of the food chain accumulate the highest levels of mercury. These are the same fish species that humans often consume, and they constitute the primary human sources of mercury exposure.

Exposure to high levels of mercury can result in irreversible damage to the central nervous system. Additionally, studies have shown that methylmercury can adversely affect the cardiovascular system, and may contribute to heart disease. Symptoms of severe mercury poisoning include ataxia (lack of coordination of muscle movements), numbness in the hands and feet, general muscle weakness, narrowing of the field of vision, and damage to hearing and speech. In extreme cases, insanity, paralysis, coma and death follow within weeks of the onset of symptoms. While all fish consumers could suffer from mercury exposure, the developing fetus is most at risk due to its sensitivity to methylmercury. This toxin can still pose a threat to children, as their central nervous system develops through the age of 14.

In December 2000, the EPA issued a "regulatory determination" under the Clean Air Act that it is "appropriate and necessary" to regulate mercury emissions from coal- and oil-fired power plants, and listed these plants as sources of hazardous air pollutants to be regulated under the Act. Importantly, the Clean Air Act requires all sources of hazardous air pollutants to install "maximum achievable control technology," or MACT, and directs the EPA to promulgate the applicable MACT standards.

To date, however, the EPA has failed to stipulate MACT standards for hazardous air pollutants from coal- and oil-fired power plants. Instead, in 2005, the EPA sought to reverse its previous regulatory determination and remove mercury from the list of hazardous air pollutants. This "de-listing" allowed the EPA to propose regulations that would limit mercury emissions from power plants, not by mandating the universal installation of MACT, but rather through a national cap-and-trade scheme, known as the Clean Air Mercury Rule (CAMR). CAMR set a national cap on mercury emissions of 38 tons in 2010 and 15 tons after 2018, for a total reduction of 70% from 2003 levels. Within this cap, power plants were granted tradable allowances to emit mercury.

Fifteen states and various environmental groups challenged the EPA's decision to remove mercury from the list of hazardous air pollutants. In February 2008, the U.S. Court of Appeals for the District of Columbia issued a decision in the case *(New Jersey v. EPA)*, holding that the EPA's reversal of the December 2000 regulatory determination was unlawful. The Court vacated both the reversal and the Clean Air Mercury Rule, and remanded CAMR to the EPA.

In December 2008, the Natural Resources Defense Council and other environmental organizations sued the EPA for its continued failure to issue MACT standards for mercury and other hazardous air pollutants, despite the Court of Appeals' decision. This suit was settled in October 2009 when the EPA submitted to a consent decree that requires (1) that by March 2011 it publish its proposed MACT standard for hazardous air pollutants from coal- and oil-fired power plants, and (2) that by November 2011 it issue its final rule.

Likely Timing and Nature of the EPA's Regulation of Mercury and Other Hazardous Air Pollutants

The October 2009 consent decree and key provisions of the Clean Air Act provide an unusual degree of visibility into the likely timing and nature of the EPA's regulation of mercury and other hazardous air pollutants. First, the Clean Air Act stipulates that, once EPA has issued a final rule regulating hazardous air pollutants, all sources of the hazardous air pollutant must comply with the MACT standard within three years. As the EPA is required under the consent decree to issue its final rule in November 2011, the compliance deadline for utility sources of HAPs becomes November 2014. Although a one-year extension may be granted on a case-by-case basis, 2015 may be thought of as the year by which all U.S. coal- and oil-fired power plants must have installed MACT for mercury and other hazardous air pollutants.

Second, the Clean Air Act limits the EPA's flexibility in setting MACT standards for hazardous air pollutants. Specifically, Section 112(d) of the Act stipulates that MACT standards shall not be less stringent than "the average emission limitation achieved by the best performing 12 percent of existing sources" of the hazardous pollutant. To achieve such a reduction in emissions, it may be necessary for coal-fired power plants to install a costly combination of SO2 scrubbers, NOx emissions controls and fabric filters.

Mercury is emitted in such low concentrations that its removal from the flue gas of coal-fired power plants is particularly difficult. It is also emitted in several forms (elemental, oxidized and particulate-bound), some of which are harder to capture than others. In cases where coal-fired power plants have been retrofitted with emissions controls for SO2, NOx and particulate matter, however, mercury emissions have also been dramatically reduced. A study published in October 2009 by the U.S. Government Accountability Office (GAO), titled *Mercury Control Technologies at Coal-Fired Power Plants Have Achieved Substantial Emissions*

Reductions, points out that "EPA 1999 data, the most recent available, indicate that about one-fourth of the industry achieved mercury reductions of 90 percent or more as a co-benefit of other pollution control devices," specifically a combination of a scrubber for sulfur dioxide control, a selective catalytic reduction system for nitrogen oxides control, and a fabric filter for particulate matter control. If the EPA finds that these units include "the best performing 12 percent of existing sources," and sets a MACT standard that reflects the emissions reductions achieved by these units, then uncontrolled coal-fired power plants may face the requirement to install this costly combination of emissions control devices to meet the new emissions standards for mercury.

While the EPA has not yet issued its proposed MACT standard, the expectation in the power industry is that MACT emissions limits will be set by coal type and will imply the need to install the following combinations of pollution control technologies.

- For bituminous coals (including most Appalachian grades), a combination of wet flue gas desulfurization (FGD) technology for SO2 control and a selective catalytic reduction (SCR) system for NOx control;
- For sub-bituminous coal, such as Powder River Basin, dry FGD and fabric filter systems with halide treated activated carbon injection; and
- For lignite coals, a combination of FGD, SCR and fabric filters.

Some industry sources believe that it will be possible to achieve the required reductions in mercury emissions from coal-fired power plants using control technologies that are significantly cheaper to install. The most mature alternative technology involves injecting sorbents — powdery substances, typically activated carbon, to which mercury binds — into the exhaust from boilers before it is emitted from the stack. The GAO study found that boilers equipped with sorbent injection systems achieved, on average, reductions in mercury emissions of about 90%.

Sorbent injection technologies, however, are not as effective as the conventional combination of FGD, SCR and fabric filters in curtailing emissions of a second group of hazardous air pollutants, acid gases. In recent meetings with both environmental groups and the power industry trade group, the Edison Electric Institute, we found agreement that the FGD/SCR/fabric filter combination is likely to be deemed MACT for acid gases. Because the Clean Air Act requires that all sources of hazardous air pollutants deploy maximum achievable control technology, a finding by the EPA that MACT for acid gases involves such a combination of pollution control devices would require all coal- and oil-fired power plants in the country to deploy these controls by 2015.

Within this group of required pollution controls, the flue gas desulfurization technology — commonly referred to as an "SO2 scrubber" — is the most expensive component. The Electric Power Research Institute, a research institute sponsored by the power industry, estimates the cost of installing an SO2 scrubber at a typical 500 MW Midwestern plant to be some $420 per kW. Due to economies of scale in the design and construction, the cost per kW cost of both SO2 and NOx emissions controls increase significantly at smaller generating units. Thus, the cost of installing an SO2 scrubber at a 200 MW unit is estimated to be $607 per kW, equivalent to the cost of gas turbine peaker; at a 100 MW unit, $784 per kW; and at a 50 MW unit, $1,137 per kW, equivalent to the cost of a new combined cycle gas turbine power plant.

Modeling the Impact of the New Emissions Limits

We have modeled the effect on the utility industry of the emissions limits to be set by the EPA under the Transport and Air Toxics Rule. We have modeled the impact of the two rules separately — first assessing the extent to which utilities will be required to install SO2 scrubbers to comply with the state-by-state limits on SO2 emissions set by the Transport Rule, and second, the incremental impact of an MACT standard under the forthcoming Air Toxics Rule, which we assume will require the installation of SO2 scrubbers by all coal-fired power plants to meet target emissions of mercury and acid gases.

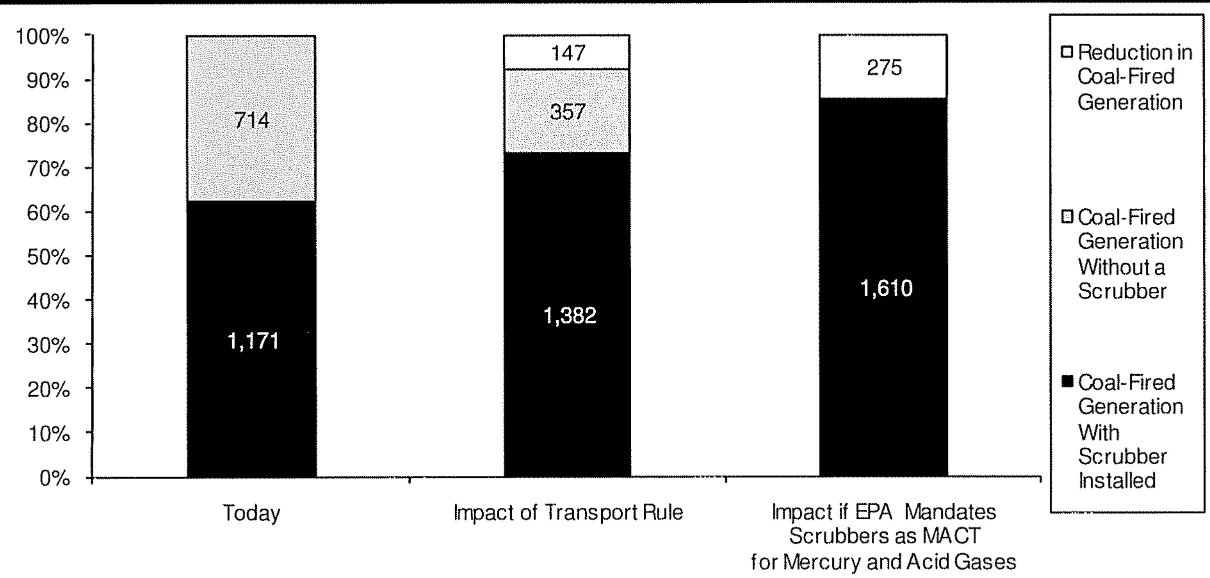
To quantify the impact of the Air Toxics Rule, we have identified those coal-fired power plants that currently lack SO2 scrubbers, and assessed which of these would be economic to retrofit with scrubbers and which would not. Specifically, we have compared at each of these plants (1) the present value of its after-tax operating cash flow over its remaining useful life, given forward prices for energy and capacity, forward coal prices, and the heat rate of the unit in question, with (2) the estimated cost of installing SO2 scrubbers, net of any tax benefits from the additional depreciation expense. We have assumed that scrubbers will be added at those plants where the present value of future operating cash flow exceeds the cost of the scrubbers. Where scrubber installation costs exceed the present value of future operating cash flow, we have assumed that emissions controls are not installed. Because such units would fail to comply with the Air Toxics Rule's emissions limits, we assume they cease to operate in 2015.

Forecast and Conclusions

As we did in forming our conclusions for the Transport Rule, we use data provided by the Ventyx Global Energy. Based on the Ventyx database, we estimate the net generation of the U.S. coal-fired fleet in 2009 at 1,885 million MWh of electricity. Of this total, 1,171 million MWh, or 62%, was produced by units already equipped with SO2 scrubbers or where plans have been announced to install such a unit in the next two years. The remaining 714 million MWh (38% of U.S. of coal-fired generation) was produced by units where adequate SO2 emission controls have not been installed nor have plans been announced to do so (see Exhibit 35).

Based on the assumptions outlined earlier, we estimate that to achieve the Transport Rule's target of limiting SO2 emissions in the eastern United States to 2.5 million tons by 2014 it will be necessary (1) to cease generation at unscrubbed coal-fired power plants that today produce some 147 million MWh, or 8% of U.S. of coal-fired generation, and (2) to install SO2 scrubbers at power plants that today generate 211 million MWh, or a further 11% of U.S. coal-fired generation (see Exhibit 35).

Exhibit 35 **Scrubbed and Unscrubbed Coal-Fired Generation in 2009 vs. That Expected in 2015 from the Existing Fleet Under the Transport Rule's SO2 Targets for 2014 and an EPA Mandate to Install SO2 Scrubbers as MACT for Mercury and Acid Gases**



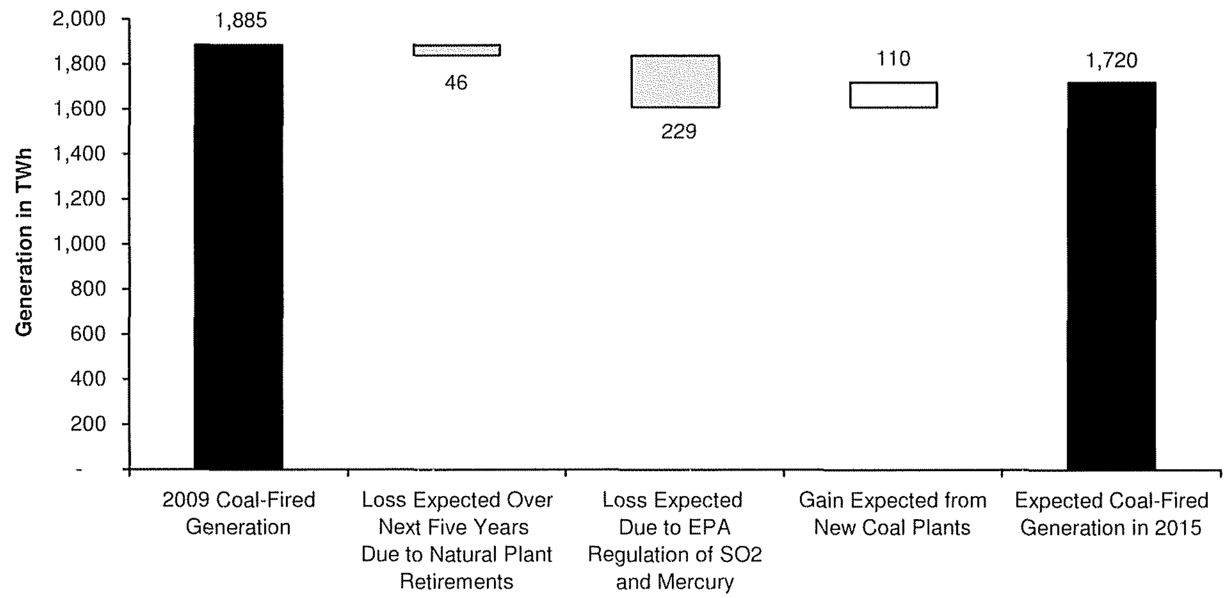
Source: Ventyx, EPRI, EIA and Bernstein analysis.

We also assessed the impact of a decision by the EPA under the Air Toxics Rule that MACT for hazardous air pollutants, including mercury and acid gases, must include the installation of SO2 scrubbers. Such a decision, we estimate, would require U.S. utilities to cease generation at unscrubbed coal-fired power plants that today produce 275 million MWh (15% of 2009 coal-fired generation), while forcing plants that generate 439 million MWh (23% of the 2009 total) to install scrubbers (see Exhibit 35).

The reduction of 275 million MWh in coal-fired generation expected in this worse-case scenario will be offset in part by the output of new coal-fired power plants scheduled to come on line by 2015. We estimate the increase in coal-fired generation attributable to these new plants at 110 million MWh annually, equivalent to 6% of U.S. coal-fired generation in 2009. Therefore, in a scenario where the EPA determines that MACT for hazardous air pollutants must include the installation of SO2 scrubbers, we would expect the net decline in U.S. coal-fired generation by 2015 to be 165 million MWh, equivalent to 9% of U.S. coal-fired generation in 2009.

This net reduction in the power output of the U.S. coal-fired fleet by 2015 is broken down into its component parts in Exhibit 36: the decrease attributable to the natural attrition of older coal-fired power plants over the next five years (46 million MWh, or 2% of 2009 coal-fired net generation); the reduction in generation from coal-fired power plants at which it is uneconomic to install SO2 scrubbers (229 million MWh, or a further 12% of the total); and the increase in coal-fired generation from new power plants scheduled to come on line over the next five years (110 million MWh, or 6% of 2009's coal-fired generation).

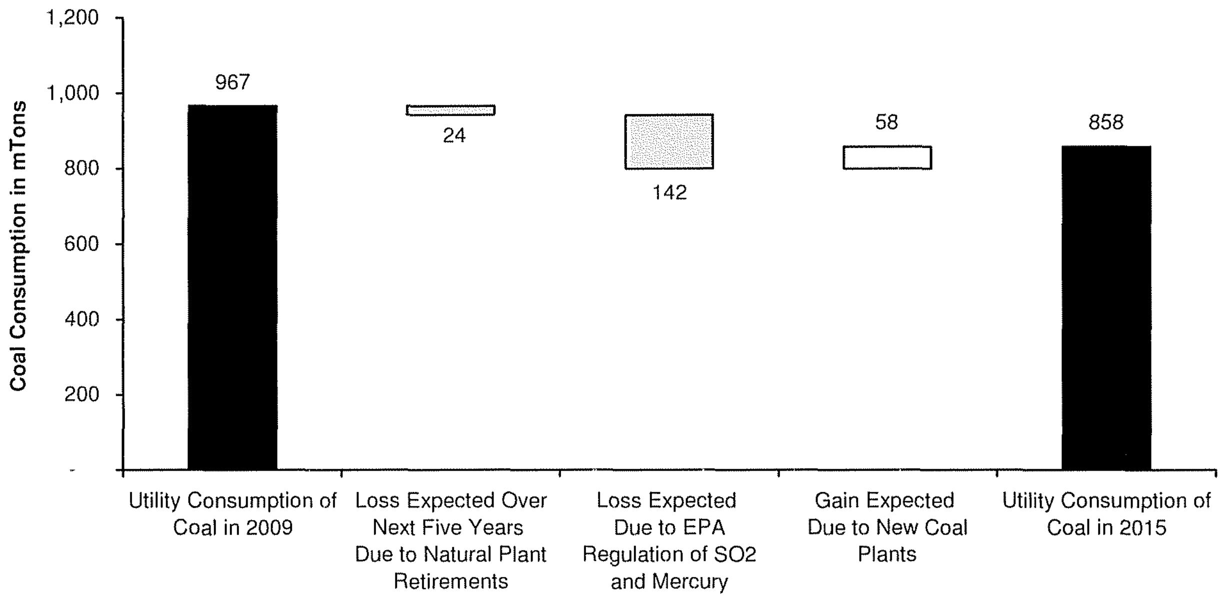
Exhibit 36 **Coal-Fired Net Generation in 2009 vs. That Expected in 2015, Given an EPA Mandate to Install SO2 Scrubbers as MACT for Mercury and Acid Gases (Includes New Additions of Coal-Fired Capacity)**



Source: Ventyx, EPRI, EIA and Bernstein analysis.

By converting this reduction in coal-fired generation into its fuel equivalent, it is possible to estimate the expected reduction in coal consumption by the utility industry. Using data provided by the Ventyx Global Energy database, we estimate the consumption of coal by U.S. utilities in 2009 at some 967 million tons. As explained above, in a scenario where the EPA determines that MACT for hazardous air pollutants must include the installation of SO2 scrubbers, we would expect the net decline in U.S. coal-fired generation by 2015 to total 165 million MWh. Based on the regional composition of utility coal supplies and the heat content of the different coals consumed, we estimate that such a drop in coal-fired generation would reduce utility demand for coal by 108 million tons, equivalent to 11% of U.S. coal production in 2009. This expected decline in the coal consumption of U.S. utilities is broken down into its component parts in Exhibit 37.

Exhibit 37 **Expected Reduction in Coal Burned by U.S. Utilities from 2009 to 2015 Assuming an EPA Mandate to Install SO2 Scrubbers as MACT for Mercury and Acid Gases**

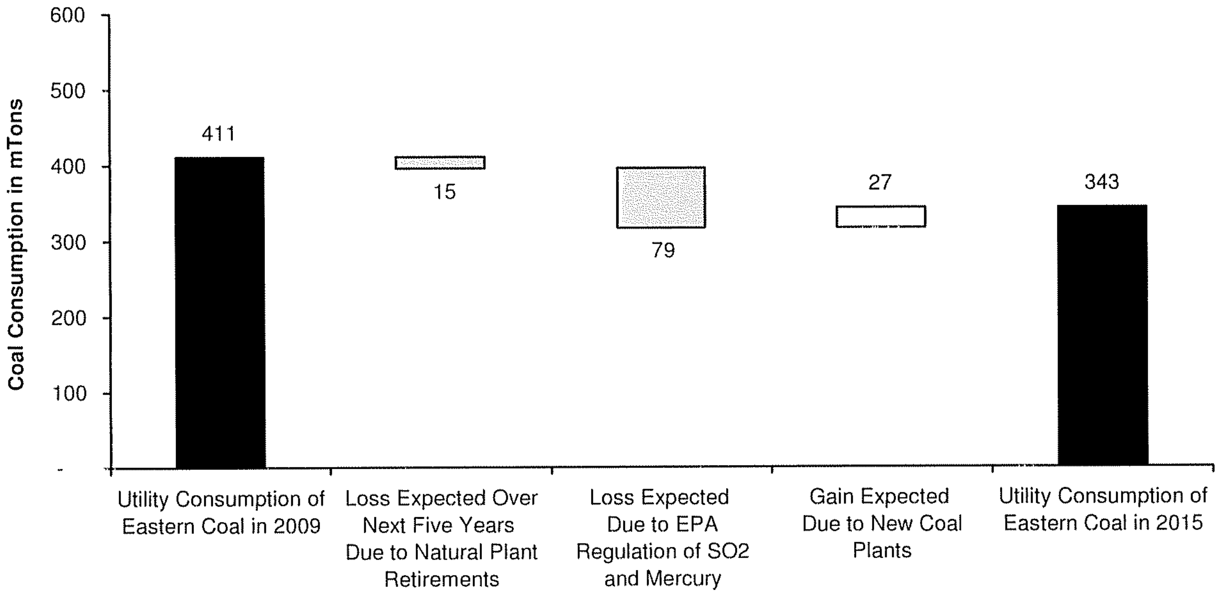


Source: Ventyx, EPRI, EIA and Bernstein analysis.

Given the regional breakdown of the expected decline in coal-fired generation, and the regional composition of utility coal supplies, we expect demand for coal grades mined east of the Mississippi (eastern coal) to be more heavily affected than demand for coal grades mined west of the Mississippi (western coal). Specifically, in a scenario where the EPA determines that MACT for hazardous air pollutants must include the installation of SO2 scrubbers, we estimate that by 2015 utility demand for eastern coal will fall by 68 million tons, or 16% (see Exhibit 38). Utility demand for western coal, by contrast, is estimated to drop by 40 million tons, or only 7% (see Exhibit 39).

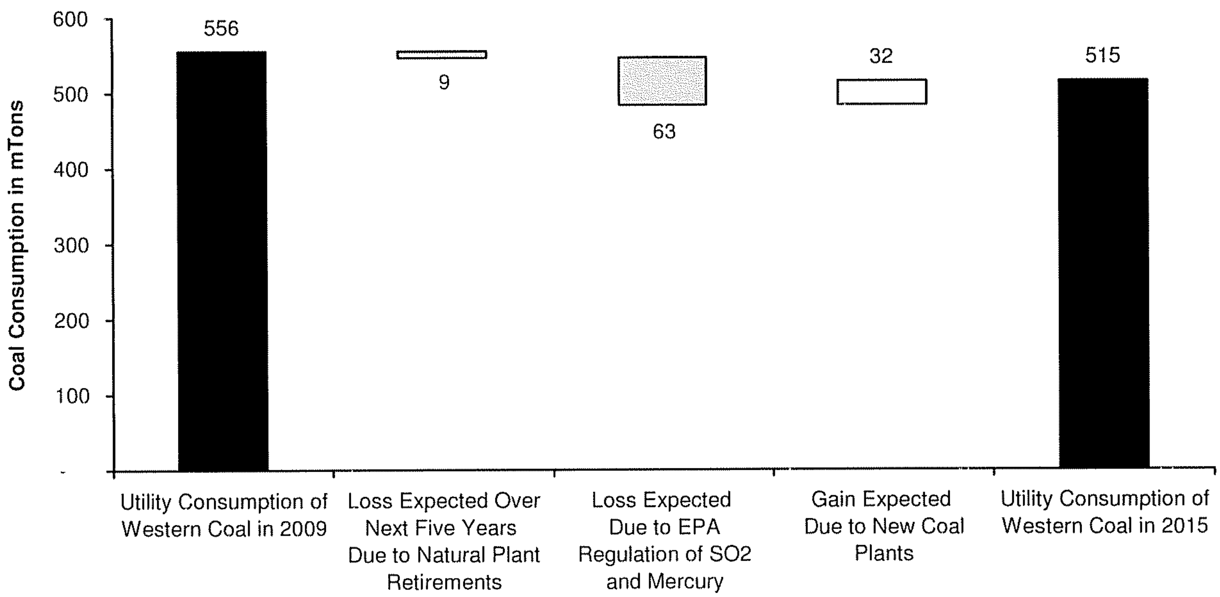
It is also possible to estimate the increase in utility demand for gas that is likely to result from these coal plant retirements. In a scenario where the EPA determines that MACT for hazardous air pollutants must include the installation of SO2 scrubbers, we estimate that coal-fired generation will suffer a net decline of 164 million MWh by 2015. If this reduction in coal-fired generation were to be offset by a like increase in the output of currently under-utilized combined cycle gas turbine generators, U.S. annual consumption of gas would be expected to rise by 6% or 1.2 Tcf, from 20.9 Tcf in 2009 to 22.1 Tcf in 2015, without taking into account the growth in demand from other sources (see Exhibit 40).

Exhibit 38 **Expected Reduction in Eastern Coal Consumption from 2009 to 2015 Assuming CAIR's SO2 Targets for 2015 and an EPA Mandate to Install SO2 Scrubbers as MACT for Mercury**



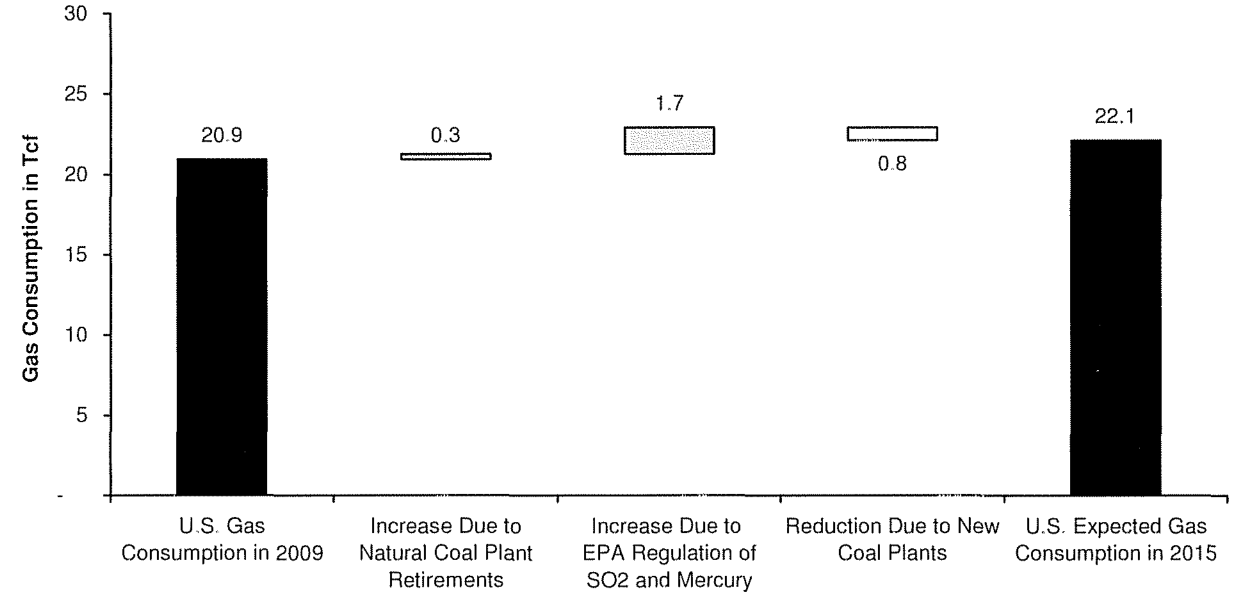
Source: Ventyx, EPRI, EIA and Bernstein analysis.

Exhibit 39 **Expected Reduction in Western Coal Consumption from 2009 to 2015 Assuming CAIR's SO2 Targets for 2015 and an EPA Mandate to Install SO2 Scrubbers as MACT for Mercury**



Source: Ventyx, EPRI, EIA and Bernstein analysis.

Exhibit 40 **Estimated Increase in U.S. Consumption of Natural Gas from 2009 to 2015 Assuming an EPA Mandate to Install SO2 Scrubbers as MACT for Mercury and Acid Gases**



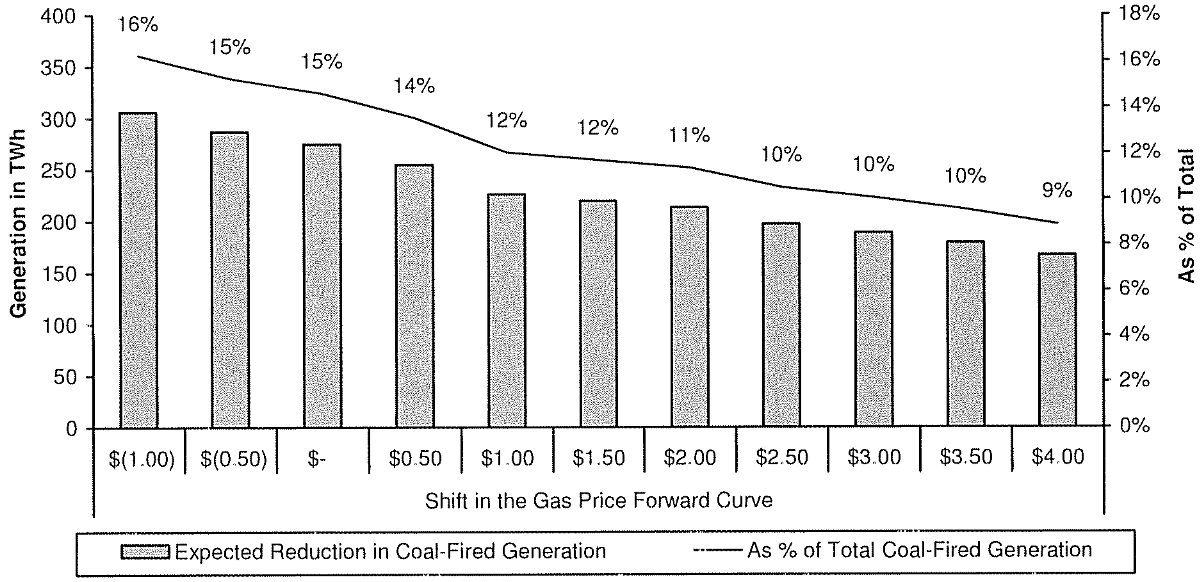
Source: Ventyx, EPRI, EIA and Bernstein analysis.

Sensitivity Analysis: Natural Gas Price, Expected Useful Life of Coal-Fired Power Plants and a Price on Carbon

We sought to quantify the sensitivity of our results to changes in key assumptions, including the expected level of natural gas prices and the age at which currently operating coal-fired generating units would normally be retired. These assumptions affect our results in two ways. First, higher natural gas prices drive higher power prices, increasing the generation gross margin of coal-fired power plants, thereby raising the present value of their future cash flow. The capital cost of installing emissions controls can thus be more easily recovered. As a result, a higher gas price renders more coal-fired generating units economic to retrofit, and reduces the forecast decline in coal-fired generation. Second, if unscrubbed coal-fired generators are assumed to have a longer remaining useful life, the present value of their future generation gross margin is again increased, rendering more units economic to retrofit, and thus limiting the decline in coal-fired generation.

Our analysis indicates that the reduction in coal-fired generation forecast by our model is sensitive to the assumed price of natural gas. Our base-case analysis assumes the currently prevailing forward price curve for natural gas. In a scenario where all coal-fired power plants are required to install SO2 scrubbers to meet EPA emissions standards for mercury and acid gases, our model suggests that a \$1.00/MMBtu increase in the forward price of natural gas could reduce the decline in generation of the existing coal-fired fleet by one fifth, from a forecast decline of 15% to one of 12% (see Exhibit 41). On the flip side, a \$1.00/MMBtu drop in forward gas prices could cause the expected decline in generation of the existing coal-fired fleet to increase from 15% to 16%.

Exhibit 41 **Sensitivity Analysis in Natural Gas Prices: Expected Reduction in Coal-Fired Generation If EPA Sets a Maximum Achievable Control Technology Standard for Mercury and Acid Gases That Requires the Installation of SO2 and NOx Emissions Controls**



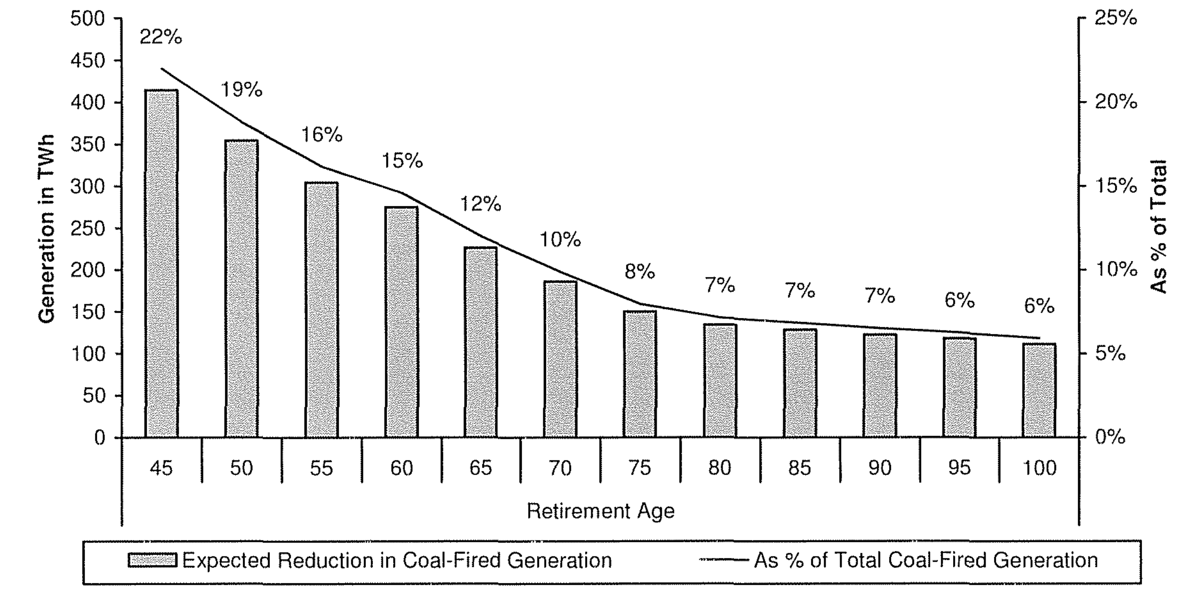
Source: Ventyx, EPRI, EIA and Bernstein analysis.

Our estimates of the decline in coal-fired generation are also sensitive to the expected useful life of coal-fired power plants that have yet to be retrofitted with SO2 emissions controls. We have assumed this useful life to be 60 years. An increase in the estimated useful life of unscrubbed, coal-fired power plants to 70 years reduces the forecast decline in generation of the existing coal-fired fleet by one-third, from a forecast decline of 15% to 10%. Conversely, if we assume that these units are retired after 50 years of operation, our model estimates the expected decline in generation of the existing coal-fired fleet at 19% (see Exhibit 42).

In addition, we have tested the sensitivity of our results to the potential cost of CO2 regulation. The economic impact of CO2 regulation is a critical factor for many utilities in making a decision to retrofit existing coal-fired power plants with environmental emissions controls. We have attempted to model how a price on CO2 (whether imposed by a tax or via a cap-and-trade scheme that requires power plants to purchase allowances to emit CO2) might affect the decision to upgrade existing coal-fired power plants with SO2 scrubbers.

First, we have assumed that fossil-fueled generators would be required to pay the CO2 tax (or purchase allowances to emit CO2) in direct proportion to their emissions of CO2. As coal-fired steam turbine generators emit, on average, one metric ton of CO2 per MWh produced, we have assumed that their cost of operation would increase by the tax on or price of one ton of CO2 emissions. Combined cycle gas turbine generators, by contrast, emit approximately half a ton of CO2 per MWh, and we assumed therefore that their cost of operation increases by the tax on or price of half a ton of CO2.

Exhibit 42 **Sensitivity Analysis in Utility Plant Retirement Age: Expected Reduction in Coal-Fired Generation If EPA Sets a Maximum Achievable Control Technology Standard for Mercury and Acid Gases That Requires the Installation of SO2 and NOx Emissions Controls**



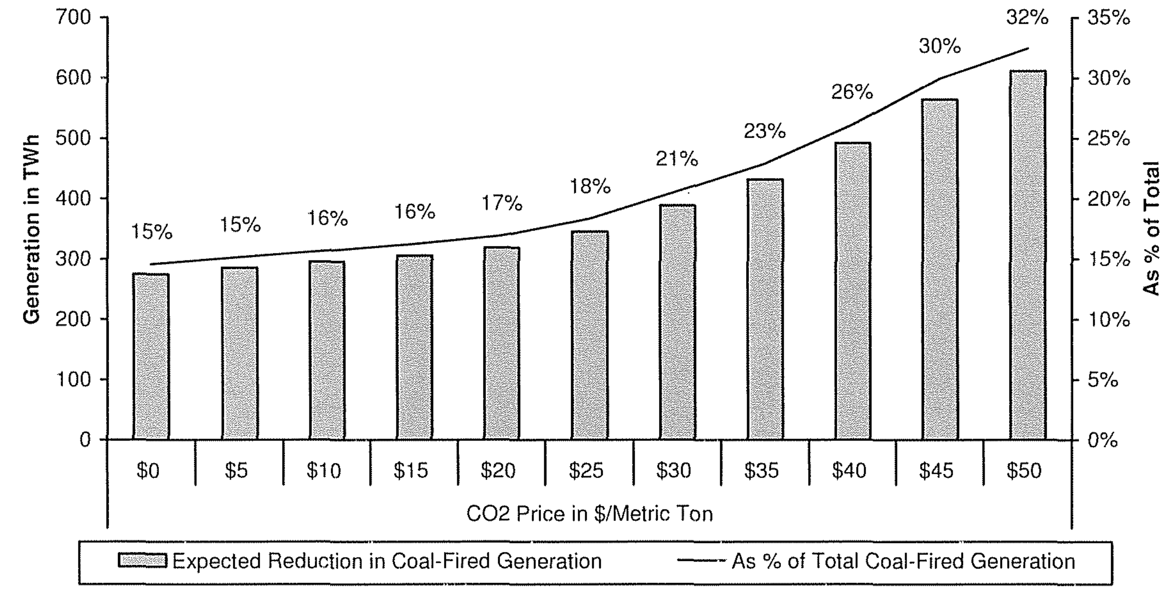
Source: Ventyx, EPRI, EIA and Bernstein analysis.

Second, based on economic studies of the behavior of power markets in Europe following the introduction of the European Union's CO2 cap-and-trade scheme, we have assumed that prices in competitive wholesale markets rise to reflect 80% of these incremental costs of generation. As a result, in markets where combined cycle gas turbine generators are the marginal or price-setting units (as they are during most hours of the year in New England, New York, the Mid-Atlantic and Texas), we have assumed that power prices rise to reflect the cost of 0.4 tons (0.5 tons/MWh x 80%) of CO2 emissions; in markets where coal-fired generators are the marginal or price setting units, we have assumed that power prices rise to reflect the cost of 0.8 tons (1.0 ton/MWh x 80%) of CO2 emissions.

The implication of this assumption is that coal-fired power plants operating in markets where coal is the price-setting fuel should recover 80% of the increase in their cost of generation, while in markets where gas is on the margin, coal-fired generators would recover only 40% of their increase in cost. Therefore, in markets where gas is on the margin, coal-fired generators would suffer a material erosion in gross margin that is directly proportional to the price of CO2. As a result, the present value of future cash flows generated by such plants is commensurately reduced, limiting the potential to recover the cost of SO2 scrubbers.

As CO2 prices rise, therefore, we find that plants representing a rising percentage of coal-fired generation would find it uneconomic to retrofit with SO2 scrubbers and, failing to comply with the EPA's Air Toxics Rule, would be forced to shut down. We estimate that the loss of generation from existing coal-fired plants would rise from 15% in the absence of a CO2 price to 18% at a price of $25 per metric ton and to 32% at a price of $50 per metric ton (see Exhibit 43).

Exhibit 43 **Sensitivity Analysis in CO2 Price: Expected Reduction in Coal-Fired Generation If EPA Sets a Maximum Achievable Control Technology Standard for Mercury and Acid Gases That Requires the Installation of SO2 and NOx Emissions Controls**



Source: Ventyx, EPRI, EIA and Bernstein analysis.

Company Impact from the Air Toxics Rule

The next set of exhibits present our estimates of the company-by-company impact of a decision by the EPA that MACT for hazardous air pollutants, including mercury and acid gases, must include the installation of SO2 scrubbers. Given that the Clean Air Act stipulates that all sources of hazardous air pollutants must install MACT, we have assumed that every coal-fired power plant in the United States either installs an SO2 scrubber or shuts down. We first present our estimates of the reduction in coal-fired generation in this scenario, and the resulting potential retirements of coal-fired generation capacity. Our estimate of the impact on regulated utilities is presented in Exhibit 44, and our estimate of the impact on competitive generators in Exhibit 45. We next present our estimates of the capital cost likely to be incurred to comply with the new regulations, for regulated utilities in Exhibit 46 and for unregulated generators in Exhibit 47.

Most at risk are unregulated generators with a high proportion of older, smaller, coal-fired power plants in their generating fleets. Not only is the cost of retrofitting smaller units markedly higher, but the short remaining useful lives and limited hours of operation of older units also make it difficult to recover the capital cost of a scrubber out of the plant's future cash flows. Our analysis suggests that the unregulated generators likely to suffer the largest drop in coal-fired generation as a result of the new regulations are RRI Energy (RRI), Ameren (AEE), Edison International (EIX), NRG Energy (NRG), FirstEnergy (FE) and Dynegy (DYN). The capital cost of retrofitting existing coal-fired power plants to meet the emissions standards set by the Air Toxics Rule is expected to be highest, relative to market capitalization, for Dynegy (DYN), RRI Energy (RRI), NRG Energy (NRG), Edison International (EIX), and Ameren (AEE).

Numerous regulated utilities may also be forced to significantly curtail their coal-fired generation, including CMS Energy (CMS), Black Hills (BKH), SCANA (SCG), Integrys Energy (TEG), ALLETE (ALE), Wisconsin Energy (WEC), Southern (SO), DTE Energy (DTE), Great Plains Energy (GXP), Empire District Electric (EDE), Alliant Energy (LNT), and American Electric Power (AEP). The revenues of these companies, however, are a function of their retail sales of electricity, which will be unaffected by the composition of their power supplies.

And if the cost of the power purchased to replace the lost output of coal-fired power plants were to increase the cost of power supplied, regulatory mechanisms are in place to pass through this increase to customers.

Exhibit 44 **Regulated Utilities: Estimated Reduction in Coal-Fired Generation Due to an EPA Mandate to Install SO2 Scrubbers as MACT for Mercury and Acid Gases**

		Company Total		Regulated Coal-Fired Plants			
		Nameplate	Generation	Reduction in Nameplate Capacity		Reduction in Generation	
Holding Company Name	Ticker	Capacity MW	GWh	In MW	As % of Total	In GWh	As % of Total
CMS Energy Corp	CMS	6,463	12,215	1,780	28%	7,393	61%
Black Hills Corp	BKH	*382*	*1,757*	*125*	33%	762	43%
SCANA Corp	SCG	5,568	26,065	1,832	33%	8,501	33%
Integrys Energy Group Inc	TEG	2,425	9,436	492	20%	2,878	30%
ALLETE Inc	ALE	1,346	7,310	359	27%	2,182	30%
Wisconsin Energy Corp	WEC	6,114	18,513	845	14%	4,260	23%
Southern Co	SO	42,519	182,605	8,698	20%	38,735	21%
DTE Energy Co	DTE	11,754	48,037	2,096	18%	9,093	19%
Great Plains Energy Inc	GXP	5,760	23,740	709	12%	3,962	17%
Empire District Electric Co (The)	EDE	1,235	3,084	88	7%	488	16%
Northeast Utilities	NU	1,094	3,774	100	9%	585	16%
Alliant Energy Corp	LNT	6,419	15,891	792	12%	2,309	15%
American Electric Power Co Inc	AEP	38,239	168,505	5,290	14%	19,972	12%
AES Corp (The)	AES	11,502	40,475	879	8%	3,948	10%
TECO Energy Inc	TE	4,565	18,405	326	7%	1,700	9%
Ameren Corp	AEE	16,482	74,302	923	6%	5,305	7%
Westar Energy Inc	WR	7,292	27,367	281	4%	1,809	7%
Progress Energy Inc	PGN	21,688	90,686	1,446	7%	5,121	6%
Duke Energy Corp	DUK	34,538	132,866	2,545	7%	7,250	5%
Dominion Resources Inc	D	24,314	110,437	1,504	6%	5,938	5%
Xcel Energy Inc	XEL	16,154	68,536	667	4%	2,609	4%
Allegheny Energy Inc	AYE	*9,991*	*31,881*	*601*	6%	243	1%
DPL Inc	DPL	3,648	15,713	414	11%	79	1%
NextEra Energy Inc	NEE	38,814	151,516	27	0%	76	0%
Total United States		**970,280**	**3,722,034**	**51,116**	**5%**	**219,117**	**6%**

Source: Ventyx, EPRI, EIA and Bernstein analysis.

Exhibit 45 **Competitive Generators: Estimated Reduction in Coal-Fired Generation Due to an EPA Mandate to Install SO2 Scrubbers as MACT for Mercury and Acid Gases**

		Company Total		Unregulated Coal-Fired Plants			
		Nameplate	Generation	Reduction in Nameplate Capacity		Reduction in Generation	
Holding Company Name	Ticker	Capacity MW	GWh	In MW	As % of Total	In GWh	As % of Total
RRI Energy Inc	RRI	13,381	23,779	1,465	11%	5,535	23%
Ameren Corp	AEE	16,482	74,302	1,906	12%	11,624	16%
Edison International	EIX	15,198	78,531	2,002	13%	7,925	10%
NRG Energy Inc	NRG	22,997	65,390	1,263	5%	5,856	9%
FirstEnergy Corp	FE	13,381	64,964	1,333	10%	5,492	8%
Dynegy Inc	DYN	17,433	44,128	775	4%	3,611	8%
Allegheny Energy Inc	AYE	*9,991*	*31,881*	*461*	5%	*1,121*	4%
Duke Energy Corp	DUK	34,538	132,866	1,024	3%	3,405	3%
AES Corp (The)	AES	11,502	40,475	149	1%	959	2%
Pepco Holdings Inc	POM	6,055	4,316	74	1%	47	1%
Public Service Enterprise Group Inc	PEG	16,274	58,916	103	1%	634	1%
Exelon Corp	EXC	27,797	149,257	895	3%	1,233	1%
Constellation Energy Group	CEG	8,713	47,600	136	2%	318	1%
Dominion Resources Inc	D	24,314	110,437	330	1%	666	1%
Calpine Corp	CPN	23,144	89,017	252	1%	332	0%
Total United States		**970,280**	**3,722,034**	**13,815**	**1%**	**55,813**	**1%**

Source: Ventyx, EPRI, EIA and Bernstein analysis.

Indeed, it is possible that regulated utilities may benefit from the loss of a portion of their coal-fired generation. If they can persuade regulators to allow the replacement of their unscrubbed coal-fired power plants — generally older, fully depreciated assets — with new generating capacity, these firms may accelerate the expansion of regulated rate base, and with it the growth of earnings. Also contributing to rate base growth would be the cost of retrofitting existing coal-fired power plants to meet the emissions standards set by the Air Toxics Rule. Relative to existing rate base, we expect these environmental capital expenditures to be highest at Alliant (LNT), DTE Energy (DTE), Xcel Energy (XEL), Empire District Electric (EDE), Ameren (AEE), and American Electric Power (AEP).

Exhibit 46 **Regulated Utilities: Estimated Capital Cost to Install Emission Controls to Comply With an EPA Mandate to Install SO2 Scrubbers as MACT for Mercury and Acid Gases**

Holding Company Name	Ticker	Rate Base ($ million)	Capital Cost Required ($ milion)	Capital Cost Required as % of Rate Base
OGE Energy Corp	OGE	$4,752	$1,199	25%
DTE Energy Co	DTE	$10,633	$1,499	14%
Alliant Energy Corp	LNT	$6,424	$853	13%
Xcel Energy Inc	XEL	$15,222	$1,843	12%
Empire District Electric Co (The)	EDE	$1,274	$144	11%
Ameren Corp	AEE	$14,932	$1,525	10%
American Electric Power Co Inc	AEP	$28,047	$2,591	9%
CMS Energy Corp	CMS	$9,387	$509	5%
Integrys Energy Group Inc	TEG	$4,299	$233	5%
Great Plains Energy Inc	GXP	$6,144	$290	5%
Entergy Corp	ETR	$15,778	$555	4%
DPL Inc	DPL	$2,285	$54	2%
ALLETE Inc	ALE	$1,357	$27	2%
IDACORP Inc	IDA	$2,427	$44	2%
Westar Energy Inc	WR	$4,964	$72	1%
Southern Co	SO	$32,273	$361	1%
Progress Energy Inc	PGN	$19,800	$207	1%
Dominion Resources Inc	D	$21,458	$204	1%
Cleco Corp	CNL	$2,749	$18	1%
NextEra Energy Inc	NEE	$32,336	$208	1%
NorthWestern Corp	NWE	$1,854	$11	1%
NV Energy	NVE	$7,755	$42	1%
Wisconsin Energy Corp	WEC	$8,250	$9	0%

Source: Ventyx, EPRI, EIA and Bernstein analysis.

Exhibit 47 **Competitive Generators: Estimated Capital Cost to Install Emission Controls to Comply With an EPA Mandate to Install SO2 Scrubbers as MACT for Mercury and Acid Gases**

Holding Company Name	Ticker	Market Capitalization ($mil.)	Capital Cost Required ($ mil.)	Capital Cost Required as % of Market Cap.
Dynegy Inc	DYN	$444	$349	79%
RRI Energy Inc	RRI	$1,371	$440	32%
NRG Energy Inc	NRG	$5,881	$1,201	20%
Edison International	EIX	$10,983	$2,075	19%
Ameren Corp	AEE	$6,443	$710	11%
American Electric Power Co Inc	AEP	$17,456	$703	4%
Dominion Resources Inc	D	$25,657	$824	3%
Constellation Energy Group	CEG	$6,212	$189	3%
FirstEnergy Corp	FE	$11,495	$345	3%
Public Service Enterprise Group Inc	PEG	$16,393	$188	1%
PPL Corp	PPL	$12,903	$143	1%
Duke Energy Corp	DUK	$22,946	$23	0%

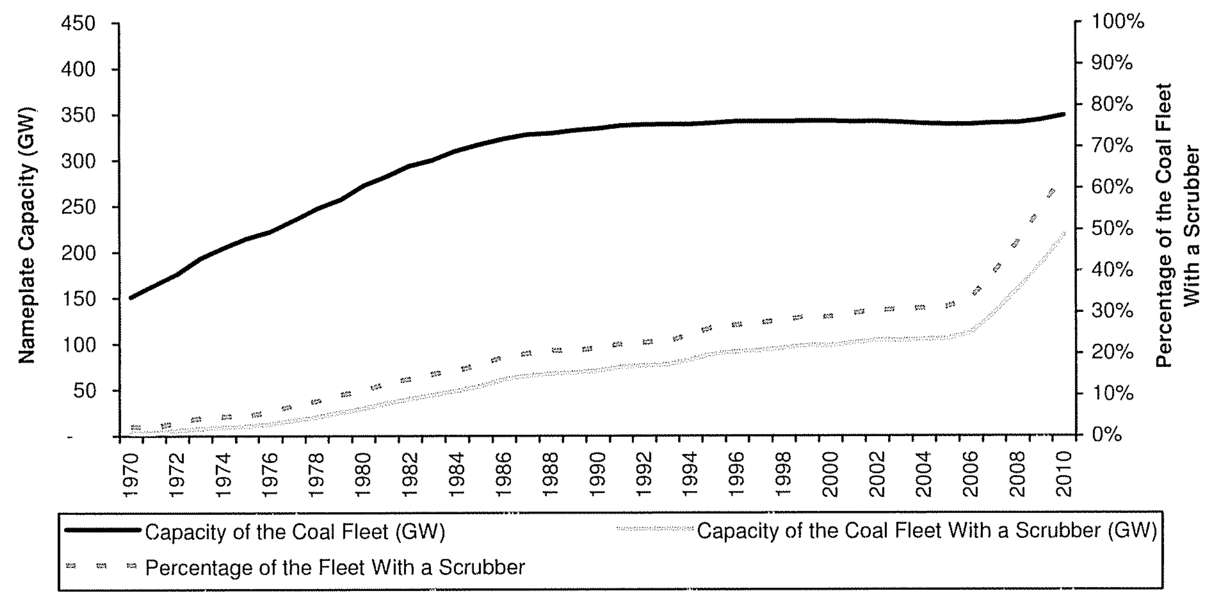
Source: Ventyx, EPRI, EIA and Bernstein analysis.

Scale of Expected Retrofits and Retirements

Our analysis suggests that compliance with the EPA's Transport and Air Toxics Rules would require U.S. utilities to (1) install SO2 scrubbers at plants that generate 440 million MWh (23% of the 2009 coal-fired generation), and (2) cease generation at unscrubbed coal-fired power plants that today produce 274 million MWh (15% of 2009 coal-fired generation).

How do these estimates compare with recent trends? Exhibit 48 presents total U.S. coal-fired capacity from 1970 to 2010, as well as the portion of that capacity equipped with SO2 scrubbers. It shows that scrubbed capacity has increased dramatically over the last five years, rising from 106 MW to 219 MW, or from 31% to 63% of the total.

Exhibit 48 **The U.S. Coal-Fired Generating Fleet: Total and Scrubbed Capacity**

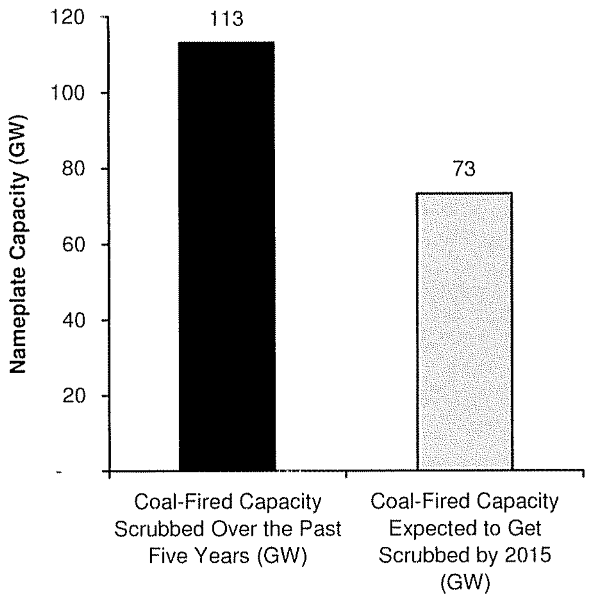


Source: Ventyx and Bernstein analysis.

At 113 GW, the capacity of coal-fired plants scrubbed over the past five years is 54% larger than the 73 GW of capacity we expect to be equipped with scrubbers over the next five years (see Exhibit 49). The risk that the industry's compliance with the Transport and Air Toxics Rules would be rendered infeasible by capacity constraints thus seems limited.

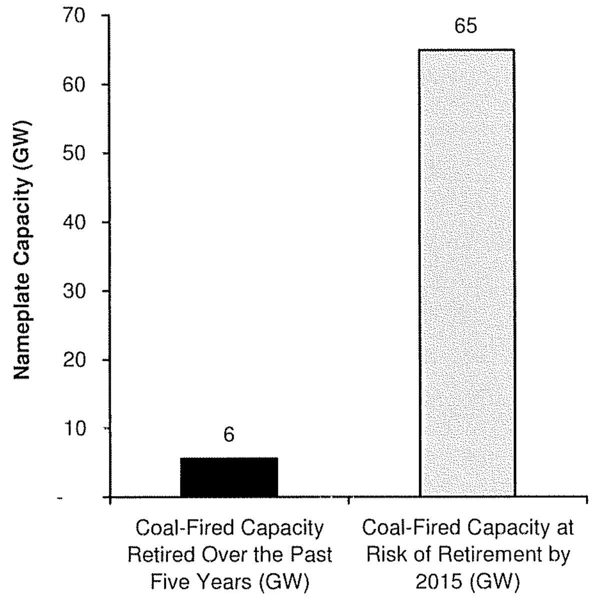
A much starker contrast presents itself, however, when we compare the potential scale of coal plant retirements over the next five years with that over the last five years. As can be seen in Exhibit 50, we estimate the amount of coal-fired capacity at risk of being retired by 2015 at 65 GW, as compared with only 6 GW retired over the past five years. This difference reflects (1) our assumption that all coal-fired power plants will be required to install scrubbers to comply with the Air Toxics Rule, thus sweeping up all the older, smaller, less profitable units which the industry had avoided scrubbing to date, and (2) the stark decline in gas and hence power prices since 2008, which has markedly reduced the profitability of the coal-fired fleet and therefore the economic incentives to install emissions controls.

Exhibit 49 Comparison of Coal Capacity Scrubbed Over the Past Five Years and Coal Capacity Expected to Be Scrubbed by 2015



Source: Ventyx, EPRI, EIA and Bernstein analysis.

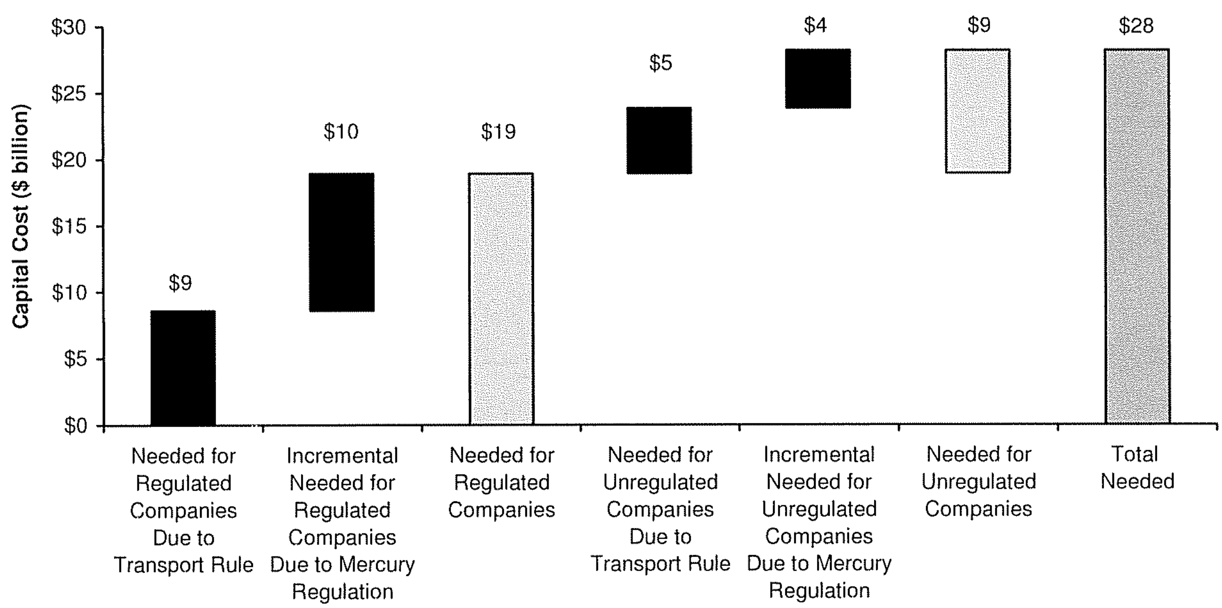
Exhibit 50 Comparison of Coal Capacity Retired Over the Past Five Years and Coal Capacity Expected to Be Retired by 2015



Source: Ventyx, EPRI, EIA and Bernstein analysis.

Exhibit 51 totals up the capital costs we estimate will be needed to comply with the Air Toxics Rule (discussed in this chapter) and the Transport Rule (discussed in the previous chapter) for both the regulated and unregulated utilities. The figure comes to $28 billion.

Exhibit 51 Estimated Capital Cost to the Power Industry of Complying With New EPA Air Emissions Regulations



Source: Ventyx, EPRI, EIA and Bernstein analysis.

Forthcoming EPA Emissions Regulations Will Force Power and Capacity Prices Higher — Who Will Benefit?

Overview

As we've discussed in the preceding two chapters, the EPA's Transport Rule (released for public comment on July 6, 2010) and its forthcoming Air Toxics Rule (which must be released by March 2011) will set new and significantly more stringent limits on emissions of SO2, NOx, mercury and acid gases from utility boilers. Given the current low level of gas and power prices, the cash generation capacity of many smaller, older coal-fired power plants is insufficient to recover the cost of the emission controls required to comply with the new rules. By 2015, therefore, when both rules will be in effect, we calculate that power plants accounting for 15% of current coal-fired generation may be unable to comply and will cease to operate.

We expect the loss of this generation to translate into higher wholesale energy and capacity prices. To quantify the impact, we studied how the forthcoming EPA emissions regulations might affect the PJM Interconnection, which is the FERC-recognized regional transmission organization (RTO) that coordinates the generation and transmission of electricity across the Mid-Atlantic region and portions of the Midwest. We focus our analysis on the PJM Interconnection because we expect it to experience a significant reduction in coal-fired generation as a result of the new rules. The consequent movement in prices, we estimate, will materially affect the gross margins of several of the competitive generators operating in PJM.

Specifically, we expect the loss of coal-fired capacity in the RTO to materially increase the number of hours that higher cost, gas-fired power plants are the marginal or price-setting units. We estimate that this will raise the price of electricity during on-peak hours by $3 to $5 per MWh. We also expect the withdrawal of significant portion of PJM's coal-fired capacity from the market's annual capacity auctions to result in materially higher prices for capacity. To estimate the impact that expected coal plant retirements might have on the price of capacity in PJM, we re-ran the results of the 2012/2013 capacity auction (the last for which the capacity prices offered by generators have been published by PJM), adjusting the supply curve for the expected loss of coal-fired capacity in PJM by 2015 due to the Air Toxics Rule. The pro forma results suggest that capacity prices would have settled at $85/MW-day in the western part of the RTO (versus the 2012/2013 auction result of $17/MW-day) and at $178/MW-day in the eastern part of region (versus the 2012/2013 auction result of $130/MW-day).

Investment Implications

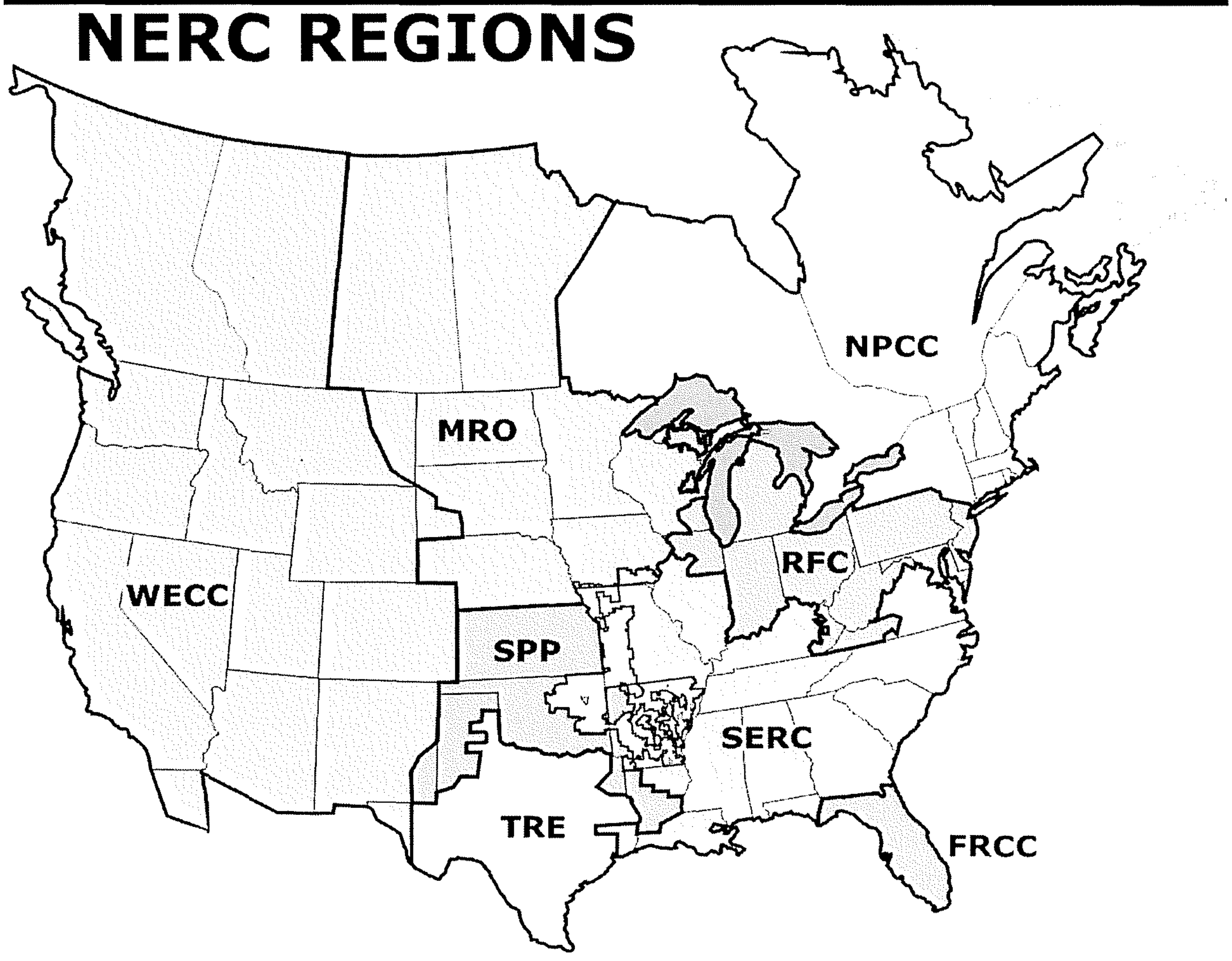
In the PJM Interconnection, the potential loss of coal-fired generation as a result of the Air Toxics Rule is expected to drive on-peak power prices materially higher by 2015, enhancing the revenues and gross margins of those competitive generators that are relatively unaffected by coal plant retirements. Among the principal beneficiaries will be PPL (PPL), Exelon (EXC) and FirstEnergy (FE). Also likely to benefit, according to our analysis, are Constellation (CEG), PSEG (PEG) and Mirant (MIR). We estimate that PPL could enjoy a gross margin increase from higher on-peak power prices equivalent to 8% of its last 12 months' EBITDA, while FirstEnergy, Exelon and Mirant could enjoy gross margin increases of 5%; Constellation 4%; PSEG and Dynegy 3%. The EPS impact, based on current shares outstanding, is estimated at \$0.19 for PPL, \$0.40 for FirstEnergy, \$0.33 for Exelon, \$0.24 for Constellation, \$0.16 for PSEG and \$0.15 for Mirant.

Many of these companies are also positioned to benefit from the increase in PJM capacity prices that would result from the expected loss of coal-fired capacity in the RTO due to the Air Toxics Rule. Based on our re-running of the results of the 2012/2013 capacity auction adjusted pro forma for the expected loss of coal-fired capacity, we find that the impact on gross margin of the resulting capacity price increases would be material for FirstEnergy (13% of last 12 months' EBITDA and \$0.88 added to EPS), PPL (9% and \$0.23), Mirant (7% and \$0.35), and Exelon (6% and \$0.37).

Impact on Regional Power Markets

Our analysis of how the forthcoming EPA emissions regulations will affect power and capacity prices begins with a review of the impact of the expected reduction in coal-fired generation by region. Our assessment is based on the reliability regions established by the North American Electric Reliability Corporation (NERC), which are illustrated in the map in Exhibit 52.

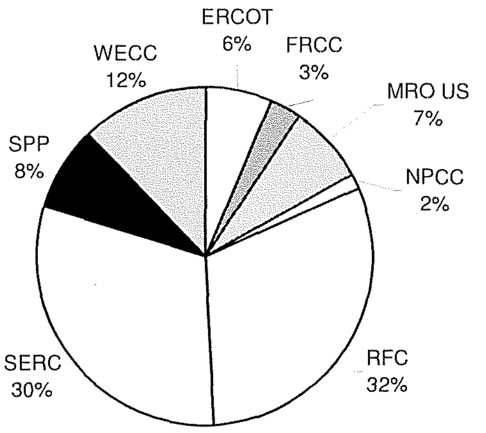
Exhibit 52 **Map of NERC Regions**



Source: NERC.

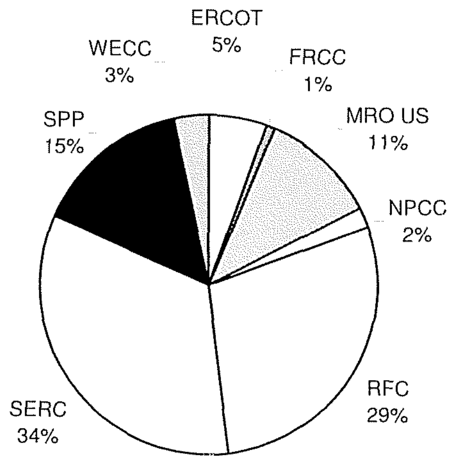
Exhibit 53 presents the breakdown of U.S. coal-fired generation in 2009 by NERC region. SERC and RFC each account for at least 30% of U.S. coal-fired generation. In these two regions, a significant portion of coal-fired generation is produced by power plants that currently lack SO2 scrubbers: 42% in SERC and 35% in RFC (see Exhibit 55). Consequently, when the nation's unscrubbed coal-fired generation is broken down by region, SERC and RFC once again predominate, with 34% and 29% of unscrubbed generation, respectively (see Exhibit 54).

Exhibit 53 Breakdown of Coal-Fired Generation by NERC Region



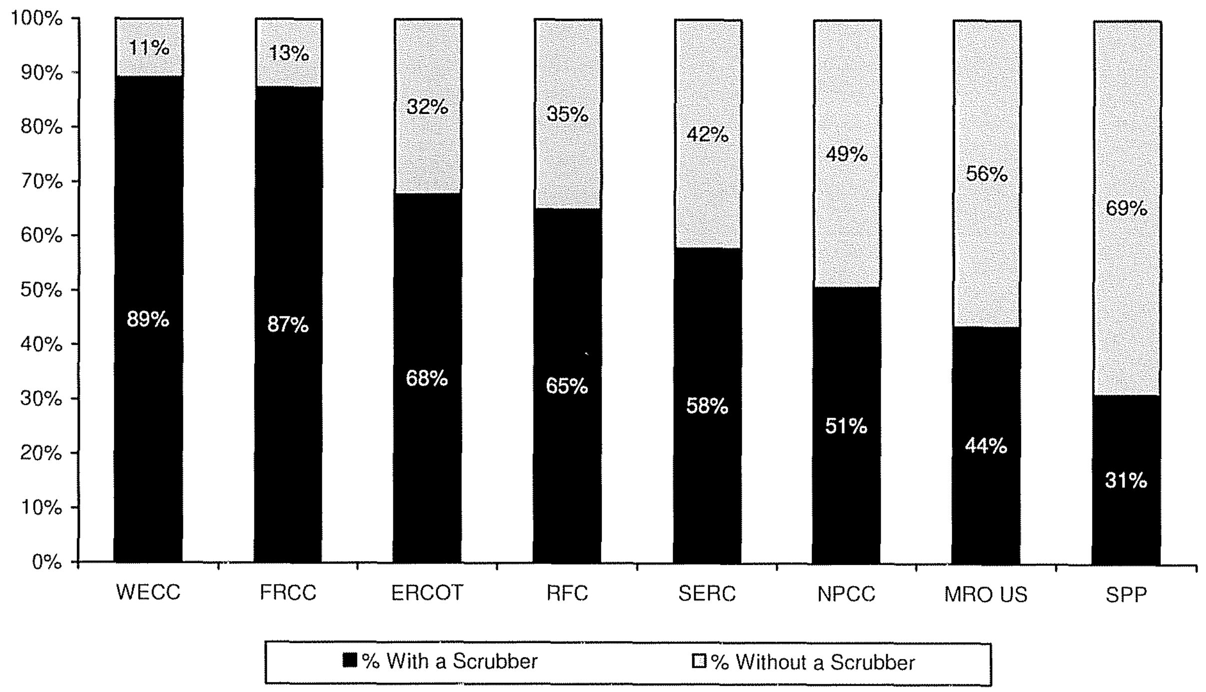
Source: Ventyx and Bernstein analysis.

Exhibit 54 Breakdown of Unscrubbed Coal-Fired Generation by NERC Region



Source: Ventyx and Bernstein analysis.

Exhibit 55 Coal-Fired Generation from Plants With and Without SO2 Scrubbers by NERC Region

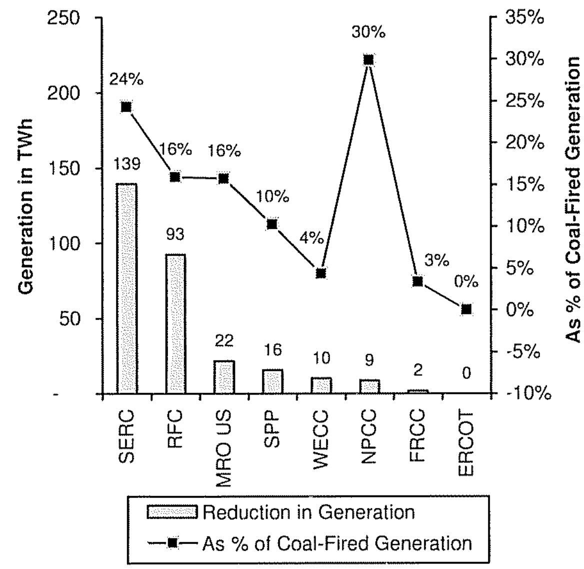


Source: Ventyx and Bernstein analysis.

Not surprisingly, therefore, in a scenario where EPA determines that maximum achievable control technology for hazardous air pollutants must include the installation of SO2 scrubbers, the expected reduction in coal-fired generation is estimated to be greatest in SERC and RFC.

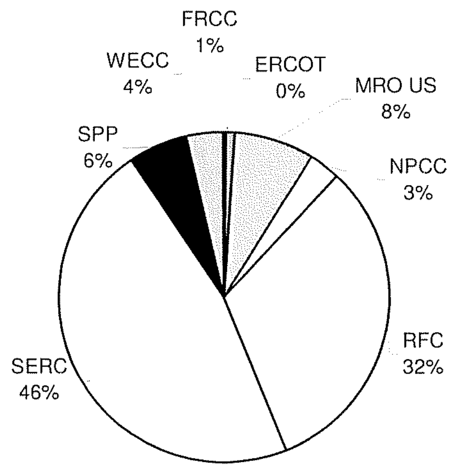
SERC appears to be the most at risk. It is characterized by a combination of low wholesale power prices and a heavy reliance on higher-cost Appalachian coal, as well as a fleet of unscrubbed coal-fired power plants with a higher percentage of smaller and older units than other regions. For SERC, therefore, our model estimates that 24% of coal-fired generation comes from plants that would be uneconomic to retrofit were the EPA's MACT standard to require the installation of SO2 scrubbers, compared to 16% in RFC, 16% in MRO and 10% in SPP (see Exhibit 56 and Exhibit 57).

Exhibit 56 Expected Reduction in Coal-Fired Generation by NERC Region Assuming EPA's MACT for Mercury and Acid Gases Requires SO2 Scrubbers



Source: Ventyx and Bernstein analysis.

Exhibit 57 Breakdown by NERC Region of Expected Reduction in Coal-Fired Generation Assuming EPA's MACT for Mercury and Acid Gases Requires SO2 Scrubbers

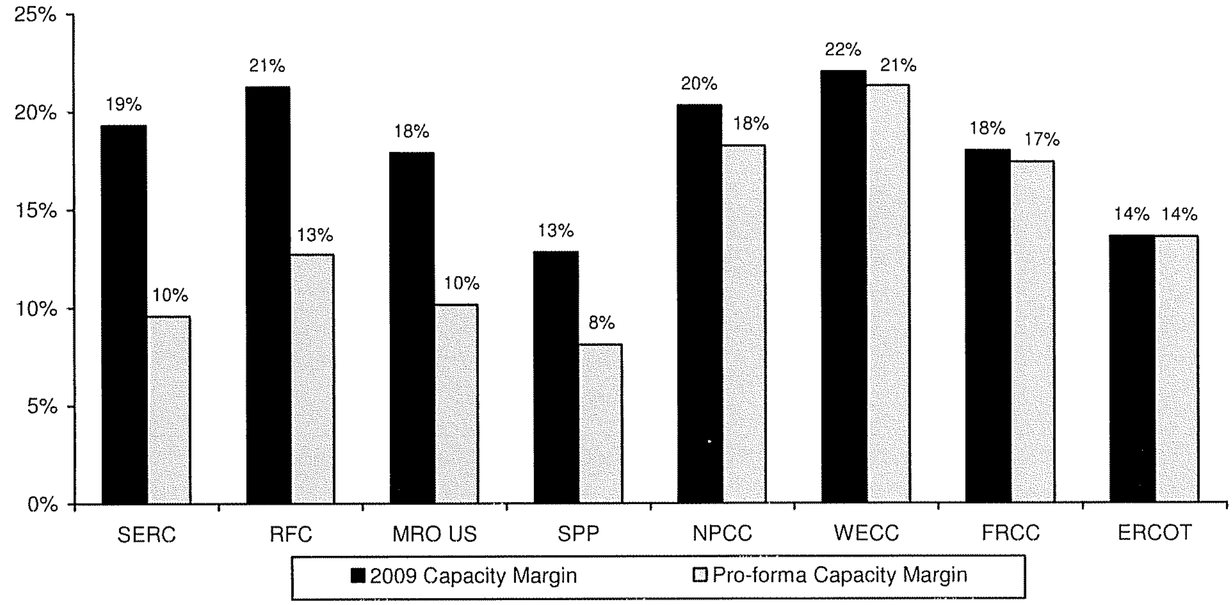


Source: Ventyx and Bernstein analysis.

Were these expected reductions in coal-fired generation to be accompanied by the retirements of the affected units, capacity margins in SERC, RFC, MRO and SPP would be significantly reduced. Exhibit 58 presents regional capacity margins in 2009, as well as pro forma adjustments to these capacity margins to reflect the assumed retirement of those coal-fired power plants that we estimate are uneconomic to retrofit with SO2 scrubbers.

In certain regions, including SERC, MRO and SPP, these adjusted capacity margins are unacceptably low, and would likely force regional transmission organizations and state regulators to reach accommodations with some the affected units to ensure that they remained in service. We would expect these arrangements to take the form of "reliability must run" (RMR) contracts. Compliance with the SO2, NOx and mercury emissions limits required by EPA's Transport and Air Toxics Rules could potentially be achieved by retrofitting the RMR units to burn gas. Based on interviews with several utilities, we understand the cost of such conversion to be relatively low (approximately $10 million per unit) at sites where adequate gas transmission capacity is available.

Exhibit 58 **Impact of Potential Coal-Fired Retirements on Regional Capacity Margins**



Source: Ventyx, EPRI, EIA and Bernstein analysis.

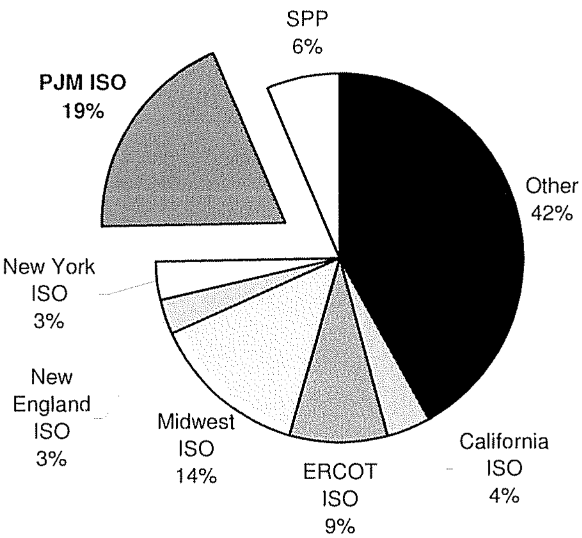
Impact on Energy Prices: A Focus on PJM

We next assess the likely impact of the expected reduction in coal-fired generation on wholesale power prices in the PJM Interconnection. PJM Interconnection is the FERC-recognized RTO that coordinates the generation and transmission of electricity across the Mid-Atlantic region and portions of the Midwest. As can be seen in Exhibit 61, the RTO encompasses the bulk of Pennsylvania, Maryland, New Jersey, Delaware, Virginia, West Virginia and Ohio, as well as parts of North Carolina, Tennessee, Indiana, Michigan and Illinois.

We have modeled the scenario where the EPA sets a maximum achievable control technology standard for mercury and acid gases that requires the installation of SO2 scrubbers across the coal-fired fleet. We focus our analysis on the PJM Interconnection because we expect it to experience a significant reduction in coal-fired generation in this scenario, and because of the number of competitive generators operating in this market whose gross margins would be materially affected by the consequent movement in wholesale power prices.

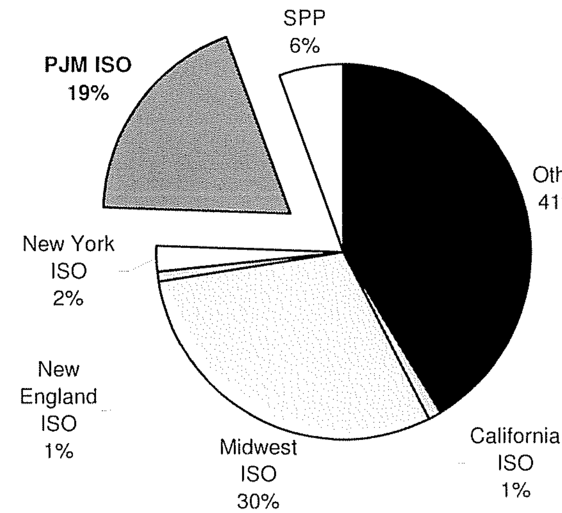
As can be seen in Exhibit 59, 19% of all electricity generated in the United States in 2009 came from power plants located in the PJM RTO. In the scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers across the coal-fired fleet, we estimate that 19% of the coal-fired generation at risk of retirement is also located in the PJM RTO (see Exhibit 60).

Exhibit 59 Breakdown of Total U.S. Electricity Generation by ISO in 2009 (MWh)



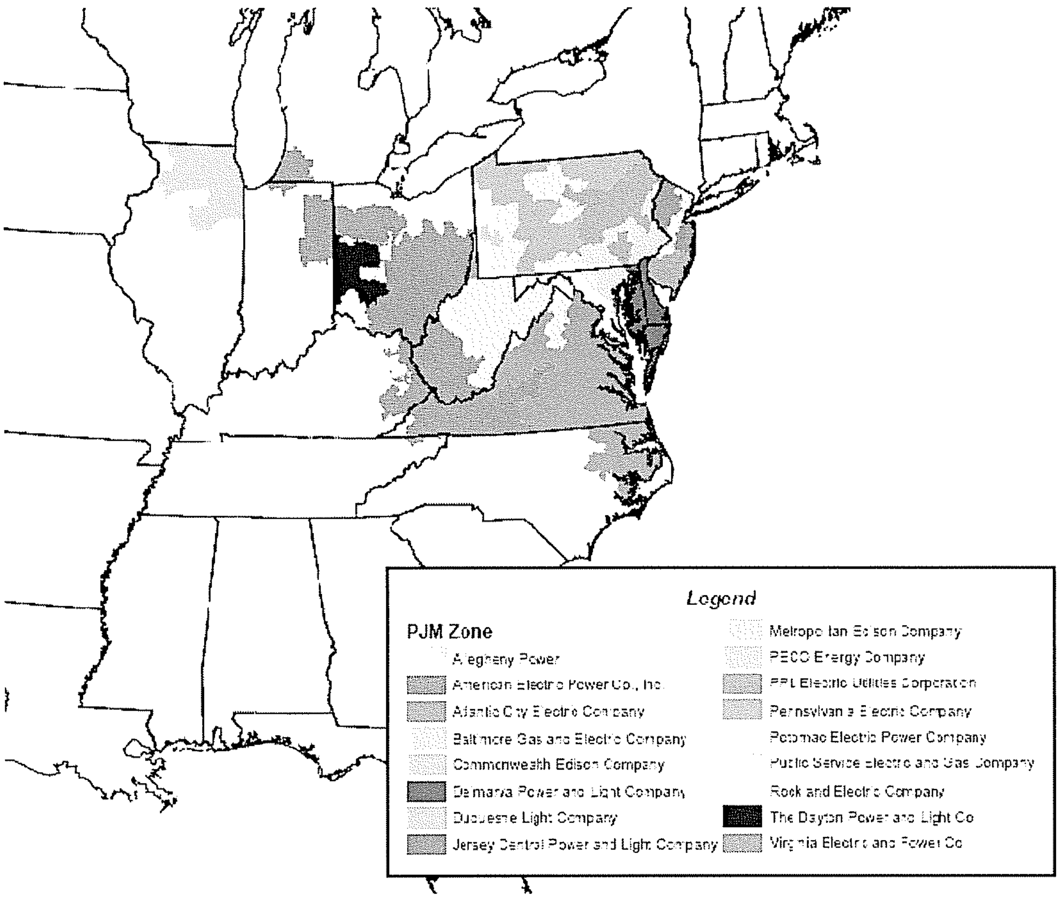
Source: Ventyx and Bernstein analysis.

Exhibit 60 Generation at Risk of Retirement by ISO (MWh)



Source: Ventyx, EPRI, EIA and Bernstein analysis.

Exhibit 61 PJM Interconnection: Map of Territory Served



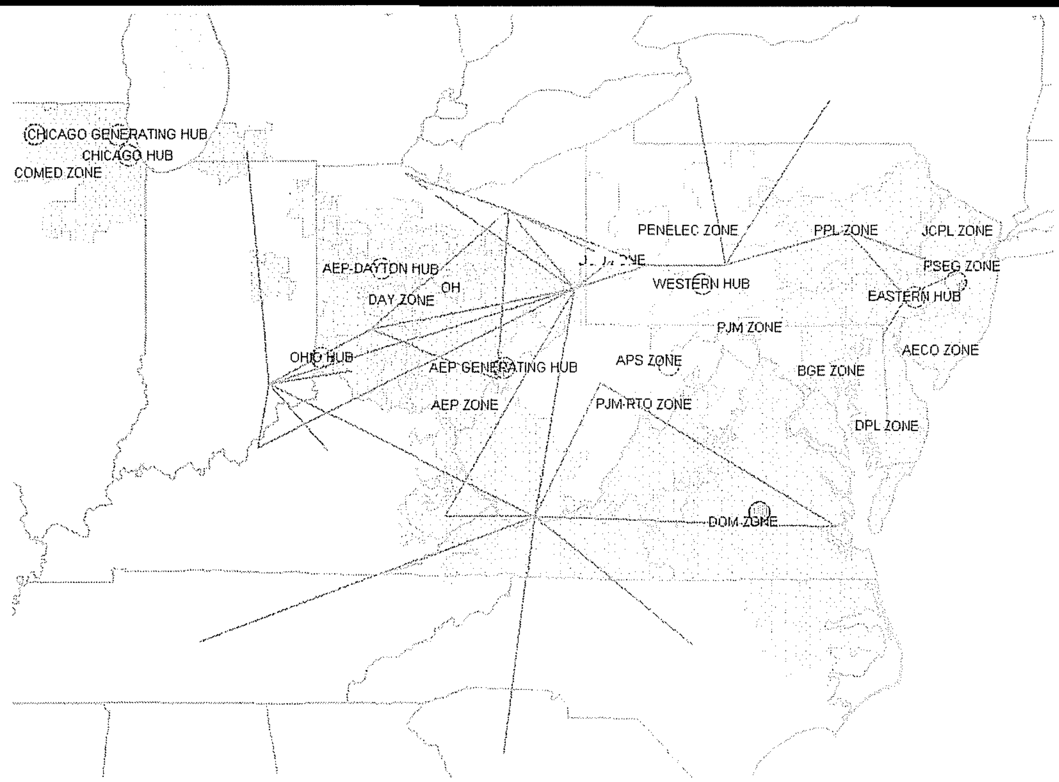
Source: PJM.

PJM's function is to match generation to load on an instantaneous basis across the RTO, thereby maintaining the supply and demand for electricity in continuous balance. PJM's responsibilities include forecasting load, scheduling generation resources to assure that sufficient power is available, and scheduling the use of transmission lines to transport power from generators to load. In managing the grid, PJM dispatches about 163,500 MW of generating capacity over 56,350 miles of transmission lines. It also operates wholesale electricity markets that enable participants to buy and sell electricity on a day-ahead basis or in real time on the spot market. Finally, PJM operates a forward market for capacity called the Reliability Pricing Model or RPM.

While operated by PJM as a single power market, limited east-west transmission capacity in the RTO frequently results in wide disparities in power prices between its eastern and western regions. In the absence of adequate transmission links across the RTO, prices in the eastern and western regions of PJM reflect the local balance between power supply and demand. Therefore, rather than converging across the RTO, power prices in the two different regions sustain material differences across many of the hours of the year.

Exhibit 62 illustrates the transmission bottleneck that gives rise to the two regional power markets within PJM. The generating hubs along the Ohio River (where a fleet of coal-fired power plants capitalize on the river's ample water supplies as well as the ready access it allows to Appalachian coal) are well connected with each other and with load centers to the north on the shores of the Great Lakes. However, these generating hubs have only limited connection with the huge load centers to the east, stretching from New York through Philadelphia, and Baltimore to Washington in the south. Whereas both the eastern and western regions of PJM have generation fleets with capacities of some 75,000 to 85,000 MW, the transmission interconnections between them have a combined capacity of only 5,593 MW, according to our estimates.

Exhibit 62 **Map of Transmission Lines in PJM**



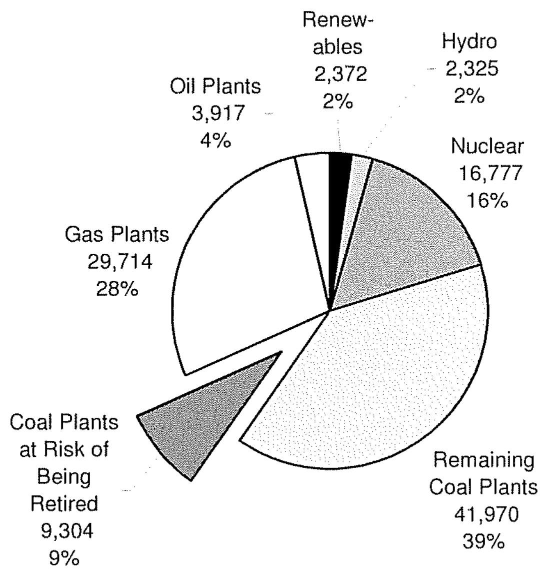
Source: Ventyx and Bernstein analysis.

For the purpose of our analysis, therefore, we have divided PJM into two sections that we call "PJM East" and "PJM West." PJM East comprises the service territories of DPL, MetEd, JCPL, PSEG, Penelec, PPL, Pepco, AECO, PECO, and BGE. We refer to the rest of the PJM RTO as "PJM West," which consists of the service territories of APS, DUQ, Dominion, Comed, AEP, UGI, DAY, and ATSI, the new region created following the integration of the FirstEnergy service territory into the PJM Interconnection.

A breakdown of the generation capacity in PJM West by energy source is presented in Exhibit 63. As can be seen, the generation capacity in PJM West consists of coal at 48%, natural gas at 28%, nuclear at 16%, oil at 4%, hydroelectric at 2%, and other renewable sources at 2%. In a scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers across the coal-fired fleet, we estimate that the coal-fired plants at risk of retirement would represent 9% of the total installed capacity in PJM West.

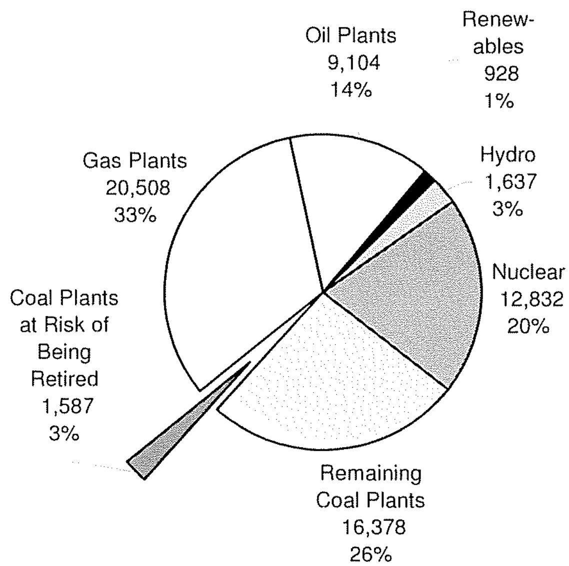
A breakdown of the generation capacity in PJM East by energy source is presented in Exhibit 64. Compared with PJM West, PJM East is less well endowed with coal-fired generation, and relies more heavily on gas turbines and oil-fired steam turbine generators. The generation capacity in PJM East is broken down as follows: natural gas at 33%, coal at 29%, nuclear at 20%, oil at 14%, hydroelectric at 3%, and other renewable sources at 1%. In a scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers across the coal-fired fleet, we estimate that the coal-fired plants at risk of retirement would represent only 3% of the total installed capacity in PJM East.

Exhibit 63 PJM West: Capacity by Fuel Type — MW and Share



Source: Ventyx and Bernstein analysis.

Exhibit 64 PJM East: Capacity by Fuel Type — MW and Share

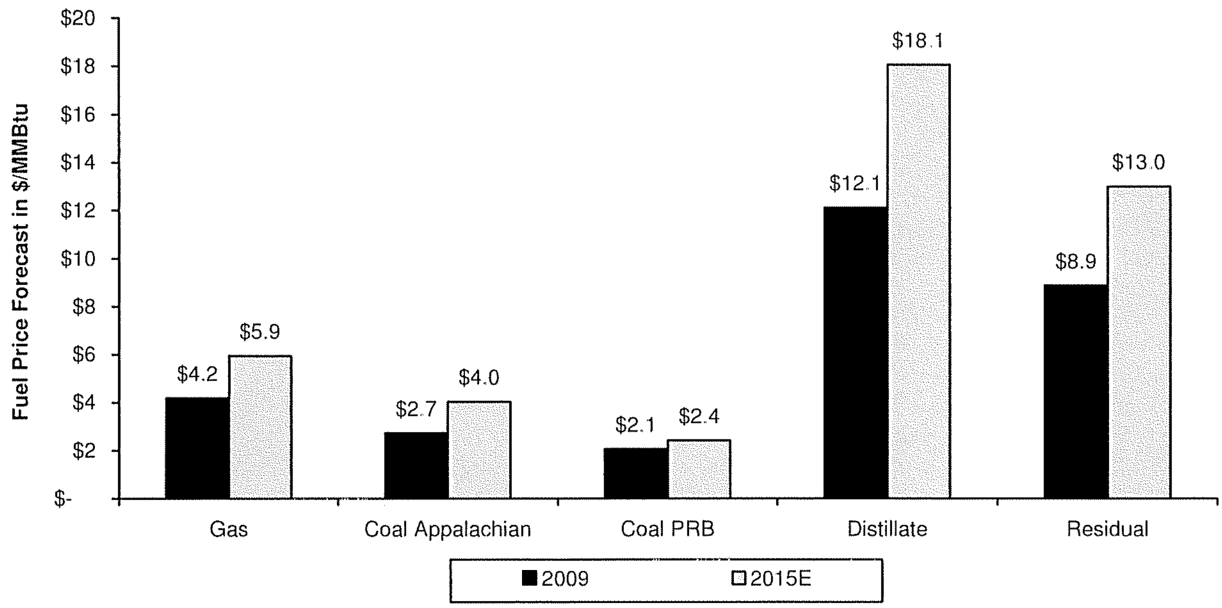


Source: Ventyx and Bernstein analysis.

To estimate the impact of these coal plant retirements on power prices in PJM, we have constructed forecast power supply curves for PJM East and PJM West. These forecast power supply curves reflect the estimated variable cost of operation of each of the power generating units in the two regions in 2015. To estimate these variable costs, we have used currently prevailing forward prices for coal, natural gas and fuel oil (see Exhibit 65); the heat rates of each existing generating unit in the two regions; and the estimated heat rates for each new generating unit scheduled to come on line by 2015.

In addition, we have prepared a second set of regional power supply curves corresponding to a scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers across the coal-fired fleet. In this case, our power supply curves for PJM East and PJM West have been adjusted to reflect the withdrawal from operation of those coal-fired power plants that we estimate it would uneconomic to retrofit with SO2 scrubbers.

Exhibit 65 **Fuel Prices in $/MMBtu: Historical 2009 vs. Currently Prevailing Forward Prices for 2015**



Source: Bloomberg L.P. and Bernstein analysis.

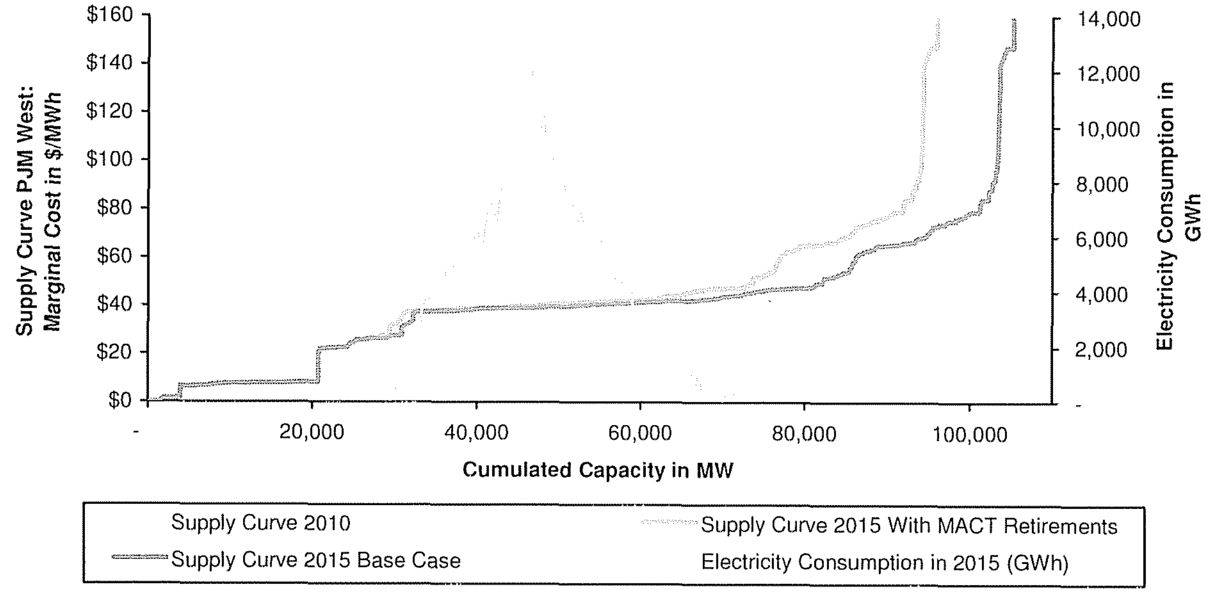
To estimate power demand in the PJM RTO in 2015, we have used historical load duration curves for PJM East and PJM West and adjusted these for the load growth forecast by the North American Electric Reliability Corporation (NERC) for its ReliabilityFirst (RFC) region, and more particularly its PJM subzone. The NERC forecast calls for power demand in PJM to grow by 12% through 2015.

Using these forecast load duration curves and power supply curves for PJM East and PJM West, it is possible to match (1) forecast power demand during each hour of 2015 with (2) the variable cost of production at the last plant required to be dispatched to meet demand during that hour. In this way it is possible to estimate the marginal of cost of power supply in each of the two PJM regions during each hour of 2015.

Exhibit 66 and Exhibit 67 present our estimated 2015 supply curves for PJM West and PJM East, respectively, both in our base-case scenario and in the scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers. These exhibits also present the estimated distribution of electricity demand along the supply curves in the two regions. These mountain-shaped lines reflect electricity consumed (measured in GWh on the right-hand vertical axis) at various levels of power demand (measured in MW on the horizontal axis).

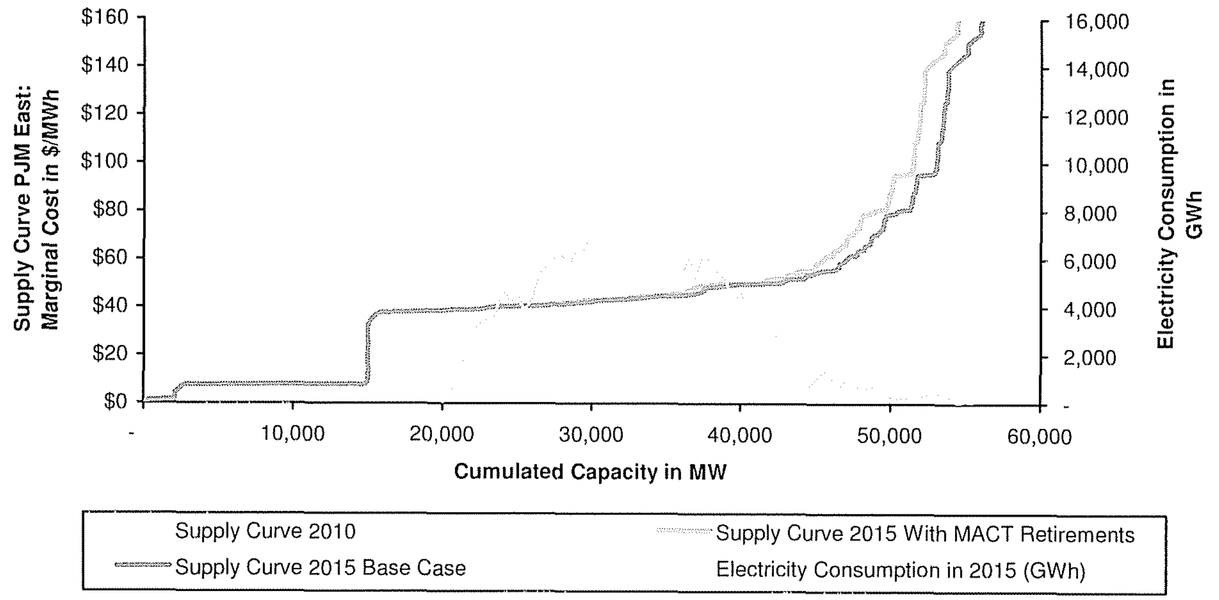
Thus in PJM East, illustrated in Exhibit 67, the minimum level of power demand in 2015 is estimated to be 20,000 MW (the far left point of the mountain-shaped curve). Because power demand is expected to fall to such a very low level for only a few hours a year, the number of MWh of electricity consumed when demand is at 20,000 MW is quite limited (as is reflected in the low elevation of the mountain-shaped curve at this point). The maximum level of power demand estimated for PJM East in 2015, by contrast, is approximately 55,000 MW (the far right point of the mountain-shaped curve). Again, because power demand is expected to rise to such a very high level for only a few hours a years, only a limited number of MWh of electricity are expected to be consumed when demand is at 50,000 MW (reflected in the low elevation of the curve at this point). The bulk of electricity consumed in PJM East in 2015 will be consumed when power demand is between these two extremes, in the range of approximately 25,000 MW to 40,000 MW (the peak of the mountain).

Exhibit 66 **PJM West Supply Curve in 2010, 2015 Base-Case Scenario and With MACT Retirements**



Source: Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

Exhibit 67 **PJM East Supply Curve in 2010, 2015 Base-Case Scenario and With MACT Retirements**



Source: Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

In both Exhibit 66 and Exhibit 67, it is possible to see how the 2015 supply curve shifts to the left when adjusted for expected coal plant retirements as a result of a MACT standard for mercury requiring the installation of SO2 scrubbers. The vertical distance between the supply curve adjusted for coal plant retirements and the base case supply curve for 2015 suggests the extent of the increase in the marginal cost of supply in the two regions as a result of the retirements. In both markets, the supply curve adjusted for coal plant retirements tends to follow the base case 2015 supply curve for much of its length, only rising above it at relatively high levels of demand. This suggests that it will be primarily the cost of supply during peak hours that will be affected by coal plant retirements in response to an MACT standard for mercury.

What If the East-West Transmission Bottleneck Were to Be Eliminated?

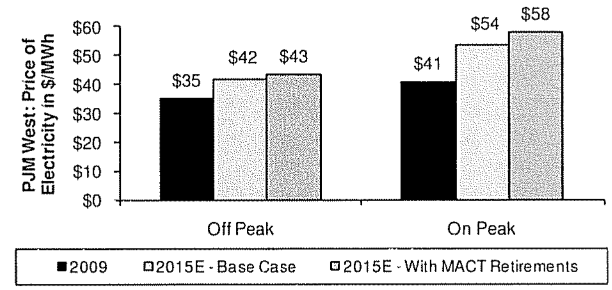
Our modeling of the price impact of coal plant retirements on the PJM Interconnection is complicated by the fact that the transmission bottlenecks that currently separate PJM East from PJM West may be eliminated by 2015, potentially allowing these two markets to clear as one. Several transmission projects are currently being developed in the PJM Interconnection to connect the western and eastern regions. At least 5,920 MW of new east-west transmission capacity is planned to be built, reflecting primarily the 5,000 MW Potomac-Appalachian Transmission Highline (PATH) project currently under development by Allegheny and AEP. Costing an estimated $1.8 billion, this 765 kV transmission line would run 290 miles from West Virginia to Maryland. Approved by the PJM Board of Managers in June 2007 and by FERC in March 2008, PATH is scheduled to be completed by 2015.

To capture the possibility that the construction of PATH and other west-to-east transmission links might unify the PJM Interconnection and allow it operate as a single power market, we have designed two forecast scenarios. In our first scenario, called the "Unified Market Hypothesis," we assume that these transmission projects are completed by 2015, allowing the PJM Interconnection to operate as a single market during all hours of the year. In our second scenario, which we call our "Two Markets Hypothesis," we assume that the transmission projects are not completed by 2015, and that PJM continues to operates as two distinct markets during on-peak hours, when the transmission constraints limiting the export of power PJM West to PJM East become binding. During off-peak hours, when these transmission constraints are not binding, the PJM Interconnection tends to clear as a single market across the two regions.

Exhibit 68 and Exhibit 69 present our power price forecasts for 2015 in our Unified Market Hypothesis, where we assume that planned transmission interconnections allow the PJM Interconnection to operate as a single, integrated market. Exhibit 68 presents our power price forecast for 2015 in PJM West in both in our base-case scenario and in the scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers. Exhibit 69 present our power price forecast for 2015 in PJM East, considering the same two scenarios.

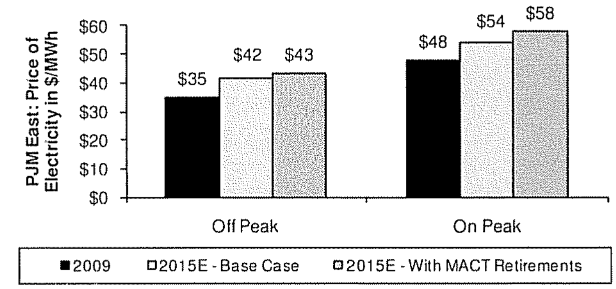
As can be seen in Exhibit 68 and Exhibit 69, we estimate the impact of coal plant retirements, in a scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers, will raise the on-peak price of electricity prevailing in the PJM RTO by 2015 by $4 per MWh compared to our base case.

Exhibit 68 Unified Market Hypothesis: 2015 Power Price Forecast for PJM West



Source: Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

Exhibit 69 Unified Market Hypothesis: 2015 Power Price Forecast for PJM East

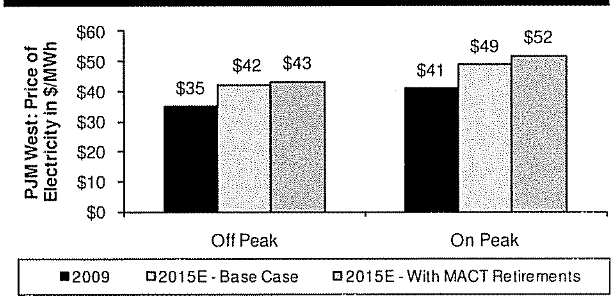


Source: Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

Exhibit 70 and Exhibit 71 present our power price forecasts for 2015 in our Two Markets Hypothesis. In this case, existing transmission bottlenecks are assumed to prevent the export of power from West to East during on-peak hours, causing on-peak power prices to diverge in PJM West and PJM East. Reflecting its higher-cost generating fleet, on-peak power prices in PJM East tend to settle at higher level.

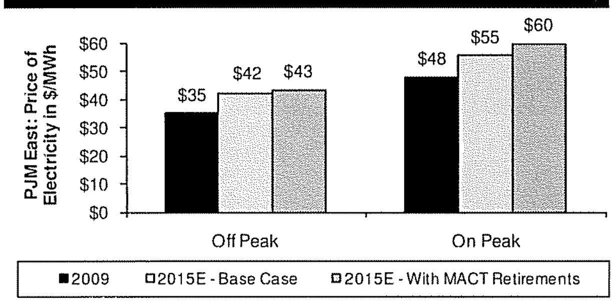
Exhibit 70 presents our power price forecast for 2015 in PJM West in both our base-case scenario and in the scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers. Exhibit 71 present our power price forecast for 2015 in PJM East, again considering the same two scenarios. As can be seen in Exhibit 70 and Exhibit 71, we estimate the impact of coal plant retirements, in a scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers, will raise the on-peak price of electricity prevailing in the PJM West by 2015 by $3 per MWh compared to our base case, while the on-peak price in PJM East could increase by $5 per MWh.

Exhibit 70 Two Markets Hypothesis: 2015 Power Price Forecast for PJM West



Source: Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

Exhibit 71 Two Markets Hypothesis: 2015 Power Price Forecast for PJM East



Source: Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

Company Impact: Effect of Price Movements on Revenue and Gross Margins

To estimate the impact of these power price movements on the revenues and gross margins of the generators operating in the PJM Interconnection, we have taken into consideration not only our forecast power price increases but also the potential loss of power output that these generators may suffer as a result of expected coal plant retirements. Exhibit 72 presents our estimates of the loss of generation that utilities in PJM are expected to suffer in the scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers. As can seen there, we estimate that Edison International could lose up to 17% of its generation in PJM, while RRI Energy could lose 16%, American Electric Power and AES Corp 10%, Dominion and FirstEnergy 6%, Calpine 5%, NRG and Allegheny 3%, and Constellation 1%.

Exhibit 72 **Loss of PJM Generation by Company as Percentage of Total Generation**

Holding Company Name	Ticker	Net Generation – Basecase (GWh)	Net Generation – With Retirements (GWh)	Net Generation at Risk of Being Retired in PJM
Duke Energy Corp	DUK	26,673	26,673	0%
NextEra Energy Inc	NEE	5,050	5,050	0%
Public Service Enterprise Group Inc	PEG	51,178	51,178	0%
Dynegy Inc	DYN	4,222	4,222	0%
Exelon Corp	EXC	128,703	128,703	0%
Mirant Corp	MIR	21,821	21,821	0%
PPL Corp	PPL	46,714	46,714	0%
DPL Inc	DPL	16,900	16,835	0%
Constellation Energy Group	CEG	34,059	33,730	-1%
NRG Energy Inc	NRG	3,210	3,105	-3%
Allegheny Energy Inc	AYE	31,178	30,138	-3%
Calpine Corp	CPN	33,147	31,439	-5%
FirstEnergy Corp	FE	79,510	75,124	-6%
Dominion Resources Inc	D	95,501	89,675	-6%
American Electric Power Co Inc	AEP	148,606	133,919	-10%
AES Corp (The)	AES	9,522	8,562	-10%
RRI Energy Inc	RRI	26,841	22,418	-16%
Edison International	EIX	40,449	33,739	-17%

Source: Ventyx, EPRI, EIA and Bernstein analysis.

We next considered the impact that our forecast of power price increases — reflecting coal plant retirements in the scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers — is likely to have on the generation gross margins of the competitive generators operating in PJM. Our estimates reflect the expected loss in coal-fired generation on the one hand and the expected increase in the price of power on the other hand. Exhibit 73 presents our estimate of the gross margin impact by company in our Unified Market Hypothesis.

Exhibit 73 **2015 Gross Margin Impact by Company — Assuming PJM Operates as a Unified Market During All Hours**

Holding Company Name	Ticker	LTM EBITDA ($ million)	Gross Margin Impact ($ million)	EPS Impact	Margin Impact as % of LTM EBITDA
PPL Corp	PPL	$1,666	$127	$0.19	8%
FirstEnergy Corp	FE	$2,798	$150	$0.40	5%
Exelon Corp	EXC	$6,835	$362	$0.33	5%
Mirant Corp	MIR	$665	$35	$0.15	5%
Constellation Energy Group	CEG	$1,778	$80	$0.24	4%
Public Service Enterprise Group Inc	PEG	$3,968	$135	$0.16	3%
Dynegy Inc	DYN	$479	$14	$0.07	3%
Allegheny Energy Inc	AYE	$1,202	$22	$0.08	2%
Duke Energy Corp	DUK	$4,891	$76	$0.03	2%
Dominion Resources Inc	D	$4,219	$38	$0.04	1%
NRG Energy Inc	NRG	$2,695	$11	$0.02	0%
NextEra Energy Inc	NEE	$5,025	$8	$0.02	0%
AES Corp (The)	AES	$4,524	$4	$0.00	0%
Calpine Corp	CPN	$1,515	$1	$0.00	0%
RRI Energy Inc	RRI	$257	$(2)	$(0.00)	-1%
Edison International	EIX	$3,662	$(61)	$(0.12)	-2%

Source: Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

In this scenario, we estimate that PPL would enjoy a gross margin increase of 8% when compared to its respective last 12 months' EBITDA, while Exelon, FirstEnergy and Mirant would enjoy an increase of 5%; Constellation 4%; Dynegy and PSEG 3%, Allegheny and Duke 2%, and Dominion 1%. Conversely, we estimate that Edison International could see its gross margin in the PJM RTO decrease by 2% of its last 12 months EBITDA, while RRI Energy would suffer a 1% reduction.

Exhibit 74 presents the gross margin impact by company in our Two Markets Hypothesis. In this scenario, we estimate that PPL would enjoy a gross margin increase of 8% when compared to their last 12 months EBITDA, while Constellation, Mirant and Exelon would enjoy an increase of 5%, PSEG 4%, FirstEnergy and Dynegy 3%, Allegheny 2%, Duke and Dominion 1%. On the flip side, we estimate that RRI Energy could see its gross margin in the PJM RTO decrease by 3% and Edison International by 1%.

Exhibit 74 **2015 Gross Margin Impact by Company — Assuming PJM Operates as Two Markets During Peak Hours**

Holding Company Name	Ticker	LTM EBITDA ($ million)	Gross Margin Impact ($ million)	EPS Impact	Margin Impact as % of LTM EBITDA
PPL Corp	PPL	$1,666	$133	$0.20	8%
Mirant Corp	MIR	$665	$36	$0.16	5%
Exelon Corp	EXC	$6,835	$323	$0.29	5%
Constellation Energy Group	CEG	$1,778	$82	$0.24	5%
Public Service Enterprise Group Inc	PEG	$3,968	$145	$0.17	4%
FirstEnergy Corp	FE	$2,798	$97	$0.26	3%
Dynegy Inc	DYN	$479	$13	$0.06	3%
Allegheny Energy Inc	AYE	$1,202	$18	$0.07	2%
Duke Energy Corp	DUK	$4,891	$55	$0.02	1%
Dominion Resources Inc	D	$4,219	$35	$0.04	1%
NRG Energy Inc	NRG	$2,695	$11	$0.02	0%
NextEra Energy Inc	NEE	$5,025	$11	$0.02	0%
Calpine Corp	CPN	$1,515	$3	$0.00	0%
AES Corp (The)	AES	$4,524	$4	$0.00	0%
Edison International	EIX	$3,662	$(52)	$(0.10)	-1%
RRI Energy Inc	RRI	$257	$(7)	$(0.01)	-3%

Source: Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

Impact on Capacity Prices

We have also assessed the impact on capacity prices in PJM of the expected retirement of coal plants in the scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers. To do so, we re-ran the results of the 2012/2013 PJM capacity auction (the last for which the capacity prices offered by generators have been published by PJM) adjusting pro forma for the expected loss of coal-fired capacity in PJM by 2015 due to the Air Toxics Rule.

The key elements of PJM's system of capacity pricing (referred to as the Reliability Pricing Model or RPM) are three: (1) a three-year-forward, location-specific capacity requirement for load serving entities; (2) a PJM-coordinated auction to procure capacity three years in advance; and (3) a downward-sloping demand curve to price the capacity bid into these auctions. These key elements are described in greater detail in the following paragraphs.

Locational capacity requirements. Each load serving entity (LSE) in PJM must have access to sufficient generation capacity to satisfy its customers' forecasted peak use of electricity plus a reserve for contingencies. LSEs may meet this obligation with generation they own, purchase bilaterally or purchase through PJM's auctions. In recognition of transmission constraints that may limit the delivery of energy to certain regions, each LSE is required to procure capacity for its load from plants deemed by PJM, in light of existing transmission constraints, to be capable of delivering energy to that zone. The RPM auctions can thus result in clearing prices that vary by region, reflecting the higher value of capacity located within transmission-constrained areas. In particular, recent capacity auctions have produced much higher capacity prices in transmission-constrained areas in the eastern portion of the RTO (the MAAC region) than they have in the west (the Rest of RTO region).

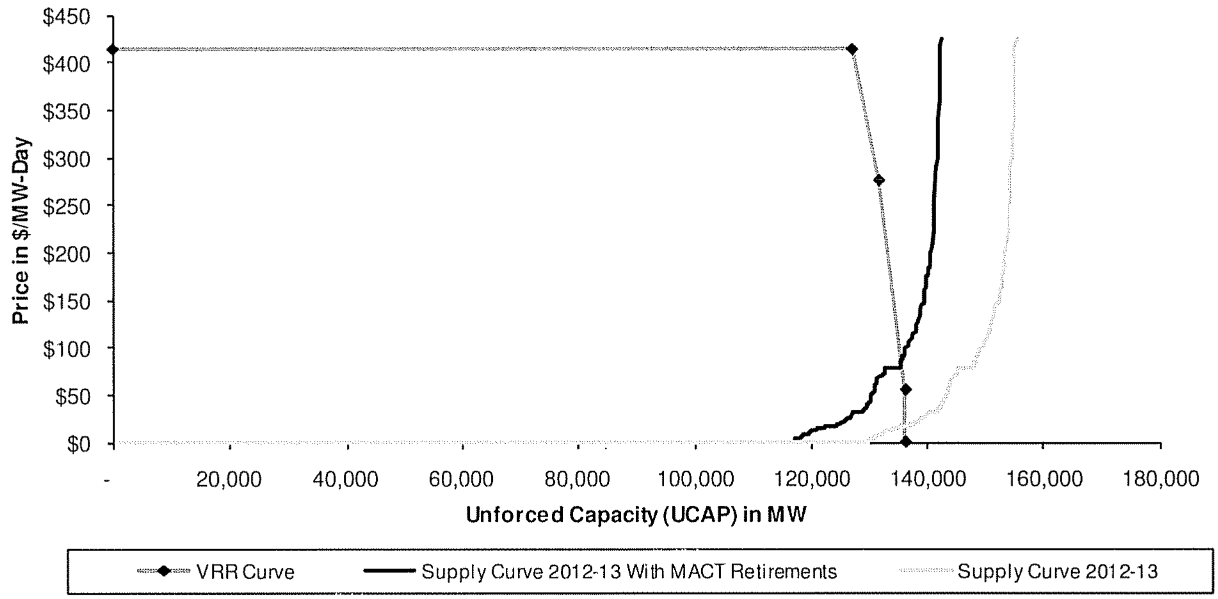
Three-year-forward procurement auction. Each LSE in PJM is required to meet its capacity obligation three years in advance. The year for which capacity is procured is known as the "Delivery Year," and runs from June 1 through May 30. Acting as agent for the LSEs, PJM procures capacity on their behalf through an auction. Existing generation assets, planned generation additions and bilateral contracts for unit-specific capacity may be offered into the auction, as may existing generation capacity located outside PJM if it is available for import to the capacity zone in question. The auctions set the price paid during the Delivery Year to all capacity that clears the auction (i.e., capacity offered at or below the clearing price). These capacity payments are funded with reliability charges paid by the LSEs.

Downward-sloping demand curve. The price to be paid per MW of capacity is set at the procurement auction using a downward-sloping demand curve, so that capacity prices are high when generation resources are scarce, and prices are low when resources are abundant. The demand curve is designed so that if the capacity offered equates to a 16% reserve margin (1% above PJM's target reserve margin of 15%), then the capacity payment per MW per year equals the "levelized" annual cost per MW of installing a new gas turbine generator (referred to as the "cost of new entry" or CONE) less the annual generation gross margin of such a unit (energy and ancillary services revenues less fuel). The cost of new entry less generation gross margin is referred to as "net CONE." If the capacity offered implies a reserve margin of only 12%, then the capacity payment per MW-year rises to 1.5 times net CONE. Conversely, if the capacity offered implies a reserve margin in excess of 20%, the capacity payment falls to zero. (PJM's reserve margin calculations include an adjustment for forced outages, which involves dividing installed generation capacity by one minus the pool wide equivalent forced outage rate, or EFORd. The resulting estimate of capacity available net of forced outages is called unforced capacity or UCAP.)

The latest auction for which PJM has disclosed the capacity prices offered by generators (i.e., the capacity supply curve) was that for the delivery year 2012/2013. This auction was held in the spring of 2009, and resulted in significantly lower clearing prices for capacity than the 2013/2014 auction held in the spring of 2010. To estimate the impact that expected coal plant retirements might have on the price of capacity in PJM, we re-ran the results of the 2012/2013 capacity auction adjusting pro forma for the expected loss of coal-fired capacity in PJM by 2015 due to the Air Toxics Rule.

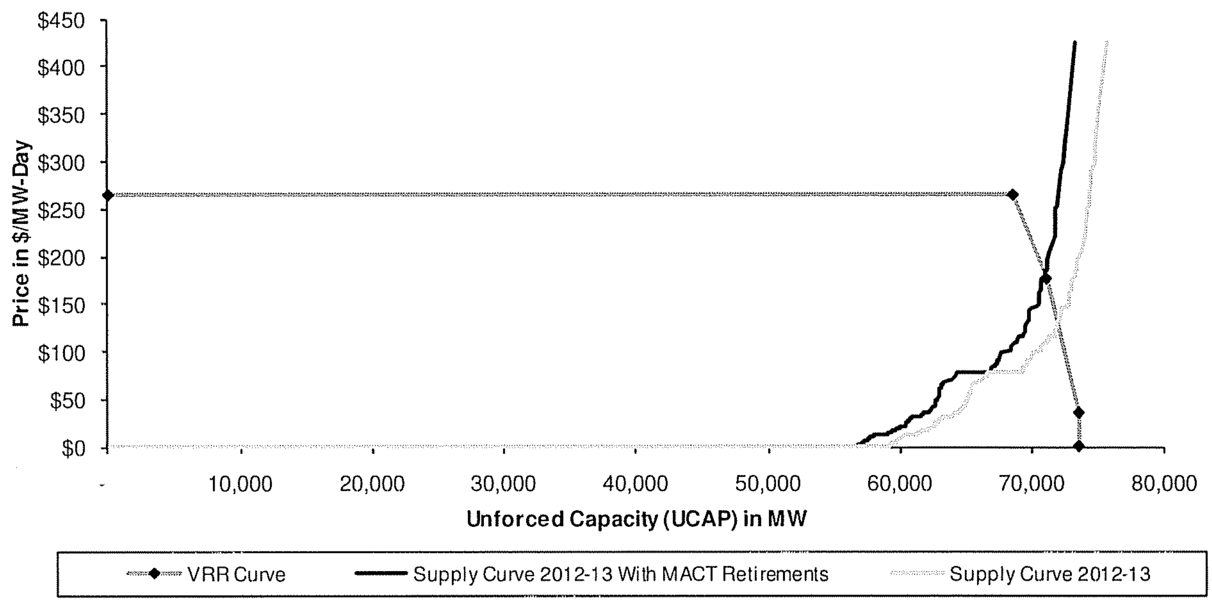
In Exhibit 75 and Exhibit 76 we have recreated the capacity supply curves and downward-sloping demand curves used in the 2012/2013 capacity auction to determine capacity prices for the MAAC region (the eastern portion of the RTO) and Rest of RTO region (the western portion of the RTO). Thus, in Exhibit 75, the line with the diamond markers (labeled "VRR Curve") recreates PJM's downward-sloping demand curve for the Rest of RTO region in the 2012/2013 auction year, and the gray upward-sloping line plots the capacity supply curve for that region. Next, we have removed from this historical capacity supply curve the coal-fired power plants in the Rest of RTO region that we believe to be at risk of retirement in a scenario where the EPA sets a MACT standard for mercury and acid gases that requires the installation of SO2 scrubbers. This modified supply curve appears in black to the left of the historical supply curve. (We have made the conservative assumption that all the PJM power plants we believe to be at risk of retirement in our MACT scenario were price takers in the 2012/2013 auction — in effect, that they bid their capacity in at a price of zero dollars per MW-day.) We then calculated the price at which the 2012/2013 auction would have cleared under these circumstances (i.e., the intersection of the modified supply curve in red in Exhibit 75 with the downward-sloping demand curve). In Exhibit 76, we repeat this analysis for the MAAC region.

Exhibit 75 **2012/2013 Capacity Auction for PJM's Rest of RTO Region: Downward-Sloping Demand Curve and Capacity Supply Curve — Historical on the Right and Modified for Coal Plant Retirements on the Left**



Source: PJM, Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

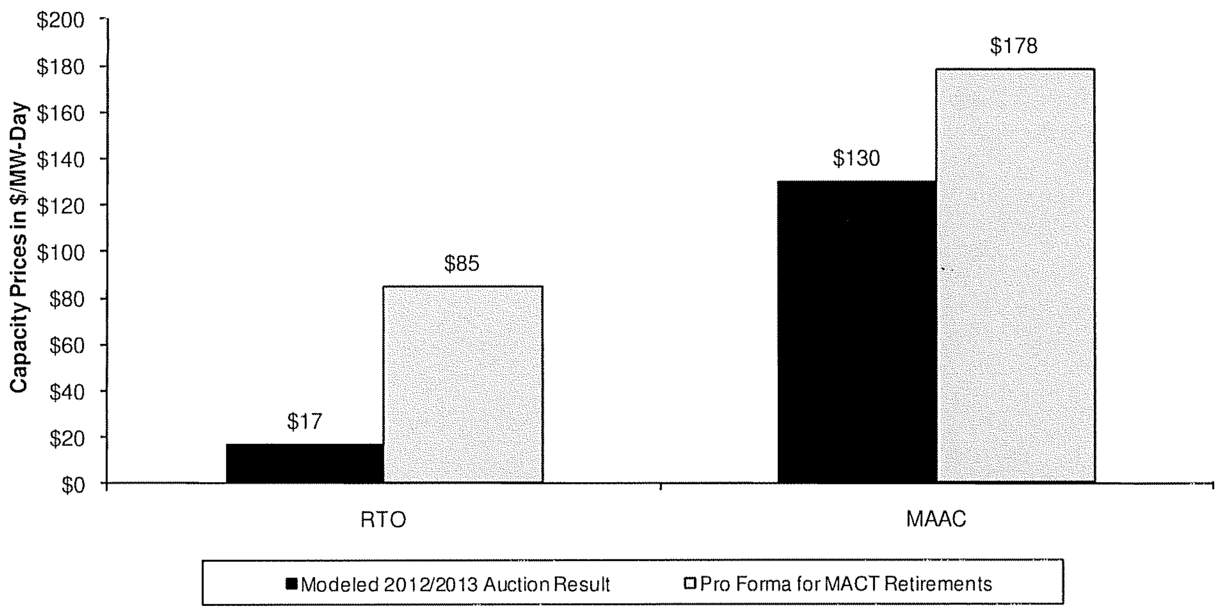
Exhibit 76 **2012/2013 Capacity Auction for PJM's MAAC Region: Downward-Sloping Demand Curve and Capacity Supply Curve — Historical on the Right and Modified for Coal Plant Retirements on the Left**



Source: PJM, Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

Exhibit 77 and Exhibit 78 illustrate the impact that the expected retirement of coal-fired capacity in PJM would have had on the 2012/2013 capacity auction. The auction price is set by the intersection of PJM's downward-sloping demand curve with the capacity supply curve. Using our modified supply curve, reflecting the impact of expected coal plant retirements as a result of the Air Toxics Rule, capacity prices would have cleared at markedly higher levels. In Rest of RTO region, we estimate that capacity prices would have risen from $17 per MW-day in the 2012/2013 auction to $85 per MW-day. In the MAAC region, we estimate that capacity prices would have risen from $130 per MW-day in the 2012/2013 auction to $178 per MW-day (see Exhibit 77).

Exhibit 77 **What Would Have Been the Effect on PJM's 2012/2013 Capacity Auction If Supply Had Been Reduced by Our Estimate of Coal Plant Retirements in Response to an EPA MACT Standard for Mercury? (Rest of RTO Region)**



Source: PJM, Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

In Exhibit 78 we assess the impact that such an increase in PJM capacity prices would have on the long-term earnings power of unregulated generators in PJM. We arrived at our estimates by multiplying the capacity price increase in each region by the remaining unregulated capacity in PJM that each utility owns, adjusted for the pool-wide equivalent forced outage rate, and then compared the result with the utility's EBITDA over the last 12 months.

As can be seen in Exhibit 78, the capacity revenue increases from the PJM auctions could contribute materially to the earnings power of the largest unregulated generators in the RTO. As a percentage of LTM EBITDA, the utilities that would appear to benefit the most are RRI Energy, for which the increase in capacity revenues is equivalent to 52% of LTM EBITDA; Mirant with 12%; FirstEnergy with 11%; PPL with 10%; Dynegy with 7%; Exelon, Allegheny and Constellation with 6%; Calpine and PSEG with 5%; Edison International and Duke with 3%.

Exhibit 78 **Potential Impact of PJM Auction Prices on Company Gross Margins**

Holding Company Name	Ticker	LTM EBITDA ($ million)	Gross Margin Impact ($ million)	EPS Impact	Margin Impact as % of LTM EBITDA
RRI Energy Inc	RRI	$257	$133	$0.25	52%
Mirant Corp	MIR	$665	$78	$0.35	12%
FirstEnergy Corp	FE	$2,798	$317	$0.85	11%
PPL Corp	PPL	$1,550	$153	$0.23	10%
Dynegy Inc	DYN	$479	$35	$0.16	7%
Exelon Corp	EXC	$6,835	$405	$0.36	6%
Allegheny Energy Inc	AYE	$1,202	$67	$0.25	6%
Constellation Energy Group	CEG	$1,778	$99	$0.29	6%
Calpine Corp	CPN	$1,515	$75	$0.13	5%
Public Service Enterprise Group Inc	PEG	$3,968	$196	$0.24	5%
Edison International	EIX	$3,662	$126	$0.25	3%
Duke Energy Corp	DUK	$4,891	$139	$0.05	3%
NRG Energy Inc	NRG	$2,695	$30	$0.06	1%
Dominion Resources Inc	D	$4,219	$47	$0.05	1%
AES Corp (The)	AES	$4,524	$29	$0.03	1%
NextEra Energy Inc	NEE	$5,025	$25	$0.05	0%

Source: PJM, Ventyx, Bloomberg L.P., EPRI, EIA and Bernstein analysis.

EPA Proposes Coal Ash Rules to Phase Out Wet Ash Handling and Storage

Overview

The EPA is not only changing standards for air quality. It is also tackling solid waste: On May 4, 2010, the agency proposed two alternative rules to regulate the management and disposal of coal ash from power plants under the Resource Conservation and Recovery Act (RCRA). The agency's long-term objective under both proposals is to end the wet handling of coal ash and the use of surface impoundments (ash ponds) in favor of dry ash storage in properly lined landfills.

Perhaps more important than what the rules would do are two things they would not do. First, neither of the proposed rules would classify coal ash as a hazardous pollutant, which would have required costly "cradle to grave" handling procedures. Second, EPA is not proposing to regulate the beneficial use of coal ash. The agency defines "beneficial use" as the use of coal ash in encapsulated form, where the coal ash is bound into products such as in wallboard, concrete, roofing materials and bricks.

Rather, the two alternative rules proposed by the EPA would regulate coal ash destined for disposal in a landfill or surface impoundment. The first of the two proposed rules — known as the "Subtitle C proposal" — would regulated coal ash under Subtitle C of the RCRA. Subtitle C of RCRA allows the federal government to set requirements for the issuance of waste management permits and to monitor and enforce the requirements of such permits. The Subtitle C proposal would thus create a comprehensive program of federally enforceable requirements for waste management and disposal designed, in the EPA's words, "to phase out the wet handling of coal ash and existing surface impoundments." Before the Subtitle C proposal would become effective, however, states would need to adopt the rule, a process that could take several years.

The second proposed rule — known as the "Subtitle D proposal" — would regulate coal ash destined for disposal in a landfill or surface impoundment under Subtitle D of the RCRA. Subtitle D of RCRA allows the federal government to set national criteria to guide states in the issuance of waste management permits. The Subtitle D option would not require these permit programs to be established, however, nor would any such permits be federally enforceable. The Subtitle D proposal would allow utilities to continue the wet handling of ash and the use of surface impoundments subject to locational standards, composite liner requirements, groundwater monitoring and corrective action standards, and requirements to address the stability of surface impoundments. While less Draconian in its approach, the Subtitle D proposal would nonetheless "create strong incentives to close these impoundments and transition to safer landfills which store coal ash in dry form," according to the EPA.

While the two proposals have similar objectives, the ability of the federal government to set and enforce the conditions for waste management permits under the Subtitle C proposal is expected to result in higher utility compliance costs than under the Subtitle D proposal. The EPA's Regulatory Impact Analysis (RIA) estimates the average cost of compliance over the next 50 years to be $1.5 billion annually under the Subtitle C option and $0.6 billion per year under the Subtitle D option. These estimates include the costs of industry compliance as well as state and federal government oversight and enforcement costs. By way of comparison, in 2009, the U.S. power industry's electricity revenues totaled $354 billion, according to the EIA, while the aggregate pretax income of the nation's investor-owned utilities totaled $48.5 billion, according to the Edison Electric Institute.

Over 50 years at a 7% discount rate, the EPA estimates the present value of the compliance costs at $20.3 billion under the Subtitle C option and $8.1 billion under the Subtitle D option. To put that amount in perspective, the combined market capitalization of all publicly traded U.S. electric utilities is some $440 billion.

Investment Implications

Even though the overall cost of compliance with the EPA's two proposals is relatively modest compared to the revenues, earnings and market capitalization of the nation's electric utilities, the cost to particular utilities that rely heavily on wet ash handling and storage could be quite high. Among competitive generators in particular, for which such costs would not be subject to recovery in regulated rates, we estimate that the cost of conversion to dry ash handling and storage at existing coal-fired power plants could be very significant for Dynegy (DYN) and, to a lesser extent, for Ameren (AEE) and Mirant (MIR).

For regulated utilities, however, the capital cost of conversion to dry ash handling should be recoverable in regulated rates. Indeed, to the extent these capital expenditures can be incorporated in regulated rate base, they may accelerate growth in rate base and thus in regulated earnings. Such investments could represent a material opportunity for rate base growth at Cleco (CNL), DPL (DPL), Empire District Electric (EDE), AEP (AEP), Duke (DUK), Progress (PGN), Southern (SO), PNM Resources (PNM) and CMS Energy (CMS). Among the remaining regulated utilities, the capital outlays associated with conversion to dry ash handling represent a small percentage of regulated rate base.

What's the Issue?

The combustion of coal and the capture of air pollutants from the flue gas of coal-fired power plants produce significant amounts of solid waste. In the United States, coal combustion waste totals approximately 136 million tons annually. About two-thirds of this is coal ash (which in the United States averages about 10% by mass of the coal burned). The remainder comprises residues from SO2 scrubbers, such as the gypsum and calcium sulfite that are the byproducts of flue gas desulfurization (FGD) (see Exhibit 79 and Exhibit 80).

Coal-fired power plants remove and dispose of these solid wastes from their boilers and FGD systems through both wet and dry disposal methods. Dry disposal methods include hauling the waste to an offsite landfill or selling it for use in the production of cement and concrete or the construction of embankments and road bases. (An estimated 60 million tons of coal combustion waste, or 45%, is recycled each year.)

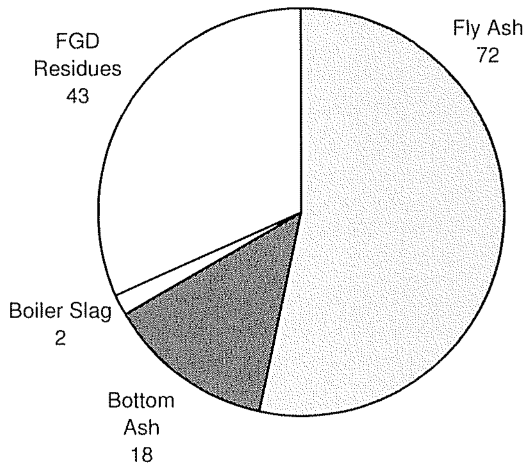
In wet ash handling systems, coal ash and scrubber residues are sluiced from the boiler and FGD system and transported in a slurry to surface impoundment settling ponds generally maintained onsite. In these settling ponds, the coal ash and FGD residues precipitate out of the slurry and eventually accumulate at the bottom of the pound. This process leaves relatively clear water at the surface of the pond, which may eventually be discharged into nearby rivers or lakes.

Wet ash handling systems give rise to several coal combustion wastewater streams. These are:

- Fly ash transport water, or the water used to transport to the surface impoundment a boiler's production of fly ash, the fine ash particles carried out of the boiler along with the flue gas and captured in pollution controls devices such as electrostatic precipitators and fabric filter baghouses;
- Bottom ash transport water, or the water used to transport to the surface impoundment a boiler's production of bottom ash, the heavier ash particles that fall to the bottom of the boiler during combustion;
- FGD wastewater, which is the wastewater remaining following the use of a sorbent slurry (e.g., lime or limestone) to remove sulfur dioxide (SO2) from flue gas; and

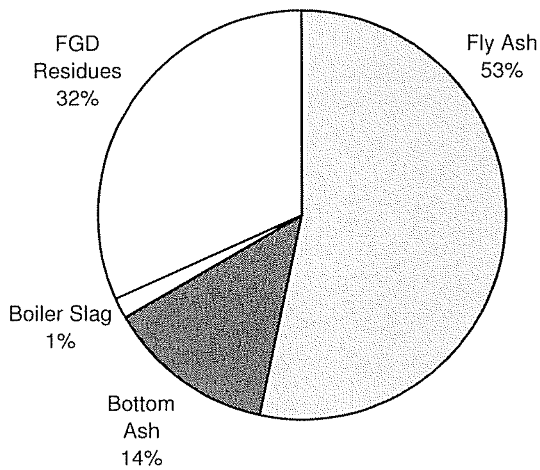
- Leachate or seepage from surface impoundments or landfills containing coal combustion residues.

Exhibit 79 Annual U.S. Production of Coal Combustion Wastes by Type: Millions of Tons



Source: American Coal Ash Association.

Exhibit 80 Annual U.S. Production of Coal Combustion Wastes by Type: Percentage Breakdown



Source: American Coal Ash Association.

FGD wastewaters generally contain significant levels of poisonous metals, including arsenic, mercury and selenium. These metals are also present, albeit to a lesser degree, in ash transport waters. The primary routes by which these pollutants in coal combustion wastewaters affect the environment are through discharges to surface waters, leaching to ground water, and by wildlife exposure to the surface impoundments.

The EPA has focused increasingly on the adverse ecological impact of coal combustion wastewater pollutants. In an October 2009 report, titled *Steam Electric Generating Point Source Category: Final Detailed Study Report,* the EPA summarizes its concerns as follows:

> An increasing amount of evidence indicates that the characteristics of coal combustion wastewater have the potential to impact human health and the environment. Many of the common pollutants found in coal combustion wastewater (e.g. selenium, mercury, and arsenic) are known to cause environmental harm and can potentially represent a human health risk. Pollutants in coal combustion wastewater are of particular concern because they can occur in large quantities (i.e., total pounds) and at high concentrations...in discharges and leachate to groundwater and surface waters. In addition, some pollutants in coal combustion wastewater present an increased ecological threat due to their tendency to persist in the environment and bioaccumulate in organisms. (Ibid., page 6-2).

By way of example, the EPA cites the discharge by Duke Power of ash pond effluent into a cooling reservoir at its Belews Creek power plant in North Carolina. Before Duke commenced the discharges in 1974, there were 19 fish species living in the reservoir; by 1975, morphological abnormalities were reported in all 19 species; by 1976, several species experienced complete reproductive failure; by 1978, only four species survived. Morphological abnormalities and reproductive failure in the fish correlated with high whole-body concentrations of selenium from the coal ash effluent (Ibid., page 6-9).

The EPA has uncovered numerous cases of groundwater and surface water contamination by coal combustion wastes. In an August 2006 study, titled *Damage Case Assessment Under RCRA for Fossil Fuel Combustion Wastes*, the EPA found

24 proven cases of coal combustion wastes contaminating groundwater or surface water, and another 39 potential damage cases.

A second risk associated with wet handling and storage systems for coal combustion wastes is the failure of surface impoundments and the release of large quantities of coal ash waste. There are two categories of wet ash surface impoundments: depression impoundments, which are excavated or built around natural depressions, and diked impoundments, which are surrounded by man-made walls and are used when sub-surface conditions are unsuitable for the construction of an excavated impoundment.

The EPA classifies surface impoundments using National Inventory of Dams hazard potential ratings, which reflect the potential consequences of failure of the dam. A high hazard potential rating indicates that a failure will probably cause loss of life. (Importantly, these ratings do not reflect the probability of failure, but rather the likely consequences were a failure to occur.) Surface impoundments at 30 different locations have been assigned high hazard potential ratings.

This risk gained public attention, and the EPA's focus, in December 2008, when a dike ruptured at an 84-acre coal ash pond at the TVA's Kingston Fossil Plant in Tennessee. The failure of the dike released 1.1 billion gallons of coal ash slurry, covering some 300 acres of surrounding land, and flowing into the Emory and Clinch Rivers. Within a year of that event, the EPA had sent a draft proposal to regulate coal ash to the Office of Management and Budget (OMB) for review.

EPA's Proposed Regulations and the Estimated Cost of Compliance

On May 4, 2010, the EPA announced two proposed rules to regulate the disposal and management of coal ash from coal-fired power plants under the Resource Conservation and Recovery Act (RCRA). Perhaps most important to the utility industry are two things the regulations would not do. First, neither of the proposed rules would classify coal ash as a hazardous pollutant, thus requiring costly "cradle to grave" handling procedures. Second, EPA is not proposing to regulate the beneficial use of coal ash. EPA defines as "beneficial use" the use of coal ash in encapsulated form, such as in wallboard, concrete, roofing materials and bricks, where the coal ash is bound into products. (EPA considers certain uses of coal ash, such as to fill sand and gravel pits, and other large scale fill operations, as disposal and not as "beneficial use.")

The first proposed rule announced by the EPA, the "Subtitle C proposal," would regulate coal ash destined for disposal in a landfill or surface impoundment under Subtitle C of the RCRA. Subtitle C of RCRA allows the federal government to set requirements for the issuance of waste management permits and to monitor and enforce the requirements of such permits. The Subtitle C proposal would thus create a comprehensive program of federally enforceable requirements for waste management and disposal designed, in the EPA's words "to phase out the wet handling of coal ash and existing surface impoundments." Before the Subtitle C rule would become effective, however, states would need to adopt the rule, a process that could take several years.

The second proposed rule, the "Subtitle D proposal," would regulate coal ash destined for disposal in a landfill or surface impoundment under Subtitle D of the RCRA. Subtitle D of RCRA allows the federal government to set national criteria to guide states in the issuance of waste management permits. The Subtitle D option would not require these permit programs to be established, however, nor would any such permits be federally enforceable. The Subtitle D proposal would allow utilities to continue the wet handling of ash and the use of surface impoundments subject to locational standards, composite liner requirements, groundwater monitoring and corrective action standards, and requirements to address the stability of surface impoundments. While less Draconian in its approach, the Subtitle D proposal would nonetheless "create strong incentives to close these impoundments and transition to safer landfills which store coal ash in dry form."

Exhibit 81 presents a side-by-side comparison of the Subtitle C and Subtitle D options.

Exhibit 81 **Comparison of the Subtitle C and Subtitle D Options**

	Subtitle C Option	Subtitle D Option
Effective date	Timing depends on each state approval Could take several years	Six months after final rule is promulgated for most provision; certain provisions have a longer effective date
Enforcement	State and federal enforcement	Enforcement through citizen suits (states can act as citizens)
Corrective action	Monitored by authorized states and EPA	Self-implementing
Financial assurance	Yes	Considering subsequent rule using CERCLA 108 (b) Authority
Permit issuance	Federal requirement for permit issuance by states	No
Requirements for storage, including containers, tanks, and containment buildings	Yes	No
Surface Impoundments built before rule is finalized	Remove solids and meet land disposal restrictions; retrofit with a liner within five years of effective date Would effectively phase out use of existing surface impoundments	Must remove solids and retrofit with a composite liner or cease receiving coal ash within five years of effective date and close the unit
Surface Impoundments built after rule is finalized	Must meet Land Disposal Restrictions and liner requirements Would effectively phase out use of new surface impoundments	Must install composite liners No Land Disposal Restrictions
Landfills built before rule is finalized	No liner requirements, but require groundwater monitoring	No liner requirements, but require groundwater monitoring
Landfills built after rule is finalized	Liner requirements and groundwater monitoring	Liner requirements and groundwater monitoring
Requirements for closure and post-closure care	Yes Monitored by states and EPA	Yes Self-implementing

Source: EPA and Bernstein analysis.

While the two proposals have similar objectives, the ability of the federal government to set and enforce the conditions for waste management permits under the Subtitle C proposal is expected to result in higher utility compliance costs than under the Subtitle D proposal. The EPA's Regulatory Impact Analysis (RIA) estimates the average cost of compliance over the next 50 years to be $1.5 billion a year under the Subtitle C option and $0.6 billion a year under the Subtitle D option. These estimates include the costs of industry compliance as well as state and federal government oversight and enforcement costs. The difference in the cost estimates for the two options reflects the differences in assumed compliance rates and retrofit costs. In particular, the EPA's analysis assumes a 48% compliance rate under Subtitle D (where the EPA has no enforcement authority) versus a 100% compliance rate under Subtitle C.

To put these compliance costs in context, in 2009, the U.S. power industry's electricity revenues totaled $354 billion, according to the EIA, while the aggregate pretax income of the nation's investor-owned utilities totaled $48.5 billion, according to the Edison Electric Institute. Over 50 years at a 7% discount rate, the EPA estimates the present value of these compliance costs at $20.3 billion under the Subtitle C option and $8.1 billion under the Subtitle D option. By way of comparison, the combined market capitalization of all publicly traded U.S. electric utilities is some $420 billion.

Under either of the EPA's two proposals, the agency's long-term objective is to end the wet handling of coal ash and the use of surface impoundments (ash ponds) in favor dry ash storage in properly lined landfills. The EPA has identified approximately 100 coal-fired power plants that have wet ash handling or storage systems. The combined capacity of these plants, at almost 120 GW, is equivalent to one-third of U.S. coal-fired capacity (see Exhibit 82).

Exhibit 82 **Wet Ash Handling and Storage System at U.S. Coal-Fired Power Plants**

	Number of Plants	Capacity in MW
Fly ash settling pond	4	7,240
Bottom ash settling pond	37	44,700
Settling pond commingling fly and bottom ash	23	25,200
Settling pond, unknown whether commingled or not	10	9,690
Bottom ash dewatering bins	25	31,776
Total	99	118,606

Source: EPA and Bernstein analysis.

The gradual phase-out of wet ash handling and storage systems would imply significant conversion costs for these plants. The conversion of bottom ash gathering and transport systems at existing utility boilers can be particularly challenging from an engineering perspective — and at some units, conversion to dry ash handling systems may not be technically feasible. Fly ash gathering and transport systems also would have to be adapted, and wet ash impoundments would need to be replaced with dry ash landfills.

Estimates of the cost of conversion to dry ash handling systems are difficult to come by. Based on estimates provided by the Edison Electric Institute (EEI) and reports prepared by EOP Group, a consulting firm to the industry, we understand the average cost per unit of converting bottom ash handling systems to be some $20 million, the average cost per unit of converting fly ash handling systems to be $10-$15 million, and the cost of new landfills for the dry ash to be $30-$50 million.

EEI also notes that wet ash impoundments are frequently used to manage storm water and low volume effluents from power plants. EEI expects the EPA by 2012 to set performance standards that will require physical, chemical, and biological treatment of storm water discharge and low volume effluents. The cost of such waste water treatment facilities, the EEI estimates, is between $120 and $150 million per unit.

Which Utilities Are Most Exposed?

To assess which utilities are most exposed to these potential expenditures, we have used the Ventyx Global Energy database. This database identifies power plants with coal ash ponds, but does not track individual boilers designed with wet ash handling systems. We therefore have applied the EEI's estimates of the average per unit cost of conversion at the plant level, possibly underestimating the cost incurred to retrofit multiple boilers at a single plant.

However, at this stage in the regulatory process, when new, potentially costly environmental regulations are under consideration by the government, regulated industries have an incentive to overstate the expected cost of compliance in an effort to persuade government to adopt less stringent regulations. It is not known, moreover, whether wastewater treatment plants will be universally required as power plants convert to dry ash handling systems.

Given the uncertainties surrounding the estimated cost of compliance with new ash handling regulations, we would suggest that readers use our analysis to identify those companies that are likely to be most at risk, and to ballpark on a preliminary basis the potential scale of their exposure. Exhibit 83 presents our estimates of the cost of conversion to dry ash handling systems at the publicly traded U.S. utilities. In Exhibit 84, we list those companies operating wet ash handling systems at coal-fired power plants in jurisdictions where generation has been deregulated. Because these plants are not subject to regulation on a cost of service basis, the cost of conversion to dry ash handling may not be recoverable in rates.

Exhibit 83 **Estimated Cost of Conversion to Dry Ash Handling Systems by Utility ($ million)**

		Conversion to Dry Ash Handling		As % of Market Cap.		New Waste Water Treatment Plant		As % of Market Cap.	
Holding Company Name	Ticker	Low	High	Low	High	Low	High	Low	High
AES Corp (The)	AES	$60	$95	1%	1%	$80	$150	1%	2%
Allegheny Energy Inc	AYE	-	-	-	-	-	-	-	-
ALLETE Inc	ALE	-	-	-	-	-	-	-	-
Alliant Energy Corp	LNT	-	-	-	-	-	-	-	-
Ameren Corp	AEE	$480	$760	7%	12%	$720	$1,350	11%	21%
American Electric Power Co Inc	AEP	$740	$1,175	4%	7%	$1,280	$2,400	7%	14%
Avista Corp	AVA	-	-	-	-	-	-	-	-
Black Hills Corp	BKH	-	-	-	-	-	-	-	-
Calpine Corp	CPN	-	-	-	-	-	-	-	-
Central Vermont Public Service Corp	CV	-	-	-	-	-	-	-	-
Cleco Corp	CNL	$60	$95	3%	5%	$160	$300	9%	17%
CMS Energy Corp	CMS	$60	$90	2%	2%	$240	$450	6%	12%
Consolidated Edison Inc	ED	-	-	-	-	-	-	-	-
Constellation Energy Group	CEG	-	-	-	-	-	-	-	-
Dominion Resources Inc	D	$100	$160	0%	1%	$160	$300	1%	1%
DPL Inc	DPL	$80	$125	3%	4%	$160	$300	5%	10%
DTE Energy Co	DTE	$100	$160	1%	2%	$160	$300	2%	4%
Duke Energy Corp	DUK	$620	$975	3%	4%	$1,200	$2,250	5%	10%
Dynegy Inc	DYN	$300	$475	68%	107%	$400	$750	90%	169%
Edison International	EIX	$80	$130	1%	1%	$160	$300	1%	3%
El Paso Electric Co	EE	-	-	-	-	-	-	-	-
Empire District Electric Co (The)	EDE	$60	$95	8%	12%	$80	$150	10%	19%
Entergy Corp	ETR	-	-	-	-	-	-	-	-
Exelon Corp	EXC	-	-	-	-	-	-	-	-
FirstEnergy Corp	FE	$60	$95	1%	1%	$80	$150	1%	1%
Great Plains Energy Inc	GXP	$20	$30	0%	0%	$80	$150	0%	1%
IDACORP Inc	IDA	-	-	-	-	-	-	-	-
Integrys Energy Group Inc	TEG	-	-	-	-	-	-	-	-
Mirant Corp	MIR	$40	$65	1%	2%	$80	$150	2%	4%
NextEra Energy Inc	NEE	-	-	-	-	-	-	-	-
Northeast Utilities	NU	-	-	-	-	-	-	-	-
NorthWestern Corp	NWE	-	-	-	-	-	-	-	-
NRG Energy Inc	NRG	$60	$95	1%	2%	$80	$150	1%	3%
NSTAR	NST	-	-	-	-	-	-	-	-
NV Energy	NVE	-	-	-	-	-	-	-	-
OGE Energy Corp	OGE	-	-	-	-	-	-	-	-
Pepco Holdings Inc	POM	-	-	-	-	-	-	-	-
PG&E Corp	PCG	-	-	-	-	-	-	-	-
Pinnacle West Capital Corp	PNW	$80	$125	2%	3%	$160	$300	4%	7%
PNM Resources Inc	PNM	$20	$30	2%	3%	$80	$150	7%	13%
PPL Corp	PPL	$60	$95	0%	1%	$160	$300	1%	2%
Progress Energy Inc	PGN	$480	$760	4%	6%	$640	$1,200	5%	10%
Public Service Enterprise Group Inc	PEG	-	-	-	-	-	-	-	-
RRI Energy Inc	RRI	-	-	-	-	-	-	-	-
SCANA Corp	SCG	$60	$95	1%	2%	$80	$150	2%	3%
Sempra Energy	SRE	-	-	-	-	-	-	-	-
Southern Co	SO	$840	$1,335	3%	4%	$1,280	$2,400	4%	8%
TECO Energy Inc	TE	$40	$65	1%	2%	$80	$150	2%	4%
Westar Energy Inc	WR	$60	$95	2%	4%	$80	$150	3%	6%
Wisconsin Energy Corp	WEC	-	-	-	-	-	-	-	-
Xcel Energy Inc	XEL	$60	$95	1%	1%	$80	$150	1%	1%

Source: EEI, Ventyx and Bernstein analysis.

Exhibit 84 **Competitive Generators: Estimated Cost of Conversion to Dry Ash Handling Systems by Utility Relative to Market Capitalization ($ million)**

		Conversion to Dry Ash Handling		As % of Market Cap.		New Waste Water Treatment Plant		As % of Market Cap.	
Holding Company Name	Ticker	Low	High	Low	High	Low	High	Low	High
Dynegy Inc	DYN	$300	$475	32%	50%	$400	$750	42%	79%
Ameren Corp	AEE	$260	$410	4%	7%	$400	$750	7%	12%
Mirant Corp	MIR	$40	$65	2%	3%	$80	$150	4%	8%
Edison International	EIX	$80	$130	1%	1%	$160	$300	1%	3%
PPL Corp	PPL	$20	$30	0%	0%	$80	$150	1%	1%
FirstEnergy Corp	FE	$60	$95	0%	1%	$80	$150	1%	1%
Duke Energy Corp	DUK	$60	$95	0%	0%	$80	$150	0%	1%

Source: EEI, Ventyx and Bernstein analysis.

In Exhibit 85, we list those companies operating wet ash handling systems in jurisdictions where generation remains subject to regulation, and where, as a result, the capital cost of conversion to dry ash handling should be incorporated in regulated rate base. For these companies, not only is this capital expenditure likely to be recovered, but it may accelerate growth in rate base and thus in regulated earnings.

Among competitive generators, the cost of conversion to dry ash handling and storage could be very significant for Dynegy and, to a lesser extent, for Ameren and Mirant (see Exhibit 84). Generally among regulated utilities, the capital outlays associated with conversion to dry ash handling represent a small percentage of regulated rate bases. Such investments could represent a material opportunity for rate base growth, however, at Cleco, DPL, Empire District Electric, AEP, Duke, Progress, Southern, PNM Resources and CMS Energy (see Exhibit 85).

Exhibit 85 **Regulated Utilities: Estimated Cost of Conversion to Dry Ash Handling Systems by Utility Relative to Estimated Rate Base ($ million)**

		Conversion to Dry Ash Handling		As % of Rate Base		New Waste Water Treatment Plant		As % of Rate Base	
Holding Company Name	Ticker	Low	High	Low	High	Low	High	Low	High
Cleco Corp	CNL	$60	$95	3%	5%	$160	$300	9%	17%
DPL Inc	DPL	$80	$125	3%	5%	$160	$300	7%	13%
Empire District Electric Co (The)	EDE	$60	$95	5%	8%	$80	$150	6%	12%
American Electric Power Co Inc	AEP	$740	$1,175	3%	4%	$1,280	$2,400	5%	9%
Duke Energy Corp	DUK	$560	$880	2%	3%	$1,120	$2,100	4%	7%
Progress Energy Inc	PGN	$480	$760	3%	4%	$640	$1,200	3%	7%
Southern Co	SO	$840	$1,335	2%	3%	$1,280	$2,400	3%	6%
PNM Resources Inc	PNM	$20	$30	1%	1%	$80	$150	3%	6%
CMS Energy Corp	CMS	$60	$90	1%	1%	$240	$450	3%	5%
Ameren Corp	AEE	$220	$350	1%	2%	$320	$600	2%	4%
Pinnacle West Capital Corp	PNW	$80	$125	1%	2%	$160	$300	2%	4%
Westar Energy Inc	WR	$60	$95	1%	2%	$80	$150	2%	3%
DTE Energy Co	DTE	$100	$160	1%	2%	$160	$300	2%	3%
TECO Energy Inc	TE	$40	$65	1%	1%	$80	$150	1%	3%
Great Plains Energy Inc	GXP	$20	$30	0%	0%	$80	$150	1%	2%
SCANA Corp	SCG	$60	$95	1%	1%	$80	$150	1%	2%
NRG Energy Inc	NRG	$60	$95	1%	1%	$80	$150	1%	2%
Dominion Resources Inc	D	$100	$160	0%	1%	$160	$300	1%	1%
PPL Corp	PPL	$40	$65	0%	1%	$80	$150	1%	1%
Xcel Energy Inc	XEL	$60	$95	0%	1%	$80	$150	1%	1%
AES Corp (The)	AES	$60	$95	0%	0%	$80	$150	0%	1%

Source: EEI, Ventyx and Bernstein analysis.

California and New York Move to Require Cooling Towers, Raising Risks to Nuclear Generators

Overview

On May 4, 2010, California's State Water Resources Control Board issued regulations governing the intake by power plants of river and ocean water to cool steam from steam turbines. The new regulations mandate a 93% reduction in water intake, effectively requiring steam turbine generators to replace their "once-through" cooling water systems — which draw water from the ocean or rivers and then discharge it back into the ocean or rivers — with "closed-loop" systems that continuously re-circulate cooling water through the plant, requiring costly cooling towers to cool the heated water. California's decision follows a similar action by New York's Department of Environmental Conservation, which on March 10 proposed regulations that would also require cooling towers at the state's power plants. These decisions by New York and California, which together account for 8% of U.S. power output, may influence regulators in other states.

Cooling water intake by power plants is subject to federal regulation under Section 316(b) of the Clean Water Act, which requires that plants use "the best technology available for minimizing adverse environmental impact." Currently, however, there are no applicable EPA standards for implementing Section 316(b) for existing power plants. Moreover, the permitting of water intake structures under the Clean Water Act is managed in partnership with state environmental agencies, and the EPA has authorized 46 states to issue such permits directly. States are therefore implementing their own regulations to enforce Section 316(b).

In addition to this state action, the EPA is preparing national standards for implementing Section 316(b) at existing power plants, and plans to publish a Notice of Proposed Rulemaking early next year. The rulemaking process will likely extend through 2011. Pursuant to the Supreme Court's decision in *Entergy v. Riverkeeper,* the EPA is permitted, but is not required, to rely on cost-benefit analysis of alternative compliance options in setting national performance standards under 316(b). The EPA, therefore, could decide that cooling towers, while costly, are the "best technology available for minimizing adverse environmental impact," and require their installation by steam turbine generators nationally.

Investment Implications

Such a decision by the EPA, or similar decisions by environmental regulators in other states besides California and New York, could burden the power industry and individual utilities with significant compliance costs. We have identified 404 plants that potentially could be required to install cooling towers. The aggregate generation of these plants is 1,059 TWh, representing 27% of the total generation of the country. We have estimated the capital cost of retrofitting these power plants with cooling towers by examining (1) estimates made in state regulatory filings of the construction cost of cooling towers at nuclear power plants, and (2) the EPA's analysis of the projected cost of installing cooling towers at fossil-fueled power plants, published in a report titled, *Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule.*

If required by federal or state environmental regulations to install cooling towers at all generating units currently using once-through cooling, unregulated generators would be forced to incur capital expenditures representing a significant claim on distributable cash flow, putting a future drag on earnings in the form of increased depreciation and interest expense. For regulated utilities, by contrast, the cost of compliance with state and federal environmental regulations would generally be recoverable in rates. In a best-case scenario, these compliance costs could be capitalized in rate base, accelerating the growth of regulated earnings.

Among regulated utilities, DTE Energy (DTE) appears to face the largest potential cost, with required capital expenditures equivalent to 33% of estimated rate base. Capital expenditures equivalent to between 10% and 24% of estimated rate base could be required at regulated generating units owned by Dominion (D), Progress (PGN), Duke (DUK), Great Plains (GXP), Westar (WR), Entergy (ETR), PG&E (PCG), NextEra (NEE) and SCANA (SCG).

Among unregulated utilities, Dynegy (DYN), RRI Energy (RRI), and Mirant (MIR) could potentially incur the largest capital expenditures as a percentage of their market capitalization. For Dynegy, we estimate the capital expenditure required to install cooling towers would be equivalent to 204% of the company's market capitalization, while the cost to RRI Energy and Mirant is estimated at 58% and 49%, respectively. Also facing large potential capital expenditures, equivalent to between 19% and 43% of market capitalization, would be FirstEnergy (FE), Constellation (CEG), Exelon (EXC), Entergy (ETR) and PSEG (PEG).

Technical Background

Nuclear and coal-fired power plants use steam turbines to drive their power generators. In such plants, a boiler heated by a coal furnace or a nuclear reactor core produces steam to drive the turbine; exhaust steam from the turbine is then condensed and returned under pressure to the boiler. When equipped with "once-through" (or "open-loop") cooling systems, these plants will take in large amounts of water from a river, lake or ocean to condense the exhaust steam. The water is run through the condensers in a single pass and is discharged, a few degrees warmer, back into the river, lake or ocean.

The volume of cooling water used by such power plants is extremely large. The cooling water requirement of a single nuclear-generating unit, for example, can range from 300,000 to 1,100,000 gallons per minute. As a result, power plants account for one-half of U.S. water use.

Once-through cooling has a significant adverse environmental impact: As water flows into the cooling water intake structures of power plants, fish and shellfish are trapped against the screens that cover the structures (known as "impingement"), and smaller aquatic organisms are drawn into the cooling system ("entrainment"). Large power plants can thus kill millions of fish and billons of smaller organisms annually. In aggregate, the scale of this impact is huge: The 90 power plants using once-through-cooling on the Great Lakes, for example, are estimated to kill in excess of 40 million fish per year due to impingement.

To avoid these adverse environmental effects, power plants may limit the intake of cooling water by constructing a "closed-loop" system that re-uses the cooling water discharged from the plant's condenser. As it circulates through the condenser, the cooling water is heated by the exhaust steam; prior to re-use, it must be cooled in large, open air cooling towers. Poured from the top of the cooling tower and allowed to drip down over its internal surfaces, the water cools through contact with the air. While approximately 5% of the cooling water will be lost to evaporation, the remainder can be re-used in the condenser, limiting the need for additional water intake.

Legal Background

Cooling water intake by power plants is subject to federal regulation under Section 316(b) of the Clean Water Act, which requires that plants use "the best technology available for minimizing adverse environmental impact." The EPA has set national standards for compliance with Section 316(b), issuing regulations covering new onshore facilities (the "Phase I Rule," promulgated in 2001), regulations covering large existing power plants (the "Phase II Rule," promulgated in 2004), and regulations covering new offshore oil and gas extraction facilities (the "Phase III Rule," promulgated in 2006).

In January 2007, however, significant portions of the Phase II Rule governing existing power plants were set aside or remanded to the EPA by a decision of the Second Circuit Court of Appeals. The Phase II Rule had allowed power plants significant discretion in the choice of strategies to comply with Section 316(b), thereby seeking to limit the cost of compliance to the power industry. Thus, the Phase II Rule allowed power plants to design their cooling water intake structures so as to reduce the number of fish killed by impingement, or to replace fish killed in one water body by stocking another with fish. The Appeals Court determined that the provisions of the Phase II Rule that allowed plants to select among compliance options were not in accordance with the Clean Water Act. The court concluded that section 316(b), which requires plants to the use "the best technology available for minimizing adverse environmental impact" (BTA), "does not permit the EPA to choose the BTA on the basis of cost-benefit analysis."

On July 9, 2007, the EPA formally suspended the Phase II Rule, pending its preparation of new regulations stipulating how existing power plants must comply with Section 316(b) of the Clean Water Act. In the interim, the EPA stipulated that state-permitting agencies should use their best professional judgment in applying the requirement of the Clean Water Act that cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.

On April 14, 2008, the U.S. Supreme Court granted a petition filed by affected utilities to review the key element of the Second Circuit Court's opinion — that Section 316(b) of the Clean Water Act does not authorize the EPA to compare costs with benefits in determining the best available technology to minimize adverse environmental effects. On April 1, 2009, the Supreme Court overturned the Appeals Court's ruling, finding that it was indeed permissible for the EPA to rely on cost-benefit analysis in setting national performance standards for compliance with Section 316(b) (*Entergy v. Riverkeeper).*

In response to the Supreme Court's ruling, the EPA is preparing national standards for implementing Section 316(b) at existing power plants, and plans to publish a Notice of Proposed Rulemaking early next year. The rulemaking process will likely extend through 2011.

Until the EPA promulgates a new Phase II Rule, however, there are no applicable EPA standards for implementing Section 316(b) for existing power plants. Under the Clean Water Act, the permitting of water intake structures is managed in partnership with state environmental agencies, and the EPA has authorized 46 states to issue such permits directly. States are therefore implementing their own regulations to enforce Section 316(b).

On May 4, 2010, California's State Water Resources Control Board issued regulations governing the intake of river and ocean water by the state's power plants. The new regulations mandate a 93% reduction in water intake, effectively requiring steam turbine generators to replace their once-through cooling water systems with costly closed-loop cooling towers. California's decision follows a similar action by New York's Department of Environmental Conservation, which on March 10 proposed regulations that would also require cooling towers at the state's power plants. These decisions by New York and California, which together account for 8% of U.S. power output, may influence regulators in other states — and the EPA itself.

Importantly, the Supreme Court's April 1, 2009 decision in *Entergy v. Riverkeeper* allows but does not require the EPA to rely on cost-benefit analysis in promulgating regulations for existing power plants under Section 316(b). The EPA could decide, therefore, that cooling towers, while costly, are the "best technology available for minimizing adverse environmental impact," and require their installation by steam turbine generators nationally.

Methodology

The objective of the analysis in this chapter is to identify those power plants potentially subject to such a requirement and to estimate the cost of installing cooling towers at these facilities. We also assess the financial impact of these capital expenditures on individual utilities. For unregulated generators, the cost of installing cooling towers at existing power plants may represent a significant claim on distributable cash flow and a future drag on earnings in the form of increased depreciation and interest expense. For regulated utilities, by contrast, the cost of compliance with state or federal environmental regulations would generally be recoverable in rates. In a best-case scenario, these compliance costs could be capitalized in rate base, accelerating the growth of regulated earnings.

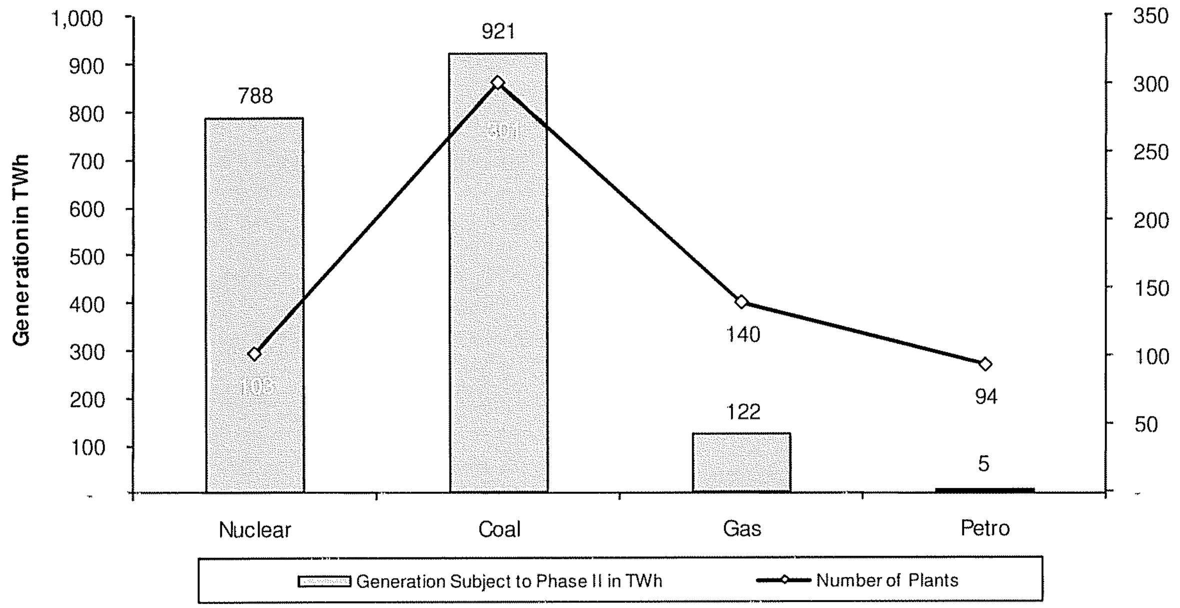
The EPA's Phase II Rule would have regulated all power plants with water intake in excess of 50 million gallons per day (MGD). On the assumption that future federal and state regulations will adopt a similar standard, our analysis focuses on those power plants subject to regulation under the EPA's Phase II Rule. Currently, there are 651 power generating units in the United States with water intake in excess of 50 MGD, and of these, 404 are not equipped with closed-looped cooling systems (cooling towers).

To estimate the capital costs of installing cooling towers at these plants, we have taken two approaches. For nuclear power plants, we have examined the estimates made in state regulatory filings in New York, California and New Jersey, where state environmental authorities have taken steps to require the construction of cooling towers at nuclear plants. For fossil-fueled power plants, we have relied on the EPA's analysis of the projected cost of installing cooling towers, titled *Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule.*

Characteristics of the Affected Facilities

In Exhibit 86 through Exhibit 90, we analyze the characteristics of the generating units subject to the EPA's Phase II Rule. The 651 generating units subject to the Phase II Rule produced 1,836 TWh in 2009, or 46% of total U.S. generation. Exhibit 86 breaks down this generation by fuel type (not shown on the chart are 13 other types of plants). Some 301 coal-fired units account for half of the affected generation, or some 921 TWh. There are 103 nuclear-generating units that account for 788 TWh of the affected generation, or 43% or the total. Another 7%, or 122 TWh, is accounted for by 140 gas-fired steam turbines and 5 TWh by 94 oil-fired plants.

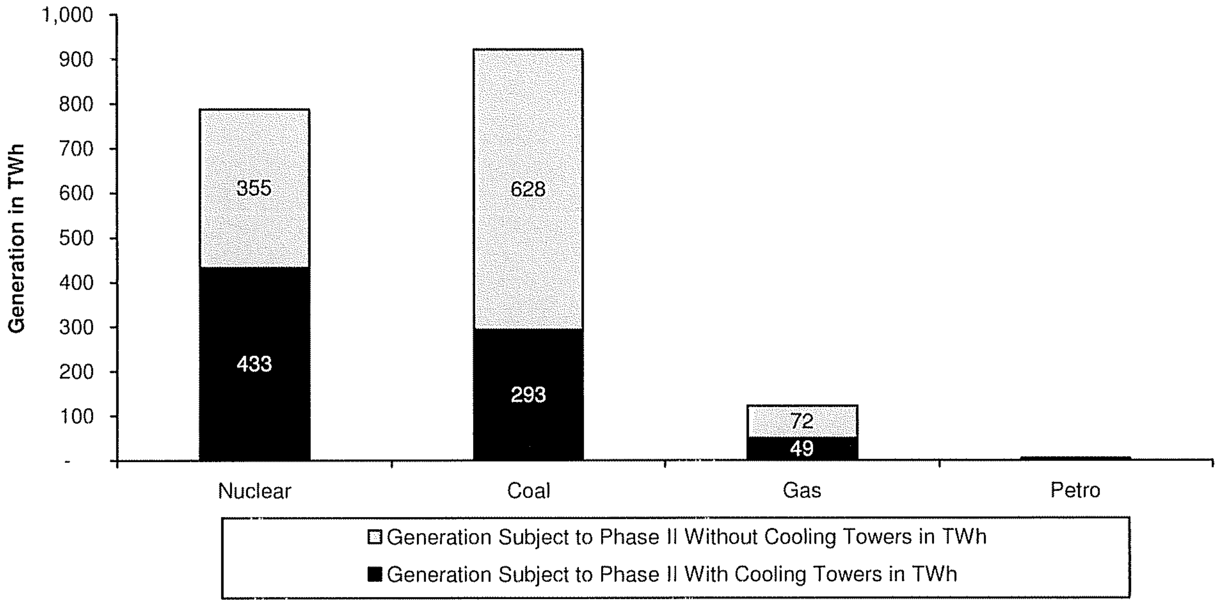
Exhibit 86 — Generation Subject to the EPA's Phase II Rule (Greater Than 50 MGD Water Intake)



Source: EPA, Global Energy and Bernstein analysis.

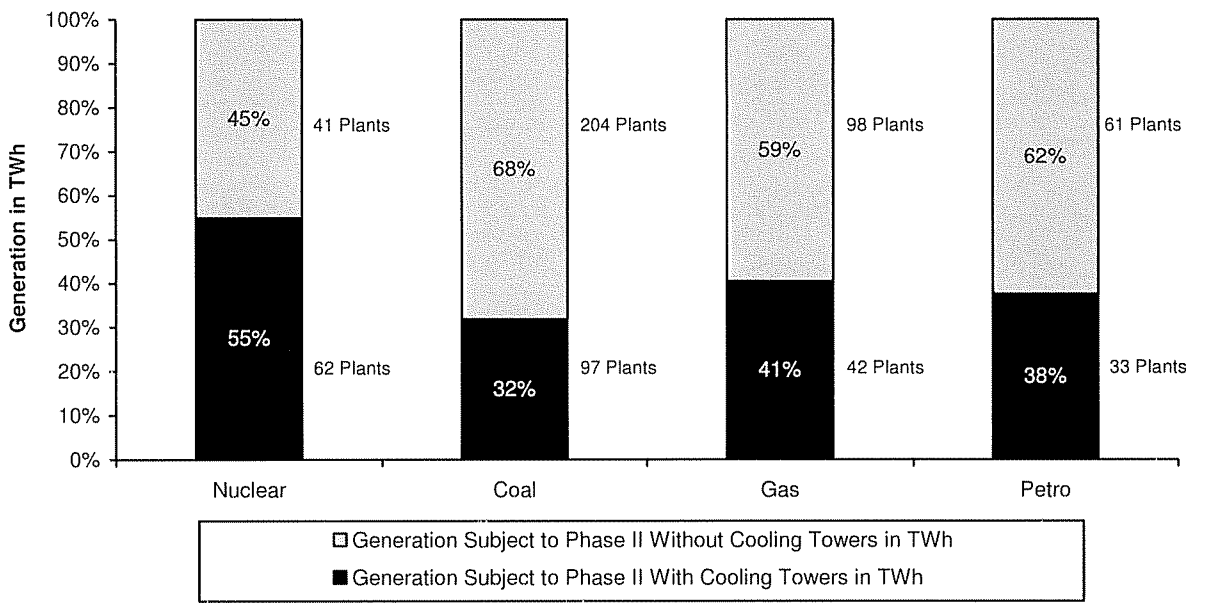
Of the 1,836 TWh produced at plants subject to the Phase II Rule, 778 TWh is generated at units that lack close-loop cooling systems (cooling towers) and rely instead on once-through cooling. This is equivalent to 20% of total U.S. power generation in 2009. Exhibit 87 and Exhibit 88 break down the units subject to the rule and show the percentage of generation by fuel category that is equipped or not equipped with closed-loop cooling systems. Generating units lacking cooling towers comprise 204 coal-fired plants with 628 TWh of generation, 41 nuclear plants with 355 TWh, 98 gas-fired plants with 72 TWh, and 61 oil-fired plants with only 3 TWh. Considered as a percentage of national generation, the output of these units is equivalent to 36% of U.S. coal-fired generation, 45% of U.S. nuclear generation, 8% of gas-fired generation and 23% of oil-fired generation.

Exhibit 87 **Generation Subject to the EPA's Phase II Rule from Units Equipped With Cooling Towers and from Units Relying on Once-Through Cooling Systems**



Source: EPA, Global Energy and Bernstein analysis.

Exhibit 88 **Percentage of Generation Subject to the EPA's Phase II Rule from Units Equipped With Cooling Towers and from Units Relying on Once-Through Cooling Systems**

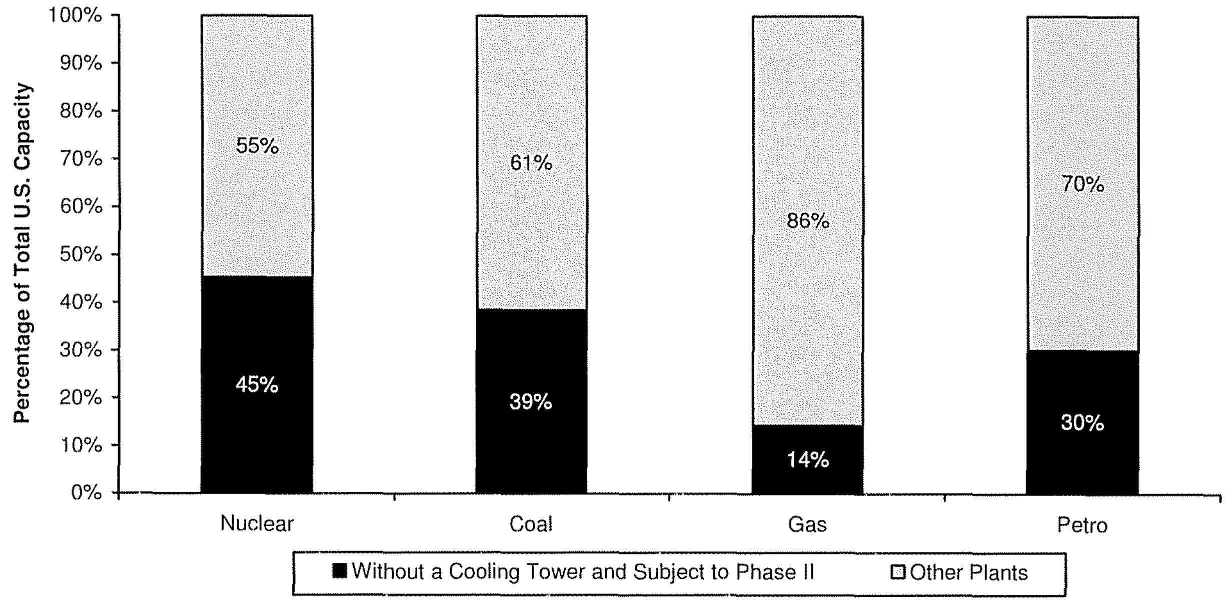


Source: EPA, Global Energy and Bernstein analysis.

Exhibit 89 and Exhibit 90 present the capacity and power output of the units subject to the Phase II Rule that lack closed-loop cooling systems, expressed as a percentage of the nation's total capacity and generation. As can be seen there, 39% of the U.S. coal-fired capacity, accounting for 36% of total coal-fired generation, lacks closed-loop cooling systems. Similarly, 45% of the U.S. nuclear capacity, accounting for 45% of the U.S. nuclear generation, lacks the systems. Of the nation's gas-fired capacity, 14% lacks closed-loop cooling systems, accounting for 8% of total gas-fired generation, while 30% of the U.S. oil-fired capacity and 23%

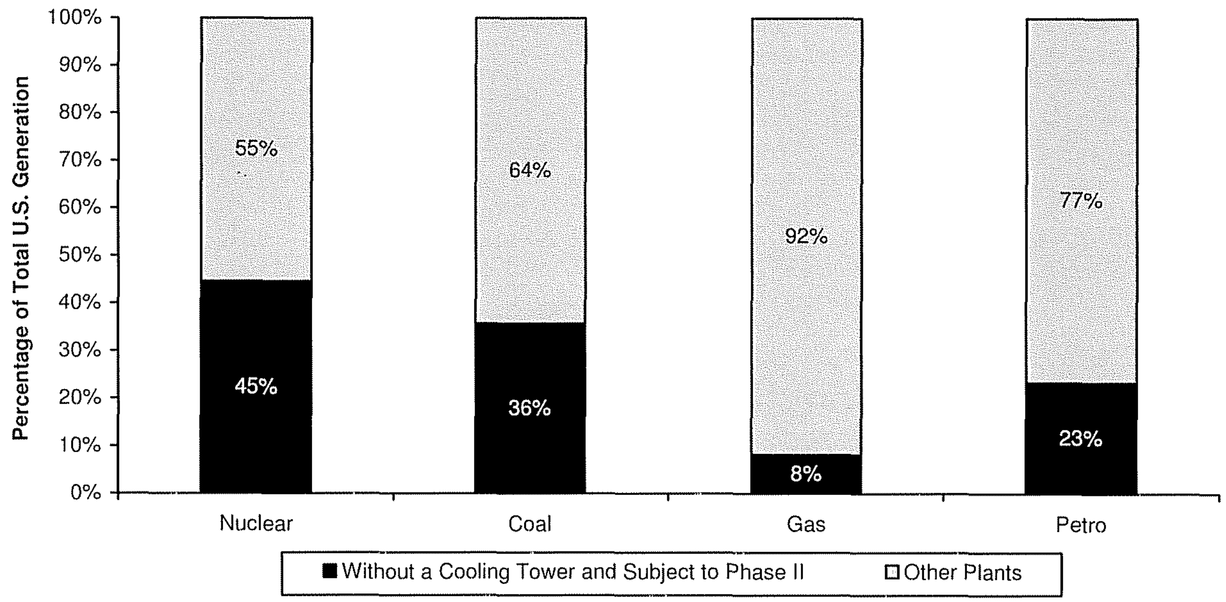
of the generation lacks cooling towers. In aggregate, the generation of those units lacking closed-loop cooling systems totals 1,059 TWh, or 27% of the total generation of the country.

Exhibit 89 **Units That Lack Cooling Towers and Are Subject to the EPA's Phase II Rule, Expressed as a Percentage of Total Operating Capacity — By Fuel**



Source: EPA, Global Energy and Bernstein analysis.

Exhibit 90 **Generation from Units That Lack Cooling Towers and Are Subject to the EPA's Phase II Rule, Expressed as a Percentage of Total Generation — By Fuel**



Source: EPA, Global Energy and Bernstein analysis.

Which Utilities Are Potentially at Risk?

Exhibit 91 and Exhibit 92 assess the exposure of U.S. regulated utilities to potential future environmental regulations requiring plants with open-loop cooling systems to install cooling towers to minimize the environmental impact of their water withdrawals.

As can be seen in Exhibit 91, 92% of Great Plains Energy's generation would require cooling towers under such regulation, as would 85% of the generation of DTE Energy and 74% of the generation of CMS Energy. Also lacking closed-loop cooling systems on units responsible for more than 50% of their generation are Northeast Utilities, Duke Energy, PG&E and Dominion. Exhibit 92 shows the capacity of the affected regulated power plants owned by each utility, broken down by fuel type.

Exhibit 91 **Regulated Generation from Units Lacking Cooling Towers and Subject to the EPA's CWA §316(b) Phase II Rule — By Holding Company and by Fuel Type**

		Generation Subject to Retrofit in GWh					Total Operating	
Holding Company Name	Ticker	Nuclear	Coal	Gas	Petro	Total	Generation in GWh	% of Total
Great Plains Energy Inc	GXP	4,121	18,081	193	-	22,396	24,369	92%
DTE Energy Co	DTE	-	40,756	58	(3)	40,811	48,149	85%
CMS Energy Corp	CMS	-	14,585	0	0	14,585	19,626	74%
Northeast Utilities	NU	-	2,411	-	173	2,583	3,731	69%
Duke Energy Corp	DUK	39,907	54,361	(1)	0	94,267	139,107	68%
PG&E Corp	PCG	16,236	-	-	-	16,236	24,752	66%
Dominion Resources Inc	D	30,964	26,968	2,614	1	60,546	110,151	55%
Ameren Corp	AEE	-	36,378	0	-	36,378	74,871	49%
TECO Energy Inc	TE	-	8,310	13	-	8,323	18,422	45%
Wisconsin Energy Corp	WEC	-	5,828	2,273	(3)	8,098	18,358	44%
Alliant Energy Corp	LNT	-	6,905	-	-	6,905	15,868	44%
Progress Energy Inc	PGN	29,408	933	4,213	196	34,750	91,245	38%
SCANA Corp	SCG	4,582	1,373	3,605	-	9,559	26,177	37%
Westar Energy Inc	WR	4,121	4,622	-	-	8,744	27,555	32%
Cleco Corp	CNL	-	2,562	-	-	2,562	8,822	29%
OGE Energy Corp	OGE	-	6,558	-	-	6,558	27,962	23%
ALLETE Inc	ALE	-	1,568	-	-	1,568	7,329	21%
Integrys Energy Group Inc	TEG	-	1,982	3	-	1,984	9,690	20%
Sempra Energy	SRE	3,100	-	-	-	3,100	17,133	18%
American Electric Power Co Inc	AEP	8,326	18,785	162	-	27,273	168,798	16%
NextEra Energy Inc	NEE	20,453	-	3,761	48	24,262	151,584	16%
Edison International	EIX	12,122	-	-	-	12,122	78,909	15%
Entergy Corp	ETR	8,949	-	9,807	-	18,756	126,906	15%
Empire District Electric Co (The)	EDE	-	459	-	-	459	3,141	15%
NorthWestern Corp	NWE	-	345	-	-	345	2,670	13%
AES Corp (The)	AES	-	-	2,795	-	2,795	40,213	7%
Southern Co	SO	-	9,640	45	(14)	9,671	182,508	5%
Xcel Energy Inc	XEL	-	1,282	783	-	2,065	71,126	3%
PPL Corp	PPL	-	1,050	-	-	1,050	50,291	2%
NV Energy	NVE	-	-	313	-	313	22,317	1%
Allegheny Energy Inc	AYE	-	80	-	-	80	31,356	0%

Source: EPA, Global Energy and Bernstein analysis.

Exhibit 92 **Regulated Generation Capacity Lacking Cooling Towers and Subject to the EPA's CWA §316(b) Phase II Rule — By Holding Company and by Fuel Type**

		Capacity Subject to Retrofit in MW					Total Operating	% of
Holding Company Name	Ticker	Nuclear	Coal	Gas	Petro	Total	Capacity in MW	Total
Northeast Utilities	NU	-	433	-	434	866	1,130	77%
Great Plains Energy Inc	GXP	545	2,863	417	-	3,825	5,840	66%
DTE Energy Co	DTE	-	7,004	459	50	7,512	11,485	65%
Wisconsin Energy Corp	WEC	-	1,505	1,120	3	2,628	5,691	46%
Duke Energy Corp	DUK	4,738	10,767	213	93	15,811	34,924	45%
Dominion Resources Inc	D	3,768	5,286	397	127	9,578	24,486	39%
PG&E Corp	PCG	2,300	-	-	-	2,300	5,911	39%
TECO Energy Inc	TE	-	1,550	60	-	1,610	4,279	38%
CMS Energy Corp	CMS	-	2,518	13	13	2,544	7,379	34%
Ameren Corp	AEE	-	5,422	108	-	5,530	16,148	34%
Entergy Corp	ETR	1,176	-	8,261	-	9,437	29,524	32%
Progress Energy Inc	PGN	3,751	174	1,875	460	6,260	21,923	29%
SCANA Corp	SCG	644	344	559	-	1,547	5,530	28%
Alliant Energy Corp	LNT	-	1,555	-	-	1,555	6,100	25%
ALLETE Inc	ALE	-	341	-	-	341	1,372	25%
Integrys Energy Group Inc	TEG	-	431	83	-	514	2,341	22%
AES Corp (The)	AES	-	-	2,449	-	2,449	11,605	21%
Cleco Corp	CNL	-	590	-	-	590	3,105	19%
Westar Energy Inc	WR	545	709	-	-	1,254	7,005	18%
Sempra Energy	SRE	450	-	-	-	450	2,702	17%
American Electric Power Co Inc	AEP	1,077	4,802	268	-	6,147	37,266	16%
OGE Energy Corp	OGE	-	1,046	-	-	1,046	7,102	15%
NextEra Energy Inc	NEE	2,579	-	2,431	565	5,575	39,510	14%
Edison International	EIX	1,760	-	-	-	1,760	14,831	12%
NorthWestern Corp	NWE	-	56	-	-	56	542	10%
Southern Co	SO	-	2,519	675	250	3,443	41,546	8%
Xcel Energy Inc	XEL	-	282	1,046	-	1,328	16,339	8%
Empire District Electric Co (The)	EDE	-	78	-	-	78	1,239	6%
NV Energy	NVE	-	-	226	-	226	5,586	4%
Allegheny Energy Inc	AYE	-	235	-	-	235	9,465	2%
PPL Corp	PPL	-	154	-	-	154	9,854	2%

Source: EPA, Global Energy and Bernstein analysis.

Exhibit 93 and Exhibit 94 assess the exposure of U.S. unregulated utilities to potential future regulations requiring plants with open-loop cooling systems to install cooling towers to minimize the environmental impact of their water withdrawals.

As can be seen in Exhibit 93, 61% of Mirant's generation, 47% of Constellation's, 43% of Exelon's, 41% of PSEG's and 40% RRI Energy's comes from units that lack closed-loop cooling systems. Also exposed to a potential future cooling tower requirement, with between 20% and 30% of their generation from units lacking closed-loop cooling systems, are Dynegy, FirstEnergy, Dominion, Pepco, Entergy and DPL. Exhibit 94 shows the capacity of the unregulated generating units that lack cooling towers, broken down by utility and fuel type.

Exhibit 93 **Unregulated Generation from Units Lacking Cooling Towers and Subject to the EPA's CWA §316(b) Phase II Rule, by Holding Company and by Fuel Type**

		Generation Subject to Retrofit in GWh					Total Operating	
Holding Company Name	Ticker	Nuclear	Coal	Gas	Petro	Total	Generation in GWh	% of Total
Consolidated Edison Inc	ED	-	-	2,450	-	2,450	2,451	100%
Mirant Corp	MIR	-	9,698	172	571	10,441	17,188	61%
Constellation Energy Group	CEG	19,181	3,272	-	0	22,453	47,426	47%
Exelon Corp	EXC	60,623	2,565	1,187	0	64,375	148,987	43%
Public Service Enterprise Group Inc	PEG	20,586	3,848	31	115	24,579	59,843	41%
RRI Energy Inc	RRI	-	8,589	786	1	9,376	23,346	40%
Dynegy Inc	DYN	-	7,634	5,234	432	13,299	43,707	30%
FirstEnergy Corp	FE	-	18,340	-	0	18,340	63,728	29%
Dominion Resources Inc	D	16,041	15,417	-	0	31,458	110,151	29%
Pepco Holdings Inc	POM	-	1,093	-	0	1,093	4,365	25%
Entergy Corp	ETR	29,335	-	-	-	29,335	126,906	23%
DPL Inc	DPL	-	3,442	-	-	3,442	15,677	22%
Edison International	EIX	-	14,783	-	1	14,784	78,909	19%
PPL Corp	PPL	-	8,864	-	0	8,864	50,291	18%
Ameren Corp	AEE	-	12,876	-	-	12,876	74,871	17%
AES Corp (The)	AES	-	6,897	-	-	6,897	40,213	17%
NRG Energy Inc	NRG	-	4,652	4,087	34	8,773	66,169	13%
Duke Energy Corp	DUK	-	10,042	-	(0)	10,042	139,107	7%
American Electric Power Co Inc	AEP	-	10,149	364	-	10,513	168,798	6%
NextEra Energy Inc	NEE	7,779	-	-	-	7,779	151,584	5%
Allegheny Energy Inc	AYE	-	1,503	-	-	1,503	31,356	5%

Source: EPA, Global Energy and Bernstein analysis.

Exhibit 94 **Capacity of Unregulated Generating Units Lacking Cooling Towers and Subject to the EPA's CWA §316(b) Phase II Rule, by Holding Company and by Fuel Type**

		Capacity Subject to Retrofit in MW						
Holding Company Name	Ticker	Nuclear	Coal	Gas	Petro	Total	Total Operating Capacity in MW	% of Total
Consolidated Edison Inc	ED	-	-	615	-	615	690	89%
Mirant Corp	MIR	-	2,272	1,400	1,374	5,046	10,046	50%
Exelon Corp	EXC	9,084	1,693	2,060	63	12,900	26,723	48%
Constellation Energy Group	CEG	2,358	1,334	-	28	3,720	8,362	44%
RRI Energy Inc	RRI	-	2,601	2,580	180	5,361	12,567	43%
Dynegy Inc	DYN	-	1,331	4,000	1,239	6,570	17,146	38%
FirstEnergy Corp	FE	-	4,979	-	64	5,043	13,296	38%
Public Service Enterprise Group Inc	PEG	2,435	2,085	453	697	5,670	15,689	36%
NRG Energy Inc	NRG	-	910	4,401	494	5,805	22,780	25%
Dominion Resources Inc	D	1,946	3,436	-	9	5,392	24,486	22%
Edison International	EIX	-	2,622	-	305	2,927	14,831	20%
Pepco Holdings Inc	POM	-	863	-	13	876	4,562	19%
DPL Inc	DPL	-	567	-	-	567	3,621	16%
PPL Corp	PPL	-	1,442	-	8	1,450	9,854	15%
Entergy Corp	ETR	3,582	-	-	-	3,582	29,524	12%
Ameren Corp	AEE	-	1,916	-	-	1,916	16,148	12%
AES Corp (The)	AES	-	1,325	-	-	1,325	11,605	11%
Allegheny Energy Inc	AYE	-	886	-	-	886	9,465	9%
American Electric Power Co Inc	AEP	-	1,720	488	-	2,208	37,266	6%
Duke Energy Corp	DUK	-	1,742	-	243	1,985	34,924	6%
NextEra Energy Inc	NEE	1,099	-	-	-	1,099	39,510	3%

Source: EPA, Global Energy and Bernstein analysis.

Four Major Cooling Methods

Four major types of cooling methods are most commonly used by the power industry (see Exhibit 95).

Open-loop cooling. In open-loop cooling systems (also called "once-through systems"), the cooling water is withdrawn from a local body of water such as a lake, river or ocean, and the warm cooling water is subsequently discharged back to the same water body after passing through a surface condenser. Because cooling water is continuously withdrawn from the water source, plants equipped with once-through cooling systems have high volumes of water withdrawal and a commensurately high environmental impact.

Closed-loop. Closed-loop or recirculating cooling systems use wet cooling towers to dissipate heat into the atmosphere. Cooling water from the condenser is dropped from the top of a cooling tower, transferring heat to the ambient air through evaporation and releasing the heat in the water into the atmosphere. The water falls downward over surfaces in the tower, increasing the contact time between the water and the air. This helps maximize heat transfer between the two. Wet cooling towers are available in two basic designs: (1) natural draft wet process and (2) mechanical draft wet process. Natural draft towers rely on the difference in air density between the warm air in the tower and the cooler ambient air outside the tower to draw air up through the tower, while mechanical draft towers utilize a fan to move ambient air through the tower. Natural draft designs use very large concrete chimneys to introduce air through the water. Due to the tremendous size of these towers (500 feet high and 400 feet in diameter at the base), they are generally only used for large utility power stations. Mechanical draft cooling towers are much smaller in scale and utilize large fans to force air through circulated water.

Dry cooling. Dry cooling systems can use either a direct or indirect air cooling process. In direct dry cooling, exhaust steam from a power plant's steam turbines flows through tubes of an air-cooled condenser (ACC) where the steam is cooled directly via conductive heat transfer using a high flow rate of ambient air that is blown by fans across the outside surface of the tubes. Indirect air cooling uses a conventional water-cooled surface condenser to condense the turbine exhaust steam, but a dry cooling tower is used to transfer the heat from the cooling water to the ambient air. In a dry cooling tower, there is no direct contact between the heated water and the air; rather, as in an automobile radiator, air flows over pipes containing the heated water.

Hybrid cooling. Hybrid cooling systems use a combination of the above-mentioned cooling methods. For example, a plant may utilize both once-through and closed-loop technology. Or a plant could have installed both a dry cooling system for normal use, and a wet cooling system for heavy cooling needs in the summer.

Exhibit 95 **Major Cooling Methodologies Used by Power Plants**

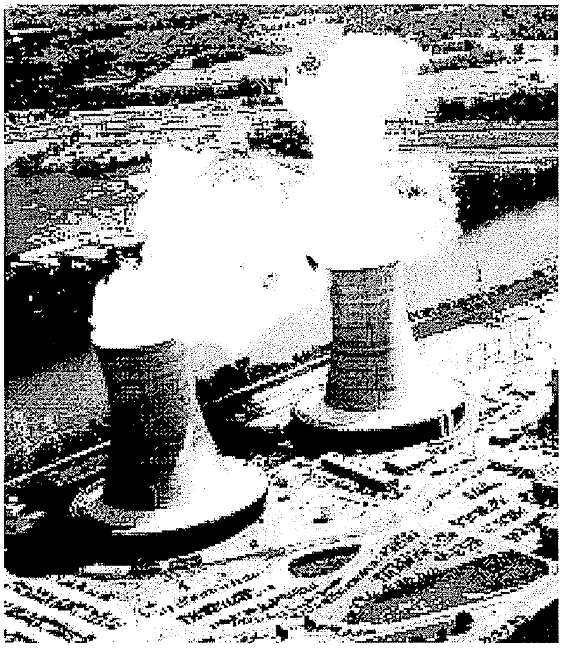
	Water cooling			
	Open loop	Closed loop	Dry cooling	Hybrid cooling
Water withdrawn	Largest	Small	None	Closed loop in summer
Cooling performance	Best	Good	Inconsistent	Okay
Environmental impact	Huge	Small	Smallest	Small
Capital costs	Low	High	Modest	High

Source: Bernstein analysis.

Potential future environmental regulations prohibiting once-through cooling systems would leave power plants with two compliance options: installing wet cooling towers or dry cooling technology. While air cooling technology involves a lower capital cost than wet cooling towers, it is far less effective at cooling exhaust steam, resulting in reduced power generation output. This is particularly true during the hot summer months, when power prices are the highest. It is likely, therefore, that utilities will favor wet cooling towers for retrofitting existing power plants.

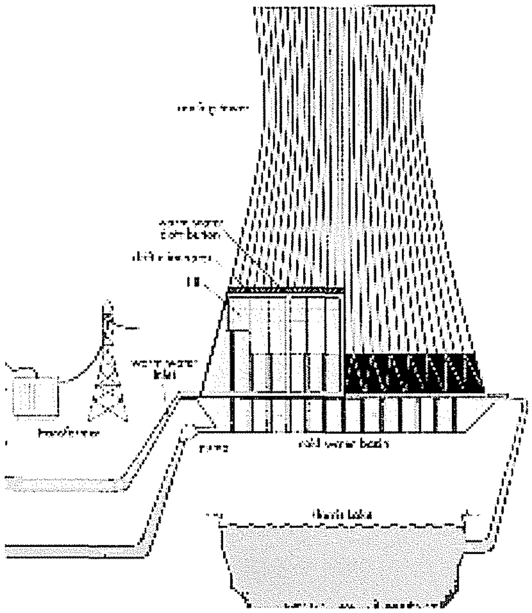
As noted above, there are two major types of wet process cooling towers: natural draft wet process cooling towers and mechanical draft wet process cooling towers. Exhibit 96 and Exhibit 97 shows two natural draft wet process cooling towers at the Three Mile Island nuclear plant and a simplified schematic of such cooling towers. Exhibit 98 and Exhibit 99 shows an array of mechanical draft wet process cooling towers and a simplified schematic of mechanical draft cooling towers.

Exhibit 96 Natural Draft Wet Process Cooling Towers at the Three Mile Island Nuclear Plant



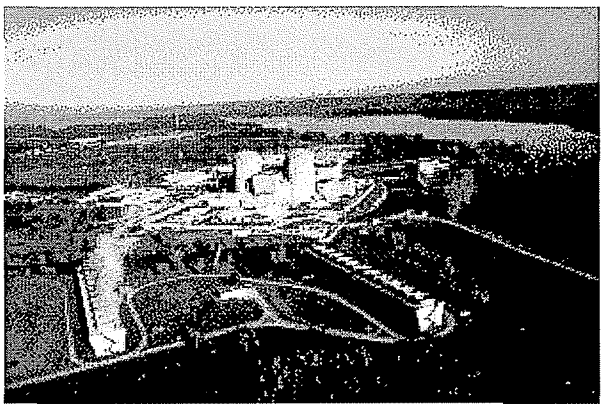
Source: NuclearTourist.com.

Exhibit 97 Natural Draft Wet Process Cooling Tower Schematics



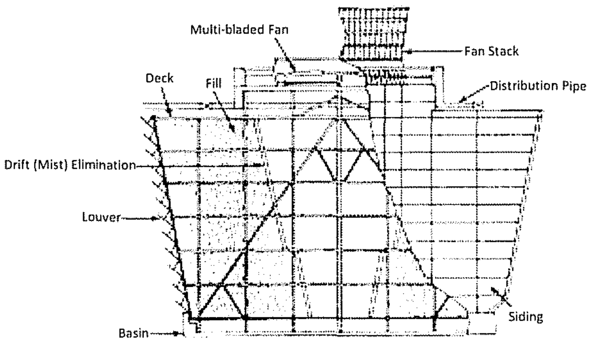
Source: NuclearTourist.com.

Exhibit 98 Mechanical Draft Wet Process Cooling Towers (Foreground)



Source: NuclearTourist.com.

Exhibit 99 Mechanical Draft Wet Process Cooling Tower Schematics



Source: gc3.com.

Estimating the Cost of Compliance

The capital costs of retrofitting a power plant with cooling towers are a function of a variety of factors, including: (1) the capacity of the plant and the volume of cooling water it requires; (2) construction costs, including raw materials and labor; and (3) space constraints on construction.

We have taken two approaches to estimating the likely cost of such retrofits. One is for nuclear plants, and the other is for fossil-fueled plants.

For nuclear power plants, we have examined the estimates made in state regulatory filings in New York, California and New Jersey, where state environmental authorities have taken steps to require the construction of cooling towers at nuclear plants. Estimates of the cost of installing cooling towers at nuclear power plants are presented in Exhibit 100.

Exhibit 100 **Estimated Cooling Tower Costs for Nuclear Power Plants**

Owner	Plant	Owned Capacity (MW)	Estimated Upgrade Cost $ Million	Estimated Upgrade Cost $ per kW
Constellation	Ginna	581	$189	$325
Exelon	Salem	981	$500	$510
Exelon	Oyster Creek	615	$750	$1,221
Entergy	James Fitzpatrick	852	$240	$282
Entergy	Indian Point	2,045	$1,079	$528
Edison International	San Onofre	2,250	$3,000	$1,333
PG&E	Diablo Canyon	2,300	$4,500	$1,957
Average		9,623	$10,258	$1,066

Source: Corporate reports and Bernstein analysis.

For fossil-fueled power plants, we have relied on the EPA's analysis of the projected cost of installing cooling towers, titled *Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule.* Exhibit 101 presents the equation found that EPA study, which derives dry cooling tower cost based on the generating unit's water intake. In this equation, X is the water inflow in gallons-per-minute. This equation is applied for dry cooling towers leaving less than a 5°F differential between the water inflow and outflow temperature. When applied to historical cost data points, this equation produces an R-squared of 99.9%. We applied the results of this equation to thermal generating units using fossil fuels.

Exhibit 101 **Equation to Determine Cooling Tower Costs for Fossil Fuel Plants**

$$\text{Capital Cost} = -2 \times 10^3 X^3 + 0.00002 X^2 + 337.56 X + 973608$$

$$R^2 = 0.9989$$

Where X is the water intake flow in gpm

Source: EPA and Bernstein analysis.

Based on these cost estimates, we have assessed the potential cost to individual utilities of retrofitting power plants with cooling towers. For unregulated generators, the cost of installing cooling towers at existing power plants may represent a significant claim on distributable cash flow and a future drag on earnings in the form of increased depreciation and interest expense. For regulated utilities, by contrast, the cost of compliance with state or federal environmental regulations would generally be recoverable in rates. In a best-case scenario, these compliance costs could be capitalized in rate base, accelerating the growth of regulated earnings.

Exhibit 102 presents our estimate of the potential cost of retrofitting regulated power plants with cooling towers, broken down by holding company. As can be seen there, DTE Energy appears to have the largest exposure among regulated utilities, with required capital expenditures equivalent to 33% of estimated rate base. Capital expenditures equivalent to between 10% and 24% of estimated rate base could be required at Dominion, Progress, Duke, Great Plains, Westar, Entergy, PG&E, and NextEra Energy.

Exhibit 102 **Estimated Cooling Tower Capital Costs at Affected Regulated Facilities — By Holding Company**

			Capital Cost Required to Install Cooling Towers	
Holding Company Name	Ticker	Rate Base ($ million)	$ Million	As % of Rate Base
DTE Energy Co	DTE	$10,633	$3,505	33%
Dominion Resources Inc	D	$21,458	$5,223	24%
Progress Energy Inc	PGN	$19,800	$4,227	21%
Duke Energy Corp	DUK	$39,060	$6,834	17%
Great Plains Energy Inc	GXP	$6,144	$1,007	16%
Westar Energy Inc	WR	$4,964	$686	14%
Entergy Corp	ETR	$15,778	$2,168	14%
PG&E Corp	PCG	$24,215	$2,453	10%
NextEra Energy Inc	NEE	$32,336	$3,167	10%
American Electric Power Co Inc	AEP	$28,047	$2,463	9%
Edison International	EIX	$22,966	$1,877	8%
SCANA Corp	SCG	$9,718	$766	8%
TECO Energy Inc	TE	$5,923	$398	7%
Ameren Corp	AEE	$14,932	$985	7%
ALLETE Inc	ALE	$1,357	$86	6%
Wisconsin Energy Corp	WEC	$8,250	$411	5%
Empire District Electric Co (The)	EDE	$1,274	$58	5%
Alliant Energy Corp	LNT	$6,424	$226	4%
Integrys Energy Group Inc	TEG	$4,299	$141	3%
CMS Energy Corp	CMS	$9,387	$298	3%
Sempra Energy	SRE	$17,403	$481	3%
Cleco Corp	CNL	$2,749	$37	1%
Southern Co	SO	$32,273	$390	1%
Northeast Utilities	NU	$7,665	$92	1%
Xcel Energy Inc	XEL	$15,222	$141	1%
AES Corp (The)	AES	$23,739	$192	1%
NorthWestern Corp	NWE	$1,854	$8	0%
Allegheny Energy Inc	AYE	$7,414	$30	0%
OGE Energy Corp	OGE	$4,752	$18	0%
NV Energy	NVE	$7,755	$27	0%
PPL Corp	PPL	$10,728	$15	0%

Source: Bernstein analysis.

Among unregulated utilities, Dynegy, RRI Energy and Mirant could potentially incur the largest capital expenditures as percentage of their market capitalization. Exhibit 103 shows that Dynegy could face a capital requirement to install cooling towers equivalent to 204% the company's market capitalization, while the cost to RRI Energy and Mirant is estimated at 58% and 49%, respectively. Also facing large potential capital expenditures, equivalent to between 19% and 43% of market capitalization, would be Constellation, FirstEnergy, Exelon, Entergy and PSEG.

Exhibit 103 **Estimated Cooling Tower Capital Costs at Affected Unregulated Facilities — By Holding Company**

Holding Company Name	Ticker	Rate Base ($ million)	Capital Cost Required to Install Cooling Towers: $ Million	Capital Cost Required to Install Cooling Towers: As % of Rate Base
Dynegy Inc	DYN	$444	$907	204%
RRI Energy Inc	RRI	$1,371	$792	58%
Mirant Corp	MIR	$1,583	$773	49%
Constellation Energy Group	CEG	$6,212	$2,679	43%
FirstEnergy Corp	FE	$11,495	$4,357	38%
Exelon Corp	EXC	$27,868	$10,073	36%
Entergy Corp	ETR	$14,903	$3,822	26%
Public Service Enterprise Group Inc	PEG	$16,393	$3,097	19%
NRG Energy Inc	NRG	$5,881	$940	16%
Dominion Resources Inc	D	$25,657	$2,686	10%
Edison International	EIX	$10,983	$772	7%
DPL Inc	DPL	$3,049	$213	7%
NextEra Energy, Inc	NEE	$22,085	$1,173	5%
Ameren Corp	AEE	$6,443	$291	5%
Allegheny Energy Inc	AYE	$3,943	$129	3%
AES Corp (The)	AES	$8,487	$256	3%
Pepco Holdings Inc	POM	$3,846	$114	3%
American Electric Power Co Inc	AEP	$17,456	$466	3%
Duke Energy Corp	DUK	$22,946	$425	2%
PPL Corp	PPL	$12,903	$194	2%
Consolidated Edison Inc	ED	$13,312	$64	0%

Source: Bernstein analysis.

What Impact Would Climate Change Legislation Have on Generators?

Highlights

In June 2009, the House of Representatives passed the American Clean Energy and Security Act of 2009 (H.R. 2454), commonly known as the Waxman-Markey bill, to regulate emissions of greenhouse gases (GHG). In May of 2010, Senator John Kerry (Democrat from MA) and Senator Joseph Lieberman (Independent from CT) introduced a companion bill in the Senate, entitled the American Power Act, and referred to herein as Kerry-Lieberman. The 111th Congress failed to pass climate change legislation, and expected Republican gains in the 2010 elections make it unlikely that the next Congress will do so.

Yet, over the last two years, climate change legislation has enjoyed the support of both the power industry and the environmental lobby, a coalition that may continue to press for legislation in future. To the power industry, climate change legislation offers the combination of regulatory certainty, facilitating the planning of long-lived generation investment; mechanisms to mitigate the cost to utilities and ratepayers of transitioning to a carbon-constrained market for energy; and enormous subsidies for the deployment of low-emitting nuclear and coal-fired power plants. To the environmental lobby, these concessions are acceptable if they provide the mechanism to control emissions of greenhouse gases and address the challenge of climate change. Therefore, despite the failure of the 111th Congress to pass climate change legislation, we believe it useful to analyze the Waxman-Markey and Kerry-Lieberman bills and assess their impact on utilities.

Waxman-Markey and Kerry-Lieberman adopt a common regulatory approach to greenhouse gases. Both bills would impose an overall cap on U.S. emissions of GHGs that would decline over time, so that by 2050, U.S. emissions of GHG would be reduced by over 80%. To enforce the cap, the federal government would issue each year a fixed number of permits to emit ("emission allowances"), and require emitters at the end of each year to surrender allowances equivalent to their GHG emissions. Initially, these emissions allowances would be largely granted to emitters; as time passed, an increasing percentage would be sold at auction by the government. The allowances would be freely tradable.

Both bills would allocate to regulated utilities the bulk of the allowances they require through 2025, minimizing their cost of compliance and resulting in relatively limited rate increases. When allowance grants cease in 2030, however, utilities in the Midwest and Southeast that rely heavily on coal-fired generation will face materially higher costs of supplying their retail loads, and will be forced to pass through these cost increases to rates. The largest rate increases, we calculate, would be required by AES (AES), AEP (AEP), Allegheny (AYE), Westar (WR), OGE (OGE), DPL (DPL), Ameren (AEE), Black Hills (BKH), Alliant (LNT), Integrys (TEG), Wisconsin Energy (WEC), Great Plains (GXP), PNM Resources (PNM), and CMS Energy (CMS) (see Exhibit 112 at the end of this chapter).

Also at risk from the regulation of GHG emissions are unregulated coal-fired generators. Combined cycle gas turbine generators emit, on average, about 0.5 Mt of CO_2 per MWh; coal-fired generators, by contrast, emit a full ton. By putting a price on GHG emissions, climate change legislation would increase cost of operation at both gas and coal-fired power plants. In most unregulated power markets, however, gas-fired generators are the marginal or price setting units. It will therefore be their increase in operating cost — equivalent to the price of half a ton of CO_2 — that would be reflected in the price. As the operating cost of coal-fired generators will increase by a full ton, the generation gross margin per MWh of the coal-fired merchants can be expected to fall by the value of roughly one-half ton of CO2 during every hour that gas is on the margin.

To offset this loss, both Waxman-Markey and Kerry-Lieberman would grant allowances to coal-fired merchant generators in an amount equivalent to one half ton of CO2 per MWh of generation. Over the five-year period spanning 2026-30, however, these grants would be phased out, falling to zero in 2030. Once allowance grants are fully phased out in 2030, coal-fired generators in markets where gas is the price-setting fuel will face a significant deterioration in gross margin. Most adversely affected will be RRI Energy (RRI), Dynegy (DYN), NRG Energy (NRG), Allegheny Energy (AYE), Mirant (MIR), Ameren (AEE), Westar Energy (WR), PNM Resources (PNM), Edison International (EIX) and PPL (PPL) (see Exhibit 113 at the end of this chapter).

Investment Implications

Academic studies of power markets and prices in Europe following the imposition of the EU's GHG cap-and-trade scheme have found that wholesale power prices rose to reflect 80% to 90% of the value of allowances consumed in the generation of electricity. In the United States, gas-fired generators tend to be the marginal or price-setting suppliers in wholesale power markets, particularly during hours of peak demand. Therefore, were the United States to pass climate change legislation, we would expect the increase in the variable cost of operation of gas-fired power plants — equivalent to the price of half a ton of CO2 — to be reflected in the wholesale price of electricity.

This increase in wholesale power prices will benefit materially those generators that incur no incremental cost of compliance — that is, the unregulated nuclear and renewable generators. Among the principal beneficiaries of climate change legislation, therefore, will be utilities with a large proportion of unregulated nuclear generation, such as Exelon (EXC), Entergy (ETR) and NextEra Energy (NEE) (see Exhibit 113 at the end of this chapter).

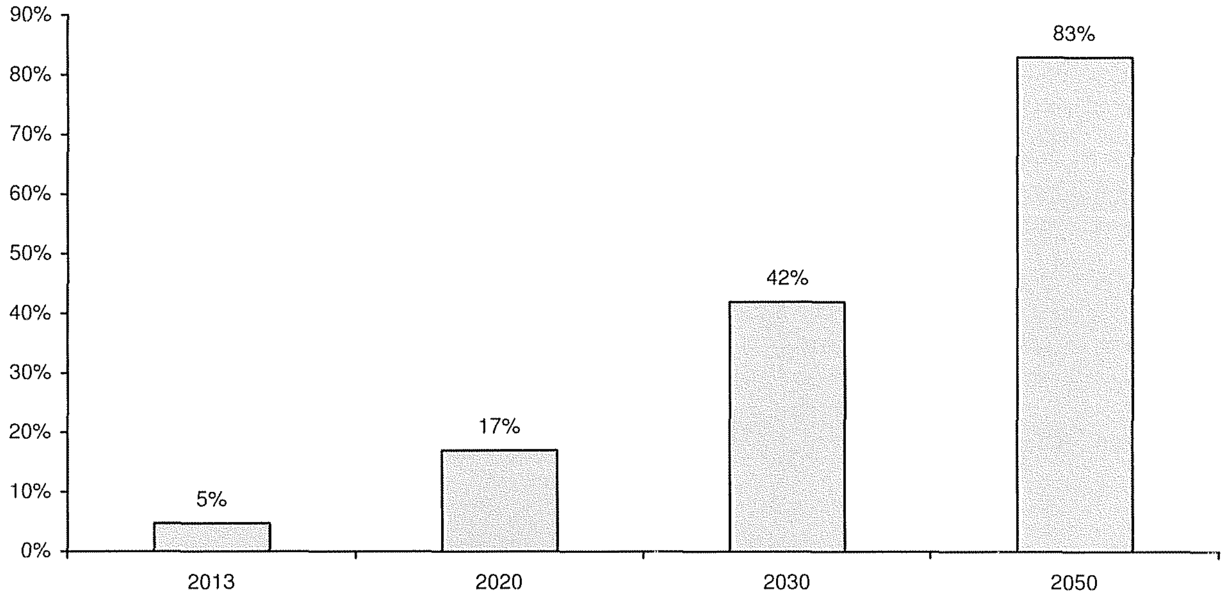
A Cap on Greenhouse Gas Emissions

The Waxman-Markey and Kerry-Lieberman bills adopt a common regulatory approach to greenhouse gases. Like Waxman-Markey, Kerry-Lieberman would set an overall cap on U.S. emissions of GHGs that would decline over time. Thus, each year the federal government would issue a fixed quantity of allowances or permits to emit greenhouse gases; on April 1 of the following year, emitters of greenhouse gases would be required to surrender to the government emission allowances equivalent to their emissions in the prior year. Those that fail to do so would be required to make good on any shortfall in the allowances they hold, and to pay a penalty equal to twice the market price of their allowance shortfall.

The permitted level of GHG emissions, and thus the quantity of GHG emission allowances issued by the government, would decline each year. Using the level of greenhouse gas emissions in 2005 as its base, Kerry-Lieberman would require a 17% cut in emissions by 2020, a 42% cut by 2030 and an 83% cut by 2050 (see Exhibit 104).

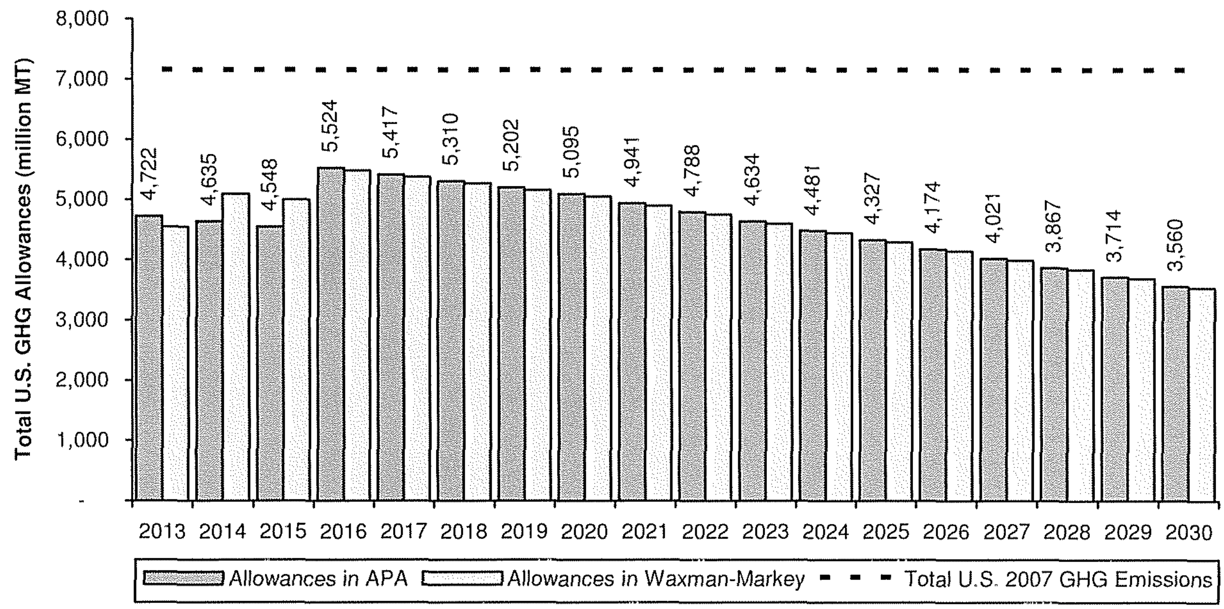
Exhibit 105 compares the total amount of GHG emissions allowances available by year under Kerry-Lieberman (darker bar on the left) with those available under Waxman-Markey (lighter bar on the right). As can be seen there, the allowances available under Kerry-Lieberman are slightly lower in 2014 and 2015 than those available under Waxman-Markey; this reflects the fact that Kerry-Lieberman delays the regulation of large industrial emitters and local gas distribution companies until 2016. From 2016 to 2030, however, both bills offer broadly similar amount of yearly CO2 allowances, and thus set similar reduction targets for national GHG emissions.

Exhibit 104 **Reductions in Greenhouse Gas Emissions of Covered Sectors Required by the Kerry-Lieberman Bill**



Source: American Power Act.

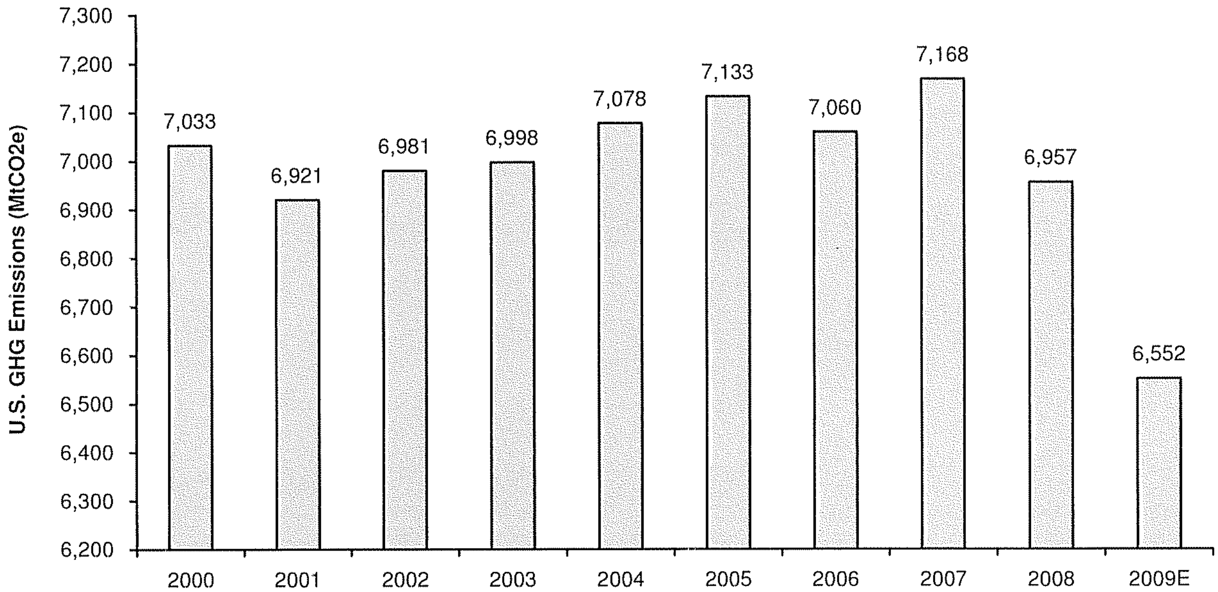
Exhibit 105 **Emissions Allowances Granted Under the American Power Act vs. Waxman-Markey Bill**



Source: American Power Act, H.R. 2454 and Bernstein analysis.

While the caps on GHG emissions in Kerry-Lieberman are similar to those in the Waxman-Markey bill, the dramatic decline in U.S. GHG emissions caused by the 2008-09 recession has made these caps much easier for emitters to meet. The EPA estimates that national GHG emissions fell by 2.9% in 2008 (see Exhibit 106). EIA data on CO2 emissions from fossil fuel consumption in 2009 suggest that total greenhouse gas emissions fell a further 5.8% in that year. If so, U.S. greenhouse gas emissions in 2009 were already 8.1% below 2005 (see Exhibit 107).

Exhibit 106 **U.S. Greenhouse Gas Emission in Metric Tons of CO2 Equivalent**



Source: EPA and Bernstein estimate for 2009 based on EIA data.

Exhibit 107 **U.S. Greenhouse Gas Emission in Metric Tons of CO2 Equivalent**

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009E
U.S. GHG Emissions (MtCO2e)	7,033	6,921	6,981	6,998	7,078	7,133	7,060	7,168	6,957	6,552
Percentage Change	2.5%	-1.6%	0.9%	0.2%	1.1%	0.8%	-1.0%	1.5%	-2.9%	-5.8%
Index: 2005 = 100	98.6	97.0	97.9	98.1	99.2	100.0	99.0	100.5	97.5	91.9

Source: EPA and Bernstein estimate for 2009 based on EIA data.

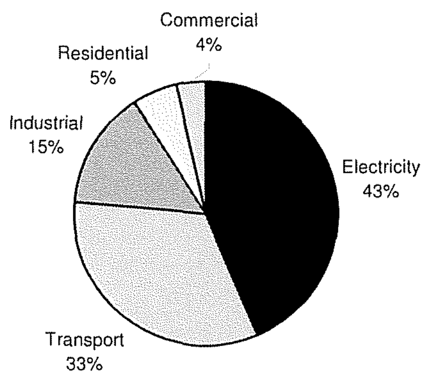
Different Mechanisms for Compliance

Like Waxman-Markey, the Kerry-Lieberman bill takes two different approaches to regulating GHG emissions, depending on the nature of the source. Both bills classify emitters into two categories: (1) large stationary sources, such as power stations and industrial plants, and (2) mobile and small stationary sources, such as vehicles and buildings. Large, stationary sources of GHG emissions comprise approximately 7,500 power plants and industrial facilities, each emitting over 25,000 MtCO2e annually. Emissions from large stationary sources would be regulated directly, by requiring these sources to hold emissions allowances equivalent to their GHG emissions in the prior year. Such sources would be required to monitor their emissions of greenhouse gases, report these emissions to the government, and surrender to the government GHG emissions allowances sufficient to cover them.

In contrast, emissions from mobile and small stationary sources would be regulated indirectly, via the suppliers of transportation and heating fuels. The suppliers of refined petroleum products, and the local distribution companies delivering natural gas, would be required each year to surrender to the government sufficient emission allowances to cover the GHG emissions produced by the combustion of the fuels they sell.

Exhibit 108 provides a breakdown by source of U.S. emissions of CO2, which account for about 85% of national greenhouse gas emissions. As can be seen there, electricity generation accounts for 43% of U.S. CO2 emissions. Industry makes up another 15%. These two large, stationary sources, which are subject to direct regulation of GHG emissions, thus account for about 58% of the total. The combustion of transportation fuels accounts for 32% of U.S. CO2 emissions, and the emissions of residential and commercial buildings for another 10%. Together, these small and mobile sources of GHG emissions account for 42% of the total.

Exhibit 108 **Breakdown of U.S. Carbon Dioxide Emissions by Sector in 2008 (Excludes Greenhouse Gases Other Than CO2)**



	Metric Tons of CO2 (billion)	% of U.S. Total
Electricity	2.4	43%
Transport	1.8	32%
Industrial	0.8	15%
Residential	0.3	6%
Commercial	0.2	4%
Total	5.5	100%

Source: EPA.

The Kerry-Lieberman bill sets different phase-in schedules for the various covered sectors. Emissions from power generation and the combustion of refined petroleum products would be subject to regulation beginning in 2013. Emissions from large industrial sources as well as from the combustion of natural gas by residential, commercial and small industrial consumers would commence in 2016.

Allowance Grants and Allowance Auctions

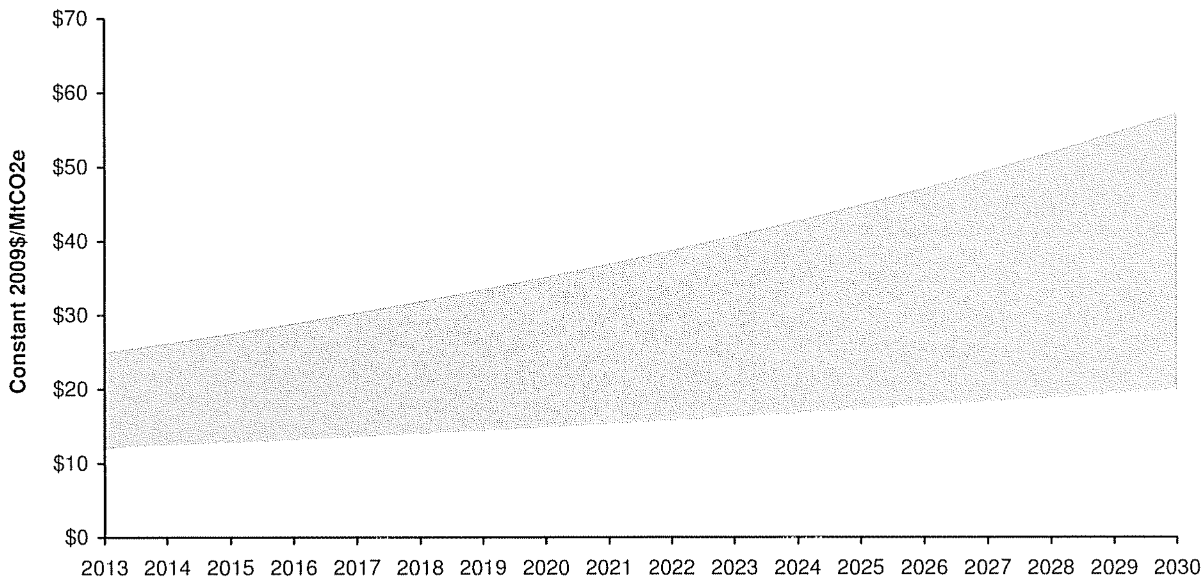
Like the Waxman-Markey bill, Kerry-Lieberman makes extensive use of allowance grants to protect regulated industries, and the consumers of their products, from economic losses. Thus, between 2016 and 2025, approximately 65% of each year's emissions allowances would be granted to regulated emitters: 35% to local electric distribution companies and power generators, 15% to energy-intensive, trade-exposed industries, 9% to local gas distribution companies, 4% to petroleum refiners, and 2% to suppliers of home heating oil and propane. Over the five-year period spanning 2026-30, however, these grants are phased out, falling to zero in 2030.

From 2016 through 2025, another 15% of annual allowances, on average, are set aside to promote investment in various targeted areas, such as transportation infrastructure and carbon capture and sequestration. The remaining allowances, approximately 20% of the total, are to be sold by the federal government through quarterly auctions. The proportion of allowances auctioned rises over time as allowance grants tail off, reaching over three-quarters of the total by 2030.

Unlike Waxman-Markey, Kerry-Lieberman sets both a cap and a floor on the price at which the government can auction allowances (see Exhibit 109). Thus, the reserve price at the allowance auctions (the price below which the government will not accept bids) is set in 2013 at $12 per metric ton of CO2 equivalent (MtCO2e), expressed in constant 2009 dollars. Thereafter, the reserve price rises each year at a rate equal to the rate of consumer price inflation plus 3.0%.

To prevent price spikes, Kerry-Lieberman also creates a "cost containment reserve" of 4.0 billion allowances of 1.0 MtCO2e each, equivalent to roughly 85% of the total cap on allowances in 2013. Emitters are allowed to purchase up to 15% of their annual allowance requirement from the reserve. The price at which the government is required to sell these reserve allowances in 2013 is set at $25/MtCO2e in constant 2009 dollars, and rises annually thereafter at a rate equal to the rate of consumer price inflation plus 5.0%.

Exhibit 109 **Price Collar: Minimum and Maximum Price of GHG Emissions Allowances at Auction (Constant 2009$/MtCO2e)**



Source: American Power Act and Bernstein analysis.

Like Waxman-Markey, Kerry-Lieberman stipulates that the value of allowances granted to local electric distribution companies must be passed through to customer bills so as to mitigate the impact on ratepayers of higher energy costs. Similar provisions apply to local gas distribution companies and suppliers of home heating oil and propane. In the case of natural gas utilities, however, 20% of the allowances the utilities receive must be used to help customers invest in energy efficiency measures. For suppliers of home heating oil and propane, this proportion rises to 50%, and the energy efficiency programs are to be administered by the states.

Kerry-Lieberman would also grant allowances to energy-intensive, trade-exposed industries. About 3% of American manufacturing firms — producers of commodities such as steel, aluminum, cement and some chemicals — are highly energy intensive and account for about one-half of all industrial CO2 emissions. These firms have limited ability to recoup their increased costs when competing with goods imported from countries that have not yet adopted comparable carbon limits. To protect energy-intensive industries, Kerry-Lieberman would grant allowances to these emitters so as to offset the increase in their cost of energy resulting from CO2 regulation. The distribution formula, based on the industry-average emission rate and each firm's specific output, rewards firms that become more energy-efficient and lower-emitting.

As an additional safeguard, Kerry-Lieberman creates a "border adjustment" — a requirement for importers to buy carbon allowances when bringing in energy-intensive commodities such as steel, aluminum or cement from countries that have not adopted their own carbon control programs. The border adjustment would take effect in 2025, after which the direct grant of allowances to energy-intensive industries would be phased out.

Offset Program

Like Waxman-Markey, Kerry-Lieberman relies heavily on carbon offsets to minimize the cost to emitters and consumers of complying with increasingly stringent limits on emissions of CO2 and other greenhouse gases. Carbon offsets are projects that capture and sequester CO2 or otherwise prevent emissions of greenhouse gases from unregulated sources. Examples include reforestation projects, as well as projects to limit emissions of methane, a very powerful greenhouse gas, from cattle feedlots. Kerry-Lieberman establishes criteria, to be administered by the EPA and the Department of Agriculture, to assure that offset credit is earned only for permanent reductions in greenhouse gas emissions that would not otherwise have occurred. These credits may then be sold to covered emitters, which are permitted to use them in lieu of emissions allowances.

Kerry-Lieberman allows emitters to use up to 2.0 billion MtCO2e of offset credits each year, equivalent to over 40% of the total cap on allowances in 2013. Three-quarters of these credits must come from domestic sources, and these may be substituted at a 1:1 ratio for GHG emissions allowances. The remaining 25% of credits may come from international sources, but may only be substituted for allowances at ratio of 1.25 to 1.0. The bill authorizes the president to ease the limit on the use of international credits if domestic credits are insufficient.

Limits on State and EPA Regulation of Greenhouse Gas Emissions

Because it regulates greenhouse gas emissions through a comprehensive, nation-wide, cap-and-trade program, Kerry-Lieberman seeks to eliminate other forms of GHG regulation at both the federal and state level. By prohibiting EPA regulation of GHG under existing provisions of the Clean Air Act, Kerry-Lieberman seeks to avoid overlapping levels of federal regulation, thereby minimizing compliance costs for industry. By prohibiting state cap-and-trade programs for greenhouse gases, Kerry-Lieberman seeks to avoid a patchwork of potentially conflicting federal and state regulatory schemes.

To prevent EPA regulation of greenhouse gases under existing provisions of the Clean Air Act, Kerry-Lieberman eliminates the EPA's authority under Section 111 of the Act to set pollution performance standards for new and existing sources of GHG emissions. Similarly, Kerry-Lieberman eliminates the EPA's authority to require Prevention of Significant Deterioration (PSD) and New Source Review (NSR) permits for new or expanded sources of GHG emissions. Kerry-Lieberman also exempts greenhouse gases from several other Clean Air Act regulatory programs, such as the National Ambient Air Quality Standards and hazardous air pollutant standards.

However, Kerry-Lieberman does set one important standard of its own — on the GHG emissions of new coal-fired power plants. Thus, within four years of the date that 10 GW of coal-fired capacity with carbon capture and sequestration (CCS) capability has become operational in the United States, all coal-fired power plants permitted between 2009 and 2015 are required to achieve at least a 50% reduction in their emissions of CO2. And plants permitted after 2020 must meet a standard requiring a 65% reduction in CO2 emissions. These provisions imply a significant contingent cost for the developers of coal-fired power plants, which may be required to retrofit these units with CCS technology. The costs associated with such a retrofit would be particularly difficult to recover if the affected units operate in competitive markets and are thus not subject to cost of service-based rate regulation.

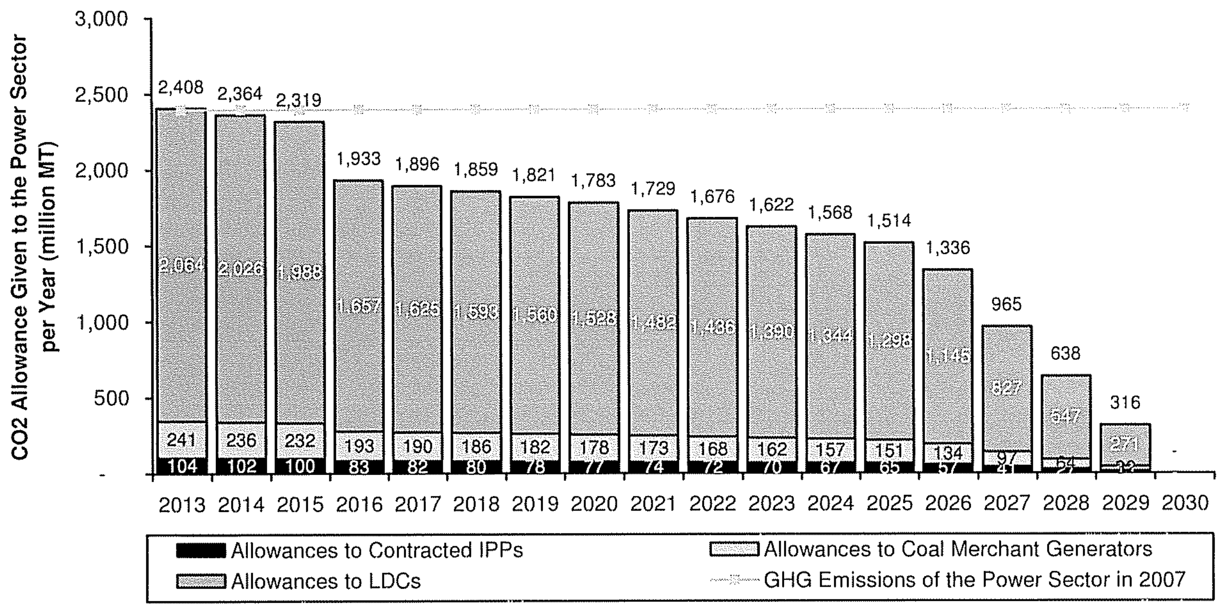
In addition to limiting the scope of EPA regulation of CO2, Kerry-Lieberman also prohibits state regulation of GHG emissions under state or regional cap-and-trade schemes. Holders of GHG emissions allowances issued under such schemes would be allowed to exchange these for federal allowances. Affected states, moreover, would receive revenue from federal allowance auctions to replace revenues lost from auctioning allowances at the state level.

In other respects, however, Kerry-Lieberman preserves states' authority to regulate GHG emissions. In particular, states would retain their authority to set standards for vehicle emissions of greenhouse gases. Indeed, the bill instructs the EPA and the Department of Transportation to set a second round of greenhouse gas and fuel economy standards in cooperation with California, other states, and stakeholders to replace the program promulgated this year, which expires with the 2017 vehicle model year. States would also retain authority to establish clean energy and energy efficiency programs that are more stringent than federal requirements.

Impact of the Cap-and-Trade Scheme on the Power Industry

The total amount of allowances granted to the power industry under Kerry-Lieberman is presented in Exhibit 110. Allowance grants are allocated in the amounts indicated among local electric distribution companies (LDCs), coal-fired merchant generators and qualifying facilities and independent power producers (IPPs) operating under long-term contracts. After a sharp drop in 2016, when large industrial emitters and local gas distribution companies enter the cap-and-trade scheme, allowance grants to the power sector decline gradually through 2026, reflecting the global decline in allowances created under the cap-and-trade program. Over the five years from 2026 through 2030, allowance grants to the power sector are completely phased out.

Exhibit 110 **Emissions Allowances Granted to the Power Sector Under the American Power Act**



Source: American Power Act and Bernstein analysis.

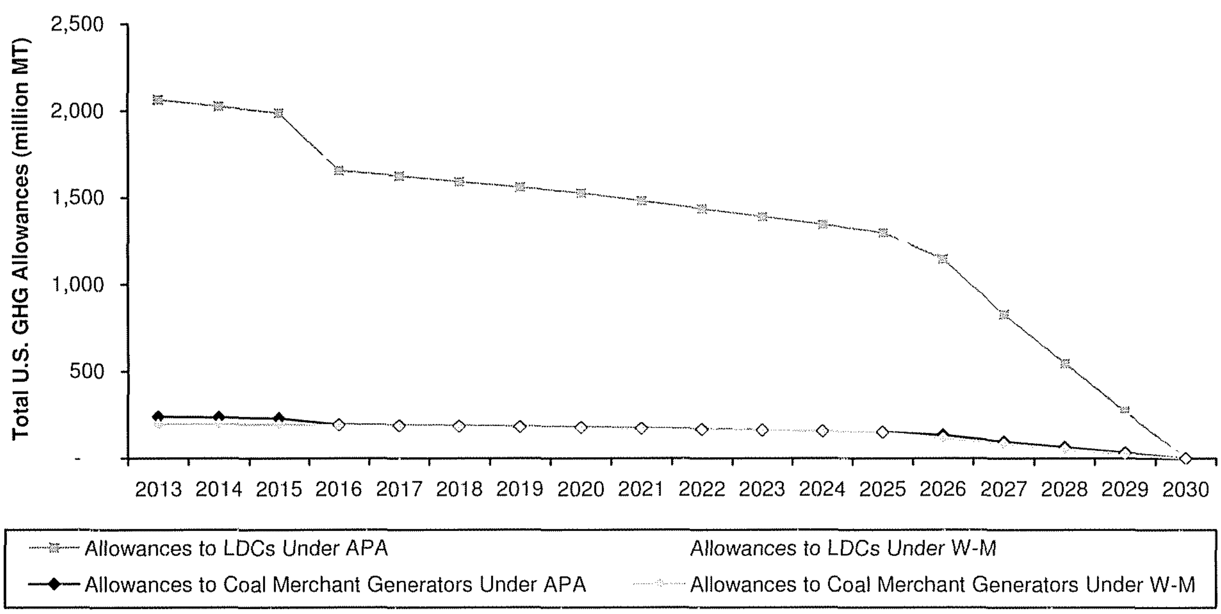
From 2026 through 2030, therefore, carbon-intensive utilities, such as the coal-fired generators of the Midwest, will incur significant increases in their cost of supply. The local electric distribution companies, being regulated utilities subject to cost of service-based rates, will seek to recover this cost through rate increases. The coal-fired merchants, however, enjoy no such regulatory mechanism for cost recovery. Rather, they will seek to push these cost increases through to the wholesale price of power. If they operate in regions where coal-fired generators are the marginal, price-setting units, they may succeed in doing so. If, however, they operate in markets where gas-fired generators are the price-setting units, then they are unlikely to recover their costs in full.

Combined cycle gas turbine generators emit, on average, about 0.5 Mt of CO2 per MWh; coal-fired generators, by contrast, emit a full ton. The cost of operation at the coal-fired merchants will thus rise by the price of a full ton of CO2, or one GHG emission allowance. The combined cycle gas turbine generators, however, which set the price of power, will incur a cost increase of only half a ton. It will be this lesser increase that will be reflected in the price. As a result, the generation gross margin per MWh of the coal-fired merchants can be expected to fall by the value of roughly one-half ton of CO2 during every hour that gas is on the margin.

Kerry-Lieberman also provides grants of allowances to gas-fired, IPPs and qualifying facilities under PURPA (QFs) that supply power under long-term contracts that lack provisions for price increases to pass on the cost of GHG regulation. To the extent these facilities are still operating under such contracts by 2030, the loss of allowance grants will result in an unrecoverable increase in their cost of supply, causing a commensurate erosion in generation gross margin. By 2030, however, it is likely that the bulk of these contracts will have expired, and these units will be operating as merchant generators. Because they are gas-fired and thus are likely to be the marginal, price-setting units on the system, they are fairly well positioned to recover the increase in their cost of supply in the wholesale price of power.

Exhibit 111 compares the allowances granted under Kerry-Lieberman to local electric distribution companies and coal-fired merchants with those granted under Waxman-Markey. As can be seen there, the allowances granted LDCs under the Kerry-Lieberman bill (the uppermost line) are higher than those granted under Waxman-Markey (the second, lighter line). In particular, local electric distribution companies will receive a significantly larger number of allowances during the first three years under Kerry-Lieberman, reflecting the delayed regulation under that bill of large industrial emitters and local gas distribution companies. The advantage persists, albeit to a lesser degree, in later years.

Exhibit 111 **Emissions Allowances Granted to the Power Sector Under the American Power Act vs. the Waxman-Markey Bill**



Source: American Power Act, H.R. 2454 and Bernstein analysis.

Exhibit 111 also compares the allowances granted to LDCs and coal-fired merchant generators under Kerry-Lieberman with those granted under Waxman-Markey. The higher level of grants enjoyed by the LDCs in the first three years will allow them to offset more completely the cost they would otherwise incur of acquiring allowances, thus limiting the increase in electricity rates to be borne by the ratepayer.

Exhibit 112 estimates the rate increases required by local electric distribution companies to recover their cost of compliance under Kerry-Lieberman and Waxman-Markey. As can be seen there, the fact that Kerry-Lieberman allocates to utilities the bulk of the allowances they require through 2025 results in relatively limited rate increases in the early years of the program. When allowance grants cease in 2030, however, *utilities in the Midwest and Southeast that rely heavily on* coal-fired generation will face materially higher costs of supplying their retail loads, and will be forced to pass through these cost increases to rates.

Exhibit 112 **Estimate of Retail Electricity Rate Increases Under the Kerry-Lieberman American Power Act (APA) vs. the Waxman-Markey Bill (W-M): Percentage Increase in Retail Electricity Rates at EPA's Estimated Prices for CO2 Allowances**

		Retail Rate Increase in 2013 with CO2 Price at $12/Mt		Retail Rate Increase in 2020 with CO2 Price at $17/Mt		Retail Rate Increase in 2030 with CO2 Price at $27/Mt	
Holding Company Name	Ticker	W-M	APA	W-M	APA	W-M	APA
AES Corp (The)	AES	6%	**3%**	11%	**9%**	41%	**41%**
American Electric Power Co Inc	AEP	5%	**2%**	9%	**8%**	37%	**37%**
Allegheny Energy Inc	AYE	4%	**2%**	8%	**7%**	34%	**34%**
Westar Energy Inc	WR	4%	**2%**	8%	**7%**	33%	**33%**
OGE Energy Corp	OGE	4%	**2%**	8%	**7%**	32%	**32%**
DPL Inc	DPL	5%	**2%**	8%	**7%**	30%	**30%**
Ameren Corp	AEE	4%	**1%**	7%	**6%**	30%	**30%**
Black Hills Corp	BKH	4%	**2%**	7%	**7%**	30%	**30%**
Alliant Energy Corp	LNT	4%	**2%**	7%	**7%**	29%	**29%**
Integrys Energy Group Inc	TEG	4%	**2%**	7%	**7%**	29%	**29%**
Wisconsin Energy Corp	WEC	4%	**2%**	7%	**6%**	28%	**28%**
Great Plains Energy Inc	GXP	3%	**1%**	6%	**6%**	27%	**27%**
PNM Resources Inc	PNM	3%	**1%**	6%	**6%**	26%	**26%**
CMS Energy Corp	CMS	3%	**1%**	6%	**6%**	25%	**25%**
Duke Energy Corp	DUK	2%	**1%**	5%	**5%**	25%	**25%**
Xcel Energy Inc	XEL	3%	**1%**	5%	**5%**	24%	**24%**
Empire District Electric Co (The)	EDE	2%	**1%**	5%	**5%**	24%	**24%**
Southern Co	SO	3%	**1%**	5%	**5%**	23%	**23%**
DTE Energy Co	DTE	3%	**1%**	5%	**5%**	23%	**23%**
IDACORP Inc	IDA	0%	**-**	2%	**3%**	22%	**22%**
SCANA Corp	SCG	2%	**1%**	4%	**4%**	21%	**21%**
NorthWestern Corp	NWE	2%	**1%**	4%	**4%**	21%	**21%**
Avista Corp	AVA	0%	**-**	2%	**3%**	17%	**17%**
Dominion Resources Inc	D	0%	**-**	2%	**3%**	16%	**16%**
PPL Corp	PPL	0%	**-**	2%	**2%**	15%	**15%**
Progress Energy Inc	PGN	1%	**0%**	2%	**3%**	15%	**15%**
FirstEnergy Corp	FE	1%	**0%**	2%	**3%**	14%	**14%**
NV Energy	NVE	1%	**0%**	2%	**3%**	14%	**14%**
Pinnacle West Capital Corp	PNW	0%	**-**	1%	**2%**	12%	**12%**
Entergy Corp	ETR	-	**-**	1%	**2%**	12%	**12%**
Constellation Energy Group	CEG	1%	**0%**	2%	**2%**	10%	**10%**
Pepco Holdings Inc	POM	1%	**0%**	1%	**2%**	10%	**10%**
NextEra Energy Inc	NEE	-	**-**	0%	**1%**	9%	**9%**
Northeast Utilities	NU	0%	**-**	1%	**1%**	7%	**7%**
NSTAR	NST	-	**-**	0%	**1%**	5%	**5%**
Edison International	EIX	-	**-**	-	**0%**	5%	**5%**
Public Service Enterprise Group Inc	PEG	-	**-**	-	**0%**	5%	**5%**
Sempra Energy	SRE	-	**-**	-	**0%**	5%	**5%**
PG&E Corp	PCG	-	**-**	-	**0%**	4%	**4%**
Consolidated Edison Inc	ED	-	**-**	0%	**0%**	4%	**4%**
Exelon Corp	EXC	-	**-**	-	**-**	1%	**1%**

Source: Ventyx Global Energy and Bernstein analysis.

Prior to the phase-out of allowance grants by 2030, the different allowance allocation schemes contemplated by Kerry-Lieberman and Waxman-Markey have materially different implications for local distribution companies. Under Waxman-

Markey, one-half of these allowance grants were allocated among local electric distribution companies in proportion to each company's share of the sector's overall GHG emissions, and one-half was allocated in proportion to each company's share of total electric deliveries. Under Kerry-Lieberman, three-quarters of allowance grants are allocated based on a company's share of GHG emissions, and only one-quarter based on its share of deliveries. By granting a larger portion of allowances based on emissions, and smaller portion based on deliveries, this shift favors those LDCs with higher than average ratios of GHG emissions to MWh supplied. Benefiting from this change will be the regulated utility subsidiaries of AES (AES), AEP (AEP), Allegheny (AYE), Westar (WR), OGE (OGE), DPL (DPL), Ameren (AEE), Black Hills (BKH), Alliant (LNT), Integrys (TEG), Wisconsin Energy (WEC), Great Plains (GXP), PNM Resources (PNM), and CMS (CMS) (see Exhibit 112).

In addition to LDCs, the Kerry-Lieberman bill would also grant allowances to "merchant coal generators." These are defined as power plants that are not subject to rate regulation by state or municipal authorities. The formula for allocating allowances to merchant coal generators is very important in estimating the impact of the Kerry-Lieberman bill on wholesale power prices and competitive generators' profits. The volume of allowances granted to a merchant coal generator will be equal to *one-half* the product of (1) the generator's average rate of CO2 emissions per MWh during the three-year base period spanning 2006-08, (2) the generator's power output in MWh in the preceding year, and (3) a phase-down factor reflecting the overall decrease in allowances granted to the power sector.

The logic behind this formula is that gas-fired generators, which will be required to purchase their allowances under the Kerry-Lieberman bill, will attempt to recover the cost of these allowances by raising the prices they charge for electricity. Since gas-fired generators emit, on average, half a ton of CO2 per MWh, this should result in an increase in power prices equivalent to the value of one-half ton of CO2 during those hours when gas-fired generators are the marginal or price-setting units. But coal-fired generators emit, on average, a full ton of CO2 per MWh, implying an increase in cost in excess of the increase in price and thus an erosion of profit margins. By granting coal-fired generators half a ton of allowances per MWh produced, the Kerry-Lieberman bill attempts to eliminate this loss. The above formula for granting allowances to coal-fired merchants is similar under Kerry-Lieberman and Waxman-Markey.

Implications for Power Prices and Competitive Generators' Profits

We have estimated the impact that Kerry-Lieberman will have on power prices and competitive generators' profits. To do so, we have assumed that generators attempt to pass through to the price of power the cost of the allowances they must purchase to comply with the new law. For gas-fired generators, which must purchase allowances to recover all of their CO2 emissions, these purchases will average one-half ton of CO2 per MWh. For coal-fired generators, which receive half of their requirement as a grant from the government, purchases of allowances will also average one-half ton of CO2 per MWh. When gas-fired generators are setting the price of power, as well as when coal-fired generators are doing so, the increase in price should reflect an incremental cash cost of supply of one-half ton of CO2 per MWh.

Academic studies of power markets and prices in Europe following the imposition of the EU's Emissions Trading Scheme have found that wholesale power prices rose to reflect 80% to 90% of the value of allowances consumed in the generation of electricity. We have conservatively assumed, therefore, that U.S. generators succeed in recovering in prices 80% of their incremental cash cost of supply. For every $10/ton increase in the CO2 price, therefore, wholesale power prices are assumed to rise by $4/MWh ($10/ton x 0.5 tons/MWh x 80%).

This increase in wholesale power prices will benefit materially those generators that incur no incremental cost of compliance — that is, the unregulated nuclear and renewable generators. Among the principal beneficiaries of Kerry-

Lieberman, therefore, will be utilities with a large proportion of unregulated nuclear generation, such as Exelon (EXC), Entergy (ETR) and NextEra Energy (NEE) (see Exhibit 113). The benefit to these companies will increase materially after 2025, when the grant of allowances to coal-fired begins to be phased out. By 2030, merchant coal generators will be forced to purchase allowances to cover the entirety of their CO2 emissions, resulting in upward pressure on off-peak power prices as these generators seek to recover the cost of a full ton — rather than half a ton — of CO2 per MWh.

Exhibit 113 **Estimated Impact on Unregulated Generators' Gross Margins Under the Kerry-Lieberman American Power Act (APA) vs. the Waxman-Markey Bill (W-M)**

		EBITDA Increase at $12/Mt as % of LTM EBITDA in 2013		EBITDA Increase at $17/Mt as % of LTM EBITDA in 2020		EBITDA Increase at $27/Mt as % of LTM EBITDA in 2030	
Holding Company Name	Ticker	W-M	APA	W-M	APA	W-M	APA
Exelon Corp	EXC	13%	**12%**	18%	**18%**	34%	**34%**
Entergy Corp	ETR	6%	**6%**	8%	**8%**	13%	**13%**
NextEra Energy Inc	NEE	3%	**2%**	4%	**4%**	6%	**6%**
Public Service Enterprise Group Inc	PEG	2%	**2%**	2%	**2%**	2%	**2%**
Calpine Corp	CPN	-0%	**-0%**	0%	**0%**	2%	**2%**
Sempra Energy	SRE	0%	**-0%**	0%	**0%**	1%	**1%**
OGE Energy Corp	OGE	-0%	**-0%**	-0%	**-0%**	0%	**0%**
Southern Co	SO	0%	**0%**	0%	**0%**	0%	**0%**
CMS Energy Corp	CMS	0%	**0%**	0%	**0%**	0%	**0%**
SCANA Corp	SCG	0%	**0%**	0%	**0%**	0%	**0%**
IDACORP Inc	IDA	0%	**0%**	0%	**0%**	0%	**0%**
Progress Energy Inc	PGN	0%	**0%**	0%	**0%**	0%	**0%**
Alliant Energy Corp	LNT	0%	**0%**	0%	**0%**	0%	**0%**
Avista Corp	AVA	-	**-**	-	**-**	-	**-**
Pinnacle West Capital Corp	PNW	-	**-**	-	**-**	-	**-**
Empire District Electric Co (The)	EDE	-	**-**	-	**-**	-	**-**
PG&E Corp	PCG	-	**-**	-	**-**	-	**-**
NV Energy	NVE	-0%	**-0%**	-0%	**-0%**	-0%	**-0%**
Wisconsin Energy Corp	WEC	-0%	**-0%**	-0%	**-0%**	-0%	**-0%**
NSTAR	NST	-0%	**-0%**	-0%	**-0%**	-0%	**-0%**
DTE Energy Co	DTE	-0%	**-0%**	-0%	**-0%**	-1%	**-1%**
Consolidated Edison Inc	ED	-0%	**-0%**	-0%	**-0%**	-1%	**-1%**
Black Hills Corp	BKH	-0%	**-0%**	-0%	**-0%**	-1%	**-1%**
Duke Energy Corp	DUK	-0%	**-0%**	-1%	**-1%**	-1%	**-1%**
Dominion Resources Inc	D	0%	**0%**	0%	**0%**	-1%	**-1%**
NorthWestern Corp	NWE	-0%	**-0%**	-1%	**-1%**	-1%	**-1%**
Xcel Energy Inc	XEL	-1%	**-1%**	-1%	**-1%**	-2%	**-2%**
American Electric Power Co Inc	AEP	-0%	**-0%**	-1%	**-1%**	-2%	**-2%**
Integrys Energy Group Inc	TEG	-1%	**-1%**	-1%	**-1%**	-3%	**-3%**
Pepco Holdings Inc	POM	-1%	**-1%**	-1%	**-1%**	-3%	**-3%**
DPL Inc	DPL	-1%	**-1%**	-2%	**-2%**	-4%	**-4%**
Constellation Energy Group	CEG	0%	**1%**	0%	**0%**	-4%	**-4%**
FirstEnergy Corp	FE	-0%	**-0%**	-1%	**-1%**	-4%	**-4%**
Northeast Utilities	NU	-1%	**-1%**	-2%	**-2%**	-5%	**-5%**
AES Corp (The)	AES	-2%	**-2%**	-3%	**-3%**	-6%	**-6%**
Great Plains Energy Inc	GXP	-3%	**-3%**	-5%	**-5%**	-10%	**-10%**
PPL Corp	PPL	-1%	**-1%**	-2%	**-2%**	-10%	**-10%**
Edison International	EIX	-3%	**-3%**	-5%	**-5%**	-11%	**-11%**
PNM Resources Inc	PNM	-3%	**-3%**	-5%	**-5%**	-11%	**-11%**
Westar Energy Inc	WR	-4%	**-3%**	-5%	**-5%**	-12%	**-12%**
Ameren Corp	AEE	-4%	**-4%**	-6%	**-6%**	-13%	**-13%**
Mirant Corp	MIR	-7%	**-7%**	-11%	**-11%**	-24%	**-24%**
Allegheny Energy Inc	AYE	-8%	**-7%**	-12%	**-12%**	-26%	**-26%**
NRG Energy Inc	NRG	-9%	**-8%**	-14%	**-14%**	-31%	**-31%**
Dynegy Inc	DYN	-13%	**-13%**	-20%	**-20%**	-39%	**-39%**
RRI Energy	RRI	-40%	**-37%**	-62%	**-62%**	-134%	**-134%**

Source: Ventyx Global Energy and Bernstein analysis.

Reflecting our assumption that generators are successful in recovering in prices only 80% of the increase in their cash cost of supply, we would expect a deterioration in gross margin at most fossil-fueled competitive generators. Once allowance grants are fully phased out in 2030, this deterioration in gross margin will become significant for coal-fired generators in markets where gas is the price-setting fuel. For these generators, the phase-out of allowance grants will result in an increase in their cash cost of generation of half a ton of CO2 per MWh, with no offsetting increase in the price of power. Most adversely affected will be RRI Energy (RRI), Dynegy (DYN), NRG Energy (NRG), Allegheny Energy (AYE), Mirant (MIR), Ameren (AEE), Westar Energy (WR), PNM Resources (PNM), Edison International (EIX) and PPL (PPL) (see Exhibit 113).

Index of Exhibits

VALUATION METHODOLOGY

Our target prices reflect the results of three alternative valuation methodologies: (1) a multiple-based valuation calculated by applying the median valuation multiples of a group of comparable companies to our estimates of a utility's future earnings, dividends and EBITDA; (2) a discounted cash flow model over the forecast period of 2010-15, and a terminal value in 2015 discounted back to present value at the weighted average cost of capital; and (3) a discounted dividend model over the forecast period of 2010-15, and a terminal value in 2015, discounted back to present value at the cost of equity.

RISKS

Our earnings and cash flow forecasts — and thus our price targets — are subject to considerable uncertainty.

For primarily regulated utilities — such as American Electric Power (AEP), Dominion Resources (D), Duke Energy (DUK), Edison International (EIX), and PG&E Corp. (PCG) — our earnings forecasts are driven primarily by our projections of load growth, rate relief and, in the long run, the rate of growth in regulated rate base and long run realized returns on equity. Inaccurate estimates of any of these major variables can have a significant impact on our earnings forecasts, valuations and stock recommendations.

For utilities with significant unregulated generation, such as Exelon (EXC), FirstEnergy (FE) and NextEra Energy (NEE), as well as American Electric Power, Edison International and Dominion Resources in respect of their unregulated power sales, our earnings forecasts are predicated on the currently prevailing forward price curves for power and generation fuels, particularly natural gas, coal and nuclear fuel. Given the volatility of commodity prices, the relationship between these price curves is highly unstable. Changes in the spread between fuel costs and power prices can cause company earnings to diverge materially from our forecasts.

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  Outperform: Stock will outpace the market index by more than 15 pp in the year ahead.

  Market-Perform: Stock will perform in line with the market index to within +/-15 pp in the year ahead.

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  Not Rated: The stock Rating, Target Price and estimates (if any) have been suspended temporarily.
- As of 10/11/2010, Bernstein's ratings were distributed as follows: Outperform - 45.2% (1.6% banking clients) ; Market-Perform - 47.4% (1.0% banking clients); Underperform - 7.4% (0.0% banking clients); Not Rated - 0.0% (0.0% banking clients). The numbers in parentheses represent the percentage of companies in each category to whom Bernstein provided investment banking services within the last twelve (12) months.
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12-Month Rating History as of 10/11/2010

Ticker	Rating Changes	
AEP	M (IC) 01/15/03	
D	M (RC) 09/04/07	
DUK	M (RC) 08/05/04	
EIX	M (RC) 10/08/09	
EXC	M (RC) 02/05/10	O (RC) 01/12/05
FE	O (RC) 08/05/09	
NEE	M (IC) 12/18/09	
PCG	O (RC) 03/22/07	

Rating Guide: O - Outperform, M - Market-Perform, U - Underperform, N - Not Rated
Rating Actions: IC - Initiated Coverage, DC - Dropped Coverage, RC - Rating Change

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- I/(we), Hugh Wynne, Senior Analyst(s), certify that all of the views expressed in this publication accurately reflect my/(our) personal views about any and all of the subject securities or issuers and that no part of my/(our) compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views in this publication.

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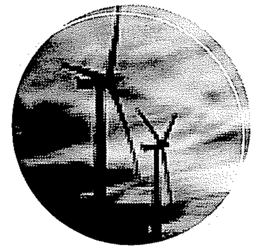

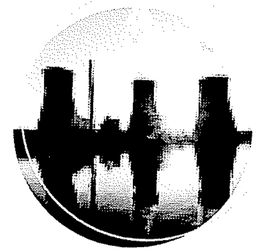

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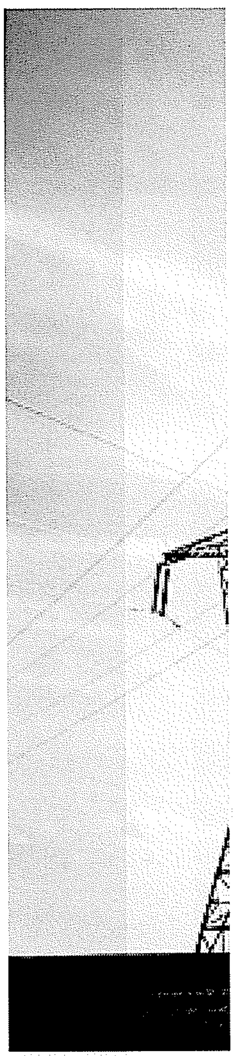

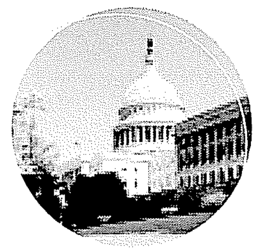

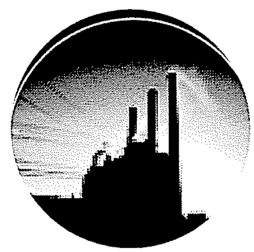

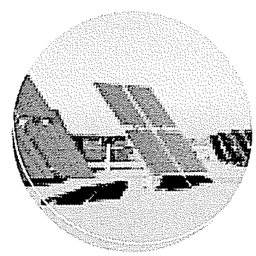

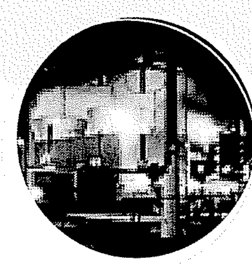

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This report was prepared by the staff of the Bipartisan Policy Center to promote a better understanding of the possible impacts of U.S. Environmental Protection Agency regulation of the electric power sector and to identify a range of strategies for managing associated reliability concerns. The views expressed here do not necessarily reflect those of the BPC Energy Project or our workshop co-sponsors, presenters, and participants.

The Bipartisan Policy Center would like to express its thanks for the strong support of its funders. In addition, we are grateful to the National Association of Regulatory Utility Commissioners and Northeast States for Coordinated Air Use Management for co-sponsoring the workshop series. Thanks also to each of the experts, listed in Appendix A, that participated in the workshop series and informed this report. Special appreciation is due to Marika Tatsutani for editing the report.

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The electric power sector in the United States faces a **changing market environment**, one that features reduced or flattened demand, low natural gas prices, new environmental regulations, and **continued uncertainty** about the future regulation of carbon. Among the **regulations recently proposed** or currently under development by the **U.S. Environmental Protection Agency** (EPA) are rules to address **air pollution transport, air toxics, coal ash,** and **cooling water intake** structures at existing plants.[1] These regulations are expected to result in **significant** public health and **environmental benefits** that, when monetized, are well in excess of compliance costs.[2]

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[1] These rules are being proposed under the Clean Air Act and other statutory authorities, which require EPA to protect public health, welfare, and the environment from adverse impacts of power plants.

[2] For example, EPA estimates the health and environmental benefits of the proposed Transport Rule range from $120 to $290 billion in 2014, while compliance costs for that year are estimated to be $2.8 billion (estimates are in 2006 dollars). See United States Environmental Protection Agency. Proposed Air Pollution Transport Rule: Reducing Pollution, Protecting Public Health. http://www.epa.gov/airquality/transport/pdfs/TRPresentationfinal_7-26_webversion.pdf.

Key benefits of the suite of EPA regulations include the avoidance of tens of thousands of premature deaths annually, reductions in pollution-related illnesses, and improved visibility and ecosystem health. These new conditions in the power sector are expected to increase the number of coal-fired power plants that will be retired in the next several years; in fact, a number of plant shutdowns have recently been implemented or announced.

Environmental compliance deadlines are likely to have a strong influence on the timing of these retirements, as plant owners will not want to make significant capital investments in some older, marginal units that might otherwise be shut down soon for economic reasons. This has led to concerns that the power sector could face reliability issues as utilities comply with new regulations. Others have argued that power companies and regional, state, and federal authorities have recourse to a range of technology options and planning approaches that can help them avoid reliability impacts from the impending suite of environmental regulations.

To shed light on these complex issues, the Bipartisan Policy Center (BPC), together with the National Association of Regulatory Utility Commissioners (NARUC) and Northeast States for Coordinated Air Use Management (NESCAUM), hosted a series of workshops to assess the possible impacts of regulation and identify a range of strategies for managing associated reliability concerns.[3] The three workshops featured presentations by leading experts on electric power system reliability, electricity market operations, power sector technology, and pollution control policies and regulations (see Appendix A).[4] Building on the presentations and public dialogue at these workshops, our review of a range of existing analyses, and our own analytic work, BPC has developed a number of findings and recommendations. Our main conclusions are summarized below.

IMPACTS ON THE RELIABILITY OF THE ELECTRIC SYSTEM DUE TO EPA REGULATIONS ARE MANAGEABLE.

BPC analysis indicates that scenarios in which electric system reliability is broadly affected are unlikely to occur. Previous national assessments of the combined effects of EPA regulations reach different conclusions, in part because they make quite different assumptions about the stringency and timing of new requirements and about the availability and difficulty of implementing control technologies. In some cases these assumptions deviate from the specifics of EPA's recent proposals in meaningful ways. Moreover, market factors, such as low natural gas prices, are as relevant as EPA regulations in driving coal plant retirements. A number of recent developments are especially relevant from the standpoint of addressing reliability concerns:

- EPA's proposed cooling water regulations are far less stringent than assumed in the vast majority of analyses, many of which considered worst-case scenarios in which cooling towers would be required on all existing units.
- Some commercially available, lower-cost technologies (e.g., dry sorbent injection) for treating hazardous air pollutants were not factored into most previous analyses. Including them significantly reduces retirement projections.
- Most of the units projected to retire are small, older units that are already operating infrequently. Some of these units may be needed to meet peak demand on the hottest and coldest days or to provide volta ge support. In some cases, there may be viable mechanisms, other than one-to-one capacity replacement, available to serve these needs.[5]
- The industry has significant amounts of existing natural gas generating capacity that is currently under-utilized and may be available to take up the slack, depending on the region.
- Some previous assessments do not account for market responses to future retirements, specifically to the potential for adding new capacity to meet reserve margins. Assuming timely permitting, the need for modest new capacity resources could be met with quick-to-build natural gas turbines, as well as demand side resources.[6]

[3] BPC gratefully acknowledges NARUC and NESCAUM as co-conveners of the workshop series. However, the report is solely a product of the staff of the Bipartisan Policy Center and does not necessarily represent the views of NARUC, NESCAUM, or any of the workshop participants.

[4] Information from each of the workshops, including video and presentations, is available at www.bipartisanpolicy.org.

[5] For example, demand response and energy efficiency programs, energy storage, and transmission upgrades.

[6] Although many gas turbines have been built within 3 years in the recent past, some in industry have raised concern that the permitting process for new construction, including greenhouse gas best available control technology (BACT) determinations, might take up to two to three years, added on top of two year construction for a new gas turbine. BPC modeling projects only 200 MW of new gas capacity would be needed, beyond the 1200 MW of new gas turbines expected in the business as usual scenario to be built by 2015.

A NUMBER OF TOOLS FOR ADDRESSING RELIABILITY CONCERNS ARE AVAILABLE TO INDUSTRY AND TO STATE AND FEDERAL REGULATORS

EPA should take advantage of its existing statutory authorities to structure clear regulations that include sensible timelines and encourage cost-effective compliance strategies. Specifically, EPA should finalize the flexibilities proposed in its Utility Air Toxics Rule (which sets "maximum achievable control technology" standards for hazardous air pollutants) and 316(b) cooling water rule. Where needed and allowed by statute, EPA and state permitting agencies should grant utilities time extensions – with as much advance notice as possible – to install pollution control technologies and to build the new capacity required to achieve compliance.[10]

Regional, state, and utility analyses should continue to examine the potential localized impacts of retirement and retrofit schedules, as well as opportunities to attract non-conventional capacity resources, such as demand resources, distributed generation, and grid-scale energy storage capacity. While most studies have taken a national approach to reliability assessments, more study is warranted to assess localized reliability impacts in the most vulnerable regions, and efforts should be made to refine and improve analytical tools.

If specific issues are identified, federal and state agencies should consider implementing strategies to assure reliability while utilities complete upgrades or bring new generation online. As a backstop, DOE has emergency powers to keep essential generation on-line, and the President has emergency powers to delay requirements in order to protect national security. In addition, EPA may enter into consent decrees – which set forth the steps needed to resolve non-compliance – to enforce the provisions of the Rule. Such consent decrees, however, should aim to eliminate any economic advantage that companies may otherwise have as a result of operating out of compliance. Consent decrees are negotiated once a company is deemed in violation, and stakeholders may not view this legal mechanism as an acceptable option that could be built into company planning. However, consent decrees do offer an additional means of backstop reliability protection.

[10] Some stakeholders endorse efforts to preempt reliability concerns and provide extra time up front in the process, rather than wait for problems and rely on emergency powers and consent decrees.

NEVERTHELESS, THE ELECTRIC POWER SECTOR AND ITS REGULATORS FACE PLANNING CHALLENGES IF THE AIM IS TO AVOID LOCALIZED RELIABILITY PROBLEMS AND MINIMIZE IMPACTS ON ELECTRIC RATES.

A rapidly shifting market and regulatory environment will create planning challenges for the electric power industry. The compliance deadlines of the Utility Air Toxics Rule, in particular, will accelerate and concentrate the decision-making timeframe for plant retirements, retrofits, and new infrastructure into a short period over the next few years. At the same time, many states are weighing new or stronger approaches to incentivize clean energy, energy efficiency, and/or non-conventional capacity resources. This convergence of issues and planning needs offers an opportunity for the industry and its regulators to work together to optimize policies and investment decisions so as to minimize consumer costs, avoid stranded assets, and maximize the benefits achieved by modernizing the nation's electric power infrastructure. At the same time, it will undoubtedly also present challenges, particularly in heavily affected regions where the resources available to support thoughtful planning and regulatory processes–both in terms of people and funding–are already under severe pressure.

Compliance planning can and should begin early and should take into account existing regulations as well as the expected regulations. If plant owners begin planning now and obtain a one year extension from their permitting authority, they will have almost five years from the date of the proposed rule to the date of the extended compliance deadline. Multi-pollutant planning and efforts to integrate non-conventional capacity resources and transmission planning will help to minimize rate impacts for electric consumers. At the same time, federal, regional, and state entities have appropriate roles to play in supporting planning efforts and mitigating anticipated reliability challenges and costs.

Specifically, state public utility commissions (PUCs) and regional transmission organizations or independent system operators (RTO/ISOs) should coordinate closely with power companies to ensure early multi-pollutant compliance planning and to coordinate retrofit outage schedules. To help with the pacing of control retrofits, states should continue to look for incentives and opportunities to encourage retrofit installations that begin well in advance of compliance deadlines.

Federal agencies, including the Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), and EPA, should provide analytic and technical support and coordinate with state and regional authorities to facilitate a smooth transition.

> This convergence of issues and planning needs offers an opportunity for the industry and its regulators to work together to minimize consumer costs, avoid stranded assets, and maximize the benefits achieved by modernizing the nation's electric power infrastructure

In light of the tight timeframes involved, state legislatures as well as EPA, DOE, and FERC should pursue strategies to help state utility regulators deal with increased workloads, particularly in the years 2012 through 2014, in order to facilitate timely decisions and allow the design and building of pollution controls and infrastructure, as needed.

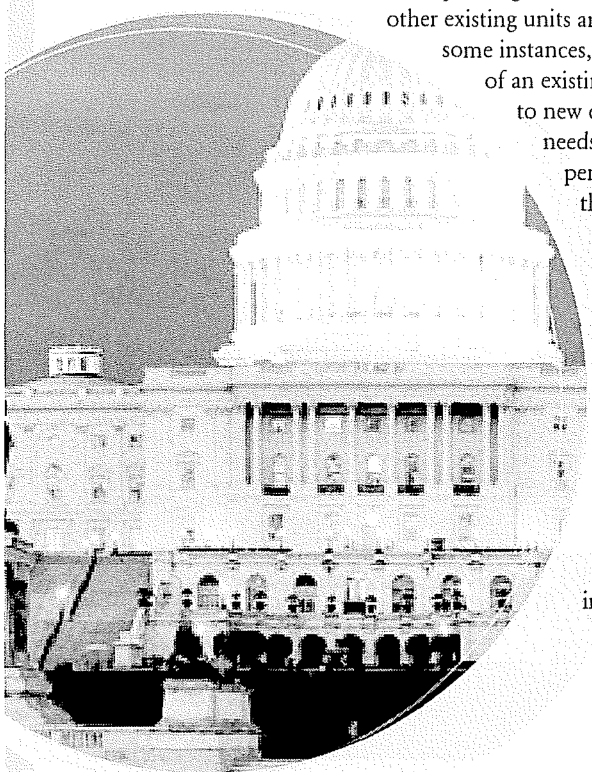
DUE TO DIFFERENCES AMONG THE STATES, THERE IS NO SINGLE APPROACH TO COMPLIANCE AND RELIABILITY THAT WILL WORK EVERYWHERE. HOWEVER, A NUMBER OF STRATEGIES ARE ALREADY BEING EMPLOYED TO SUPPORT EARLY PLANNING IN DIFFERENT TYPES OF MARKETS

In regulated states, the integrated resource planning (IRP) process informs state utility regulators who approve rate plans. State policy makers should consider a multi-pollutant approach for rate recovery and planning decisions. States should also advance policies that encourage and place responsibility with utilities for long term decision-making that avoids stranded assets and minimizes consumer costs. In addition, state regulators should recognize the value of long-term natural gas supply contracts to provide price stability and facilitate project financing. Finally, traditionally regulated states should encourage the development of non-conventional capacity resources as one means to help preserve a reliable bulk electricity system and minimize consumer costs.

In restructured states, the transparency of regional or state wholesale markets makes it easier to anticipate planned retirements and outages; in addition, competitive markets create financial incentives for timely investment in new transmission, generation, and non-conventional capacity. In these states, RTOs and ISOs typically facilitate orderly planning for power plant retirements by requiring utilities to provide advance notice if they intend to retire a unit and by conducting reliability impact studies. In light of the large number of pollution control equipment installations expected under upcoming EPA regulations, these regional entities should also play a more active role in coordinating outages, including between neighboring regions that might rely on each other to meet electricity demand during this transition period.

ENSURING A SMOOTH TRANSITION TO A CLEANER ELECTRIC POWER SECTOR WILL REQUIRE NEW INVESTMENTS IN SUPPLY AND DEMAND-SIDE CAPACITY, AS WELL AS TRANSMISSION AND OTHER INFRASTRUCTURE. STATE AND FEDERAL AGENCIES SHOULD LOOK FOR OPPORTUNITIES TO STREAMLINE THE SITING AND PERMITTING OF NEW INFRASTRUCTURE.

A smooth transition to a cleaner and more efficient generation system will require investments in energy efficiency, demand response strategies, and cleaner new generation capacity along with associated transmission and pipeline infrastructure. Fortunately retired capacity will not need to be replaced on a one-to-one basis to meet energy needs, simply because many of the units likely to be retired are not operating at full capacity now and many other existing units are under-utilized.[11] In some instances, of course, the retirement of an existing generator may give rise to new capacity or transmission needs within a relatively brief period of time. And while the industry has generally been able to add capacity on the scale and within the timeframes needed in the past, policy makers at the state and federal levels should explore approaches to facilitate this process by streamlining procedures for siting and permitting new infrastructure.



THERE MAY BE A SHORT WINDOW OF OPPORTUNITY TO ENACT A LEGISLATIVE FIX THAT COULD GUARANTEE THE ENVIRONMENTAL BENEFITS OF THE CLEAN AIR ACT AND PROVIDE A LOWER COST TRANSITION FOR THE POWER SECTOR.

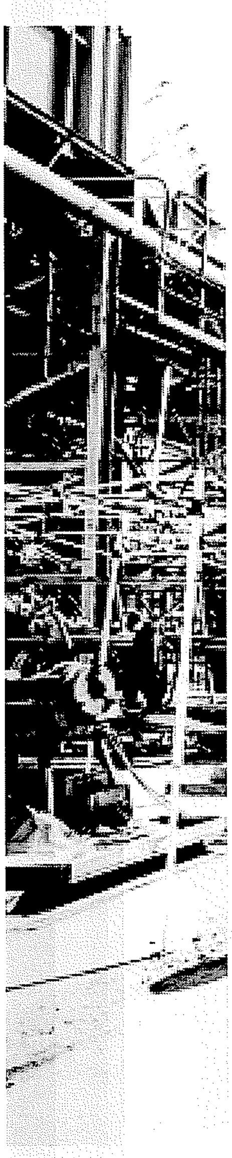
Although BPC believes that the benefits of power sector regulation, including new regulations such as the Utility Air Toxics Rule, far outweigh the cost, we also recognize that associated compliance costs will not be trivial. EPA estimates that compliance costs for the Utility Air Toxics Rule alone will total $10.9 billion annually. For the average electricity consumer, this translates to an increase of $3 to $4 per month.[12] BPC estimates annual costs of $14.5 billion in 2015 and $18.1 billion in 2025 to comply with the suite of EPA air, water, and waste rules.[13]

Some workshop participants suggested that a legislative fix could provide equivalent or greater environmental benefits at a lower cost than regulatory approaches under existing law, particularly for air pollutants. To be successful, multi-pollutant legislation would need to provide certainty on requirements and timing, and encourage rational and timely investment decisions in pollution controls and new capacity. Further, multi-pollutant legislation should ultimately guarantee the environmental benefits available under current authority, while offering a smoother transition. Several market-based, multi-pollutant legislative proposals have been debated in recent years. While recognizing that it would be politically difficult to advance new legislation, the BPC believes that this approach could provide public health and economic benefits and should be explored in the coming months.

[11] According to EPA, for units projected to retire from the Utility Air Toxics rule, the average capacity factor is 56 percent, the average age is 51 years, and the average size is 109 Megawatts.

[12] U.S. Environmental Protection Agency. Power Plant Mercury and Air Toxics Standards: Overview of Proposed Rule and Impacts. http://www.epa.gov/airquality/powerplanttoxics/pdfs/overviewfactsheet.pdf

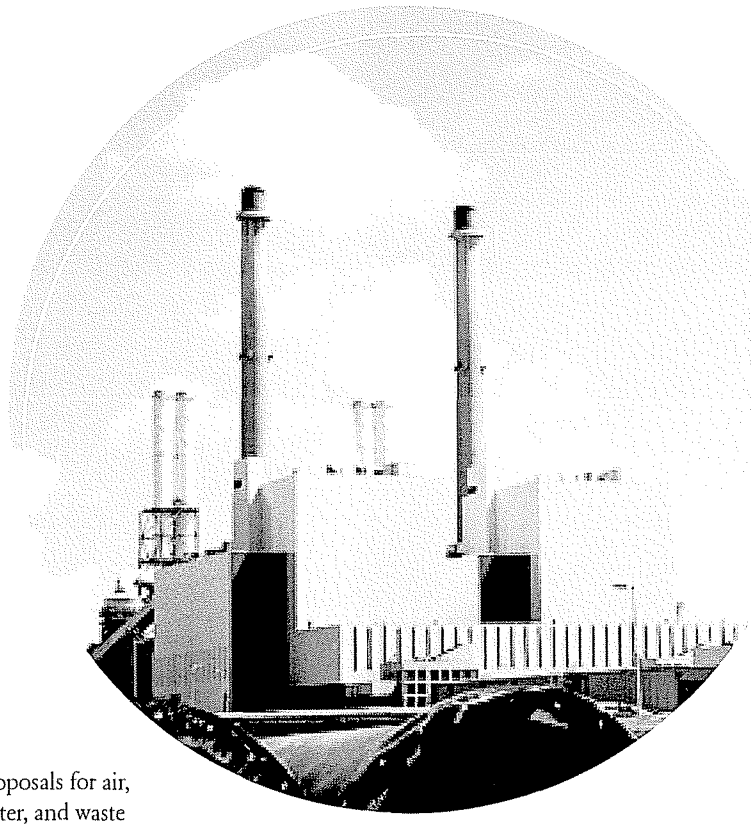
[13] See Section III and Appendix B for details on BPC analysis of the impacts of EPA regulations.



SECTION I

There continues to be debate about the effect of upcoming EPA regulations on power plant retirements and on the relative impact of these regulations compared to other factors, such as low natural gas prices and the continuing uncertainty surrounding carbon dioxide (CO_2) control. This is reflected in the range of conclusions reached by different analyses and in the spectrum of views that exists regarding whether compliance with the new regulations will present a challenge for the industry or not. Analysts disagree about how many existing coal plants are likely to be retired rather than retrofitted with new pollution controls. They also make different assessments about the ability of under-utilized existing generation, new capacity resources, and transmission upgrades to compensate for retired plants.

This report summarizes the current state of knowledge about challenges facing the electric power sector as it seeks to maintain reliability without jeopardizing important progress on public health and environmental protections.



Further, some analysts predict that the need to retrofit large numbers of power plants with pollution control equipment within a short timeframe could leave some plants unavailable for a period after the deadline until their compliance obligations are met. This is particularly a concern for Air Toxics requirements, which will take effect in 2015.

The result, according to some analysts, could be power shortages in some regions of the country that would create hardships for consumers and damage the economic recovery. However, other analysts contend that reliability concerns are unfounded or at the least overstated because under-utilized natural gas capacity, transmission from neighboring regions, and other resources are sufficient to compensate for the expected coal retirements. According to this view, even if there are legitimate localized reliability concerns, these concerns can be mitigated through a variety of technical, policy, and regulatory approaches.

Several of the EPA regulations that may have the greatest impact on coal plant retirements have not yet been finalized. However, with the issuance of recent EPA proposals for air, water, and waste regulations, including the March 16, 2011 Utility Air Toxics Rule proposal and the March 28, 2011 proposal on cooling water intake structures, the details are becoming clearer. These recent proposals provide some additional clarity on how new environmental regulations will affect power generation planning.

This report summarizes the current state of knowledge about challenges facing the electric power sector as it seeks to maintain reliability without jeopardizing important progress on public health and environmental protections. Section II of this report describes major market factors and regulations affecting the power sector and Section III summarizes and provides insights on key studies that attempt to predict the impact of EPA regulation and other variables. Section IV identifies strategies for mitigating reliability concerns and discusses the roles of regulators and stakeholders in facilitating a smooth power sector transition. The report concludes with a series of findings and recommendations on how best to meet these challenges.

SECTION II

In the next decade, our nation's electric power system is expected to transition to a more modern fleet of generators. A key element of this anticipated transformation is the retirement of a significant amount of older and increasingly uneconomic coal-fired capacity. The transition itself will be driven by a range of factors, including low natural gas prices, state renewable portfolio standards, and the possibility of some form of future regulation of greenhouse gases. In addition, many coal plants already face economic challenges as they near the end of – and in some cases, exceed – their design life expectancies.

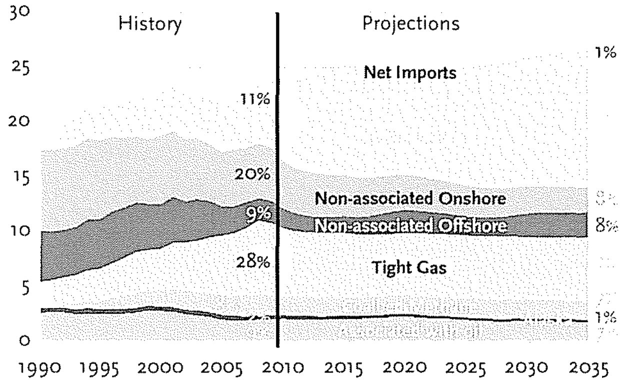
Finally, forthcoming EPA regulations for air quality, cooling water, and coal combustion waste will put additional pressure on plants that don't yet employ state-of-the-art pollution controls. It is difficult to determine the relative impacts of these factors, but a new era of low and stable natural gas prices—the result of a substantial increase in domestic supply—is expected to be an influential driver of electric power sector market conditions and resource choices for the next several decades.

The discovery of vast shale gas basins in the United States, combined with technological advances in horizontal drilling and hydraulic fracturing that make it possible to access these resources, has dramatically changed the domestic natural gas supply outlook (see Figure 1). As new shale gas resources have been developed in recent years, natural gas prices have declined (see Figure 2). They are now projected to remain at levels lower than during the previous decade.[14]

Domestic reserves of natural gas are projected to support more than 100 years of demand at present levels of consumption.[15] Annual U.S. consumption of natural gas across all sectors currently totals approximately 22 trillion cubic feet (Tcf); the electric sector accounts for roughly one-third of this total, or nearly 7 Tcf of annual demand.[16] To give some sense of the current supply context, a recent MIT study titled *The Future of Natural Gas* estimates that approximately 400 Tcf of shale gas in the United States could be developed economically with gas prices at or below $6 per million British thermal units (MMBtu) at the well-head.[17] ICF International, Inc. also recently estimated that almost 1,500 Tcf of total gas can be produced at prices below $5/MMBtu and that the same volume of shale gas alone could be produced at prices below $8/MMBtu.[18]

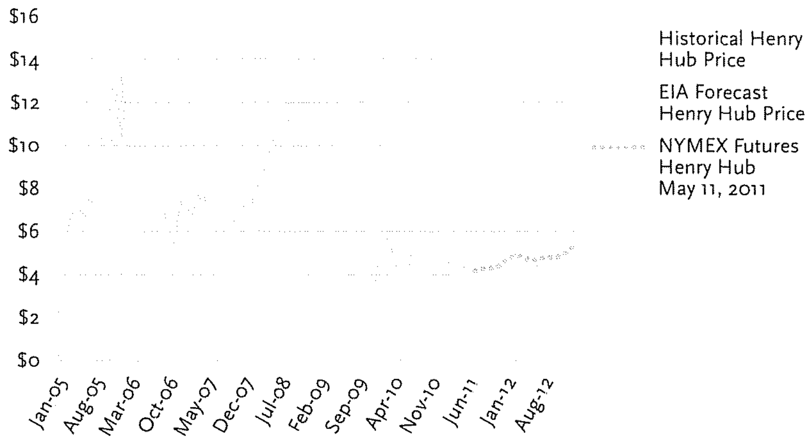
Natural gas plays an interesting role in the power sector's changing supply outlook, as both a driver of coal plant retirements and a solution to potential resource and reliability concerns. Lower gas prices will make some existing coal-fired capacity uneconomic. They may also encourage utilities to increase capacity utilization at existing natural gas-fired plants and, where both types of units are available, dispatch natural gas plants in place of some coal plants. Natural gas has already increased

FIGURE 1: FORECASTED U.S. NATURAL GAS PRODUCTION



Source: U.S. Energy Information Administration. History: Annual Energy Review 2009. Projections: Annual Energy Outlook 2011.

FIGURE 2: PROJECTED NATURAL GAS PRICES



Sources: U.S. Energy Information Administration. Short Term Energy Outlook. May 10, 2011. NYMEX Henry Hub Natural Gas Futures. May 11, 2011.

[14] U.S. Energy Information Administration. Annual Energy Outlook (AEO) 2011. Natural Gas Supply, Disposition, and Prices. The EIA AEO 2011 projects natural gas prices will be nearly $1.24/MMBtu lower, on average through 2030, than their AEO2010 estimate.

[15] Colorado School of Mines. Potential Gas Committee. Potential Supply of Natural Gas in the United States. 2009.

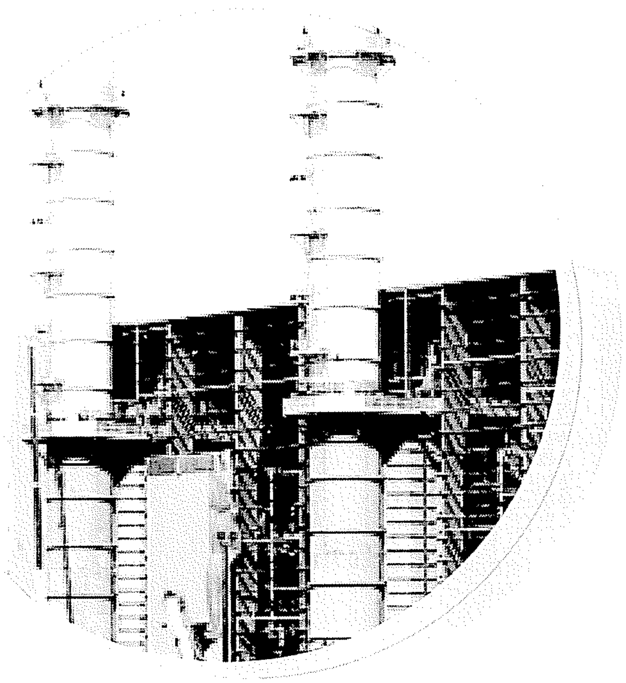
[16] U.S. Energy Information Administration. Natural Gas Consumption by End Use. Data released April 29, 2011.

[17] Massachusetts Institute of Technology. The Future of Natural Gas: An Interdisciplinary MIT Study. Xii.

[18] ICF International. 2010 Natural Gas Market Review, prepared for the Ontario Energy Board. August 2010.

its share of the generation fuel mix during the past few years, displacing some coal generation.[19] In addition, as coal plants retire due to changing economics, low gas prices may provide strategic opportunities to transition to gas-fired capacity at a relatively low cost.

Projections of future low natural gas prices are also changing the market dynamics for investment in renewable and nuclear power technologies, which have relatively higher capital costs. In an environment of low and stable gas prices, these low- and no-carbon sources may have difficulty competing with natural gas absent further incentives or policy interventions (e.g., renewable portfolio standards).



State renewable electricity standards have spurred continued growth in clean energy resources, despite low natural gas prices. Such standards, together with federal policies to incentivize clean energy, also impact electric sector investment decisions. As of January 2011, twenty-nine states and the District of Columbia have a Renewable Electricity Standard (RES) or similar policy to promote utility investment in renewable energy, energy efficiency, or other clean resources.[20] Legislation to establish a national renewable electricity standard or clean energy standard has also been introduced at the federal level. Some of these proposals would include nuclear and advanced fossil fuel-based systems with carbon capture and sequestration. The Obama Administration has proposed this latter type of clean energy standard, which would incorporate a broader portfolio of generation resources, including natural gas (as opposed to a portfolio standard that is limited to renewables).

EPA has already proposed multiple regulations for the power sector. These regulations will lead to capital investments in new technologies and pollution controls over the next fifteen or so years. The four rules that are expected to have the greatest impact are the Transport Rule, the Utility Air Toxics Rule to ensure compliance with National Emission Standards for Hazardous Air Pollutants (NESHAP), Coal Combustion Waste Disposal Regulations (known as the coal ash rule), and Clean Water Act Section 316(b) regulations for Cooling Water Intake Structures. With the exception of the ash rule, EPA has been directed by the courts to conduct these rulemakings in response to litigation over earlier rulemakings.

CLEAN AIR TRANSPORT RULE

On August 2, 2010, EPA proposed a replacement for the Clean Air Interstate Rule (CAIR), which had been previously remanded in a 2008 court decision. The new Clean Air Transport Rule (CATR), which EPA expects to finalize in the summer of 2011, will require 31 states and Washington, DC to meet new state-level pollution limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_X). Specifically, power plant emissions of SO_2 will have to be reduced by 71 percent from 2005 levels by 2014 and power plant NO_X emissions will have to be reduced by 52 percent from 2005 levels. These reductions are intended to ensure compliance with ozone and fine particulate matter (PM) National Ambient Air Quality Standards (NAAQS). The new Transport Rule limits interstate trading of emission allowances, while the remanded CAIR had allowed unrestricted trading between states. The new Transport Rule also differs from the CAIR proposal in that it precludes previously banked allowances from being used to demonstrate compliance with its new caps.

[19] U.S. Energy Information Administration. Annual Energy Outlook 2011. Electricity Supply, Deposition, Prices, and Emissions.

[20] Database of State Incentives for Renewables & Efficiency. Summary map of RPS policies. www.dsireusa.org. Accessed May 2011.

The previous CAIR proposal, which EPA issued on March 10, 2005, would have permanently capped power sector emissions of SO_2 and NO_X in the eastern United States. The purpose of CAIR was to reduce the interstate transport of pollutants that contribute to non-attainment of fine PM and ozone NAAQS. At the time it was proposed, the health and environmental benefits of this rule were valued at 25 times the estimated cost of compliance.[21]

In July 2008, the US Court of Appeals ruled that CAIR's tradable emission allowance scheme was "fatally flawed" and violated the Clean Air Act (CAA) because it could not ensure that trading would not contribute to another state's non-attainment of the NAAQS. In other words, the Court found that CAIR's trading provisions did not guarantee the ambient air quality improvements needed to achieve the NAAQS in downwind areas. While the court remanded CAIR, it ruled that CAIR would remain in effect until the EPA developed a lawful alternative.[22]

As proposed on August 2, 2010, the Transport Rule would regulate NO_X and SO_2 emissions from electric generating units in the East under a regional cap-and-trade program with limited interstate trading.[23] New NO_X and SO_2 caps would first become binding in 2012 (called "Phase I" in the Transport Rule), and power plants in a limited subset of states would become subject to more stringent "Phase II" caps on SO_2 emissions beginning in 2014.

The compliance options expected to be deployed under the Transport Rule's SO_2 caps include low-sulfur coal, wet and dry scrubbers–known as flue gas desulfurization (FGD) systems–and dry sorbent injection (DSI) with sodium-based sorbents, such as sodium bicarbonate or Trona. Expected options for compliance with the Transport Rule's NO_X caps include low NO_X burners, selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR). The Transport Rule is intended to address interstate contributions to violations of three specific NAAQS: the 1997 ozone NAAQS and the 1997 and 2006 NAAQS for $PM_{2.5}$. EPA may soon issue updated and more stringent NAAQS for both of these criteria pollutants, and subsequently may issue additional Transport Rules for the control of interstate

> EPA has already proposed multiple regulations for the power sector and has been directed by the courts to conduct these rulemakings in response to litigation over earlier rules.

NO_X and SO_2 emissions after 2014. These successors to the Transport Rule could be implemented within a range of deadlines around 2016-2018, depending on how quickly EPA makes key determinations and how the agency interprets certain timing provisions of the CAA.

UTILITY AIR TOXICS RULE

The 1990 Clean Air Act Amendments include a section (Section 112) on hazardous air pollutants that require EPA to regulate the sources of 90 percent of such emissions by 2000.[24] Because electric generating units were also to be regulated under other sections of the Act in ways that would provide some co-benefits in hazardous air pollutant reductions, Congress required a study and finding to determine if air toxics from electric generating units remained a significant source of concern. In December of 2000, EPA determined that it was "appropriate and necessary" to regulate coal and oil-fired power plants under Section 112.[25]

In 2005, however, EPA reversed course and found that it was neither appropriate nor necessary to regulate power plants under Section 112. At that point EPA removed electric generating units from the list of sources subject to 112.[26] In a March 15, 2005 rulemaking known as the Clean Air Mercury Rule (CAMR), mercury was delisted as a hazardous air pollutant (HAP) and a cap-and-trade policy was enacted under Section 111 of the Clean Air Act with the aim of reducing mercury emissions from coal-fired power plants by 70 percent (i.e., from a national baseline of 48 tons to 15 tons by 2018).[27] On February 8, 2008, the US Court of Appeals for the DC Circuit found that EPA violated the CAA by delisting electric generating units from the Act's toxics provisions and vacated the CAMR.[28,29]

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[21] U.S. EPA. Clean Air Interstate Rule. http://www.epa.gov/cair.

[22] Fozard, Colette. "Interstate Air Pollution Rule Granted Temporary Stay of Execution." Energy Legal Blog. http://www.energylegalblog.com/archives/2009/01/05/1311.

[23] Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone. 75 Fed. Reg. 45,210 (Aug. 2, 2010). (Transport Rule).

[24] Clean Air Act Section 112(n)(1)(A)

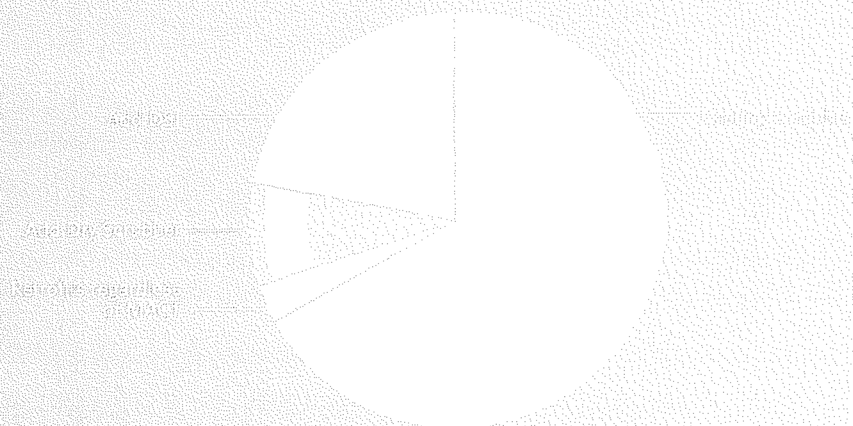
[25] 65 FR 79,825

[26] 70 FR 15,994

[27] U.S. EPA. Clean Air Mercury Rule. http://www.epa.gov/camr/basic.html.

[28] State of New Jersey v. EPA, 517 F.3d 574, 583 (D.C. Cir. 2008), cert. denied, 129 S. Ct. 1308, cert. dismissed, 129 S. Ct. 1313 (2009).

[29] Davis, Tracy. "DC Circuit Orders Immediate Tightening of Mercury Control Rules." Energy Legal Blog. http://www.energylegalblog.com/archives/2008/03/25/1354.

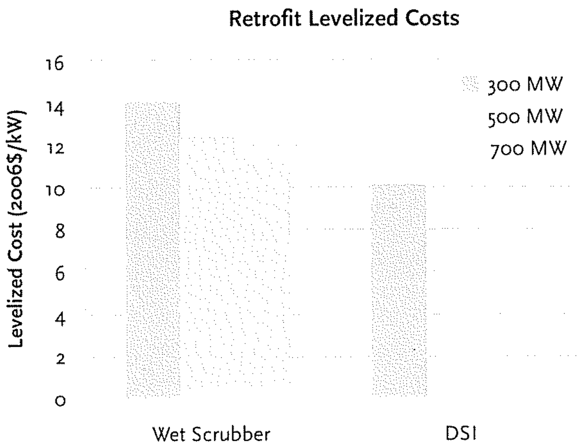


On March 16, 2011, EPA proposed emission standards for electric generating units under Section 112, consistent with the court ruling. The court ordered a final rule to be issued by November 16, 2011.

The proposed Utility Air Toxics Rule sets emission limitations for three pollutants: mercury, particulate matter, and hydrogen chloride (HCl) based on the average emission rates actually achieved by the top 12% of performers. The standards were designed to assure the achievement of required reductions in the larger category of air toxics. For dioxin/furan, EPA proposed work practice standards based on good combustion practices.

To comply with the Utility Air Toxics Rule, it may be necessary to upgrade or retrofit particulate controls and add activated carbon injection to reduce metallic toxics at many units. In addition, to meet the acid gas HCl limit at uncontrolled plants, it may be necessary to choose between a wet scrubber, dry scrubber, and dry sorbent injection.[31] Specifically, in order to meet the requirements of the Utility Air Toxics Rule, EPA's modeling projects 56 GW of DSI installed in addition to the 9 GW in the base case (for a total of 65 GW) and that 22 GW of Dry FGD will be installed in addition to the 4 GW projected to retrofit in the base case (for a total of nearly 27 GW of dry scrubber installs). EPA projects the Utility Air Toxics Rule will not require installation of any additional Wet FGD beyond 6 GW projected to retrofit in the base case to meet the Transport Rule.[32] If existing pollution controls are included in the count, EPA projects a total of 175 GW of wet scrubbers, 53 GW of dry scrubbers, and 65 GW of DSI will be in place when compliance with the Air Toxics Rule is achieved.[33]

FIGURE 4: COMPARISON OF ANNUAL COSTS OF A WET SCRUBBER VS. DRY SORBENT INJECTION



Source: Technology cost assumptions used in BPC modeling of EPA regulation scenarios, with levelized capital, fixed and operating costs of flue gas desulfurization (wet scrubber), compared with representative cost of dry sorbent injection. Site-specific costs are dependent on various factors including location, fuel-type, and complement of controls. DSI costs are shown for units less than or equal to 300 MW, based on BPC conservative modeling assumption to only offer DSI for such smaller units burning low sulfur coal.

In terms of capital costs, the most expensive control technology for compliance with the Utility Air Toxics Rule is a wet scrubber, as seen in Figure 5 (page 18). Capital costs for an alternative, dry sorbent injection, are significantly lower. On a levelized cost basis, however, the difference is far less significant. Figure 4 shows that the on-going costs for dry sorbent injection, including costs to ship and store large amounts of chemical sorbent, approach the annualized cost of a wet scrubber.

EPA estimates the average annualized cost of compliance with the Utility Air Toxics Rule at $10.9 billion. Estimated net benefits for this rule–taking into account health and other benefits, as well as compliance costs–are estimated to range from $48 billion to $129 billion per year (in 2007 dollars), according to EPA.[34]

COAL COMBUSTION WASTES (ASH) DISPOSAL REGULATIONS

On June 21, 2010, EPA published a proposed rule to take comment on whether or not coal combustion wastes should be treated as hazardous waste.[35] One option would regulate ash as a special waste under subtitle C of the Resource Conservation and Recovery Act (RCRA), which sets guidelines for the management of solid waste. (Currently, coal combustion waste is not covered by subtitle C.) Within the hazardous waste regulations, the coal ash would be classified as a "special waste" to

[31] Some companies suggest that DSI is not a proven option for HCl MACT compliance because there is still limited public data on HCl removal from full-scale DSI applications. On the other hand, a recent study by a national engineering firm endorsed DSI for HCl removal. See Lipinski, G., J. Leonard, C. Richardson. Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants. URS Corporation. April 2011.

[32] U.S. EPA Base Case pollution control installations include those retrofits projected to occur in the period 2010 through 2013 to comply with the 2012 and 2014 SO_2 and NO_X caps in the Transport Rule.

[33] Data on the number of retrofits and existing controls was calculated from EPA data files from EPA IPM runs to support the Utility Air Toxics Rule. Files: ToxR Base Case and ToxR Policy Case. Found at http://www.epa.gov/airmarkets/progsregs/epa-ipm/toxics.html. Accessed April 1, 2011.

[34] U.S. Environmental Protection Agency. Fact Sheet: Proposed Mercury and Air Toxics Standards. http://www.epa.gov/airquality/powerplanttoxics/pdfs/proposalfactsheet.pdf.

[35] Unofficial proposals were issued May 4, 2010. For additional information and the proposed rule see: http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ccr-rule/index.htm

TABLE 1. KEY DIFFERENCES BETWEEN SUBTITLE C AND SUBTITLE D OPTIONS

Effective Date	Timing will vary from state to state, as each state must adopt the rule individually-can take 1 - 2 years or more	Six months after final rule is promulgated for most provision: certain provisions have a longer effective date
Enforcement	State and Federal enforcement	Enforcement through citizen suits; States can act as citizens.
Corrective Action	Monitored by authorized States and EPA	Self-implementing
Financial Assurance	Yes	Considering subsequent rule using CERCLA 108 (b) Authority
Permit Issuance	Federal requirement for permit issuance by States	No
Requirements for Storage, Including Containers, Tanks, and Containment Buildings	Yes	No
Surface Impoundments Built Before Rule is Finalized	Remove solids and meet land disposal restrictions; retrofit with a liner within five years of effective date. Would effectively phase out use of existing surface impoundments	Must remove solids and retrofit with a composite liner or cease receiving ash within 5 years of effective date and close the unit
Surface Impoundments Built After Rule is Finalized	Must meet Land Disposal Restrictions and liner requirements. Would effectively phase out use of new surface impoundments.	Must install composite liners. No Land Disposal Restrictions
Landfills Built Before Rule is Finalized	No liner requirements, but require groundwater monitoring	No liner requirements, but require groundwater monitoring
Landfills Built After Rule is Finalized	Liner requirements and groundwater monitoring	Liner requirements and groundwater monitoring
Requirements for Closure and Post-Closure Care	Yes; monitored by States and EPA	Yes; self-implementing

Source: U.S. Environmental Protection Agency

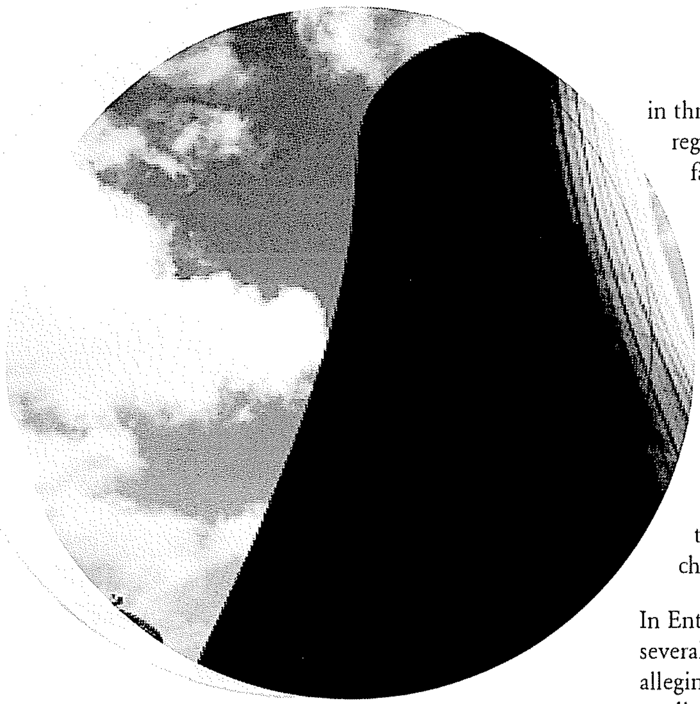
avoid the stigma associated with a hazardous designation and to allow continued beneficial uses of coal ash.[36] This option would regulate ash disposed in landfills and surface impoundments from all electric utilities and independent power producers. Coal ash would be regulated from the point where it is generated to final disposal. This means generators and transporters, as well as facilities that manage, treat, or store coal combustion waste would be subject to regulation.

A second option would instead regulate coal ash under subtitle D of RCRA. Under this proposal, EPA would establish performance standards for landfills and surface impoundments where coal combustion waste is disposed, but it would not regulate its generation, transport, or pre-disposal treatment. Under subtitle D, EPA does not have authority to enforce its requirements.

In practice, regulation under either subtitle C or subtitle D will require many of the same control technologies (see Table 1) including modifications to remove solids, line surface impoundments, and improve wastewater treatment. The main difference is whether or not the requirements are state vs. federally enforceable. While subtitle C would establish federally enforceable "special waste" provisions, the subtitle D option would establish self-implementing requirements for "non-hazardous waste" that are not federally enforceable. In the latter case, enforcement actions could only be triggered by citizen suits (including suits brought by states).

The proposed rule estimates a range of regulatory costs: \$3–\$20 billion over the life of the program or average annualized costs ranging from \$236 million to \$1.5 billion. There is some concern that designating coal

[36] Presently, coal combustion waste is used for a number of beneficial uses Coal ash has a number of agricultural and highway applications and gypsum products are frequently used in wallboard production.



combustion waste as "special waste" may further increase costs if it has the effect of constraining beneficial uses of coal ash, such as in wallboard and concrete. Materials that cannot be put to use will require disposal and, instead of representing a source of revenue, will contribute to additional costs. When factoring in the environmental benefits of the regulation, EPA estimates the average annualized net benefits of its rule will range from approximately $193 million to $18 billion.

CLEAN WATER ACT SECTION 316(B) COOLING WATER INTAKE STRUCTURES

Section 316(b)of the Clean Water Act (CWA) requires EPA to develop regulations on cooling water intake structures at electric generating units (EGU) and other industrial facilities that use large amounts of cooling water for purposes of reducing the mortality of aquatic species due to impingement and entrainment.[37,38] Specifically, the Act requires EPA to demand that cooling intake structures use the "best technology available for minimizing adverse environmental impact."[39] EPA originally promulgated these regulations in three phases: Phase I (covered in a 2001 rulemaking) regulates new facilities (both EGUs and industrial facilities); Phase II (issued in 2004) regulates existing EGUs that use large amounts of cooling water; Phase III (issued in 2006) establishes requirements for other facilities that use cooling water intake structures.[40]

The Phase I regulations require the use of closed-cycle cooling systems on new facilities. The Phase II regulations on existing facilities did not, however, establish a similar requirement. Instead, EPA set performance standards based on mortality rates. These standards could be met through a variety of technologies and would be chosen by cost-benefit analysis.[41]

In Entergy Corp. v. EPA, environmental groups and several states filed suit against the Phase II regulation alleging that the decision to not require closed-cycle cooling violated the Clean Water Act. In 2007, the Second Circuit Court ruled that the use of cost-benefit analysis to determine best technology available (BTA) is inadmissible under Section 316(b) and remanded several provisions of the rule. EPA subsequently suspended the Phase II regulations.[42]

After appeals by EPA and industry, the case went to the Supreme Court, which in April 2009 reversed and remanded the Second Circuit's decision, allowing the BTA to be determined by cost-benefit analysis.[43] The Supreme Court ruling did not hold that 316(b) *requires* cost-benefit analysis, only that it could be used.

At present, EPA's earlier regulations remain suspended, which means that compliance determinations are being decided on a case-by-case basis by the permitting authority, usually the state. EPA's new proposed rulemaking on March 28, 2011 will address these and other issues from court rulings on the earlier Phase I, II, and III rulemakings. Under the Clean Water Act's Section 316(b), EPA has considerable discretion with respect to the application of cooling water constraints that minimize entrainment and impingement, and the Agency's recent proposal draws on this flexibility.

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[37] 33 U.S.C. § 1326(b)

[38] Impingement is when fish are pinned against water intake screens or other parts at the facility. Entrainment is when aquatic organisms are drawn into cooling water systems

[39] For more information see U.S. EPA. Water: Cooling Water Intakes (316b). Basic Information. http://www.epa.gov/waterscience/316b/basic.htm. Phase II addresses large existing power plants that are designed to withdraw 50 million gallons per day or more and that use at least 25 percent of their withdrawn water for cooling purposes only.

[40] Affected facilities have a design intake flow threshold of greater than 2 million gallons per day and withdraw at least 25 percent of water for cooling purposes. See http://www.epa.gov/waterscience/316b/phase3/ph3-final-fs.html.

[41] *Entergy Corp. v. Riverkeeper, Inc.* 556 U.S. (2009)

[42] 72 FR 37107

[43] Ibid.

Under the Clean Water Act's Section 316(b), EPA has considerable discretion with respect to the application of cooling water constraints that minimize entrainment and impingement

Facilities with design intake above 2 million gallons per day, that withdraw at least 25 percent of their water from an adjacent water body for cooling, must submit information and limit the number of fish killed by being pinned against intake screens or equipment (impingement) and sucked into the water intake system (entrainment). Many existing facilities may have to install screens, make modifications to existing technology or take measures to reduce intake velocity. The EPA proposal includes additional requirements for facilities that use very large quantities of water (i.e., actual water intake above 125 million gallons per day). Facilities that exceed this threshold must submit additional information regarding entrainment, including a study that compares the costs and benefits of installing a cooling tower versus alternative technology. Lastly, the proposed water rule requires the use of cooling towers, or their equivalent, for any new unit capacity additions built at an existing facility (the requirement does not apply to capacity replacements).

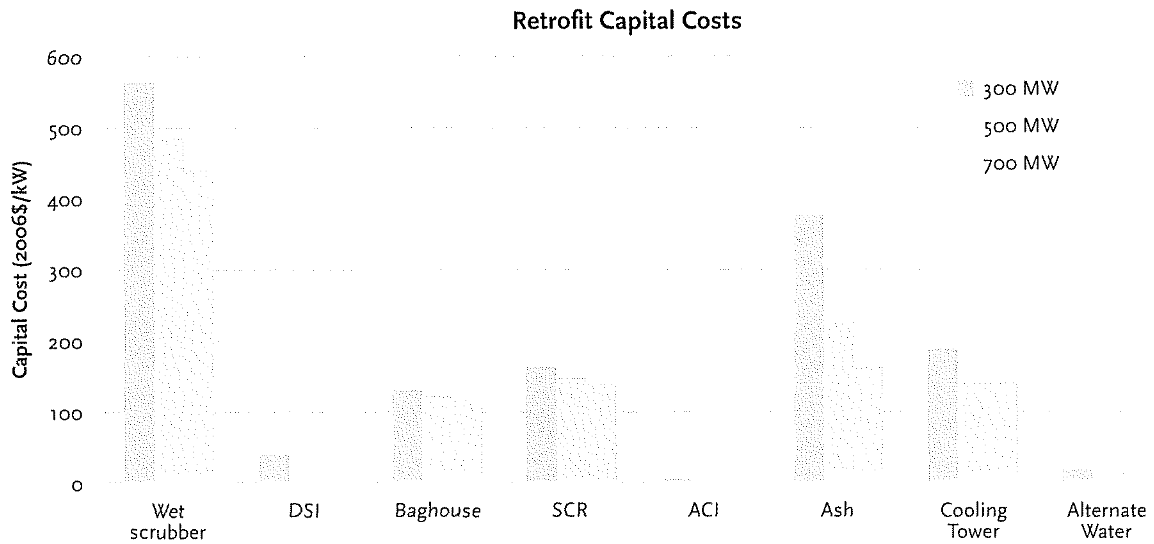
RELEVANT POLLUTION CONTROL TECHNOLOGIES

Although many existing plants will comply with some or all of the various EPA regulations based on their current configuration and already installed controls, some will require new pollution controls. Table 2 identifies some of the control technologies expected to be used for compliance with upcoming EPA regulations.[44] Figure 5 compares the relative capital cost to install such technologies on existing electric generating units.

EPA REGULATIONS AND RELIABILITY CONCERNS

The timeline for forthcoming EPA regulations has prompted concern that grid reliability issues could arise in some parts of the country as utilities comply with pollution regulations. These concerns center on the combined effects of new EPA rules on plant retrofits and retirements and on the condensed compliance timeline for the Utility Air Toxics Rule, in particular. Figure 6 lays out a likely timeline for compliance with these regulations. The figure shows that 2014 and 2015 are likely to be the most constrained years as power plant owners prepare to comply with the Air Toxics Rule.

FIGURE 5. ESTIMATED RETROFIT CAPITAL COSTS OF RELEVANT TECHNOLOGIES



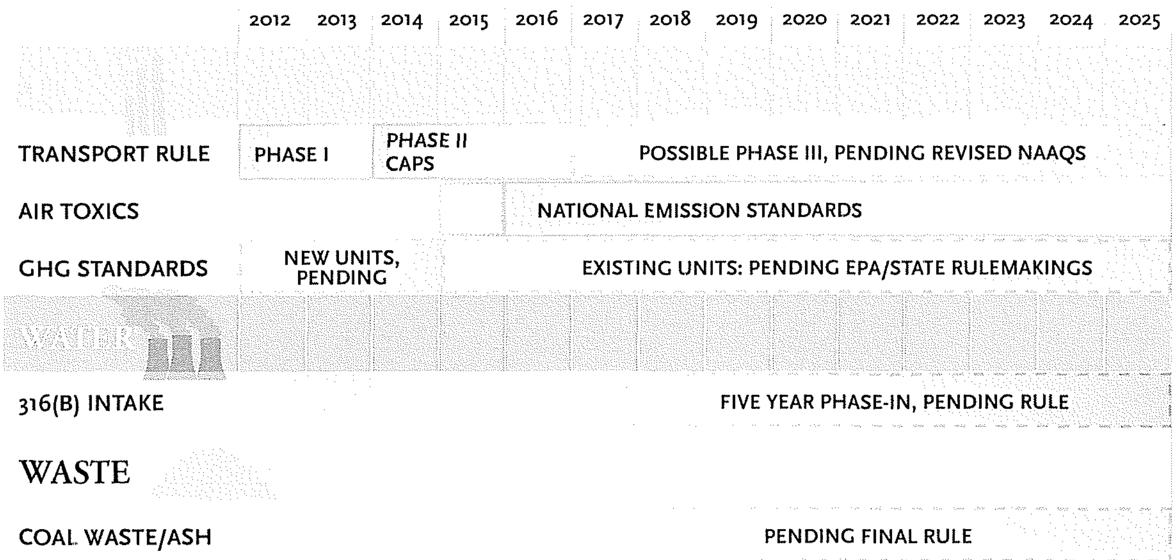
Note: The capital cost of a dry scrubber is estimated to be 10-20% lower than that of a wet scrubber.
DSI costs are shown for units less than or equal to 300 MW, based on BPC conservative modeling assumption to only offer DSI for such smaller units burning low sulfur coal.
Source: Technology capital cost assumptions used in BPC modeling of EPA Regulation scenarios.

[44] For additional information about control technologies see Lipinski, G., J. Leonard, C. Richardson. Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants. URS Corporation. April 2011.
Staudt, James E. and M.J. Bradley & Associates. Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants. March 31, 2011.
Fessenden, Jamie. NESCAUM (Boston, MA). Multi-pollutant Emission Reduction Technology for Small Utility Boilers. Presentation to Lake Michigan Air Directors Consortium, Innovative Industrial Source Control and Measurement Technologies Workshop. March 24, 2010.

TABLE 2. EPA REGULATION AND EXPECTED CONTROL TECHNOLOGIES

Acid Gases:[45] Air Toxics HCl & HF, plus Sulfur Dioxide (SO_2)	Wet scrubber *or* Dry scrubber + Particulate Controls
	or Dry Sorbent Injection (DSI) + Particulate Controls
Metallic Toxics/Particulate Matter	Baghouse/Fabric Filter *or* Electrostatic Precipitator (ESP)
Mercury	Activated Carbon Injection (ACI) + Particulate Controls
	or Wet scrubber + Selective Catalytic Reduction (SCR)
NO_X	Selective Catalytic Reduction (SCR)
	or Selective Non-Catalytic Reduction (SNCR), low-NO_X burners, etc
Coal Ash	Dry ash handling + ash pond liners, etc
Cooling Water Intake	Screens, barrier nets, low velocity caps, etc
	or Cooling Tower
GHG Performance Standards	Efficiency upgrades or, potentially, biomass co-firing

FIGURE 6. TIMELINE OF EPA REGULATIONS IMPACTING THE POWER SECTOR



[45] The acid gases hydrogen chloride (HCl) and hydrogen fluoride (HF) are regulated under Section 112 of the Clean Air Act. By contrast, SO_2 is regulated as a conventional "criteria" pollutant under the NAAQS provisions of the Act.

SECTION III

A. CURRENT TRENDS IN THE POWER SECTOR

As has already been noted, a number of market factors are likely to lead to the retirement of a significant number of coal-fired power plants, even absent EPA regulation. These include:

- Aging coal-fired power plants. About 33 percent of the existing coal-fired fleet is over 40 years old, and most of this aging capacity lacks environmental controls. These units tend to be small and relatively inefficient, and therefore do not operate near full capacity. These units are likely to become increasingly uneconomic.

- Low gas price projections. Recent advances in drilling technology for natural gas have lead to a dramatic reassessment of the magnitude of potentially available U.S. natural gas resources, and an associated decline in projected prices. Although coal-fired power plants have historically enjoyed a cost advantage over natural gas-fired plants, this cost advantage is diminishing, and older, inefficient plants are likely to become increasingly uneconomic as a result of gas prices alone.
- Ongoing uncertainty about the future regulation of carbon dioxide (CO_2) makes it even less likely that companies will invest in aging plants.

Consideration of these factors alone has led some analysts to project significant coal plant retirements over the next decade, even absent EPA regulation. For example, EEI's January 2011 analysis projected 22 GW of coal retirements in the reference case (i.e., with no new regulation) by 2015. In its October study, NERC reported that 13 GW of upcoming retirements were already announced or committed, prior to EPA's proposals for Utility Air Toxics and cooling water rules.[46]

This section summarizes the projected impacts of forthcoming EPA regulations on retirements in the power sector. In particular, it reviews findings from several existing studies along with some key underlying assumptions, with a focus on results pertaining to plant retirements and implications for resource adequacy.

BPC review of existing studies and our own modeling suggests that the actual number of retirements due to EPA regulations will be at the lower end of the range of published projections.[47] This is primarily because most analyses assume that the EPA regulations (particularly 316(b) and Utility Air Toxics) will require much more costly controls than EPA's recent proposals indicate. Analyses of resource adequacy also tend to use these retirement projections in combination with capacity projections that do not reflect how market drivers will influence the construction of additional capacity (or demand side management). As a result, these studies are likely to overstate risks to resource adequacy.

A number of studies, compared in Table 3, have evaluated the potential retirements that are likely to result from market conditions and forthcoming EPA regulations. These studies vary in terms of the regulations they cover; the assumptions they make about the stringency, timing, and cost of regulations; and the general methodology and other market assumptions they apply. It is important to consider the implications of each of these factors.

Because some studies do not include an estimate of "business-as-usual" (BAU) retirements in the absence of EPA regulations, and because the studies make different assumptions about electricity demand, fuel prices, and other variables that impact the number of retirements in the baseline case, it is not possible in many cases to determine the incremental number of retirements being projected as a result of EPA regulations. Therefore, BAU retirements are included in the total coal retirements reported in the table below.

REGULATIONS COVERED

Studies have also differed with respect to the scope of environmental regulations examined. A number of studies look only at the potential impact of upcoming air emissions rules (e.g., the Transport Rule and Utility Air Toxics Rule), while others also evaluate the impact of regulatory scenarios for cooling water, coal ash, tighter NO_X requirements to incorporate NAAQS revisions, and/or future greenhouse gas constraints. EPA's modeling for the Utility Air Toxics Rule, the CRA and PIRA studies, and some of the EIA AEO2011 EPA regulation sensitivity runs, are all limited to the Transport Rule and Utility Air Toxics Rule. The Credit Suisse analysis and an EIA AEO2011 run include tighter NO_X requirements beyond the Transport Rule, while the Brattle Group also looks at a scenario that includes the water rules. The modeling from BPC and EEI referenced in Table 3 includes EPA rules on air (Transport Rule, Utility Air Toxics Rule, and future NO_X), water, and ash. The ICF analysis quoted in the table includes air, water, and ash, plus a CO_2 price.

Based on a review of studies and internal BPC analysis, as well as recent EPA proposals, we conclude that the most important *regulatory* driver of projected coal plant retirements, and hence of possible reliability concerns, is the Utility Air Toxics Rule. But other non-regulatory factors, including low natural gas prices, may be as important. The uncertainty regarding future carbon constraints, even without an immediate regulatory driver, is also significant as it may lead some plant operators to forego life-extending pollution control investments on inefficient coal plants. Cooling water and ash regulations will increase costs for some facilities, but are not expected

[46] North American Reliability Corporation. 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations. October 2010. Page 8.

[47] See Appendix B for additional information about BPC modeling using ICF's Integrated Planning Model.

TABLE 3 COMPARISON OF COAL RETIREMENTS FROM SELECTED STUDIES AND SCENARIOS

EIA AEO2011 April 2011	TR, Mercury	**14-18 GW total**	The high ends represent retrofit cost recovery in 5 yrs vs 20. "TR, Air Toxics, NO_x" assumes wet FGD & SCR on each unit. Nat gas price below AEO2011 (≈$4/mmBtu) brings second case retirements up to 40-73 GW.
	TR, Air Toxics, NO_x	**19-45 GW total**	
EPA March 2011	TR, Toxics	**23 GW total** *(including 10 GW incremental)*	Modeling for Utility Air Toxics Rule (Toxics) proposal; Transport Rule (TR) included in the baseline and not in the incremental retirements.
BPC March 2011	TR, Toxics, Coal Ash, 316(b), NO_x	**29-35 GW total** (15-18 GW incremental)	Assumes ACI, Fabric Filter and either wet FGD or DSI for Utility Air Toxics Rule. DSI only for units <300 MW with low sulfur coal. Cooling towers if >500 MGD design intake. Stricter NO_x by 2018. Low end of the range results from higher AEO2010 natural gas price.
EEI January 2011	TR, Toxics, Coal Ash, 316(b), NO_x	**46-56 GW total** (24-34 GW incremental)	Low end estimates reflect availability of lower cost compliance strategies for some units. EEI scenarios that include CO_2 price are excluded.
CRA December 2010	TR, Toxics	**39 GW total** (includes 6 GW planned *retirements)*	Assumes ACI, fabric filter, and FGD for Utility Air Toxics Rule. Assumes AEO2010 natural gas price.
Brattle Group December 2010	TR, Toxics	**40-55 GW total** (34-49 GW 2020 incremental)	Doesn't identify specific assumptions for each rule, but assumes SCR and scrubber on every coal unit by 2015. Cooling towers on all coal units by 2015 for 316(b).
	TR, Toxics, 316(b), NO_x	**50-66 GW total** (44-60 GW 2020 incremental)	
ICF December 2010	TR, Toxics, Coal Ash, 316(b), NO_x, +CO_2 price	**70 GW total** by 2018 (including 10 GW of announced retirements)	For Utility Air Toxics Rule, scrubber, ACI, and baghouse assumed for all units. For 316(b), cooling towers on units drawing from coastal and estuarine water bodies. Retirement estimates also reflect cap-and-trade program for CO_2 emissions that begins in 2018.
NERC October 2010	TR, Toxics, 316(b), Coal Ash	**10-35 GW** by 2018 *(excludes 13 GW committed/* announced retirements, which may include non-coal units)	Range reflects 'Moderate' and 'Strict' scenarios. Both assume cooling tower required for 316(b) the primary driver of retirements. For Utility Air Toxics Rule, both assume FGD (with SCR, or ACI + baghouse).
Credit Suisse September 2010	TR, Toxics, NO_x	**60 GW total**	Assumes retirement of all small plants without SCR or FGD, and half of small plants with SCR but no FGD.
PIRA April 2010	TR, Toxics	**30-40 GW total**	This analysis was quoted in a study by MJ Bradley/ Analysis Group.

Note: Coal retirement estimates are reported for 2015 if available Total coal plant retirements, including those already announced and projected in the reference case, even absent EPA regulations, are reported, where available. Where available, incremental retirements resulting from the EPA rules are reported in parentheses

Sources:

- U.S. Energy Information Administartion. Annual Energy Outlook 2011 With Projections to 2035. DOE/EIA-0383(2011). April 2011. Page 4 http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf
- U.S. Environmental Protection Agency. Regulatory Impact Analysis for the Utility MACT Proposed Rule. March 2011 http://www.epa.gov/ttn/atw/utility/utilitypg.html
- Edison Electric Institute, with analysis performed by ICF International. Potential Impacts of Environmental Regulation on the U.S. Generation Fleet. January 2011.
- Charles River Associates. A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT. December 2010.
- Brattle Group. Potential Coal Plant Retirements Under Emerging Environmental Regulations. December 2010.
- ICF International. ICF 2010 Quarter 4 Integrated Energy Outlook: Summary of Analysis Results. December 2010.
- North American Reliability Corporation. 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations. October 2010. (page 63 coal retirements plus page 8 committed/announced.)
- Credit Suisse. Growth from Subtraction: Impact of EPA Rules on Power Markets. September 2010.
- PIRA. EPA's Upcoming MACT: Strict Non-HG Can Have Far-Reaching Market Impacts. April 2010.

to have a strong influence on reliability because of long compliance periods and low numbers of retirements, beyond those units expected to retire due to other factors. For example, in their most stringent scenario, the NERC study estimates that only 388 additional MW retire as a result of the ash rule alone; EEI's most stringent scenario for ash retires an incremental 6 GW by 2020.[48] The impact of future NO_X rules, which are yet to be proposed, will depend on how those rules are designed.

STRENGTH AND TIMING OF REGULATIONS

Generally, the available studies assume that EPA will promulgate regulations at the stringent end of the spectrum of what is possible. This assumption proved least accurate in the case of the 316(b) cooling water proposed requirements, which were signed March 28, 2011, after the referenced studies were undertaken.

Those studies generally assumed that EPA's rule would require all units to install cooling towers and move to closed cycle cooling systems. This assumption–which was not borne out in EPA's actual proposal–adds as much as 40 GW of plant retirements to the projected outcome in some analyses.

According to EPA, an estimated 70 percent of existing facilities are not expected to require a cooling tower under the new rule because their actual intake flow is below the threshold of 125 million gallons per day (MGD) and EPA expects lower cost screens and intake velocity measures to allow compliance with impingement mortality limits.[49,50] Even for facilities with actual intake above 125 MGD, EPA's proposed rule would require a cooling tower only if the state permitting authority made a site-specific determination that alternatives would not be adequate and also demonstrated that the benefits of a cooling tower outweigh the costs. Given typical valuations of fish death and ecosystem damage, it may prove difficult for states to demonstrate that benefits outweigh the cost of a new cooling tower, particularly if such a requirement would lead a plant to retire.

Furthermore, the proposed rule requires states to consider the remaining useful life of the affected facility and any electric reliability impacts. Considering that the units most vulnerable to retirement are generally well past 40 years old, it seems even less likely that a case-by-case determination would require a cooling tower installation (with a deadline of 2022 for fossil units) on plants that would be, by then, another decade older than they are today. Thus, many of the remaining 30 percent of units which are subject to a cooling tower study may comply with less expensive alternatives and the 316(b) rule may not lead to significant retirements.

The EEI study includes a sensitivity run "Alternative Water Case," which requires cooling towers on a subset of existing units with design intake flow above 125 MGD that draw water from oceans, estuaries, and tidal rivers. Even this case, however, is likely more stringent than the EPA water rule. First, the EPA threshold is based on actual intake flow. By contrast, the EEI study used design intake flow–which is often considerably higher–as the threshold to determine which units might be affected. Second, even for facilities with actual intake flows above the EPA threshold, the state case-by-case determination is likely to avoid a cooling tower requirement for at least some, if not most, facilities.

The referenced analyses also vary in terms of their assumptions about when cooling towers would be required. The NERC study appears to have the most aggressive timing assumptions. It assumes 316(b) will require cooling towers on all nuclear and fossil units by 2018. NERC projected that the 316(b) rule alone would result in about 40 GW of retirements by 2018. The EEI study maintains the assumption that cooling towers are broadly required on existing units, but delays compliance until 2020 for fossil units and 2027 for nuclear units.[51] As actually proposed, the EPA rule requires impingement controls, such as screens to be in place by 2020. If cooling towers are required, compliance is required by 2022 or 2027 for fossil and nuclear plants, respectively.

An additional variable related to regulatory stringency involves the expectation of deeper NO_X reductions beyond the first and second phases of the Transport Rule. Some analyses (including EIA, Brattle Group, Credit Suisse, and most EEI scenarios) assume that all units will be required to install selective catalytic reduction (SCR), the most costly control technology for NO_X. However, many units are expected to meet their compliance obligations–under the Transport Rule for units in the East and under Best Available Retrofit Technologies (BART) requirements in the West – using lower cost technologies, such as selective non-catalytic reduction (SNCR) or low

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[48] EEI. Potential Impacts of Environmental Regulation on the U.S. Generation Fleet. January 2011. Page 13.

[49] Federal Register Notice pre-publication. U.S. EPA Proposed Rule for Cooling Water Intake Structures, Section 316(b), Clean Water Act. March 28, 2011. Page 86.

[50] However, industry sources have expressed concern that site-specific factors or permitting decisions may lead to cooling towers to reduce impingement and entrainment mortality at facilities below the threshold.

[51] EEI specifies water policy assumptions of cooling towers required by 2022 for fossil and 2027 for nuclear. However, the IPM version supporting their analysis does not include a model year for 2022 and EEI chose to map the 2022 compliance date to the years 2020. EEI. Potential Impacts of Environmental Regulation on the U.S. Generation Fleet. January 2011. Page 12

NO_x burners. Beyond the current Transport Rule, future NAAQS revisions are expected to tighten NO_x control requirements, but there is little indication that SCR would be required on all units nationwide.

TECHNOLOGY AND COST ASSUMPTIONS

Existing studies make different assumptions about the capital and operating costs of pollution control technologies and about the costs of providing replacement capacity. Moreover, these assumptions are not always clearly and explicitly identified even though they play an important role in determining the number of retirements projected. All else equal, studies that assume higher control costs predict higher levels of retirements.

A major discrepancy between various analyses is the assumed cost of compliance with Utility Air Toxics Rule limits for acid gases. This has a notable effect on their findings with respect to number of retirements, retrofits, and price impacts. With the exception of EPA, BPC, and two sensitivity runs in the EEI analysis, all other studies assume that compliance with acid gas limitations in the Utility Air Toxics Rule will require a scrubber–the most expensive control technology related to the suite of upcoming EPA regulations–by 2015. By contrast, EPA's analysis in support of its Utility Air Toxics Rule includes DSI, in combination with particulate controls, as a compliance option to achieve acid gas limits. EPA's assumed costs for DSI are based on a detailed engineering cost analysis.[52]

BPC analysis also assumes that DSI, in combination with a fabric filter, is an option to comply with the acid gas Utility Air Toxics Rule standard, but BPC makes a conservative assumption to limit DSI to smaller units less than 300 MW that burn low sulfur coal. The NERC analysis as well as the main policy scenarios in EEI's January 2011 analysis do not allow compliance with DSI and instead require a scrubber on every unit for compliance with the Utility Air Toxics Rule. EEI does include a sensitivity run "Alternative Air Case" that allows dry sorbent injection to comply with the acid gas limit for smaller units less than 200 MW. According to the EEI analysis, the availability of DSI as a compliance option reduces expected cumulative coal retirements in 2015 by 10 GW.

FUEL PRICE ASSUMPTIONS

Fuel price assumptions for coal and natural gas will also impact the economics of individual plants. Because natural gas-fired capacity competes with coal-fired capacity, lower natural gas prices lead to the displacement of coal-fired generation in the reference case, and result in older, less-efficient coal plants becoming uneconomic.

MARKET RESPONSE

Studies vary in how they simulate the electricity market. Some studies (e.g., NERC, Brattle) do a static analysis of facilities that are at risk of retirement, comparing projected operating costs under the regulation (using generic cost factors and fuel price projections) with expected revenue based on forward electricity price projections. However, these studies do not account for the impact of the regulations themselves on electricity or fuel prices. For example, electricity prices are expected to rise as a result of the regulations, such that expected revenues will likely be higher than projected. This feedback effect would likely reduce the number of expected retirements. Other studies (EEI, EPA, and BPC) utilize dynamic power sector models that attempt to capture the effect of changing electricity and fuel prices on the cost of generation.

COMBINED SCENARIOS

With the exception of the BPC analysis, EEI's sensitivity scenarios–the "Alternate Air Case" and the "Alternative Water Case"–come closer to modeling the actual requirements and technology options for recently proposed EPA regulations than do the other referenced studies. However, EEI's analysis does not include a scenario that approximates the actual proposals for both the Utility Air Toxics Rule and the cooling water proposals together. Instead, the "Alternative Air Case" includes more stringent water requirements and the "Alternative Water Case" does not allow for lower cost air controls consistent with EPA's new regulations as recently proposed. *Thus, most of the referenced studies probably overstate the cost and number of retirements likely to be associated with forthcoming EPA regulations.*

BPC analysis using ICF's Integrated Planning Model used many assumptions similar to the EEI study (see Appendix B). The BPC analysis includes a scenario that allows for some of the lower cost Utility Air Toxics Rule controls (i.e., dry sorbent injection instead of a scrubber for units less than 300 MW) and less stringent water requirements (i.e., cooling towers on facilities which draw more than 500 MGD and operate above 35% capacity factor). These BPC assumptions, result in 20-25 GW of DSI installations instead of scrubbers as well as cooling tower installations on 93 facilities (no

[52] Sargent & Lundy. IPM Model – Revisions to Cost and Performance for APC Technologies: Dry Sorbent Injection Cost Development Methodology August 2010. Found at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/append5_4.pdf.

incremental retirements are projected from the water rule).[53] BPC assumptions result in a projected 15-18 GW of incremental coal plant retirements by 2015 from the suite of EPA regulations, with no additional incremental retirements through 2030. When factoring in BAU retirements in the reference case (14 GW of coal and 23 GW of oil/gas BAU retirements), the BPC analysis results in 57-58 GW of overall retirements by 2030.

Plant retirements alone are not the only factor to consider in evaluating the system reliability impacts of environmental regulation. Another relevant issue is resource adequacy, or the extent to which expected available generation resources will be capable of meeting forecasted demand. Planning authorities evaluate resource adequacy periodically, generally by assessing reserve margin levels and loss of load expectation (LOLE) for the relevant location.[54] Resource adequacy is a useful metric for planning purposes, though it provides limited insight into operational reliability (operational reliability is the ability to serve all customers at all locations at all times of day). Operational reliability depends not only on capacity availability, but on conditions in local transmission and distribution systems.

Where existing capacity surpluses are not sufficient to maintain reserve margin requirements in the presence of retirements, new capacity will have to be added to maintain resource adequacy. This new capacity could be in the form of new generation or demand side resources. In competitive markets, higher spot market prices and forward capacity markets will provide an incentive to construct new capacity. In regulated markets, the requirement to submit integrated resource plans for approval serves as a vehicle for identifying new capacity needs and planning accordingly.

Existing analyses vary in the way that they assess the issue of new capacity and apply the methodology and analytical tools at hand. For example, some electricity sector models inherently assume that all of the necessary capacity resources will be constructed in order to meet reserve margin requirements.[55] While such modeling cannot be used to directly draw conclusions about resource adequacy or reliability, the amount of new capacity projected to be built in response to retirements and other market changes can be instructive. This type of modeling can shed light on how much capacity will be needed, and in what timeframe, to maintain resource adequacy. For example, the January 2011 EEI analysis projects that 7 to 18 GW of incremental new capacity will be required nationally by 2015 due to the suite of EPA regulations–this is in addition to 66 GW of new capacity in the base case.[56] These capacity projections fall well within the realm of what the industry has constructed in recent periods. A CRA study found that over the period 1999–2004, the industry constructed 177 GW of natural gas-fired capacity alone.

A handful of the studies discussed in the table above attempt to make the link between projected retirements and implications for resource adequacy. By comparing projected retirements in specific regions against projected reserve margins, these studies attempt to highlight areas where there could be capacity shortfalls if adequate planning and new capacity construction does not occur.

- With respect to the Utility Air Toxics Rule, EPA concludes that projected coal plant retirements "are not expected to raise broad reliability concerns" and points to the existence of sufficient excess capacity to take up the slack for projected retirements, which the Agency estimates will total less than 10 GW. EPA calculates that the Utility Air Toxics Rule will reduce the national weighted average reserve margin by just a few percent below the 25 percent reserve margin level projected in the baseline scenario. This compares to a NERC recommended reserve margin of 15 percent. According to EPA modeling, resource adequacy is maintained in each region where coal retirements occur primarily by using excess reserve capacity and by "reversing base case retirements of non-coal capacity, building new capacity, or importing excess reserve capacity from other regions."[57] For the water

[53] For comparison, EPA modeling for the proposed water rule includes scenarios of cooling tower installations ranging from 46 facilities – affecting only baseload and load-following facilities – to 76 facilities, including the largest fossil plants that draw from tidal waters.

[54] The reserve margin is calculated as the difference between available generation capacity and expected peak demand, divided by peak demand. Sometimes calculated reserve margins are compared against region-specific North American Electric Reliability Corporation (NERC) Reference Reserve Margin levels or, if a regional reference level is not provided, against reserve margins assigned by NERC based on capacity mix. LOLE measures the number of days per year that available resources will be insufficient to serve peak daily demand; this is typically assessed through probabilistic modeling. NERC recommends an LOLE of 0.1, which implies that the system may fail to serve peak load no more than 1 day in 10 years.

[55] EPA, EEI, and BPC all use ICF's Integrated Planning Model to make these assessments. The ICF planning model assumes that all necessary capacity resources will be constructed as needed to meet reserve margins.

[56] These numbers are incremental to the capacity additions that are projected under the reference case by 2015. The projections cited here do not include EEI scenarios that included a price on CO_2 emissions.

[57] U.S. EPA. Regulatory Impact Analysis for the Utility Air Toxics Rule proposed rule. March 29, 2001. Found at: http://www.epa.gov/ttn/atw/utility/utilitypg.html. Page 234-236.

[57] U.S. EPA. Utility Air Toxics Rule Information Collection Request. Regulatory Impact Analysis for the Utility MACT proposed rule. Found at: http://www.epa.gov/ttn/atw/utility/utilitypg.html. March 29, 2011. Page 234-236.

rule, EPA made an overall determination that none of the technology options would cause unacceptable reliability concerns at the national level. But to avoid concern at individual sites, the rule will require permitting authorities to consider reliability impacts in their case by case determinations.[58]

- A December 2010 analysis by The Brattle Group, which assumes that scrubbers, SCR, and cooling towers are required on all plants by 2015, finds that reserve margins would fall below NERC reference levels in 2018 in the Reliability First Corporation (RFC) region (which includes parts of the Mid-Atlantic and the eastern Midwest) and in the Electric Reliability Council of Texas (ERCOT) region if new resources are not added.[59]

- CRA evaluated expected 2015 capacity at the level of regional transmission organizations (RTOs), NERC regions, and NERC sub-regions in comparison with reserve margin requirements for that year. At the RTO level, the study found that all regions with projected retirements were expected to meet and exceed reserve margin requirements in that year. At the NERC region level, the CRA study found modest reserve margin shortfalls in the Midwest Reliability Organization (MRO) region, and de-minimis shortfalls in the RFC and Southeast Reliability Corporation (SERC) regions. Looking at the NERC sub-region level, CRA found that the greatest potential resource adequacy impact was likely to occur in the Virginia-Carolinas (VACAR) subregion of SERC. However, nearly half of the projected capacity needed for this region is already in planning stages, but was excluded from the analysis. The CRA study concluded that a combination of coal-to-gas conversions, new gas-fired generation, load management, and existing market and regulatory safeguards would be sufficient to maintain reliability.

- The NERC study estimated that 10 to 35 GW of coal-fired capacity could be at risk of retirement by 2018, when factoring in the Transport Rule, Utility Air Toxics Rule, Coal ash, and 316(b) rules. It is important to note that NERC's aggressive assumption for 316(b) is the biggest driver of retirements, even in NERC's 'moderate' case.[60] Comparing projected retirements under its moderate case against NERC region-level estimates of capacity resources, the NERC study identified SERC as the region most at risk of capacity shortfalls. The study also identified potential capacity shortages in Arizona and New Mexico, and in the southern Nevada sub-region of the Western Electric Coordination Council (WECC). When more conservative (lower) estimates of available capacity resources are used, NERC projects potential shortages in those regions, as well as in the MRO region, New England, Texas, and the Rocky Mountain Power Area.[61] According to NERC, building new capacity, or advancing in-service dates of planned capacity additions, could help to alleviate projected losses.[62] In addition, NERC's updated 2010 demand forecasts and planned new capacity additions were not incorporated into their special assessment of EPA regulations and would have trended toward greater capacity reserves.

- The MJ Bradley and Analysis Group report notes that "the electric sector is expected to have over 100 GW of surplus generating capacity in 2013, about three times the 30 to 40 GW of total retirements projected by PIRA Energy Group" (in its analysis of the impact of the CATR and the Utility Air Toxics Rule).[63] This is largely due to much slower than expected demand growth resulting from the recession. The report further notes that the RFC and SERC regions, where expected retirements are greatest, are projected to have reserve margins of 24.3 percent and 26.3 percent respectively. Again, these figures are well above the 15 percent Reference Margin Level that NERC assigns to most regions.

While most studies have taken a national approach to the reliability assessment, it is clear that some regions will be more vulnerable during this transition period. More study is warranted to assess localized reliability impacts in the most vulnerable regions.

Although reliability concerns have mostly focused on plant retirements, there are also concerns about the ability of affected sources to install control technologies in time to meet compliance deadlines–particularly for the Utility Air Toxics Rule –and about the implications

[58] Federal Register Notice pre-publication. U.S. EPA Proposed Rule for Cooling Water Intake Structures, Section 316(b), Clean Water Act. March 28, 2011. Page 55.

[59] For a map of NERC regions, see http://www.eia.doe.gov/cneaf/electricity/chg_str_fuel/html/fig02.html.

[60] In both the moderate and strict cases, NERC assumes cooling towers on all facilities, 25 percent higher costs are assumed for the strict scenario.

[61] NERC compares potential retirements in individual regions against Summer Peak Deliverable capacity Resources and Summer Peak Adjusted Potential Capacity Resources. The former is the more conservative estimate.

[62] NERC. 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations. October 2010. Page V.

[63] M.J. Bradley & Associates LLC and Analysis Group. Ensuring a Clean, Modern Electric Generating Fleet While Maintaining Electric System Reliability. August 2010. Referencing NERC. 2009 Long-Term Reliability Assessment: 2009-2018. October 2009. And PIRA Energy Group ("PIRA"). EPA's upcoming MACT: Strict Non-Hg Can Have Far Reaching Market Impacts. April 8, 2010.

for consumer costs. Some fear that the need to install large numbers of controls on a system-wide basis in a relatively short timeframe could lead to constraints in financing or materials, which in turn could drive up the cost of compliance.

In its Regulatory Impact Analysis for the proposed Utility Air Toxics Rule, EPA predicts the rule will lead to the installation of scrubbers on an additional 24 GW of capacity; the application of DSI to an additional 56 GW of capacity; the application of ACI to an additional 93 GW of capacity; and the use of SCR on an additional 3 GW of capacity.[64] In addition, EPA predicts that additional fabric filter retrofits will be installed on 49 GW of capacity to comply with the Utility Air Toxics Rule –this is on top of fabric filter installations to meet other Clean Air Act requirements, for a total of 165 GW of capacity with new fabric filters by 2015.[65] Because EPA's assessments project fewer retirements than other studies, they generally project the highest number of control installations. However, installations required before the 2012 and 2014 Transport Rule caps take place are not included in the cited EPA Utility Air Toxics Rule retrofit estimates. In addition, because EPA has more bullish assumptions about DSI, they project fewer scrubbers and more DSI than either the BPC or EEI analyses assume. BPC projects up to 51 GW of scrubbers may be constructed in 2013, 2014, and 2015, in addition to 24 GW of DSI.

Once permitted, most pollution control projects can be implemented in less than two years from design to start-up without the need for outage or with the final step occurring during a regularly scheduled maintenance period, so as to avoid additional outage time. According to a recent report, installing scrubber systems can require from two to three years for a dry system and 24 to 44 months for a wet system from the design through construction stage.[66, 67] The high end of the range is typically associated with more challenging installations due to site-specific limitations. Plants generally continue to operate throughout most of this time, but the final step of "tying in" or connecting the scrubber system typically requires that the plant be shut down for four to eight weeks. Often this step can be completed during a regularly scheduled maintenance outage.

Rate recovery determinations and permitting processes can add to these timeframes. A number of states have avoided a time crunch by passing legislation and/or by entering into agreements with power companies that provide for early planning, timely rate recovery decisions, and a schedule for control installations and retirements. In areas that have not taken such anticipatory steps, however, waiting until after the final Utility Air Toxics Rule is signed in November 2011 to begin a lengthy approval process may be problematic, particularly if site-specific challenges have the effect of complicating scrubber installations and extending the time required to complete needed pollution control retrofits. This highlights the need for plants to immediately begin planning and designing for pollution controls.

None of the economic analyses undertaken to date have directly addressed the issue of staging retrofits. Nevertheless, insufficient planning and coordination between generating companies and state, regional, and federal institutions could result in higher than necessary costs for consumers. For example, if a large number of companies delay retrofits until close to the deadline in order to defer capital costs as long as possible or waiting for state approvals, numerous retrofits may be scheduled in close proximity, leaving the grid potentially vulnerable to supply disruptions if multiple plants go off line at the same time. This could result in higher electricity prices as more costly generation resources are dispatched to supply electricity. Section IV of this report discusses some possible strategies that could be used to manage the timing and coordination of pollution control retrofits.

[64] U.S. Environmental Protection Agency. Regulatory Impact Analysis for the Utility Air Toxics proposed rule. March 29, 2011. Found at: http://www.epa.gov/ttn/atw/utility/utilitypg.html. Page 8-13.

[65] Ibid.

[66] See Lipinski, G., J. Leonard, C. Richardson. Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants. URS Corporation. April 2011. Particulate upgrades can be completed in 12-24 months with an outage of less than 2 weeks, or up to 4 weeks if a new fan is required for a Fabric Filter upgrade (page A-3). ACI requires up to eighteen months, but no outage time (page A-9). DSI requires nine to twelve months from design to start-up, but no additional outage (page A-11).

[67] Because the formula for the Air Toxics regulation was mandated in the 1990 Clean Air Act, many companies have already begun the planning, design and, in some cases permitting and construction for pollution control equipment, in advance of the final rulemaking. Companies will have 45 months, with the opportunity to ask for a one year extension that allows 57 months, from the March 2011 Utility Air Toxics Rule proposal until the compliance deadline. Some companies say it takes an average of 54 months to install a scrubber and 4-5 years to install a baghouse, including planning, design, permitting/regulatory approval, constructing, and start-up of the control device.

SECTION IV

Federal, regional, and state institutions will play a key role in ensuring reliability as the electricity sector transitions to a new regulatory regime. These organizations have a variety of authorities and tools at their disposal to ease the transition and to help avoid significant impacts on reliability. This section describes the roles of various authorities in addressing reliability issues associated with new environmental requirements.

Environmental Protection Agency

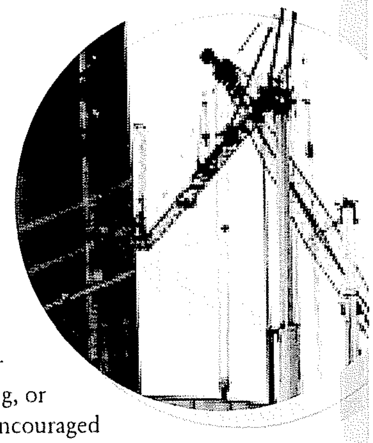
EPA provides analytical and technical support to regulated entities, state authorities, and other federal agencies in planning for and implementing new environmental regulations. In addition, Congress usually grants the Agency specific authorities and discretion in the implementing legislation for each major rulemaking, which are described below.

EPA Discretion on the Utility Air Toxics Rule

Although the Utility Air Toxics Rule is largely prescriptive, EPA does have some discretion to provide flexibility on certain provisions. The following provisions were included in the March 15, 2011 proposed Utility Air Toxics Rule and should be included in the final rule:

- Emissions averaging among units at a facility within the same sub-category.
- Provisions for units that infrequently burn oil, based on the proposed limited-use subcategory for infrequently operated oil-fired units, as well as the exemption for units that burn oil less than 10 percent of the time under the definition of fossil fuel-fired unit.[68]
- Work practice standards for dioxins/furan. EPA chose not to specify emissions limits for these pollutants, but simply required units to employ good combustion practices.
- Alternative performance standards that reduce monitoring requirements for some types of technologies.
- The use of surrogates for certain hazardous air pollutants.
- A 30 day averaging period in demonstrating compliance with the standards for coal-fired power plants.

For the proposed Utility Air Toxics Rule, EPA's discretion on the timing of implementation is limited by the explicit text in Section 112 of the Clean Air Act, which requires that sources come into compliance within three years of the promulgation of the rule.[69] This results in an expected deadline of January 2015. However, Section 112 also allows the permitting authority to extend this compliance deadline by one year, if companies demonstrate that, despite good faith efforts, more time is needed to install pollution controls.[70,71] In its March 15, 2011 proposal, EPA indicated a willingness to apply this extension in order to stagger installations for reliability or constructability purposes or for other site-specific construction issues, permitting, or local manpower or resource challenges.[72] EPA encouraged companies to begin early discussions with the permitting authority to facilitate extensions, where warranted. EPA should encourage permitting authorities to make timely decisions and grant extensions in advance, with appropriate conditions, where warranted.



EPA also requested comment on whether such an extension could be granted to complete on-site replacement capacity, rather than install controls, at an affected facility. BPC agrees that this would be an appropriate and beneficial interpretation of the Clean Air Act waiver authority. The states or EPA, as applicable, could and should use this waiver authority to allow an extra year for those electric generating units unable to complete control installation or build on-site replacement capacity in time, particularly where reliability is a concern.

As a backstop, EPA has the ability to exercise enforcement discretion and negotiate consent decrees with regulated entities in order to allow for their continued operation. Any such consent decrees, however, should eliminate economic advantages a plant might otherwise obtain as a result of operating out of compliance. Consent decrees are negotiated once a company is deemed in violation, and stakeholders may not view this legal mechanism as an acceptable option that could be built into company planning. However, consent decrees do offer an additional means of backstop reliability protection.

Presidential Authority to Delay Utility Air Toxics Rule

As a backup to the other tools and flexibilities available to smooth the phase-in of new regulations, the President also has the ability to delay Utility Air Toxics Rule requirements for some facilities, if warranted. Although this authority has never been invoked, the President is *explicitly permitted under Section 112 of the Clean Air* Act to grant an additional exemption from compliance (beyond the one year extension from states) for up to two

[68] The Utility Air Toxics Rule proposes a definition of "fossil-fuel fired" for purposes of determining if an electric generating unit is subject to the rule. According to this proposal, the unit must have fired coal or oil for more than 10 percent of the annual average heat input during the last 3 calendar years or for more than 15 percent during any one of those calendar years to be subject to the Utility Air Toxics Rule.

[69] 42 U.S.C. § 7412(i)(3)(A).

[70] In most cases, the permitting authority has been devolved to states that administer their own operating permit programs under Title V of the CAA. In a few instances, such as tribal lands, EPA retains this permitting authority.

[71] 42 U.S.C. § 7412(i)(3)(B).

[72] U.S. Environmental Protection Agency. Proposed Utility Air Toxics Rule. Signed March 16, 2011. Page 443. www.epa.gov/ttn/atw/utility/pro/proposal.pdf.

In addition, EPA has proposed and should finalize compliance deadlines that provide sufficient time for planning, coordination, and installations.

years if the "technology to implement such a standard is not available" and if the exemption is found to be in the "national security interests of the United States."[73] This exemption may be renewed an unlimited number of times provided the requisite findings are made.

Presumably, the President could interpret the term "available" to encompass both technological and economic feasibility, consistent with the interpretation of that term in the context of "best available control technology" for Prevention of Significant Deterioration permitting. In addition, a threat to electric reliability could presumably serve as grounds for determining that it is in the "national security interests" of the United States to extend the Section 112 compliance deadline.

EPA Discretion on Cooling Water Rule

The Clean Water Act provides EPA with extensive discretion on the compliance timing and stringency of regulations for power plant cooling water intake. In its proposal, EPA relied on this flexibility and on cost/benefit considerations with respect to entrainment provisions to allow alternative technologies where appropriate, to accommodate site-specific constraints, and to allow sufficient time for retrofits.

EPA's March 2011 proposal requires the largest water users to conduct a study to determine whether cooling towers or alternative technologies are needed to limit damage from aquatic life being sucked into cooling water intake systems (entrainment). Study results would be considered along with other factors–such as the useful life of the facility, reliability concerns, and the benefits versus costs of installing a cooling tower–to make a site-specific determination of the "best technology available" for a particular facility. In addition, EPA's proposed cooling water rule requires facilities to meet impingement mortality limits or reduce intake velocity. In its final rulemaking, EPA should exercise its authority to allow the consideration of site-specific factors and cost-benefit analysis with respect to impingement requirements.

In addition, EPA has proposed and should finalize compliance deadlines that provide sufficient time for planning, coordination, and installations. For example, under the proposed rule, plant owners are allowed eight years to install technologies such as screens, low velocity caps, and barrier nets. The installation of cooling towers is allowed to take five to ten years in the case of existing fossil plants, or ten to fifteen years in the case of existing nuclear plants.

EPA Discretion on Coal Ash Rule

EPA also has significant flexibility to establish compliance deadlines for its proposed RCRA regulations governing the disposal of coal combustion waste, including coal ash. In its proposal, EPA took comment on whether or not coal ash should be treated as hazardous waste.[74] One option would regulate coal ash as a "special waste" under the hazardous waste Subtitle C of RCRA, whereas an alternative option would regulate the ash as non-hazardous waste under Subtitle D. The primary difference between the alternatives is that EPA retains enforcement authority under Subtitle C, whereas Subtitle D requirements would be self-implementing with no federal enforcement authority. Aside from enforcement, the actual requirements are quite similar for the two proposed options. For example, both alternatives would eventually require that surface impoundments for coal combustion waste have leachate collection and removal systems; alternatively, the impoundments would have to be closed. EPA's proposed Subtitle D regulation would require these controls to be installed by April 2017, whereas the proposed Subtitle C regulation would allow states until 2018 to implement retrofit requirements.[75,76]

However, neither RCRA subtitle requires EPA to mandate compliance by any particular deadline. Subtitle D does not require that waste storage standards be implemented in any particular timeframe. And even if EPA adopts substantially more stringent requirements under Subtitle C, Section 3004(x) of RCRA also allows EPA to modify Subtitle C requirements for coal ash sites where justified by "practical difficulties." EPA may also allow site-specific variances from Subtitle C regulations for sites with distinctive geological, climatic or chemical

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[73] 42 U.S.C. § 7412(i)(4).

[74] See Hazardous and Solid Waste Management System, 75 Fed. Reg. 35,128 (June 21, 2010).

[75] This date is based on the following assumptions: 1) EPA promulgates the final CCW rule in September 2011; 2) RCRA regulations, including the coal combustion waste rule, generally take effect six months after promulgation–in this case, March 2012; 3) EPA's proposed Subtitle D regulations require retrofit within five years of the effective date of the regulation. Thus, retrofit would be required before April 2017.

[76] Under RCRA, Subtitle C regulations are subject to the same effective date provisions as Subtitle D regulations. However, most states administer RCRA requirements in lieu of EPA pursuant to a delegation of authority from the agency. In these states, certain core RCRA requirements included in new EPA regulations do not take effect until the state itself adopts a regulation reflecting the new EPA requirements–a process that RCRA usually requires to take place within one year of a new EPA regulation. Thus, the retrofit requirements under the proposed Subpart C regulations would not take effect in most states until one year later than the compliance deadline in the Subpart C regulations (April 2018).

characteristics.[77] This authority could be exercised to craft appropriate tailored deadlines for sites that are unusually difficult to retrofit, or to provide an across-the-board deferral in RCRA compliance deadlines (as EPA already proposed to do in its Subpart C regulation by changing the RCRA compliance deadline to five years from four years pursuant to its Section 3004(x) authority).

In its June 21, 2010 proposed rulemaking, EPA highlighted the environmental benefits, and lack of damages, from the beneficial reuse of coal combustion wastes in encapsulated uses such as wallboard, concrete, and bricks.[78] EPA should continue its efforts to support such beneficial reuses and *finalize the Bevill exemption for encapsulated beneficial reuse of coal combustion waste.*

DEPARTMENT OF ENERGY AND FEDERAL ENERGY REGULATORY COMMISSION

The Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) have specific authorities under the Federal Power Act to ensure the stability or reliability of the transmission grid. DOE and FERC authorities can be applied to avoid potential reliability issues or emergencies in the near term and, perhaps more effectively, to support long-term planning.

Addressing Near-Term Reliability Issues

While an emergency reliability issue is unlikely and should be preventable with proper planning and oversight, DOE and FERC have authority to address such situations if they arise. Under Section 202 of the Federal Power Act, the DOE can issue emergency orders to temporarily require a unit to generate and deliver electricity. In the past, this authority has been used to address a few, short-term reliability concerns.

FERC's relevant authority stems from its mission to ensure just and reasonable rates. FERC has authority to review the rates, terms, and conditions of "reliability-must-run" (RMR) contracts between a regional transmission organization or independent system operator (RTO/ISO) and a unit intended for retirement. These types of contracts are used in RTO/ISO markets when an RTO/ISO determines that a unit proposed for retirement is necessary to ensure system reliability. In such cases, the RTO/ISO can propose or enter into a RMR agreement to compensate the generator for continued operation based on cost-of-service rates or other rate agreements.[79] Through a number of recent rate reviews, FERC has indicated that RMR contracts should be considered a solution of last resort to maintain reliability.[80]

Both DOE's emergency orders and FERC-approved RMR contracts allow generators needed for reliability to be compensated for above-market costs of continued operation. If keeping such units online requires significant capital investments in pollution controls, the associated cost-of-service may be quite high. This would be the case, for example, if a unit were kept online at cost-of-service rates, retrofitted with pollution controls, and then retired well before the capital investment could be repaid. The generator might seek to amortize the relatively high costs of the retrofit investments over a short period (e.g., the term of the RMR contract or the DOE order) at the expense of ratepayers.

Alternatively, an RMR unit might operate for a period without pollution controls. This could be a lower cost solution, although the rate tariff could still provide for above-market payments. However, operation without compliant controls would violate emissions limits, as FERC's RMR authority does not supersede Clean Air Act requirements. As discussed below, such a situation would require coordination with EPA and enforcement discretion, such as the negotiation of a consent decree to continue operating for a period without controls.

FERC reviews RTO tariff provisions relating to RMR contracts under its general rate review authority (Sections 205 and 206 of the Federal Power Act), which requires that the rates, terms and conditions for provision of jurisdictional transmission service and wholesale sales must be just and reasonable and not unduly discriminatory or preferential. In some instances where FERC has found that an RTO/ISO violated its tariff provisions, FERC has intervened in RMR determinations (an example involving ISO New England and Dominion power company is discussed in the text box).

Long-Term Planning

DOE and FERC both have broad authorities to gather information and require public utilities to file reports. In addition, DOE has specific authority under Section 202 to require utilities to report on anticipated shortages of electricity or capacity, as well as on their plans to manage

[77] 42 U.S.C. § 6924(x).

[78] FR Vol 75, No 118 June 21, 2010. Coal combustion waste proposed rulemaking.

[79] In several organized markets, including Midwest ISO and California ISO, contractual or tariff requirements obligate the generator to negotiate RMR contracts to remain in operation if the RTO/ISO concludes that continued operation of the unit is necessary for reliability. In other markets, including PJM and ISO New England, the generator's decision to accept an RMR contract is voluntary.

[80] Devon Power, LLC, 103 FERC ¶ 61,082 (2003).

shortages. In addition, FERC has broad authority to conduct investigations, including subpoenaing witnesses and requiring companies to produce relevant materials.

Expanded Role for FERC

In the future, FERC could play an expanded role in monitoring RTO forward capacity markets. State PUCs have little authority to manage resource planning and generation adequacy in restructured states, where regulated utilities do not own generation resources but rather purchase electricity from wholesale markets under relatively short-term contracts. In lieu of resource planning, several RTOs have established forward capacity markets to attract new generation capacity and provide a price signal for economic retrofits of existing capacity. However, there is some concern that these markets may not provide sufficient price signals to ensure an adequate response to significant retirements of coal-fired capacity.

Thus, FERC could undertake an effort to consider: (1) whether some or all of the RTOs face resource adequacy

FERC Oversight of RMR Contracts: ISO-NE and Salem Harbor

Using its authority under the Federal Power Act, FERC recently intervened in an ISO-New England proceeding related to a reliability-must-run type contract for Dominion's Salem Harbor 3 and 4 coal-fired generating units. In December 2010, FERC's review of ISO-NE's fourth Forward Capacity Auction determined that ISO-NE had violated its tariff provisions in failing to identify alternatives to the reliability need for Salem Harbor.

Available surplus capacity contributed to several existing power plants and demand resources—a combined 1.2 GWs of capacity—opting out of the fourth ISO-NE forward capacity market auction by submitting de-list bids. However, ISO-NE determined that Dominion's Salem Harbor Units 3 and 4, in addition to Entergy's Vermont Yankee Station, could not withdraw from the market due to reliability concerns that would violate NERC, Northeast Power Coordinating Council (NPCC), and ISO-NE standards.

When ISO-NE rejects a de-list bid, their Forward Capacity Auction rules require them to look for ways to allow the generating unit to withdraw under an established timeline or, if no alternatives are available, provide compensation to retain the resource in a reliability-must-run type agreement. ISO-NE's Tariff requires that this process to identify alternatives must occur in advance of the new capacity qualification period for the subsequent Forward Capacity Auction.

Following ISO-NE's rejection of Salem Harbor's de-list bid, the Conservation Law Foundation (CLF) filed a protest which stated that ISO-NE failed to meet these procedural requirements and that this would result in unjust and unreasonable rates. ISO-NE responded by providing evidence that it repeatedly presented the specific reliability need for the Salem Harbor Units to the NEPOOL Stakeholders, including the Reliability Committee. ISO-NE also stated that because Dominion submitted a static de-list bid rather than a permanent de-list bid, Dominion did not indicate a permanent exit from the market that would trigger the need for a transmission solution. Resources that wish to withdraw from the market for a one-year period can submit either a static or a dynamic de-list bid. A permanent de-list bid withdraws the resource from all future auctions.

In December 2010, FERC concluded that ISO-NE's presentations did not satisfy the Tariff's procedural requirements. FERC ordered ISO-NE to submit a compliance filing within 60 days that either identifies alternatives to resolve the reliability need and the time to implement those solutions, or include an expedited timeline for identifying and implementing alternatives. According to CLF, such alternatives could include "energy efficiency, conservation, electric transmission line upgrades, and renewable energy."

In October 2010, Dominion submitted a permanent de-list bid for Salem Harbor.

ISO New England, Inc., 133 FERC ¶ 61,230.

Conservation Law Foundation Press Release, Federal Energy Regulatory Commission Order: ISO-NE to Plan for Closure of Salem Harbor Station, December 17, 2010.

concerns driven by EPA regulations; (2) whether capacity markets are a useful tool for assuring resource adequacy in markets facing such problems; and (3) whether Section 206 of the Federal Power Act should require the reform of existing capacity markets, or the establishment of capacity markets in RTOs where they do not now exist. In essence, the FERC review would consider how capacity markets in the organized markets could and should be used to address the issue of plant retirements. FERC could undertake such a review on an RTO-specific basis or on a generic basis covering all RTOs. FERC could act to amend current RTO tariffs to provide for capacity market reforms under Section 206 of the Federal Power Act, and could take such action in RTO-specific orders or in a generic notice and comment rulemaking. Although such actions may require more time than is available for dealing with reliability issues that arise in the 2015 Air Toxics Rule timeframe, they could potentially bolster the system to address future situations.

Supporting Alternative Capacity Resources

FERC is also involved in efforts to encourage the participation of alternative resources in wholesale energy markets administered by RTOs or ISOs. On March 15, 2011, FERC issued a Final Rule that attempts to level the playing field for alternatives to traditional generation by requiring competitive rates for demand response resources.

The term "demand response" generally refers to load management programs in which electricity customers volunteer to reduce their electricity consumption during periods of peak demand in exchange for lower rates. These programs can reduce costs for all consumers because electricity is more expensive during periods of peak demand, when higher cost generators that seldom operate are required to start-up. FERC's rule requires that cost-effective dispatch of demand response resources, as determined by a new "net benefits" test, must be compensated at the locational marginal price (LMP). To comply with the rule, each RTO and ISO must file a net benefits analysis and proposed tariff revisions by July 2011.[83]

The Final Rule also requires that the cost of obtaining demand response resources must be spread among all entities that purchase energy at the times and at the locations where those demand response resources were committed or dispatched.

> Coordination between the relevant federal agencies might allow for the continued operation of coal-fired electric generating units without compliant pollution controls, if deemed necessary for reliability. Such arrangements and accommodations must be reserved for true emergency situations—they should not be relied upon as the primary mechanism for ensuring reliability during the transition.

Although neither DOE nor FERC appear to have authority to waive environmental regulations when they issue emergency orders for a unit to continue un-economic operation for reliability reasons, EPA might exercise enforcement discretion and negotiate consent decrees that establish the terms of such operation in the absence of compliant pollution controls. Coordination of this sort between the relevant federal agencies might allow for the continued operation of coal-fired electric generating units without compliant pollution controls, if deemed necessary for reliability. Of course, such arrangements and accommodations must be reserved for true emergency situations–they should not be relied upon as the primary mechanism for ensuring reliability during the transition to a more stringent set of environmental regulations. Further, these consent decrees should ensure that plants operating out of compliance are not economically advantaged.

In the United States, electricity is regulated largely at the state level and there is considerable variation in the authorities exercised and roles played by regulators from state to state. In particular, the role of state authorities is determined by the extent to which the state has retained traditional regulation of electric utilities or has restructured its wholesale generation markets (see Figure 7).[84] In regulated states, where electric utilities remain vertically integrated, state public utility commissions (PUCs) retain oversight of resource additions, retrofits, and retirements. Utilities in regulated states have the obligation to serve load reliably, and many regulated states require that integrated resource planning be conducted periodically

[83] This rule may be subject to additional hearings and judicial review because Commissioner Moeller dissented from the Final Rule and there is likely to be divergent stakeholder views as RTOs and ISOs adjust key analytic features for the net benefits test.

[84] Twenty eight states, including most in the Midwest and South, remain traditionally regulated even though some have undertaken restructuring studies and/or pilot programs. Seven states have suspended efforts at restructuring and are left with either partially restructured markets (e.g., Arizona, California, and Nevada) or traditionally regulated utilities. The remaining fifteen states, largely in the New England and Mid-Atlantic regions, are actively restructuring and sit on a spectrum of partially to fully de-regulated, offering retail choice and competitive rates for some or all customers. For example, Oregon offers retail choice to large commercial and industrial customers only, while areas of Texas are fully competitive with separate companies for generation, transmission and distribution, and retail sales. See http://ftp.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html.

as a way to provide a built-in process for understanding and addressing future capacity needs. However, utility investments in retrofits and new capacity are subject to prudency reviews and cost recovery is not guaranteed. Uncertainty about cost recovery may cause utilities to be less proactive in making these investments.

In states that have undertaken electricity market restructuring, electric utilities have generally divested themselves of their generation resources, and may remain regulated by the state PUC only with respect to the rates they charge to retail customers. The electric utility serves load by purchasing electricity from independent producers. Because generation assets are not owned by regulated utilities, the state PUCs retain little, if any, direct authority over resource investments or operating decisions. In restructured markets, grid operators—that is, RTOs and ISOs—play an important role in fostering market conditions that encourage new investment in capacity, demand side management (DSM), or transmission when issues of resource adequacy arise.

FIGURE 7: STATUS OF STATE ELECTRICITY REGULATION/RESTRUCTURING

28 Traditionally Regulated	7 Suspended Restructuring	15 Restructured
• Most of Midwest + South • Vermont, Washington	• Regulated: Arkansas, New Mexico, Montana, Virginia • Partial restructure: Arizona, California, Nevada	• Most of New England and Mid-Atlantic • Illinois, Michigan, Ohio • Oregon (non-residential only) • Fully Competitive: Texas

Source: U.S. Energy Information Administration.

In regulated states, the integrated resource planning (IRP) process informs state utility regulators who approve rate plans. State regulators should consider a forward-looking, multi-pollutant approach for planning and rate recovery decisions and require utilities to submit multi-pollutant compliance plans that include planning for forthcoming air, water, and waste rules. State regulators can encourage utilities to minimize cost by denying automatic cost recovery if, for example, a utility proposes to retrofit an aging plant that faces an uncertain future and is unlikely to remain competitive as future requirements are phased in. State utility commissions could also facilitate a smooth transition by making timely decisions on rate approvals, as well as proposed retirements and new capacity additions, so that utilities can begin construction as soon as possible, where appropriate.

Further, several states have passed laws that require utilities to plan for the installation of air pollution controls to protect public health. For example, North Carolina, Illinois, New Hampshire, Delaware, Maryland, and Massachusetts all adopted state laws prior to EPA's Transport Rule and Utility Air Toxics Rule that require multi-pollutant reductions. As a result, power companies in these states are in a good position for timely compliance with a new round of air quality regulations under the federal Clean Air Act.[85] The text box on page 35 describes Colorado's Clean Air-Clean Jobs Act, which encourages comprehensive, multi-year compliance planning.

State utility regulations also have an important role to play in integrating non-conventional capacity resources, such as demand-side resources, into planning for a reliable bulk electricity system. Incentives and fair rate policies for demand resources, distributed generation, and energy storage create a level playing field and provide meaningful incentives for new resources that could help the electricity system deliver reliable power and minimize consumer costs. Many states have enacted renewable portfolio standards and energy efficiency programs to spur the deployment of these non-conventional capacity resources.

To the extent that new environmental regulations prompt a shift to natural gas generation, either through the utilization of existing capacity or through the construction of new capacity, state PUCs could encourage long-term contracts for natural gas supply and the use of hedging instruments to manage the risk of gas price volatility. A report recently issued by the BPC's *Task Force on Ensuring Stable Natural Gas Markets* addresses this issue as one part of its comprehensive recommendations for bolstering consumer, policy-maker and investor confidence in the stability of future gas markets and for improving the tools available for effective price risk management.[86]

[85] For example, North Carolina's 2002 Clean Smokestacks Act requires coal-fired power plants to reduce NO_X emissions by 77 percent by 2009 and SO_2 emissions by 73 percent by 2013. The Illinois Multi-Pollutant Standard (MPS) and Combined Pollutant Standard (CPS) allow utilities flexibility in complying with state mercury standards in exchange for commitments to also significantly reduce SO_2 and NO_X emissions. New Hampshire's 2002 Clean Power Act requires emission reductions from the state's three largest coal-fired plants: 75 percent in SO_2 by 2006 and 70 percent in NO_X by 2006. Massachusetts regulation requires the six largest facilities to meet output-based emission standards for SO_2, NO_X, and CO_2. Maryland's 2007 Healthy Air Act requires larger reductions in NO_X, SO_2, and mercury in a shorter timeframe than previous federal rules.

[86] Bipartisan Policy Center and American Clean Skies Foundation. Task Force on Ensuring Stable Natural Gas Markets. March 2011.

STATE ENVIRONMENTAL AGENCIES

As the permitting authority under the Clean Air Act, states generally have authority to grant a one-year waiver that extends the Utility Air Toxics Rule compliance deadline for electric generating units that need more time to install pollution controls. With this one-year extension, compliance would not be required until four years after promulgating the final Utility Air Toxics Rule. States, which have typically been lenient in granting this extra year, should draw on this authority as needed to allay reliability concerns. EPA has encouraged the use of this one-year extension in its proposed Utility Air Toxics Rule.

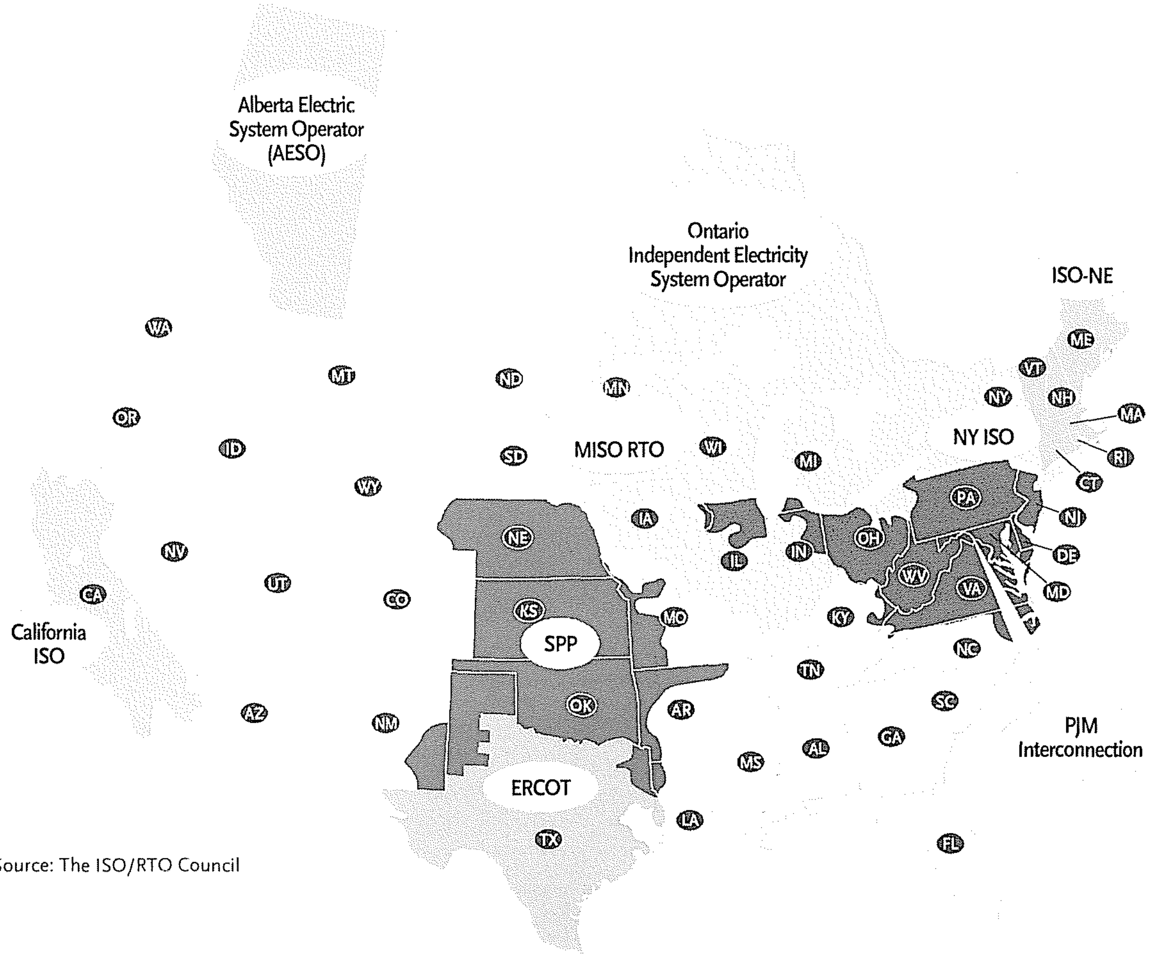
In addition to allowing retrofits to be scheduled past the compliance deadline, states should look for ways to encourage retrofits to be scheduled well before the deadline. This would help avoid a pile-up of control installations in the maintenance season or year prior to the deadline. Specifically, states should aim to reward plants that start pollution retrofit projects as soon as possible and are able to install *and operate* their pollution controls in advance of the compliance deadline. Such early action would not only provide early emission reductions, it would take pressure off the grid during the heaviest period of pollution retrofits, when new infrastructure is also coming online to take up the slack from retired plants. Early decisions made by states to grant extensions should require plants to submit a detailed schedule for installation of pollution controls and specify consequences in the event interim deadlines are not achieved.

REGIONAL TRANSMISSION ORGANIZATIONS/ INDEPENDENT SYSTEM OPERATORS

In restructured states, regional wholesale markets provide greater transparency about anticipated supply changes (including planned retirements) and create a financial incentive for timely investment in new transmission, generation, and non-conventional capacity. In these states, RTOs and ISOs typically facilitate orderly planning of power plant retirements by requiring advance notice of the intent to retire a unit and by conducting reliability impact studies. More advance notice could be helpful in identifying potential issues and allowing more time for their resolution.

RTOs and ISOs administer day-ahead and real-time electricity markets, manage transmission, and play an important role in assessing resource adequacy and ensuring operational reliability. These organizations emerged in response to FERC orders 888 and 889, which were both issued in 1996 and were intended to remove

FIGURE 8. MAP OF RTOS/ISOS IN THE U.S.



Source: The ISO/RTO Council

barriers to competitive wholesale markets by requiring open access to transmission lines. In some regions FERC approved the development of ISOs as a means of facilitating the transition to competitive wholesale markets. In 1999, FERC issued Order No. 2000, which encouraged the development of RTOs, and established criteria for them. While their activities vary somewhat by region, RTOs and ISOs serve similar functions: namely, they develop rules to govern power market and transmission market operations and operate and oversee regional wholesale markets, including coordinating the delivery of generation and transmission services.

As part of their market operations, RTOs and ISOs analyze generation and transmission resource adequacy, undertake transmission planning, review plant notices of intent to retire, and coordinate outage schedules. As noted earlier, when a generator proposes to retire a unit, the RTO/ISO assesses the reliability impact. If the RTO/ISO determines that the unit is necessary to ensure system reliability, the RTO/ISO can enter into a reliability-must-run (RMR) agreement to compensate the generator for continued operation based on cost-of-service rates.[87]

Advance notice of retirement can allow sufficient time for new resources to join the market, reducing the need to rely on RMR contracts as an interim measure to assure grid security, and mitigating the stress of assuring grid reliability in the face of retirements and retrofits. Different RTOs have different requirements with respect to the amount of notice generators must give for a proposed unit retirement. For example, PJM requires 90-day notice; NYISO requires 90 days for smaller plants and 180 days for units that are 80 MW or larger; while

[87] In several organized markets, including Midwest ISO and California ISO, contractual or tariff requirements obligate the generator to negotiate RMR contracts to remain in operation if the RTO/ISO concludes that continued operation of the unit is necessary for reliability. In other markets, including PJM and ISO New England, the generator's decision to accept an RMR contract is voluntary.

[88] PJM. Open Access Transmission Tariff §§ 113 1-2. September 17, 2010. Available at http://pjm.com/documents/agreements/~/media/documents/agreements/tariff.ashx

the Midwest ISO (MISO) requires a longer, 26-week notice.[88,89,90] These advance notification requirements can be revised by RTOs/ISOs or FERC under existing RTO/ISO tariffs through a demonstration that the existing notice period is unjust or unreasonable, or unduly discriminatory or preferential. In other words, RTOs and ISOs can consider extending the notification requirement as a way to improve regional planning and reduce reliance on RMR agreements.

Some RTOs have established forward capacity markets as a mechanism to encourage the capacity investments needed to ensure continued reliability over time. In the mid-Atlantic region and New England, for example, the two ISOs–PJM and ISO New England, respectively–have well-developed forward capacity markets that allow existing and new generation resources, as well as demand-side measures, to compete alongside each other to serve future demand. As unit retirements are scheduled, the price in forward capacity market auctions increases, encouraging the development of new resources. However, the continued use of RMR contracts in both regions has led some to question whether forward capacity markets are sufficiently effective.[91]

The overlapping jurisdictions of environmental and electricity regulators have prompted efforts to ensure that there is coordination on reliability issues. This section discusses several examples of recent efforts to initiate or improve this coordination.

For example, DOE's Electricity Advisory Committee has issued recommendations to the Secretary of Energy for addressing power reliability concerns related to pending environmental regulations for electric generating stations.[92] The Committee advised DOE to coordinate with FERC, NERC, EPA, and state regulatory authorities to address these concerns. The Committee also put forward two specific recommendations: first, that DOE, EPA, and FERC engage in a senior-level consultative process to commit to open and active communication on reliability issues, while recognizing the existing authorities of each agency; second, that DOE advance a recommendation to FERC to improve the planning process for replacing retiring units. The latter recommendation suggests that DOE and FERC support power system "planning coordinators" who would undertake proactive planning studies, including scenario analyses, to understand the impact of retirements on the need for new generation capacity, transmission system additions, or demand-side resources. To the extent that planning coordinators can better anticipate likely retirements under different scenarios, RTOs and ISOs will have more time, information, and flexibility to take necessary action to ensure reliability.

Similarly, the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC) adopted a resolution on the role of state regulatory policies in the development of federal environmental regulations at its 2011 Winter Meeting.[93] The resolution enumerated several factors that NARUC believes EPA should consider in developing its regulations and urged state utility regulators to engage with state and federal environmental regulators. Specifically, the resolution outlined ten factors for EPA to consider, including several aimed at improving state-federal coordination and addressing reliability concerns:

- "Engage in timely and meaningful dialog with State energy regulators in pursuit of these objectives;"
- "Recognize the needs of States and regions to deploy a diverse portfolio of cost-effective supply-side and demand-side resources based on the unique circumstances of each State and region;"
- "Encourage the development of innovative, multi-pollutant solutions to emissions challenges as well as collaborative research and development efforts in conjunction with the U.S. Department of Energy;" and
- "Recognize and account for, where possible, State or regional efforts already undertaken to address environmental challenges."

[89] NYISO. Technical Bulletin 185. September 19. 2009. Available at http://www.nyiso com/public/webdocs/documents/tech_bulletins/tb_185.pdf.

[90] MISO Open Access Transmission Tariff. §§ 38.2.7. January 6, 2009. Available at http://www.midwestmarket.org/publish/Document/1d44c3_11e1d03fcc5_-7cf90a48324a/Modules.pdf?action=download&_property=Attachment.

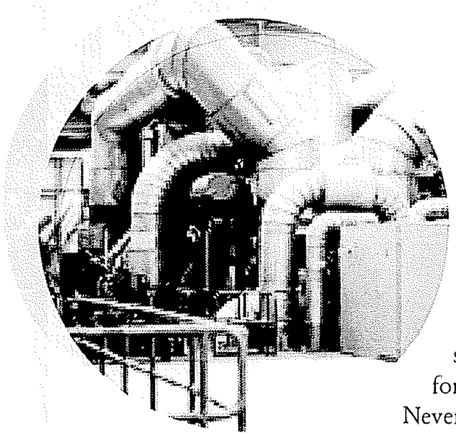
[91] Synapse Energy Economics, Inc. Prepared for Earthjustice. Public Policy Impacts on Transmission Planning. December 2010. In addition, FERC has found that RMR agreements weaken the incentive for new generation development by suppressing spot market prices and allowing inefficient existing units operating under RMRs to receive a higher price than new units. Devon Power LLC, et al. ER03-563-00.

[92] Electricity Advisory Committee Memorandum to Secretary Steven Chu. March 10, 2011. Recommendations to Address Power Reliability Concerns Raised as a Result of Pending Environmental Regulations for Electric Generation Stations. Available at http://www.oe.energy.gov/DocumentsandMedia/EAC_Memorandum_to_Secretary_Chu_and_Assistant_Secretary_Hoffman_3-11-11.pdf

[93] National Association of Regulatory Utility Commissioners. Resolution on the Role of State Regulatory Policies in the Development of Federal Environmental Regulations. February 16, 2011.

SECTION V

It is clear that the U.S. electric power sector is in a period of transition and that EPA regulations will influence the timing and scale of future changes in the nation's electricity supply mix. Coal-plant retirements are already occurring and are likely to continue because of market conditions such as low natural gas prices. EPA regulations, particularly the Utility Air Toxics Rule, will likely advance retirement timelines for these vulnerable plants.



The large numbers of retrofits and retirements expected to result from the EPA regulations raise significant challenges for the power sector. Nevertheless, based on the recently released proposed Utility Air Toxics Rule and 316(b) cooling water rule, it appears that EPA is making an effort to work with industry to ease the transition to a new regulatory regime. As a result, it appears that the scenarios that predicted the largest numbers of retirements will not be realized.

Moreover, even at the higher end of current estimates, the magnitude of new construction and investment would not be unprecedented, even in light of a relatively short timeframe. Between 1999 and 2004, U.S. generating capacity nationwide increased by 177 GW, almost all of which was natural gas capacity. By comparison, projected retirements between now and 2015 range from 10 to 70 GW–a much smaller change. Moreover, not all of the capacity that will be retired will need to be replaced because there is under-utilized existing generation, demand has flattened, and energy efficiency continues to improve. The industry has also demonstrated the ability to orchestrate substantial control technology retrofits. During the peak of the last retrofit construction cycle, scrubbers were installed on nearly 60 GW of coal capacity during the three-year period from 2008 through 2010.[94]

In the areas that may be most vulnerable to reliability problems, BPC believes that power companies, federal and state regulators, and ISO/RTOs have authorities or strategies at their disposal to ensure continued reliability. In light of these findings, we offer the following recommendations to ensure the smoothest possible transition to a cleaner, more efficient electric power system.

Where appropriate, EPA should use flexibility inherent in its existing authority to address cost and reliability concerns. EPA's March 15, 2011 proposed Utility Air Toxics Rule includes several provisions that can help minimize costs and the potential for system disruptions. These include work practice standards in lieu of limits for dioxin and furans, emissions averaging among units at a facility in the same sub-category, the use of surrogates for particular hazardous air pollutants, exemptions for units that infrequently burn oil, a 30 day averaging period for demonstrating compliance with emission standards, and alternative standards that could reduce monitoring requirements. In addition, although the Clean Air Act generally allows only three years to comply with the Utility Air Toxics Rule, EPA's proposal emphasizes that states can provide waivers to allow a fourth year for facilities to install controls if plants are unable to do so in three years despite good faith efforts.

Similarly, the proposed cooling water rules provide important flexibility with respect to the timing and choice of compliance technologies. Facilities will have up to eight years to implement lower-cost compliance measures, such as screens or velocity reduction. For the largest water users, EPA's proposed rule will require a case-by-case evaluation–one that considers site-specific constraints, the useful life of the facility, electric reliability impacts, and weighs cost against benefits–to determine which control technologies, if any, will be required. If a cooling tower is required, fossil-fired facilities are provided 5–10 years and nuclear facilities are provided 10–15 years to come into compliance.

Additional options are available that can address unexpected reliability impacts as a last resort. These include authorities to delay compliance deadlines under the Federal Power Act, authorities for the President to delay implementation, and the ability to exercise enforcement discretion through the use of consent decrees to address specific, special circumstances. While it is unlikely that these authorities will be needed, government agencies should make it clear that they will avail themselves of these tools if necessary.

A number of planning tools and authorities are available and should be used to help smooth the transition to a new suite of environmental regulations in the coming decade. Although attention has focused on reliability concerns related to plant retirements, BPC believes that managing a large number of pollution control retrofits in a relatively short period could also be a challenge. If many plant owners delay retrofits to near the end of the Air Toxics compliance period, scheduling problems could arise that would increase the need for compliance waivers and reliability-must-run agreements, potentially driving up costs. Plant owners should be encouraged–including through concrete incentives, to the extent possible–to start the process of installing controls immediately. State policy makers should look for opportunities to influence the timing of retrofits and to help spread out scheduled installations within the compliance window. In addition,

[94] M.J. Bradley & Associates LLC and Analysis Group. Ensuring a Clean, Modern Electric Generating Fleet While Maintaining Electric System Reliability. August 2010.

Well-crafted legislation could provide greater certainty about environmental outcomes and provide the incentives and the regulatory clarity for utilities to begin retrofits early.

neighboring RTO/ISOs that share transmission corridors and may rely on each other to provide adequate reserve margins should consider coordinating their outage schedules as well.

To play a more proactive role, FERC could consider extending the length of the required notification period for proposed plant retirements to allow more time for reliability assessments.[95] If FERC acted to increase advance notice requirements for unit retirements, the need to rely on RMR contracts as an interim measure to assure grid security would be reduced, and the stress of assuring grid reliability in the face of retirements and retrofits may be mitigated.

Finally, DOE and FERC should look to additional authorities under the Federal Power Act that can be used to support long-term planning for a smoother, more cost-effective transition. For example, DOE and FERC could collaborate to use their information gathering authorities to conduct assessments for decision making and coordinated planning. This type of coordination could help identify regions with potential resource adequacy problems and provide a mechanism for aggregating and disseminating information about the regulatory and market tools that are available for addressing potential problems. A stakeholder process involving federal agencies, RTOs/ISOs, and utilities could be used to develop strategies for addressing challenges posed by retirement and retrofit scheduling and to share best practices.

The transition to a cleaner, more efficient generation system will require investment in energy efficiency, demand response strategies, and new generation capacity along with associated transmission and pipeline infrastructure. Additional generation capacity will be needed to replace retired coal generation and, potentially to ensure reliability during retrofit outages. Energy efficiency and demand response strategies can help lower overall demand for electricity and better manage demand during peak periods. Some additional transmission infrastructure will be necessary to address shifts in generation capacity and demand, and pipelines may be necessary to transport natural gas to new gas-fired plants.

Previous BPC reports have noted that siting energy facilities in the United States has evolved into a complex, multi-jurisdictional, and often contentious process that is in need of reform.[96] Although a full discussion of potential reforms is beyond the scope of this report, it is worth noting that the upcoming period of transition in the power sector provides an opportunity for policy makers at the state and federal levels to seek improvements in the siting and permitting process.

There may be a short window of opportunity for a legislative change that could guarantee the environmental benefits of the Clean Air Act and provide a smoother transition for the power sector. To be successful, multi-pollutant legislation would need to provide certainty and encourage rational and timely investment decisions, so that plant owners begin adding pollution controls immediately at facilities that will remain economically viable; while also planning and coordinating the retirement and replacement of plants that will have to be shut down. For the minority of plants where the outcome is unclear, it will be important to get the information needed to make a determination in time to comply. Further, multi-pollutant legislation should aim to guarantee equivalent or greater environmental benefits than available under current authority.

Well-crafted legislation could also provide greater certainty about environmental outcomes and provide the incentives and the regulatory clarity to get started sooner. Absent new legislation, litigation over the upcoming rulemakings could prolong uncertainty over what will ultimately be required and when. In addition, the current structure provides little incentive to begin retrofits early and to turn on installed controls before the compliance deadline. Legislation could introduce such incentives and provide a backstop requirement that would be applicable if EPA is not able to promulgate regulations in time or if those regulations are tied up in litigation. This was the approach used in the successful, market-based Acid Rain Program, which is widely acknowledged to have achieved significant public health environmental benefits at lower than expected cost.

BPC continues to believe that addressing multiple pollutants in an integrated way can provide certainty, and encourage rational and timely investment decisions in pollution controls and new capacity. Several market-based, multi-pollutant legislative proposals have been developed in recent years. The BPC believes that the public health and economic benefits of these types of coordinated approaches are worth exploring in the coming months.

[95] *There are currently differing requirements in PJM, MISO, NYISO.*

[96] National Commission on Energy Policy. Clean Energy Technology Pathways: An Assessment of the Critical Barriers to Achieving a Low-Carbon Energy Future. March 2010.

APPENDIX A

The Bipartisan Policy Center, together with the National Association of Regulatory Utility Commissioners (NARUC) and Northeast States for Coordinated Air Use Management (NESCAUM), hosted a three-part workshop series from October 2010 through January 2011 exploring how to ensure the reliability of our nation's electric system without jeopardizing important progress on public health and environmental protection. Materials from each of these workshops, including video and presentations, can be found on our website.[97]

The three workshops featured presentations by leading experts on electric power system reliability, electricity market operation, power sector technology, and pollution control policies and regulations.

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[97] See http://www.bipartisanpolicy.org.

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Vice Chairman James Gardner, Kentucky Public Service Commission

Commissioner Rick Morgan, DC Public Service Commission

Chairman Edward Finley, Jr., North Carolina Utilities Commission

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APPENDIX B

BPC modeled the impacts of pending EPA regulations for the power sector using ICF International's Integrated Planning Model (IPM). IPM is a model designed to simulate the behavior of the U.S. and Canadian wholesale electricity markets. To do so it uses an extensive database that contains information on every boiler and generator in the nation.

IPM is a multi-region model that endogenously determines capacity and transmission expansion plans, unit dispatch and compliance decisions, and power, coal, and allowance price forecasts, all based on power market fundamentals. To utilize the model, it is necessary to make a number of assumptions concerning key market parameters, including electricity demand growth, fuel prices, cost and performance of new generating capacity, and cost and performance of pollution controls and other options for complying with environmental regulations. This appendix discusses the assumptions and regulatory compliance scenarios included in the BPC analysis.

BPC based most of the assumptions for this analysis on information from the Energy Information Administration's Annual Energy Outlook (EIA AEO 2010) and the Environmental Protection Agency's IPM Base Case 2009 ARRA (EPA ARRA). In some cases, BPC selected alternative assumptions to reflect recent market conditions. Assumptions for electricity demand growth, cost and performance of new capacity, and costs of regulatory compliance options were held constant across all the scenarios analyzed. Natural gas and coal prices varied by scenario based on the relative fuel demand from scenario to scenario. Table B-1 below summarizes the sources of key assumptions in the analysis. Tables B-2 through B-4 summarize our detailed assumptions for select parameters.

TABLE B-1: SOURCES OF KEY INPUT ASSUMPTIONS

Electric demand growth	EIA AEO 2010	
Cost and performance of new generation capacity, including new project financing	EIA AEO 2010	New coal capacity without carbon capture technology included a risk premium in financing costs, consistent with the approach used by EIA
Natural gas prices	EIA AEO 2010 (BPC Base Case) Gas price sensitivity at minus $1/MMBtu below the AEO2010-based supply curve	To realize gas price response in scenarios other than the BPC Base Case, ICF derived a measure of supply elasticity from multiple AEO 2010 scenarios and applied it to the BPC Base Case price and gas demand projections to generate a supply curve
Coal prices	ICF coal supply curves calibrated to EIA AEO 2010 prices and quantities	
Cost and performance of air pollution controls	EPA ARRA (SCR, SNCR, ACI), BPC (FGD, fabric filter, DSI)	BPC assumed higher capital costs for fabric filters and wet scrubbers (FGD) than those used in EPA ARRA to reflect costs closer to recent market experience
Cost of compliance options for coal ash and water intake regulations	NERC (cooling towers), EOP Group (ash)[98] BPC (alternative water intake compliance)	

[98] Based on Utility Solid Waste Activities Group 2010. Cost estimates for the mandatory closure of surface impoundments used for the management of coal combustion byproducts at coal-fired electric utilities Prepared by The EOP Group, Inc., Washington, DC.

TABLE B-2: BPC ASSUMPTIONS FOR THE COST AND PERFORMANCE OF AIR POLLUTION CONTROLS

Capital Cost (2006$/kW)	300	564	37	168	20	131	Bit - H 3.65 Bit - L 2.72 Lig 25.11 Sub 3.86
	500	487	NA	147	15	123	
	700	442	NA	140	NA	118	
Variable O&M (2006$/MWh)		1.80	Bit 8.46 Sub & Lig 3.83	0.64	0.79	Bit - H 0.10 Bit - L 0.05 Lig 0.11 Sub 0.10	Bit - H 0.41 Bit - L 0.27 Lig 0.50 Sub 0.35
Energy Penalty		2.1%	0.02%	0.5%	0%	0.5%	0%
% Removal		SO_2 - 95%	SO_2 - 70%	NO_X - 85%	NO_X - 30%	PM - 99.95%	Hg - 90%
First Year Allowed		2013	2013	2013	2011	2011	2011
Source		BPC	BPC	EPA	EPA	EPA	EPA

Bit = Bituminous coal; Sub = Subbituminous coal; Lig = Lignite; O&M = Operating and Maintenance Costs.

Note: The 70% SO_2 removal rate for DSI assumes a fabric filter is present. As a conservative modeling assumption to account for site-specific challenges, BPC assumed that DSI was only an option for units ≤ 300MW and that units projected to install DSI are restricted to burning low sulfur coals (2 lb SO_2/MMBtu).

TABLE B-3: BPC ASSUMPTIONS FOR 316(B) WATER RULE COMPLIANCE

Capital Costs	300	184	18
	500	138	14
	700	138	14

Note: Cooling tower costs derived from North American Electric Reliability Corporation.[99] Alternative compliance costs based on BPC assumption of 10% of cooling tower cost.

TABLE B-4: BPC ASSUMPTIONS FOR COAL COMBUSTION WASTE RULE COMPLIANCE

Capital Costs	23	20	200	30
Fixed O&M	-	-	4.5	3.0

Note: Ash related costs derived from EOP Group, Inc.[100]

[99] NERC. 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential US Environmental Regulations. October 2010. Available at http://www.nerc.com/files/EPA_Scenario_Final.pdf

[100] Based on Utility Solid Waste Activities Group. Cost estimates for the mandatory closure of surface impoundments used for the management of coal combustion byproducts at coal-fired electric utilities. Prepared by The EOP Group, Inc., Washington, DC. 2010

For this analysis, BPC defined three cases to examine the impacts of EPA's proposed regulations on the U.S. power sector. BPC had ICF analyze these cases using IPM based on the assumptions described above. The three cases included a base case, a regulatory scenario, and a regulatory scenario with lower natural gas prices. The cases are described in more detail below.

BPC BASE CASE

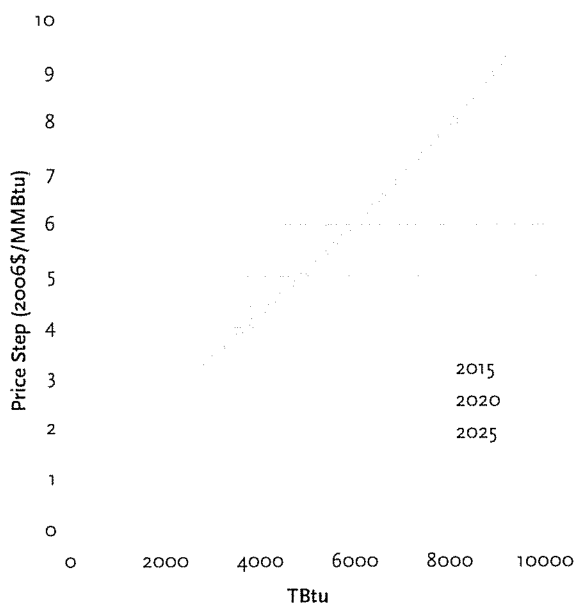
The BPC Base Case represents a business-as-usual (BAU) projection in that it includes only existing federal and state regulations. It assumes regional cap and trade programs for SO_2 and NO_X in the eastern U.S., as promulgated under Phases I and II of the Clean Air Interstate Rule (CAIR).[101] It does not include any federal mercury or carbon dioxide emission reduction requirements. The BPC Base Case includes existing state mercury, SO_2 and NO_X requirements, as well as state renewable portfolio standards. Pollution control and retirement decisions reflected in completed New Source Review consent decrees and public announcements are also included in the BPC Base Case and the other cases.

REGULATORY CASE

The second case includes requirements under EPA's proposed suite of new regulations, including the Utility Air Toxics Rule, transport, and proposed water intake and coal ash rules. BPC assumed the following requirements for each of the proposed rules:

CLEAN AIR TRANSPORT RULE (CATR) – The case includes CAIR Phases I and II as a proxy for CATR. However, BPC assumes no banking of SO_2 allowances from the Title IV Acid Rain Program and CAIR into 2012, reflecting the start of the new program under CATR. The Phase II caps under CAIR have been modified for NO_X to reflect tighter standards expected under the new ozone NAAQS. The CAIR Phase II caps were scaled in 2018 to reflect a 0.10 lb/MMBtu standard in place of the CAIR 0.125 lb/MMBtu standard. To reflect Best Available Retrofit Technology (BART) requirements in states not subject

FIGURE B-1: BPC NATURAL GAS SUPPLY CURVES (FOR GAS SUPPLIED TO POWER SECTOR)



TBtu: Trillion British thermal units

to CAIR, units were required to control for NO_X with SCR so long as the cost of control was equivalent to less than $5000 per ton of NO_X avoided.

UTILITY AIR TOXICS RULE – BPC assumes that all coal-fired electric generating units (EGUs) must be controlled with a suite of controls intended to meet emissions standards to continue operating past the 2015 compliance deadline. If units do not control by 2015, they must retire. As a conservative assumption, control of metals is assumed to require a fabric filter for every unit.[102] The analysis assumes that units greater than 300 MW meet the standard for acid gases (HCl) with a wet scrubber (flue gas desulfurization, FGD) and that units less than 300 MW in size may meet the standard for acid gases with either dry sorbent injection (DSI) combined with the fabric filter and low sulfur coal or, alternatively, with a wet scrubber.[103] Although a dry scrubber, estimated at 10-20% lower cost than a wet scrubber, would be an option in combination with particulate controls to comply with the HCl limit, it is not an assumed option in this

[101] CAIR has since been replaced with the Transport Rule, proposed in July 2010. The latter provides for more stringent caps on SO_2 and NO_X, as well as trading restrictions and limits on the use of "banked" allowances from past years of over-compliance with the SO_2 Acid Rain Trading Program. Other analyses indicate that the incremental changes between CAIR and the Transport Rule are not a significant driver in the context of the suite of EPA regulations. Thus, the policy scenario does not reflect incremental changes from CAIR, other than to restrict the use of allowances banked prior to 2012.

[102] Some studies indicate that upgrades to existing electrostatic precipitators may be sufficient to comply. (Lipinski, 2011).

[103] Studies and EPA analysis of the Air Toxics Rule indicate that lower cost dry scrubber technology combined with particulate controls would be an alternative option for acid gas compliance and that DSI may also be an option for larger units. (Lipinski, 2011)

analysis. To meet mercury standards, units may be controlled with activated carbon injection (ACI) or, for units burning bituminous coals, with a combination of wet scrubber and SCR controls.[104]

WATER INTAKE (316(B)) – BPC assumes water intake structure compliance by 2022 (fossil) and by 2027 (nuclear), both reflected as 2025 in the modeled scenario. Facilities with a weighted average capacity factor of at least 35 percent in 2009 and flow design intake greater than 500 million gallons per day (MGD) are assumed to require cooling towers to operate past the compliance date. Facilities that do not meet those two conditions must install alternative compliance measures, estimated by BPC to cost one-tenth the cost of a cooling tower at the facility.

ASH HANDLING (COAL COMBUSTION WASTE) – BPC assumes that coal-fired facilities must fully convert to dry ash handling in order to continue operating in 2015 and later. The case assumes implementation consistent with EPA's proposal under Subtitle D. Ash is not classified as hazardous and may continue to be used for beneficial purposes. For facilities that already manage some ash using dry handling systems, the retrofit costs shown above were prorated by the share of total ash managed using wet handling systems.[105]

REGULATORY CASE WITH LOW GAS PRICES

Natural gas price levels are critical to determining the projected impacts of EPA's regulations on the power sector. As noted earlier, the BPC Base Case and Regulatory Case relied on natural gas price projections based on EIA's AEO 2010. Since the publication of AEO 2010 in early 2010, expert projections of future natural gas prices have continued to fall as they incorporate growing resource projections for shale gas.[106] To reflect this expectation of lower future natural gas prices, BPC includes a sensitivity case that assumes prices $1/MMBtu lower in each year compared to the projected price in the Regulatory Case.

The following charts present select results for the three BPC cases described in the previous section. Unless specified otherwise, the results are presented for the continental United States as a whole, not including Hawaii and Alaska.

FIGURE B-2: PROJECTED ANNUALIZED CAPITAL EXPENDITURES FOR REGULATORY COMPLIANCE AND NEW GENERATING CAPACITY

[104] For mercury removal, the scenario assumes that a plant burning primarily bituminous coal with installed FGD, baghouse, and selective catalytic reduction (SCR) (for NO_X) controls will meet the Utility Air Toxics Rule 90% mercury removal requirement with no carbon injection. This is a simplified estimate based on an assumption that, for a bituminous coal plant with a baghouse, any additional cost for carbon injection (polishing ACI) would be modest. All other plants are assumed to require activated carbon injection.

[105] Data on wet and dry ash handling are taken from EIA Form 923 reporting

[106] U.S. EIA Annual Energy Outlook (AEO) 2011 projection averages nearly $1.24/MMBtu lower than the AEO 2010 projection over the period 2011 to 2030.

FIGURE B-3: PROJECTED UNIT RETIREMENTS BY TYPE

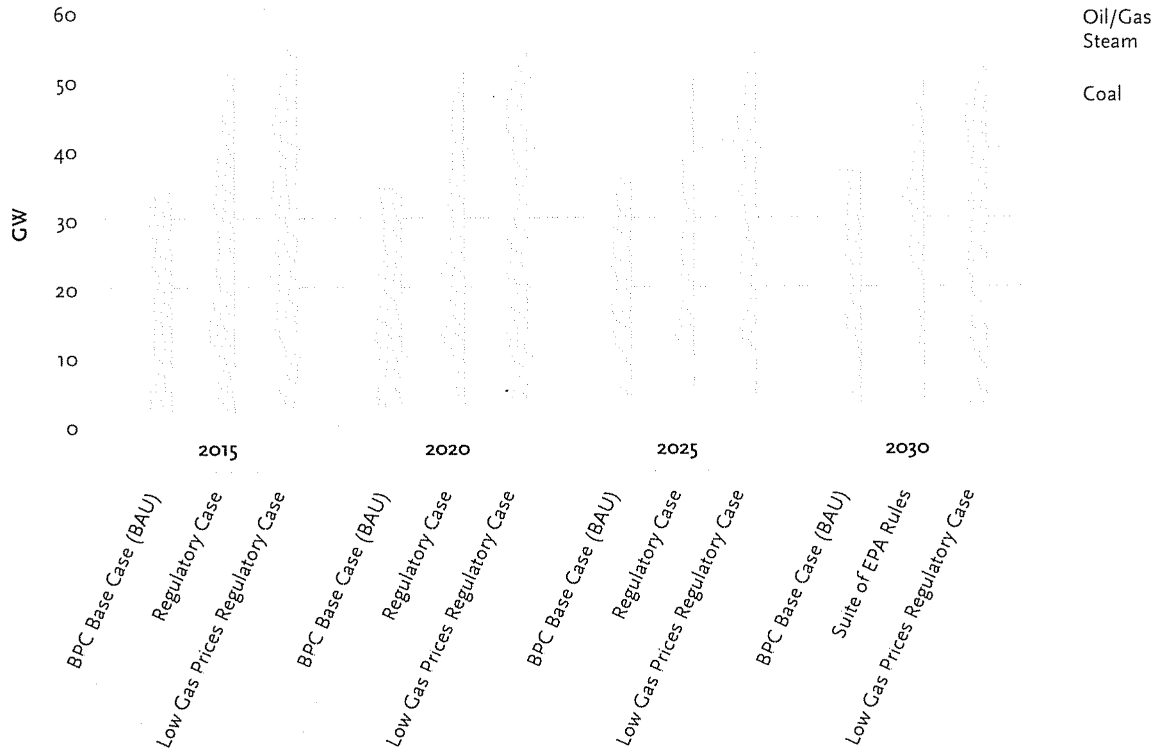


Figure B-2 shows annualized capital expenditures on all new air pollution control equipment, water intake and ash handling compliance retrofits, and new generating capacity. The 2015 value includes compliance investments for the Utility Air Toxics Rule and ash handling requirements. Water intake costs are incurred in 2025. Expenditures on new capacity take place over the entire period to meet demand growth and, in the EPA Regulatory cases, to replace capacity that retires in response to the regulations.

Capital expenditures, which do not include fuel and other costs to generate and distribute electricity, are about $10 billion higher in the Regulatory Cases compared to the BPC Base Case in 2015. The differential increases over time as costs are incurred for water intake compliance and incremental capacity additions. Costs in the Low Gas Price case are slightly lower due to lower compliance investments.

The assumed compliance requirements in the EPA Regulatory Cases drive up retirements of coal-fired capacity relative to the BPC Base Case. The regulations increase coal unit retirements by 15 GW and 21 GW in the Regulatory Case and in the Regulatory Case with Low Gas Prices, respectively, by 2030. Retirements of oil and gas steam capacity change very little from the BPC Base Case.

TABLES B-5 (A) AND (B): PROJECTED [illegible] EXPENDITURES AND UNITS CONTROLLED (ADDITIONAL TO [illegible] BASE CASE)

TABLE B-5(A): BPC REGULATORY CASE

Incremental Annualized Capital Expenditures (Million $): Change from BPC Base Case				
FGD	3,170	3,170	3,170	3,165
DSI	282	282	282	282
ACI	165	161	160	160
FF	3,463	3,432	3,432	3,432
SCR	525	691	703	731
Ash	2,897	2,897	2,897	2,897
Cooling Towers	0	0	1,626	1,626
Incremental Number of Units Controlled: Change from BPC Base Case				
FGD	85	85	85	84
DSI	199	199	199	199
ACI	392	385	381	381
FF	541	536	536	536
SCR	34	47	48	48
Ash (Facilities, in whole or in part)[107]	98	98	98	98
Cooling Towers (Facilities)	0	0	93	93

TABLE B-5(B): BPC REGULATORY CASE WITH LOW GAS PRICES

Incremental Annualized Capital Expenditures (Million $): Change from BPC Base Case				
FGD	3,124	3,124	3,124	3,119
DSI	245	245	245	245
ACI	157	154	153	153
FF	3,331	3,300	3,300	3,300
SCR	411	582	587	650
Ash	2,797	2,797	2,797	2,797
Cooling Towers	0	0	1,610	1,610
Number of Units Controlled: Change from BPC Base Case				
FGD	84	84	84	83
DSI	181	181	181	181
ACI	368	360	356	356
FF	516	511	511	511
SCR	28	41	40	44
Ash (Facilities, in whole or in part)	96	96	96	96
Cooling Towers (Facilities)	0	0	92	92

[107] The BPC analysis assumes costs for compliance with the ash handling requirements for coal-fired facilities that are proportional to the current share of wet ash handling at the facility. For example, a facility that currently relies on wet handling for one-half of its total ash handling needs is assumed to incur a cost equivalent to one-half the cost of a facility that is the same size and must convert all of its handling from wet to dry methods. BPC analysis projects that 98 facilities will be affected, either in whole or in part, by the ash handling requirements in the Regulatory Case.

FIGURE B-4: PROJECTED NATURAL GAS PRICES AT HENRY HUB

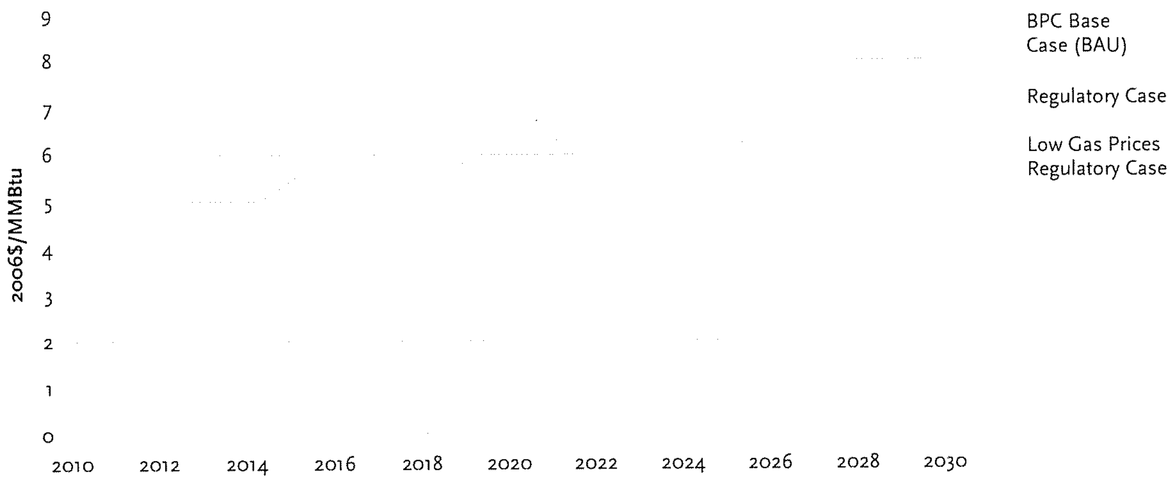


FIGURE B-5: CUMULATIVE PROJECTED CAPACITY ADDITIONS BY TYPE

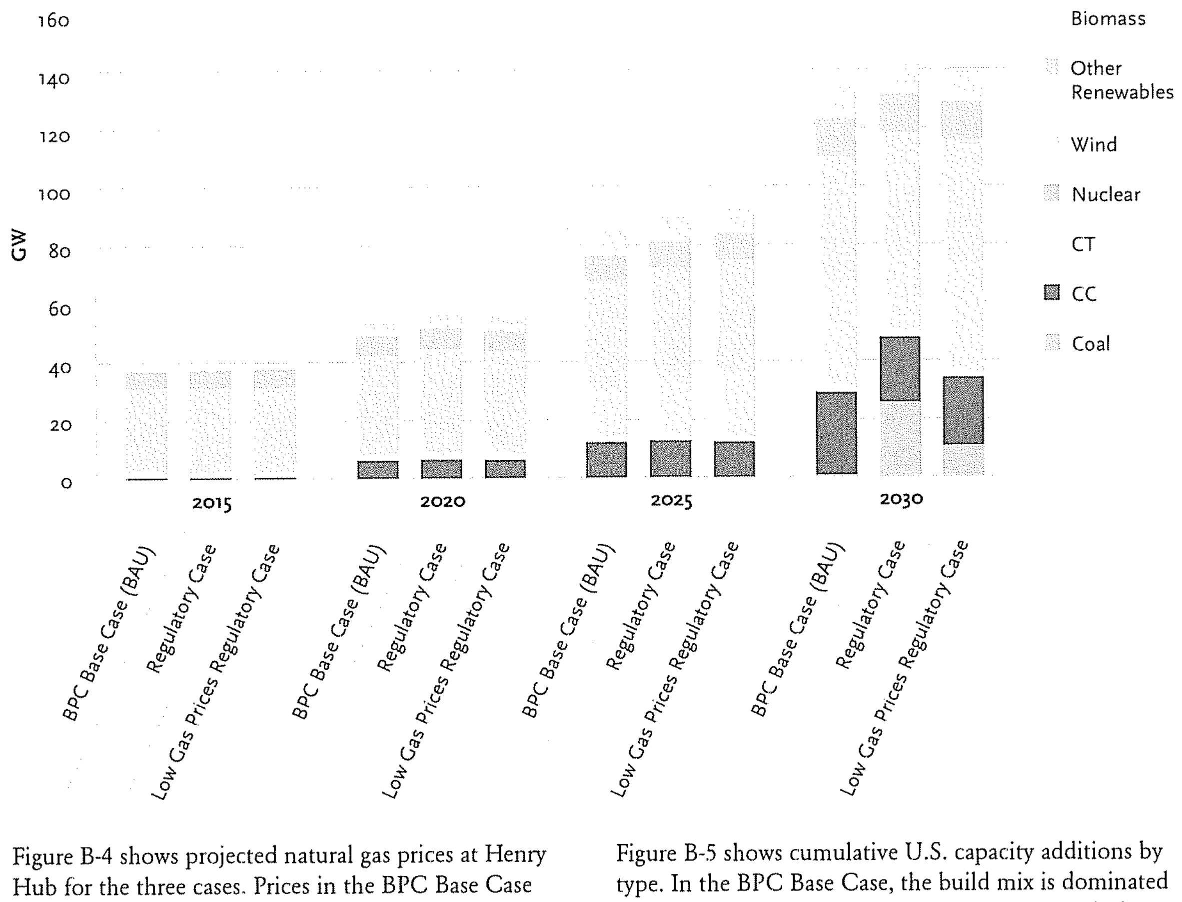


Figure B-4 shows projected natural gas prices at Henry Hub for the three cases. Prices in the BPC Base Case climb over time as demand for gas increases with electric demand growth. In the Regulatory Case, natural gas prices increase in 2015 and beyond in response to coal retirements and increased demand for gas to replace some part of that generation. As new coal capacity is brought online, gas demand and prices in the two cases approach each other and end up converging by 2030.

Figure B-5 shows cumulative U.S. capacity additions by type. In the BPC Base Case, the build mix is dominated by gas-fired capacity and renewable capacity, with the latter required to meet state RPS requirements. Higher natural gas prices in the Regulatory Case make new coal capacity an economic option, even with a financing risk premium to reflect potential carbon liabilities. Lower gas price assumptions in the Low Gas Price sensitivity case shift the economics back toward gas capacity, but some new coal capacity is also built.

FIGURE B-6: PROJECTED GENERATION MIX BY FUEL TYPE

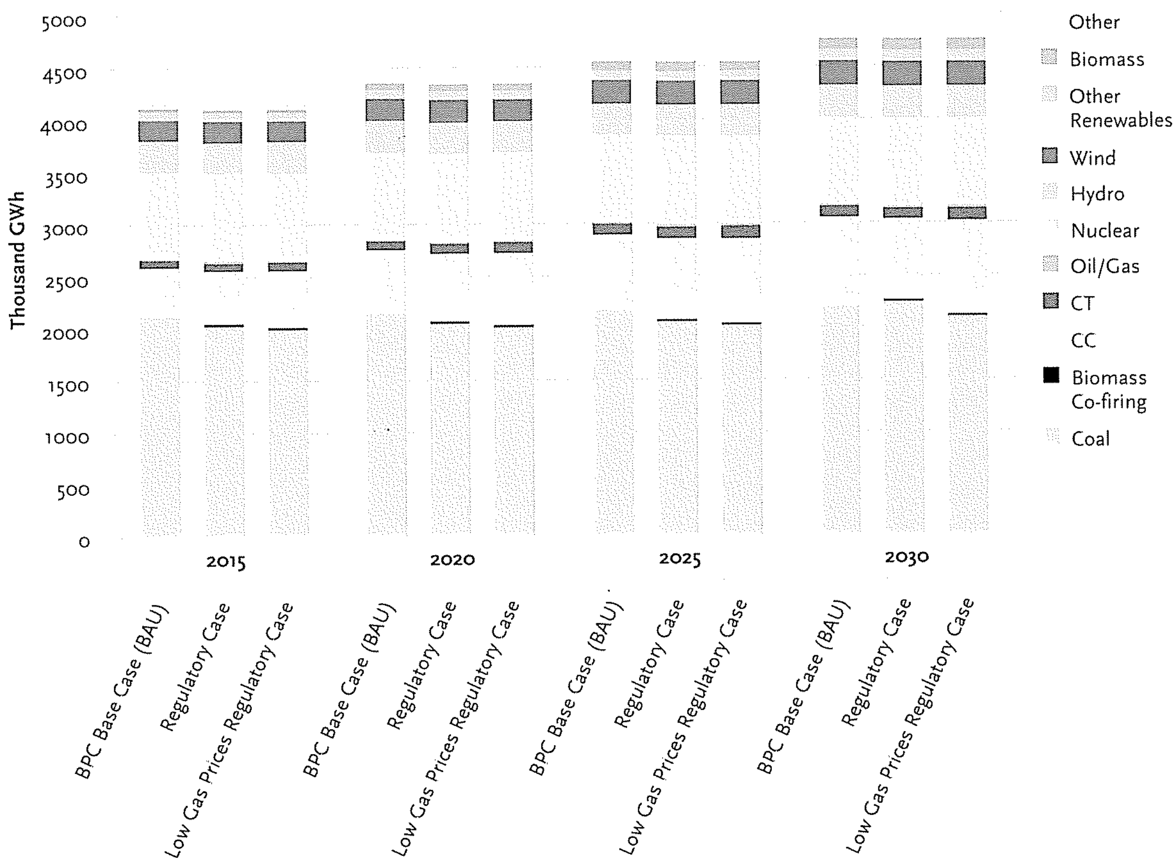


Figure B-6 shows the U.S. generation mix by type across the three cases. Generation from coal declines by 5–7 percent in the Regulatory Cases relative to the Reference Case due to retirements motivated by EPA's new regulatory requirements. Increased gas-fired generation makes up for the majority of that decline. In the Regulatory Case, generation from gas makes up roughly three-quarters of the decline in coal generation. With lower gas prices in the Low Gas Price Case, higher output from gas-fired generators makes up nearly 90 percent of the reduction from coal. In both cases, increased generation from renewables also contributes to meeting overall electricity demand growth over time.

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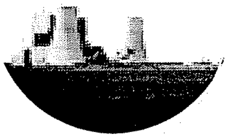
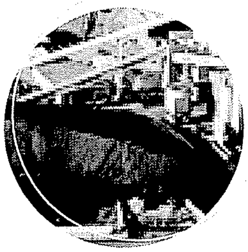
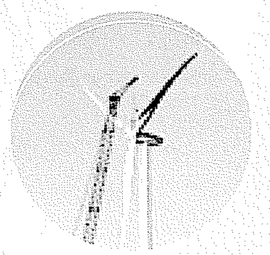
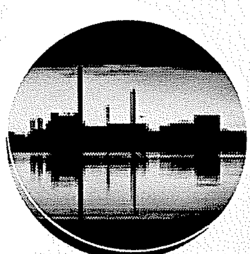
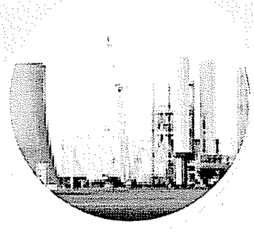
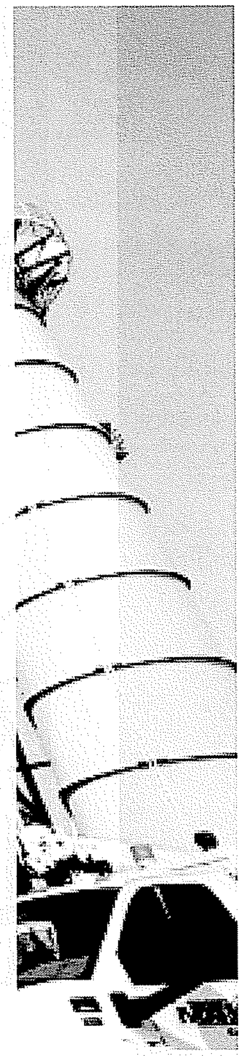












BIPARTISAN POLICY CENTER

The Brattle Group

Potential Coal Plant Retirements Under Emerging Environmental Regulations

Metin Celebi, Frank Graves, Gunjan Bathla, and Lucas Bressan

The Brattle Group

December 8, 2010

www.brattle.com

Outline

Introduction and key conclusions

EPA regulations and coal plants

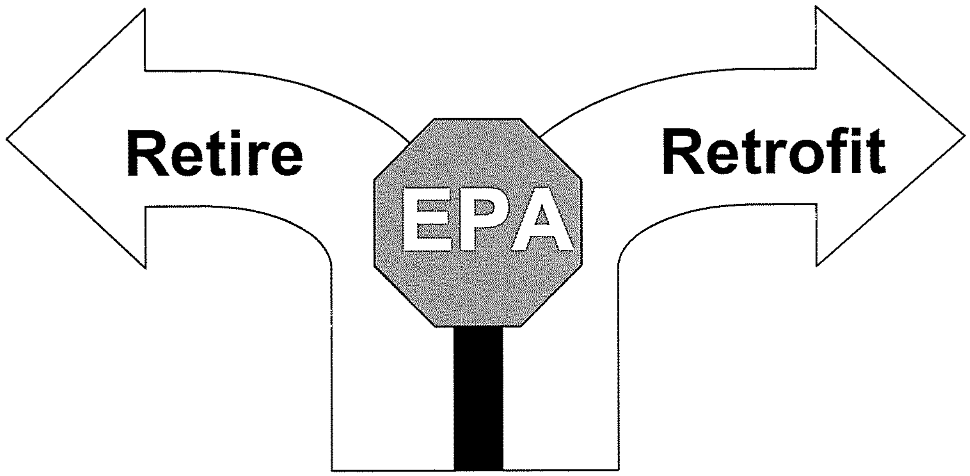
Economic retirement model

Results

Appendix

Coal plant retirements under EPA regulations

Emerging EPA regulations on air quality, water use and ash disposal will likely require existing coal units to choose between installing expensive control equipment and retirement.



Continuation of current low electricity prices in the next five years will also increase the pressure to retire.

Analysis of coal plant retirement exposure

Developed a tool to analyze economics of retrofit vs. retirement for every coal unit in the U.S. under various scenarios of environmental regulation.

- Estimate future capacity factor for each unit by dispatching against projected hourly power prices

- Decide each year whether to retire based on comparing 15-year projected avoidable costs of retrofit against:
  - revenues from energy and capacity markets for merchant units (on an after-tax basis),
  - cost of replacement power from gas CCs or CTs for regulated units.

Brattle coal plant retirement screening tool

Economic Drivers (by region)

- Hourly power prices
- Capacity prices
- Unit-specific VOM cost, heat rate, and coal prices
- FOM cost by age
- Cost of replacement power from gas CC/CTs

Environmental Drivers (by region)

- Regulation scenarios
- Existing control equipment
- CapEx for retrofit Additional FOM for each retrofit
- Compliance year

Retirement Analysis

Results

- Retired coal capacity
- Compliance costs
- CO_2 emissions
- Regional reserve margins
- Gas and coal demand

Note: The version of the tool presented here does not consider potential feedback effects of retirements on wholesale electricity or fuel prices.

Uncertainties and contingencies

These results present a retirement exposure analysis, identifying which units become uneconomic under current market projections.

- Where the local effects of potential retirements are severe, it is likely that market responses, regulatory allowances, or perhaps even environmental policy adjustments would occur that would mitigate some of the impacts, especially where reliability is at risk.
- On the other hand, there are also frictional effects of making numerous, industry-wide retrofits and capacity replacements, which would tend to increase the difficulties of meeting the new environmental regulations. These have also not been modeled.

This analysis describes just one particular set of region-specific market conditions.

- This is only one possible view of the future – There are major uncertainties surrounding long run market circumstances and regulatory policy that would affect these projections.

The modeling capability behind this presentation would allow us to explore unit-specific impacts of other potential future market conditions, investment decision criteria, and more detailed circumstances faced by individual companies or generating units.

Key conclusions – coal plant retirements

A requirement to install scrubbers and SCRs on coal units by 2015 would result in 40-55 GW of economic retirements

- Another 11-12 GW of coal units would retire if cooling towers (@ $200/kW) are also mandated
- Higher-end of range based on doubling the retrofit costs due to potentially increasing demand for labor and control equipment or due to site-specific constraints

$70-130 billion investment on scrubbers and SCRs (for 187 GW coal capacity) would be needed to comply with the EPA mandates

- **An** additional $30-50 billion compliance investment would be needed if cooling towers are also mandated.

Most of the economic retirements are with merchant units (which rely on market revenues), in contrast to regulated units whose retirement decisions are based on the cost of replacement power.

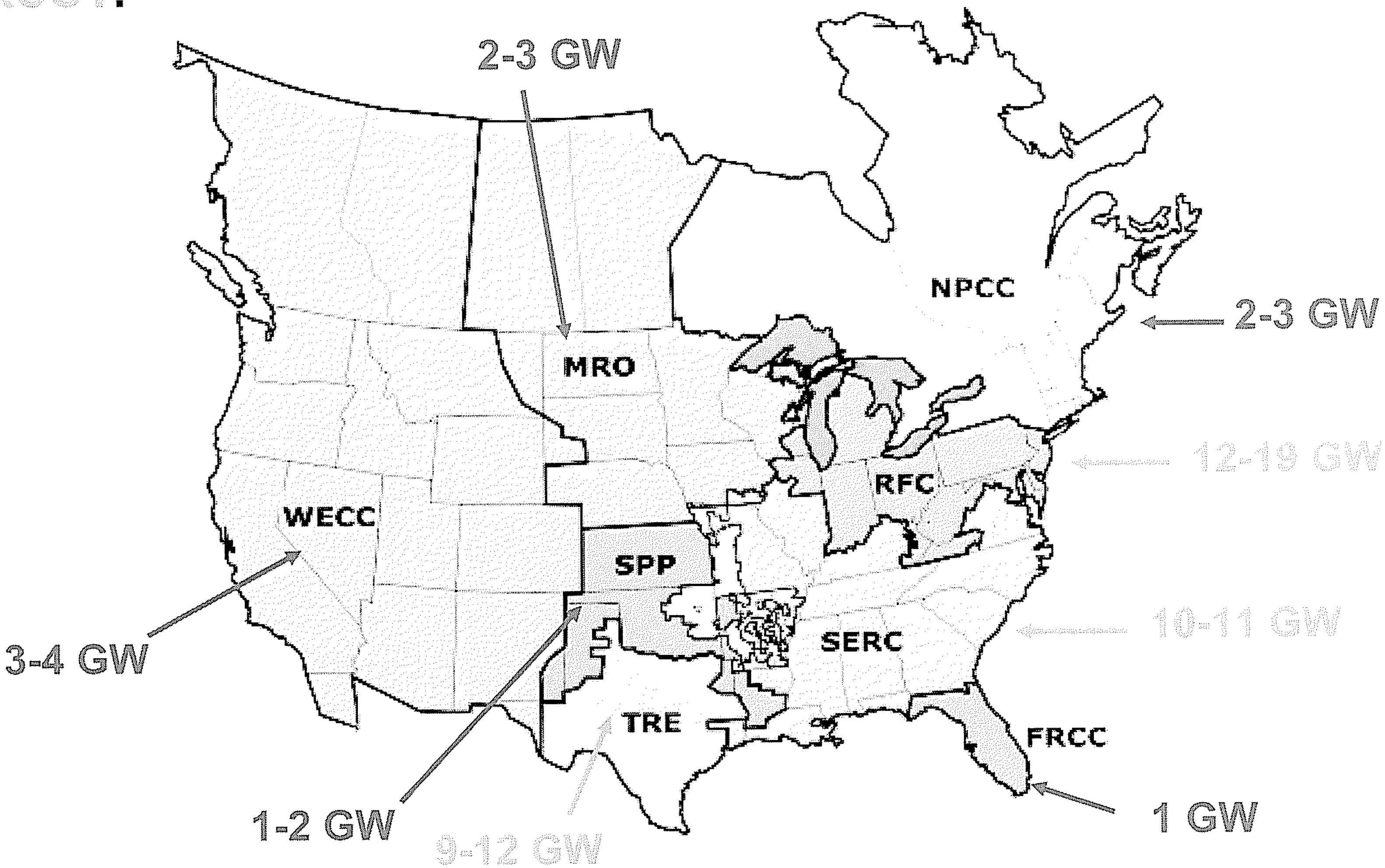
- We analyzed merchant units against wholesale spot conditions, not considering any LT PPAs

U.S. COAL PLANT CAPACITY VULNERABLE TO RETIREMENT BY 2020

	Retirements with Scrubber & SCR Mandate GW	Additional Retirements with Cooling Tower Mandate GW	**Total Retirements GW**	Percentage of		Retrofit Capital Costs for Compliance $ Billion
				Coal Capacity	Total Capacity	
Nationwide Total	**40-55**	**11-12**	**50-66**	**16-21%**	**5-7%**	**$101-181**
Merchant	37-48	8-10	**47-56**	64-76%	11-14%	$5-7
Regulated	3-6	1-4	**3-10**	1-4%	1-2%	$94-177

Key conclusions – coal plant retirements (cont'd)

Most of the retirements would be in NERC regions RFC, SERC and ERCOT.



Key conclusions – coal plant retirements (cont'd)

Market areas with the largest retirements would be Midwest ISO, ERCOT, and PJM.

- Retirements represent large portions of existing total regional capacity: 15% in ERCOT, 11-14% in Midwest ISO, and 6-11% in PJM
- All merchant coal plants in ERCOT would retire if scrubbers, SCRs, and cooling towers are mandated

COAL PLANT CAPACITY VULNERABLE TO RETIREMENT BY 2020 - SELECTED REGIONS

	Retirements with Scrubber & SCR Mandate GW	Additional Retirements with Cooling Tower Mandate GW	**Total Retirements GW**	Percentage of Coal Capacity	Percentage of Total Capacity	Retrofit Capital Costs for Compliance $ Billion
Midwest ISO Total	**12-15**	**3-5**	**16-20**	**21-28%**	**11-14%**	**$27-48**
Merchant	11-12	2-3	**14**	93-94%	30-31%	$0
Regulated	1-3	0-3	**2-6**	3-11%	2-6%	$27-48
ERCOT ISO Total	**9-12**	**1-3**	**13**	**72**	**15%**	**$3-5**
Merchant	9-12	1-3	**13**	100%	18%	$0
Regulated	0	0	**0**	0%	0%	$3-5
PJM ISO Total	**8-15**	**3-5**	**12-19**	**15-26%**	**6-11%**	**$19-29**
Merchant	8-15	3-4	**12-19**	33-54%	10-16%	$4-6
Regulated	0	0	**0**	0-1%	0-1%	$13-25

Key conclusions – coal plant retirements (cont'd)

About 1/3rd of the economic retirement capacity are younger (< 40 years) and larger (> 500 MW) units, highlighting the importance of considering regional market conditions in addition to unit age and size in retirement decisions.

Capacity revenues are moderately important, reducing them by half would add another 7 GW of retirements under the EPA mandate to install scrubbers and SCRs

Another 8 GW of regulated units would retire under scrubber and SCR mandates (~ half of them in the MRO region) if a 20% discount is applied to the cost of replacement power as a proxy for potential externality penalties imposed by regulators (such as "Probable Environmental Cost" assessments)

Key conclusions – other impacts

Retirements would reduce reserve margins in 2020 below targets in ERCOT and RFC in the absence of additional new resources coming online:

- ERCOT: from 10% to 1%, compared to target of 13%
- RFC: from 19% to 13%, compared to target of 15%
- Most retirements occur in 2015 (beginning of assumed mandates)

Coal demand falls by about 15% relative to base case in 2020 (due to retirements and lower CFs for the remaining units that installed scrubbers and SCRs).

The retirements and reduced capacity factors due to scrubber and SCR requirements would increase U.S. gas demand by at most 5.8 Bcfd (about 10% of total demand), with significant regional variation

- RFC-MISO gas demand increase about 0.7 Bcfd, compared to 0.1 Bcfd in FRCC.

CO_2 emissions would decrease by 150 million tons in 2020 (~10% of coal CO_2 emissions) if the lost coal generation (due to retirements and lowered capacity factors) is replaced by gas generation (@ 8000 Btu heat rate).

Comparison to other studies

Recent studies estimate 10-75 GW coal capacity at risk for retirement.

Study	Projected coal capacity to retire or "at risk"	Criteria to identify coal capacity at risk	Models future revenues from energy and capacity markets?	Models future capacity factors of coal units?	Distinguishes between merchant vs. regulated units?
Brattle, December 2010	50-65 GW by 2020	Regulated units: 15-year PV of cost > replacement power cost from a gas CC or CT; Merchant units: 15-year PV of cost > revenues from energy and capacity markets	Yes, based on dispatch against projected hourly prices	Yes, based on dispatch against projected hourly prices	Yes
NERC, October 2010	10-35 GW by 2018 (in addition to ~20 GW committed/announced retirement, or not relied upon by NERC as a capacity resource)	levelized costs (@ 2008 CF) after retrofitting each unit for the environmental regulations compared to the cost of a new gas-fired unit	No	No	Yes -- uses different cost of capital for regulated vs. merchant units
ICF (October 2010)	75 GW by 2018	unknown	unknown	unknown	unknown
Credit Suisse, September 2010	60 GW	size and existing controls	No	No	No
ICF/INGAAA, May 2010	50 GW	age, efficiency and existing controls	No	No	No
ICF/EEI (May 2010)	25-60 GW by 2015	cost of retrofitting coal plant compared to cost of new gas CC	unknown	unknown	Yes

Outline

Introduction and key [illegible]

EPA regulations and coal plants

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Appendix

Overview of environmental pressures

EPA is in the process of promulgating a series of new regulations to more tightly control all of the following:

- "Criteria air pollutants," especially NOx, ozone, SOx, and particulates
- Hazardous air pollutants (HAPs), especially mercury
- Cooling water discharge
- Coal combustion byproducts

The nature of most of these regulations, and the way states must implement these more stringent air quality standards, is expected to be highly tilted toward command-and-control (i.e., with no choice but to comply or retire on a strict schedule), less toward cap-and-trade of emission allowances that are fungible over space and time.

However, there has been some recent movements that suggest at least the coal ash and water regulations (316b) may be delayed

- a more flexible time table or conditional slate of control options would reduce the economic impacts we find arising under a more strict interpretation of the potential rules

Criteria air pollutants (ozone, NOx, SOx, particulates)

EPA promulgates regulations based on the Clean Air Act: Clean Air Interstate Rules (CAIR), Haze Rules, and National Ambient Air Quality Standards (NAAQS)

- States must file State Implementation Plans to demonstrate commitment to progress towards compliance with NAAQS

EPA Developments Affecting Future Regulations

- Transport Rule – Regulates NOx and SOx emissions in 31 states (Mid 2011)
  - State-specific SOx and NOx budgets starting in 2012/14; restricts interstate allowance trading
  - Reduce SOx emissions by 71%, NOx emissions by 52% (relative to 2005 levels)
- NAAQS – Stricter ozone concentrations likely in place in 2011
  - Will likely cause states to implement command-and-control regulations
- Both of these move away from market-based cap-and-trade and toward command-and-control
- Many existing units will need to add expensive scrubbers and SCRs or retire

Hazardous air pollutants (HAPs)

HAPs are pollutants (mercury, phosphoric acid, lead and selenium compounds, etc.) that are associated with cancer or other serious health affects.

EPA has not regulated HAPs from electric generators before.

As soon as EPA does regulate HAPs, the Clean Air Act dictates strict controls by EPA (Maximum Achievable Control Technology -- MACT), with little flexibility for sources to comply.

Coming EPA MACT rulemakings for mercury and other HAPs:

- EPA is expected to issue rules in March 2011
- Affects coal and oil units
- **May require scrubbers (ACI may not be enough) on all coal plants in 3-4 years**

Cooling water and ash regulations

Cooling Water

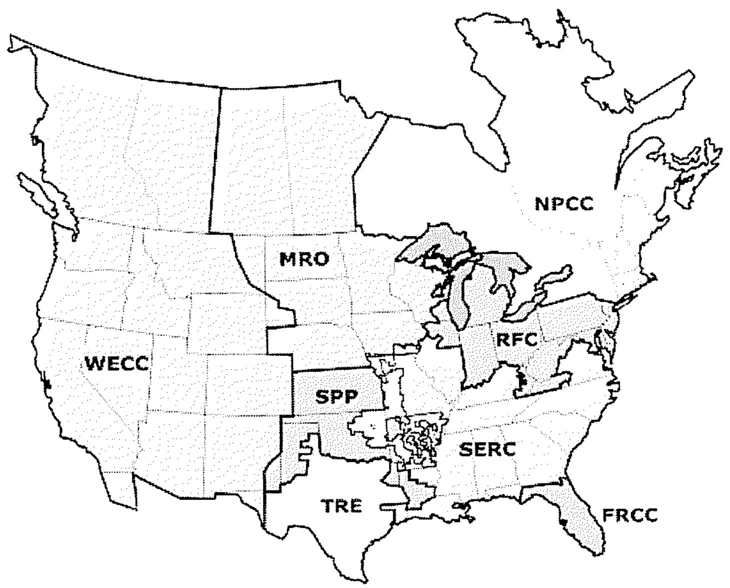
- EPA and states are beginning to apply the Clean Water Act (CWA) to force generators to replace once-through cooling, sometimes subject to cost/benefit tests
- EPA is expected to issue rules in 2011/12 regarding cooling water intake structures and waste water discharges

Ash

- **Currently** exempt from EPA hazardous waste regulations
- EPA proposed **two options**:
  - Regulate as hazardous waste under Subtitle C of Resource Conservation and Recovery Act (RCRA).
  - Regulate similar to those for municipal and non-hazardous solid waste, hence less stringent than Option 1.

Existing coal fleet

The US coal fleet has a total of 316 GW capacity (~1/3rd of all capacity), and generates roughly half of all electrical output.
About 75% of the coal fleet is owned by regulated entities (IOUs, munis, federal power agencies, etc.).
Capacity factors of coal units in U.S. averaged 61% in 2009.

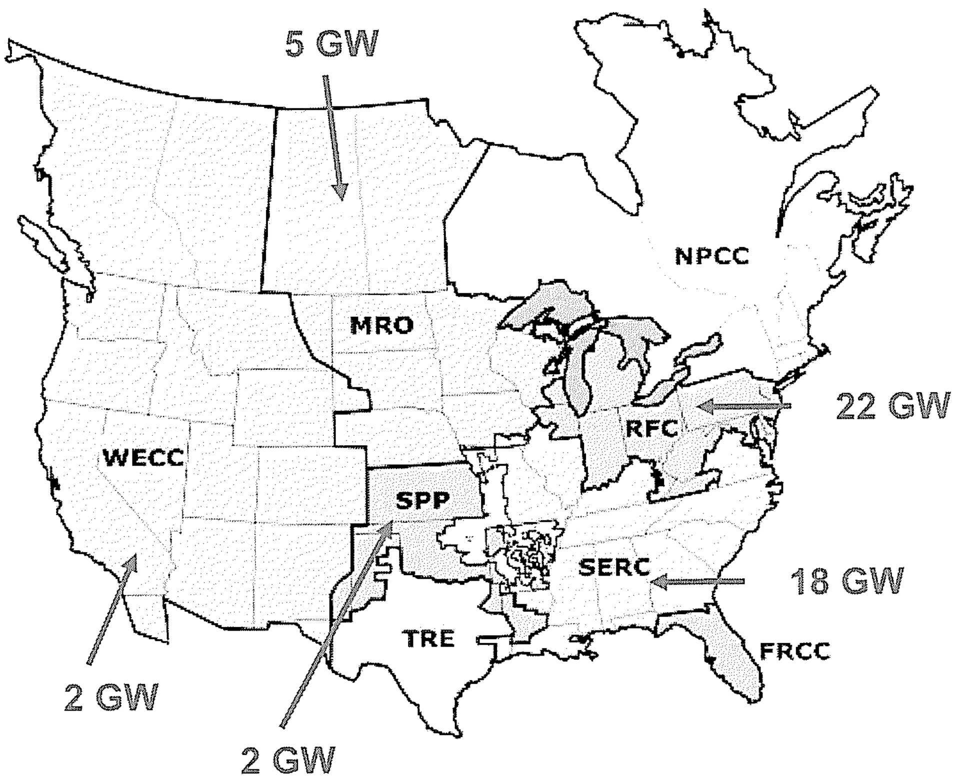


NERC Region	Coal Capacity (GW)	% Owned by Regulated Entities	2009 Capacity Factor
RFC	105	63%	61%
SERC	100	88%	62%
WECC	32	89%	78%
MRO	27	96%	70%
SPP	20	98%	72%
ERCOT	18	28%	77%
FRCC	10	92%	58%
NPCC	6	16%	58%
Total	316	77%	65%

Large portion of the current coal fleet lacks major environmental controls:
- 165 GW (52%) without scrubbers, majority of them in RFC and SERC regions
- 180 GW (57%) without SCRs, about half in RFC and SERC regions
- ~300 GW (96%) without ACI and baghouse, majority of them in RFC and SERC regions

Old and small coal units with no controls

About 50 GW of existing small (< 500 MW) and old (> 40 years) coal units have no environmental controls*. Most of these units are in RFC and SERC regions.

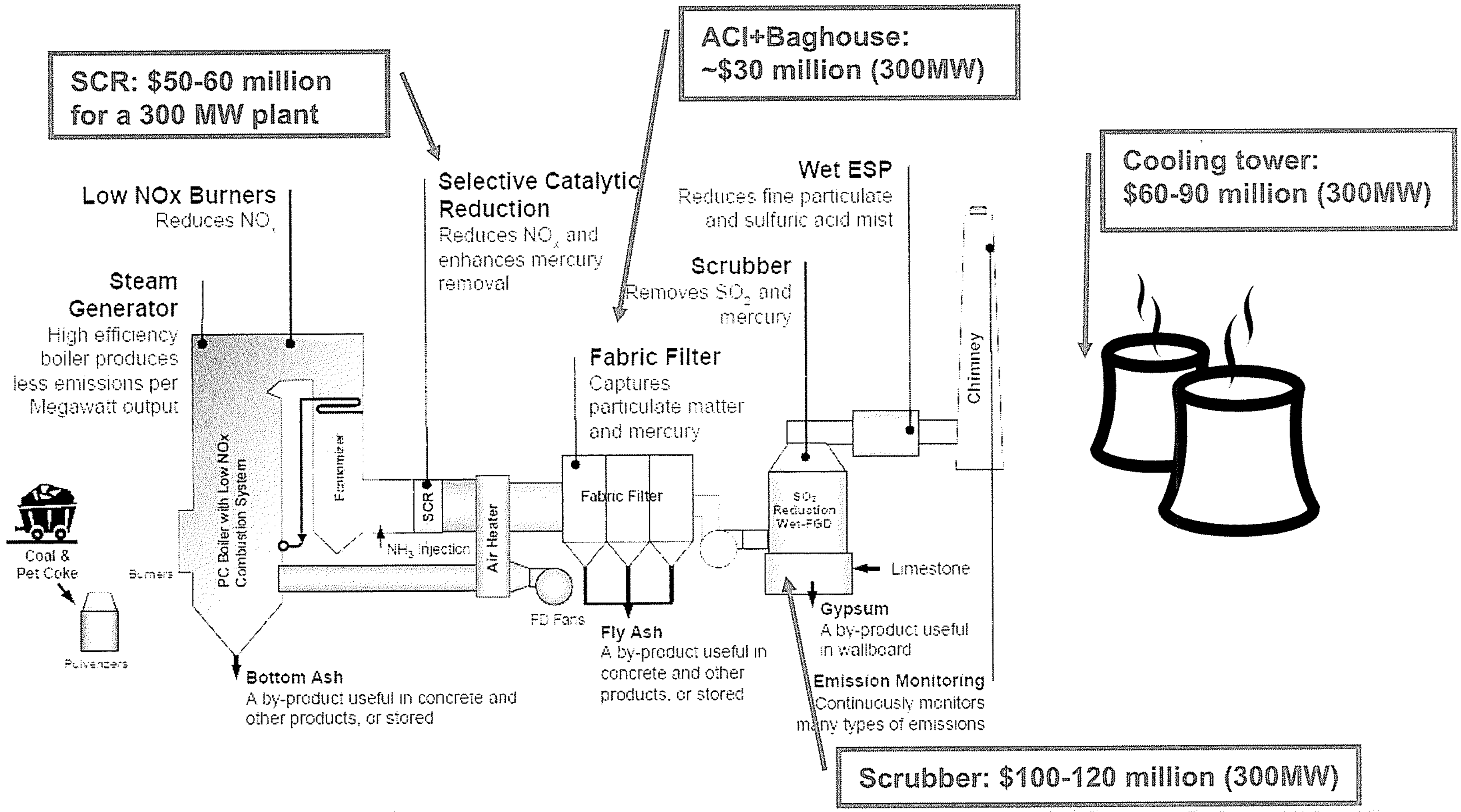


Region	% of Coal at Risk	% of 2018 Reserve Margin
RFC	20%	60%
SERC	18%	32%
MRO	20%	67%
SPP	8%	14%
WECC	5%	3%

***Environmental controls here refer to scrubber for SO_2 and SCR/SNCR for NOx.**

EPA regulations – implications

Potential technology-based environmental restrictions in air (SO_2, NOx, Mercury), water and coal ash disposal in lieu of market-based approaches.



Costs of compliance

A new regulation that requires scrubbers would add $8-34/MWh (in O&M and carrying costs) to the existing costs of coal plants. If NOx controls (SCR) and/or mercury controls (ACI) are also required, this would bring the total increase in levelized costs to $12-46/MWh.

COST OF ENVIRONMENTAL CONTROL EQUIPMENT FOR COAL PLANTS

Controls			Scenario I	Scenario II	Scenario III
FGD			x	x	x
SCR				x	
ACI (No Existing Baghouse)					x
Total Cost			*Million 2009 $'s*		
600 MW unit at 70% CF			$153	$233	$199
600 MW unit at 30% CF			$149	$227	$194
300 MW unit at 70% CF			$118	$168	$149
300 MW unit at 30% CF			$116	$165	$147
Economic Life	*Size (MW)*	*Capacity Factor*	*Levelized Cost in 2009 $/MWh*		
10	600	30%	22.36	32.22	30.38
		70%	10.63	15.31	14.31
	300	30%	34.02	46.40	45.02
		70%	15.61	21.42	20.57
15	600	30%	18.49	26.23	25.43
		70%	8.97	12.75	12.19
	300	30%	27.99	37.69	37.48
		70%	13.03	17.69	17.34
20	600	30%	16.64	23.36	23.06
		70%	8.18	11.52	11.17
	300	30%	25.10	33.51	33.86
		70%	11.79	15.90	15.79

Current energy margins (excluding capacity revenues) already low for merchant coal plants due to low gas prices, low demand growth, and new renewables

- Current dispatch costs for an existing coal plant ~$20-35/MWh
- Low wholesale power prices in 2009
  - PJM West: ~$40/MWh
  - Midwest (Illinois/Michigan): ~$25-39/MWh
  - Southeast: ~$30/MWh

Some implications of coal plant retirements

- Electric reliability (grid and reserves) at risk
- Decrease in coal demand
  - Effect on rail transport (2/3rd of coal shipped by rail, approximately 20% of rail freight revenues from coal)
- Likely increase in gas demand
  - Possibly offset partially by increased renewable expansion
  - Effect on gas prices and volatility? – not examined in this study
  - Effect on pipeline basis prices? – not examined in this study
- Increase in electricity prices (energy and capacity) – not examined in this study
- Potential stranded costs for regulated utilities – not examined in this study

Outline

Introduction and key conclusions

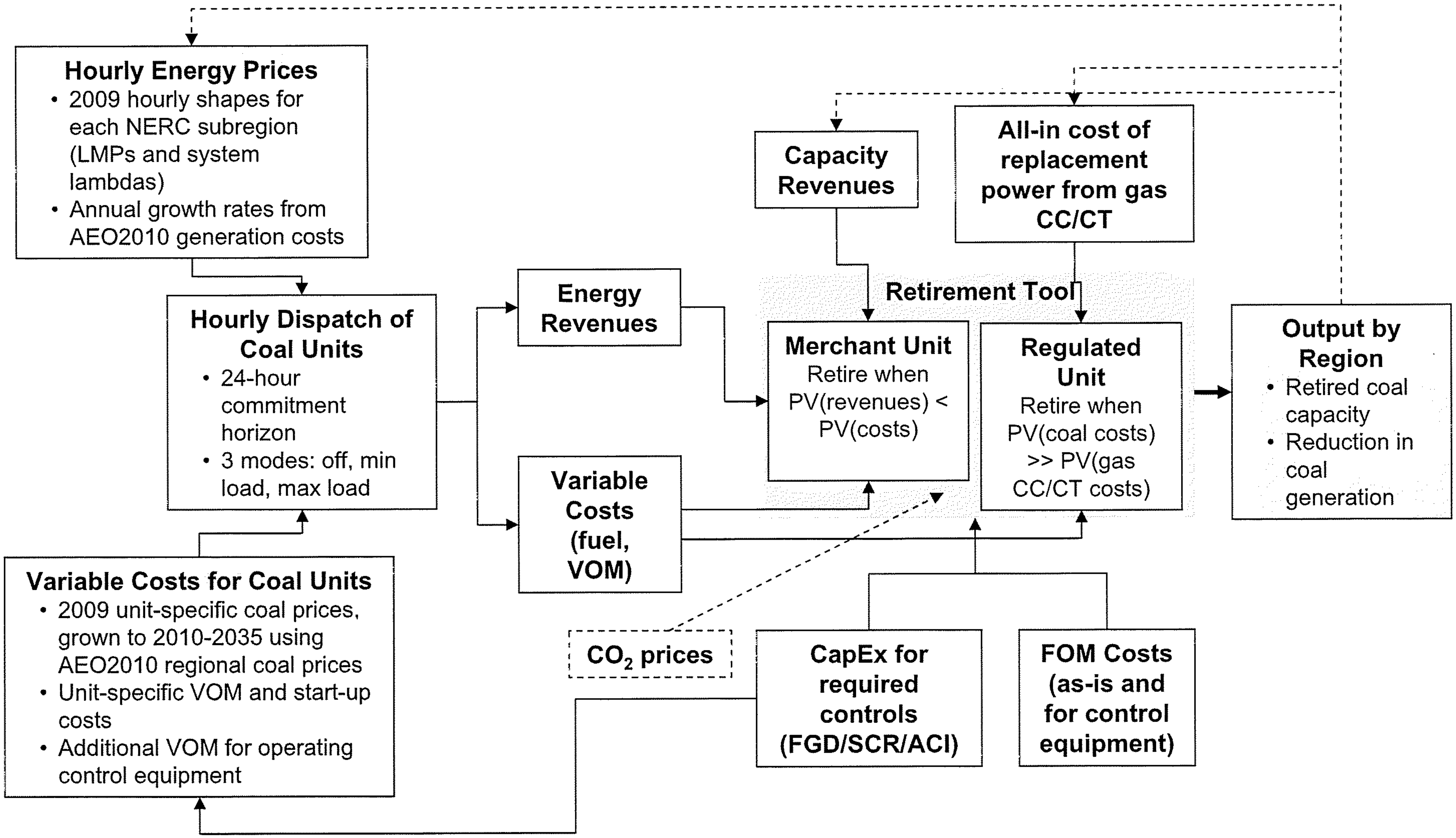
EPA regulations and coal plants

Economic retirement model

Results

Appendix

Brattle coal plant retirement screening tool – details



Note: Dashed lines and boxes represent factors and feedback effects that are planned to be incorporated into the model.

Key assumptions on markets

Wholesale power prices

- Hourly actual prices in 2009 projected to 2010-2035 using AEO2010 escalation rates for generation prices
- Annual average prices in the range of $25-35/MWh (2008 dollars), largely remain flat in the future
  - except for increasing prices in ERCOT, NYISO, and PJM

Capacity prices

- Only applied to regions with capacity markets
- In the range of $10-80/kW-year until 2020, then growing to $40-190/kW-year based on *Brattle* forecasts
- Brattle has developed region-specific capacity price outlooks based on reserves, planned additions and retirements, cost of new entry, and RTO market rules. Similar to other inputs in this study, only one scenario for capacity price outlook is examined.

Natural gas prices

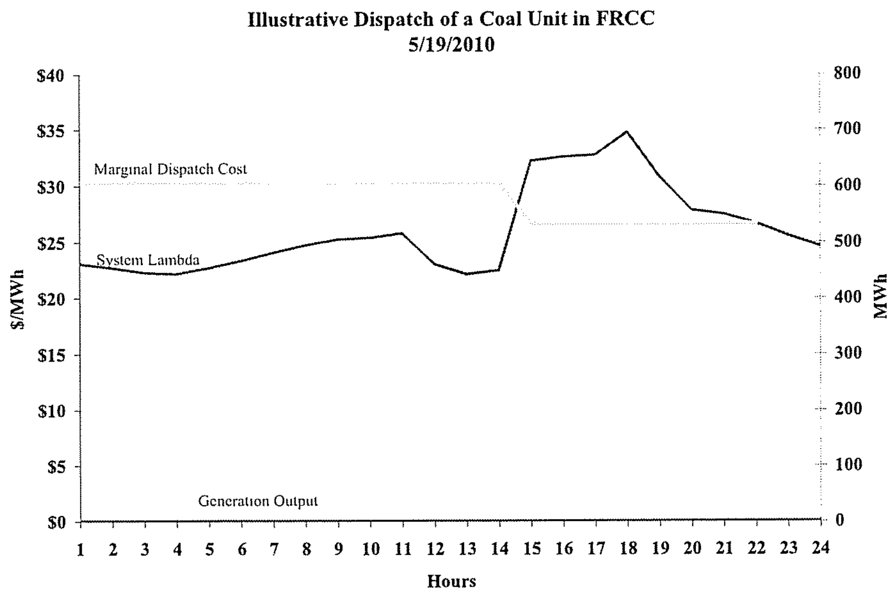
- Regional annual projections based on AEO2010
- Steep growth from $4-6/MMBtu range in 2010 to $5.5-8.5/MBtu in 2020 (all in real dollars)

Coal prices

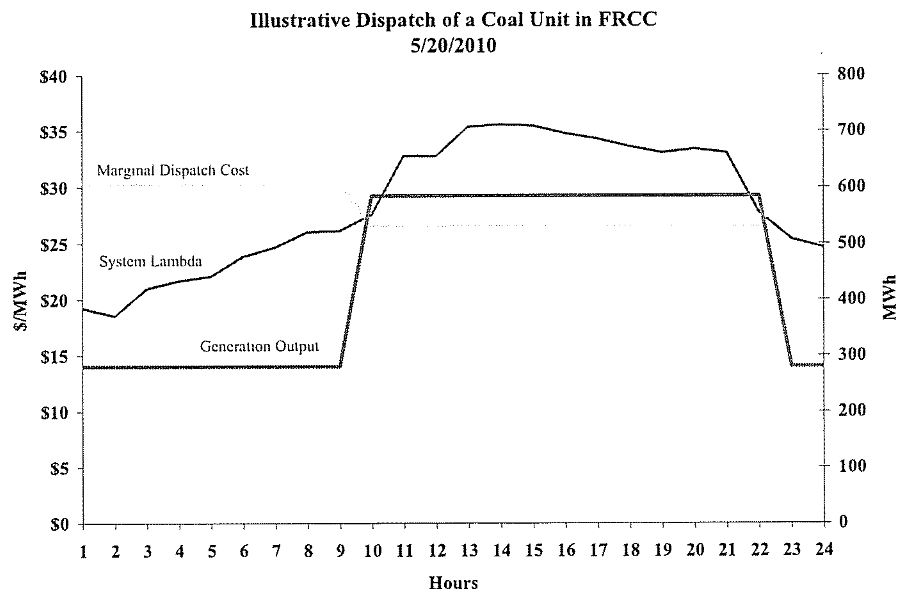
- Regional annual price projections based in AEO2010
- Most regions with flat real prices over time

More details in the Appendix

Illustration of coal hourly dispatch



No generation since operating margins during the day not sufficient to recover start-up costs.



Unit started up and generation output at min load (280 MW) or max load (584 MW) since operating margins during the day were enough to recover start-up costs.

Illustration of retirement decisions – a regulated unit

- Cost of continued coal operations is compared to cost of replacement power from a gas CC/CT (amortized over 40 years of capital recovery at a utility ATWACC).
- Even though the CapEx for installing a scrubber and an SCR on the unit is ~$220M in 2015, 15-year present value (at 7% discount rate) of continued coal operations with CapEx is roughly half of new gas CC/CT costs. Therefore, the unit does not retire in the model.

Illustration of Retirement Decision of a Regulated Unit
(400 MW, age > 40 years, no FGD or SCR)

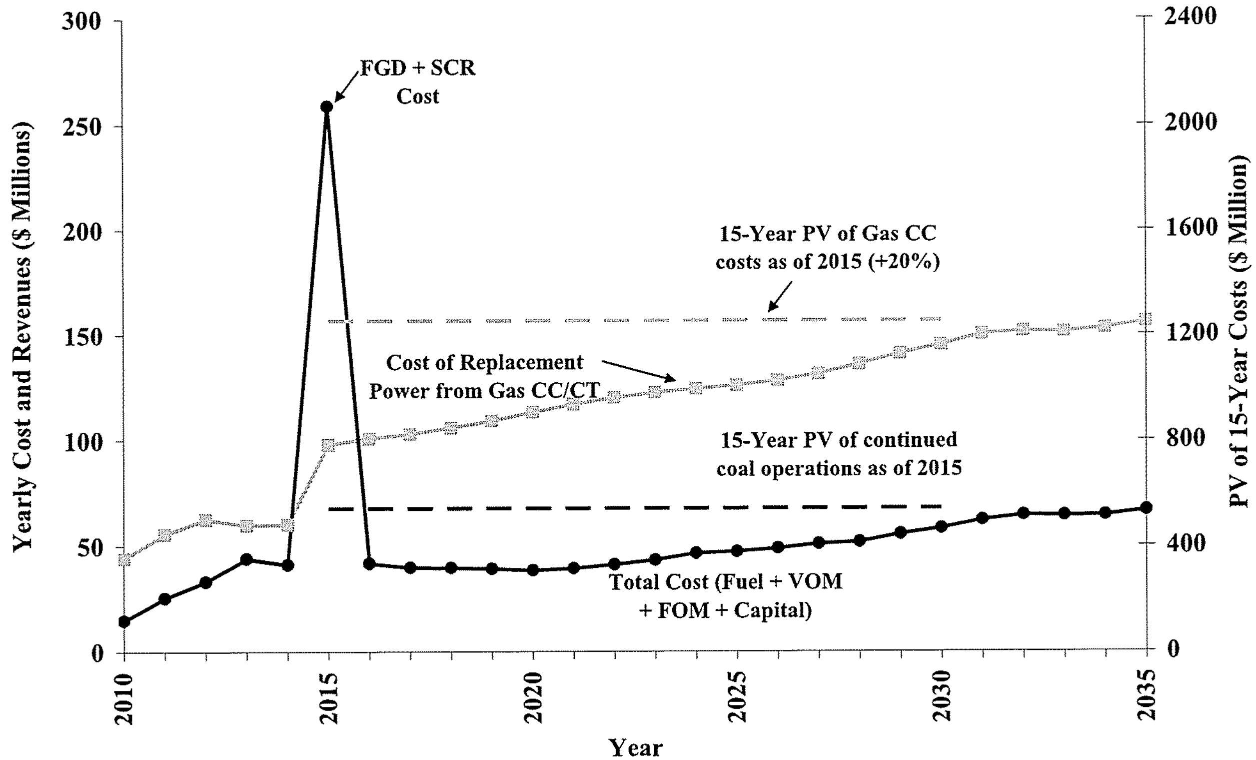
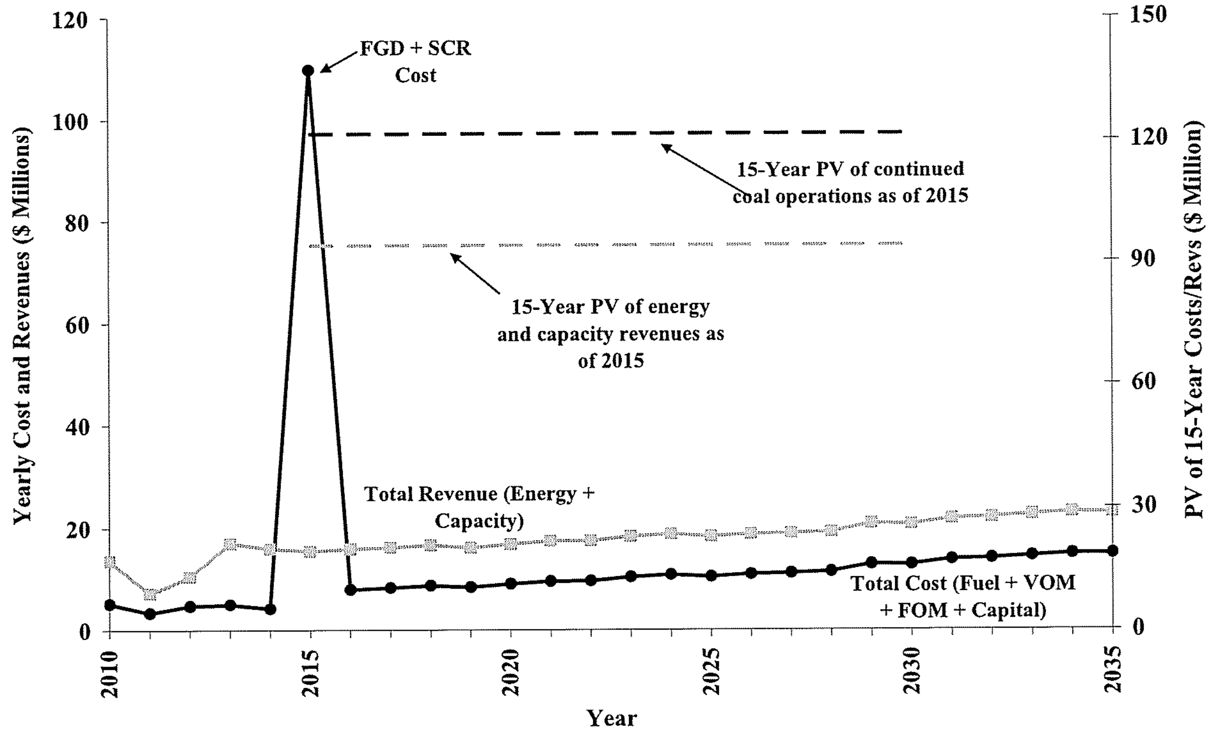


Illustration of retirement decisions – a merchant unit

Cost of continued coal operations is compared to revenues from energy and capacity markets.

The required $90 million CapEx in 2015 makes the 15-year PV (at 7% discount rate) of costs higher than revenues, hence the unit retires in 2015.

Illustration of Retirement Decision of a Non-Regulated Unit
(200 MW, age > 40 years, no FGD or SCR)



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Retirements under several criteria

Economic retirements mostly from merchant units, but more than half of coal capacity (~235 GW) could experience small (<10% of costs) or negative energy margins under an EPA mandate to install scrubbers and SCRs.

U.S. COAL PLANT CAPACITY VULNERABLE TO RETIREMENT BY 2020

Retirement Criterion		BASECASE GW	BASECASE % of coal capacity	BASECASE Output (TWh) in 2010	BASECASE % of coal generation	MANDATORY SCRUBBERS AND SCRs GW	MANDATORY SCRUBBERS AND SCRs % of coal capacity	MANDATORY SCRUBBERS AND SCRs Output (TWh) in 2010	MANDATORY SCRUBBERS AND SCRs % of coal generation
Age (> 40 yr old) and size (< 500 MW)	Merchant					13.6	18.4%	65.7	17.4%
	Regulated					35.9	14.8%	179.5	12.8%
	Total					**49.5**	**15.6%**	**245.2**	**13.8%**
Energy margins < 10% of costs	Merchant	17.7	23.8%	66.1	17.5%	49.2	66.4%	224.2	59.4%
	Regulated	120.6	49.8%	597.5	42.6%	187.5	77.4%	1026.0	73.2%
	Total	**138.3**	**43.7%**	**663.5**	**37.3%**	**236.7**	**74.8%**	**1250.1**	**70.3%**
Energy and capacity revenues for merchant units, replacement power for regulated units (+20% stranded cost adder)	Merchant	5.8	7.8%	12.2	3.2%	37.1	50.0%	156.0	41.3%
	Regulated	0.0	0.0%	0.0	0.0%	2.5	1.0%	1.6	0.1%
	Total	**5.8**	**1.8%**	**12.2**	**0.7%**	**39.6**	**12.5%**	**157.6**	**8.9%**

5.8 GW coal retirement: About the same as recent EIA and EPA projections absent new regulations

No CO_2 prices assumed, and no additional controls or operating constraints (e.g., cooling water, or ash handling).

Sensitivities on regulatory shutdown criteria

Default retirement criteria for regulated units is whether the present value of:

- future coal plant operation, FOM and environmental CapEx costs

exceed

- the cost of replacement power from a gas CC/CT plus an assumed 20% stranded cost adder

Two sensitivities are performed on this assumed regulatory criteria for retirements:

1. <u>With no 20% stranded cost adder</u>: slightly higher (+2 GW) retired capacity
2. <u>With 20% discount to gas CC/CT replacement cost</u>: significantly higher (+8 GW) retirements
    - This sensitivity is a proxy for potential externality penalties imposed by regulators (e.g., future state/federal CO_2 legislation)

Coal retirements by age and size groups

About half of the economic retirements are from younger units (< 40 years in 2009) due to unfavorable regional power prices even though younger units have cost and efficiency advantages.

Not surprisingly, smaller units account for a large portion of the retirements.

Total Retired Coal Capacity by 2020 (GW)

		< 500 MW	>= 500 MW	Total
Basecase	Age <40 years	1.4	3.8	**5.2**
	Age >=40 years	0.6	-	**0.6**
	Total	**2.0**	**3.8**	**5.8**
Scrubber+SCR Mandate	Age <40 years	7.6	14.5	**22.1**
	Age >=40 years	17.4	-	**17.4**
	Total	**25.0**	**14.5**	**39.6**

Regional summary

Retired Capacity by 2020 (GW)

NERC Subregion	Basecase	Mandatory Scrubbers and SCRs
ERCOT	2.5	**9.4**
RFC-PJM	-	**7.5**
SERC-Gateway	0.2	**6.5**
RFC-MISO	0.1	**4.8**
Northwest	1.8	**2.2**
MRO	0.0	**1.7**
Top 6 Regions	**4.6**	**32.1**
Other Regions	1.3	7.4
Total US	**5.8**	**39.6**

Six NERC subregions account for about 80% of the likely retirements under the EPA mandate scenario.

Retired Capacity by 2020 (GW)

ISO/RTO Region	Basecase	Mandatory Scrubbers and SCRs
Midwest ISO	0.3	**12.3**
ERCOT ISO	2.5	**9.4**
PJM ISO	-	**8.3**
New York ISO	-	**1.2**
New England ISO	0.1	**0.8**
SPP	0.3	**0.6**
California ISO	-	**0.5**
Total ISO/RTO	**3.2**	**33.2**
Other Regions	2.6	**6.4**
Total US	**5.8**	**39.6**

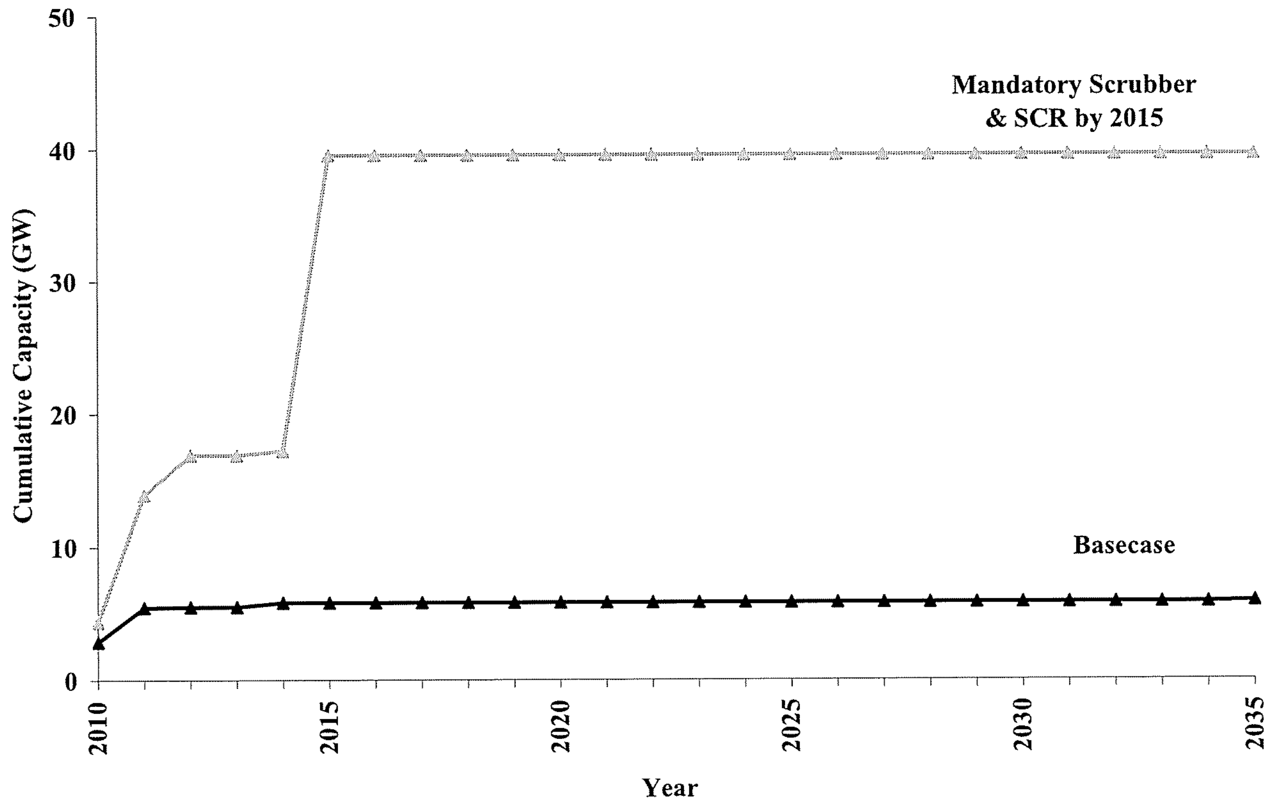
Most of the retirements are in ISO/RTO regions (33 GW under the EPA mandate), with Midwest ISO being the largest one (12 GW).

Economic retirements with mandatory scrubber and SCRs

If all coal units are required to install scrubbers and SCRs by 2015, 39 GW of coal capacity would find it economic to retire by 2015.

Under base case assumptions (no equipment mandates), only 6 GW would retire.

Cumulative Retired Coal Capacity - All US



Regional detail and reduced coal generation

Most retirements are in ERCOT, RFC-PJM and SERC-Gateway (IL, MO) regions.

EPA mandate would result in 275 TWh (16%) decrease in U.S. coal generation in 2020.

	Basecase						Mandatory Scrubber & SCR by 2015					
NERC Subregion	Cumulative Retired Capacity (GW)		Weighted Average Capacity Factor (%)		Generation Output (TWh)		Cumulative Retired Capacity (GW)		Weighted Average Capacity Factor (%)		Generation Output (TWh)	
	2010	**2020**	**2010**	**2020**	**2010**	**2020**	**2010**	**2020**	**2010**	**2020**	**2010**	**2020**
ERCOT	-	2.5	52%	44%	79.3	58.7	-	**9.4**	52%	39%	79.3	28.0
RFC-PJM	-	-	69%	72%	385.7	402.9	-	**7.5**	69%	74%	385.7	366.1
SERC-Gateway	0.2	0.2	72%	72%	93.2	92.9	0.3	**6.5**	73%	64%	92.6	46.6
RFC-MISO	0.1	0.1	60%	51%	217.5	185.6	1.3	**4.8**	61%	48%	213.1	152.3
Northwest	1.8	1.8	85%	85%	77.6	77.6	1.8	**2.2**	85%	80%	77.6	70.3
MRO	0.0	0.0	65%	51%	152.6	119.9	0.1	**1.7**	66%	44%	152.5	97.1
NYISO	-	-	46%	45%	11.3	10.9	-	**1.2**	46%	50%	11.3	6.7
Entergy	-	-	75%	75%	52.3	52.3	-	**1.2**	75%	69%	52.3	41.2
TVA	0.0	0.0	68%	68%	148.0	148.6	0.0	**0.9**	68%	60%	148.0	126.4
ISO-NE	-	0.1	37%	36%	9.0	8.3	-	**0.8**	37%	32%	9.0	5.6
FRCC	0.7	0.7	32%	61%	25.1	47.0	0.7	**0.8**	32%	57%	25.1	43.6
Southern	0.0	0.0	71%	72%	160.0	161.1	0.0	**0.6**	71%	66%	160.0	144.4
VACAR	0.0	0.0	62%	62%	144.2	145.6	0.0	**0.5**	62%	59%	144.2	134.7
California	-	-	78%	78%	15.4	15.4	-	**0.5**	78%	78%	15.4	12.3
SPP South	-	0.3	50%	40%	50.7	39.8	-	**0.4**	50%	30%	50.7	29.8
SPP North	-	0.0	60%	51%	44.3	37.7	-	**0.2**	60%	45%	44.3	32.3
Arizona	-	-	71%	69%	67.1	64.8	-	**0.2**	71%	67%	67.1	61.7
Rocky Mountain	0.0	0.0	72%	68%	40.4	38.3	0.0	**0.1**	72%	61%	40.4	33.7
Total US	**2.9**	**5.8**	65%	63%	**1,774**	**1,708**	**4.4**	**39.6**	65%	59%	**1,769**	**1,433**

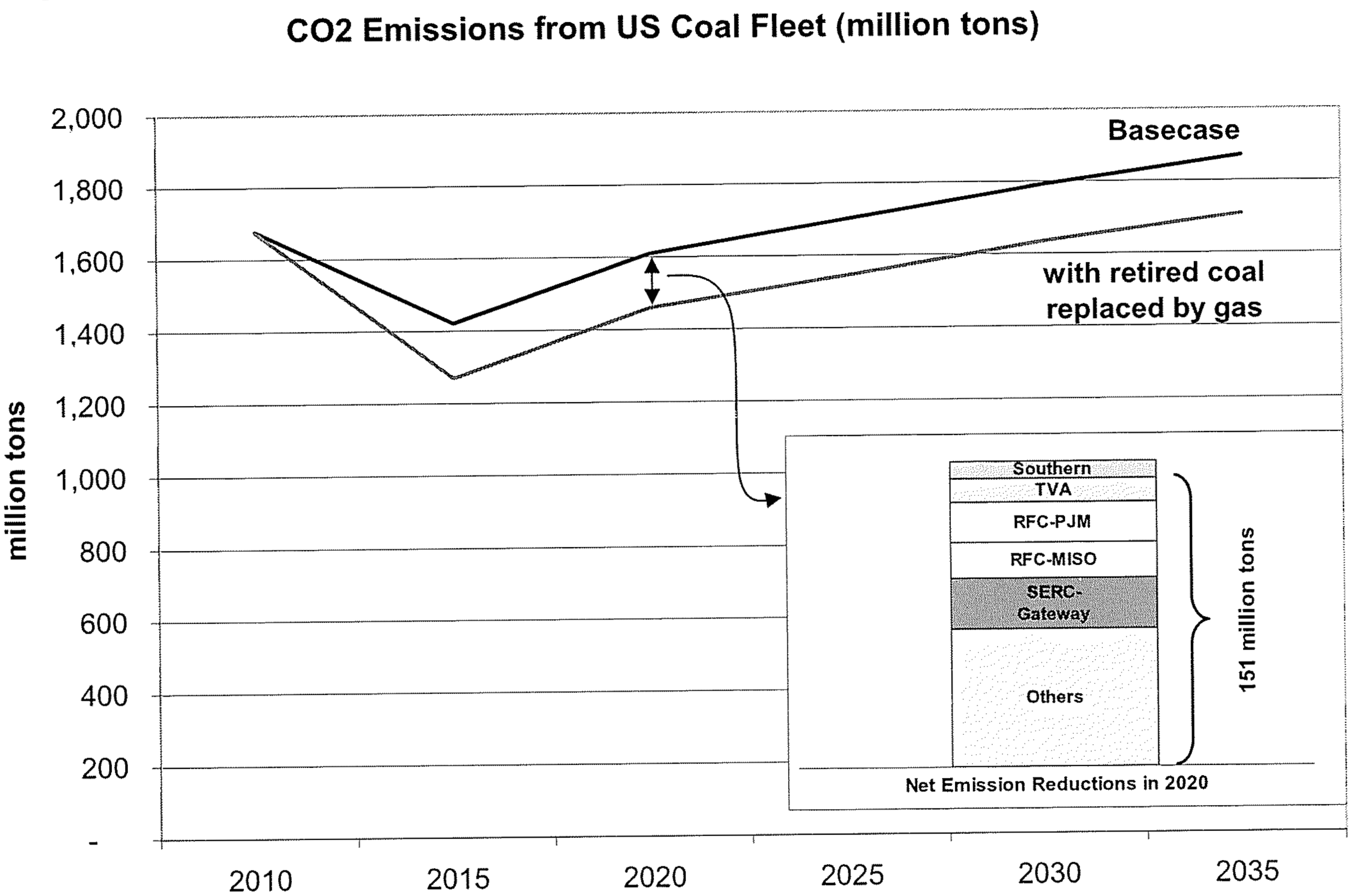
Potential impact on gas generation

Coal retirements could increase gas generation by up to 5.8 Bcf/d in 2020 (assuming all of the decrease in coal generation is replaced with 8000 btu/kWh gas generation).

	Difference in Annual Coal Generation Output (TWh)		Increase in Natural Gas Use Relative to BaseCase (BCF/day)	
NERC Subregion	2010	2020	2010	2020
SERC-Gateway	(0.6)	(46.3)	0.0	**1.0**
RFC-PJM	-	(36.9)	-	**0.8**
RFC-MISO	(4.4)	(33.3)	0.1	**0.7**
ERCOT	-	(30.7)	-	**0.7**
MRO	(0.1)	(22.7)	0.0	**0.5**
TVA	-	(22.2)	-	**0.5**
Southern	-	(16.7)	-	**0.4**
Entergy	-	(11.1)	-	**0.2**
SPP South	-	(10.0)	-	**0.2**
VACAR	-	(10.9)	-	**0.2**
Northwest	-	(7.3)	-	**0.2**
SPP North	-	(5.4)	-	**0.1**
NYISO	-	(4.2)	-	**0.1**
Rocky Mountain	-	(4.6)	-	**0.1**
California	-	(3.1)	-	**0.1**
Arizona	-	(3.0)	-	**0.1**
ISO-NE	-	(2.8)	-	**0.1**
FRCC	-	(3.5)	-	**0.1**
Total US	**(5.1)**	**(275.0)**	**0.1**	**5.8**

Impact on CO_2 emissions

Reduction in coal generation due to EPA mandates could reduce CO_2 emissions from the coal fleet by 10% in 2020 if the lost generation is replaced by gas CCs.



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Impact on regional reserve margins

Economic retirements would have significant reductions below target in ERCOT and RFC.

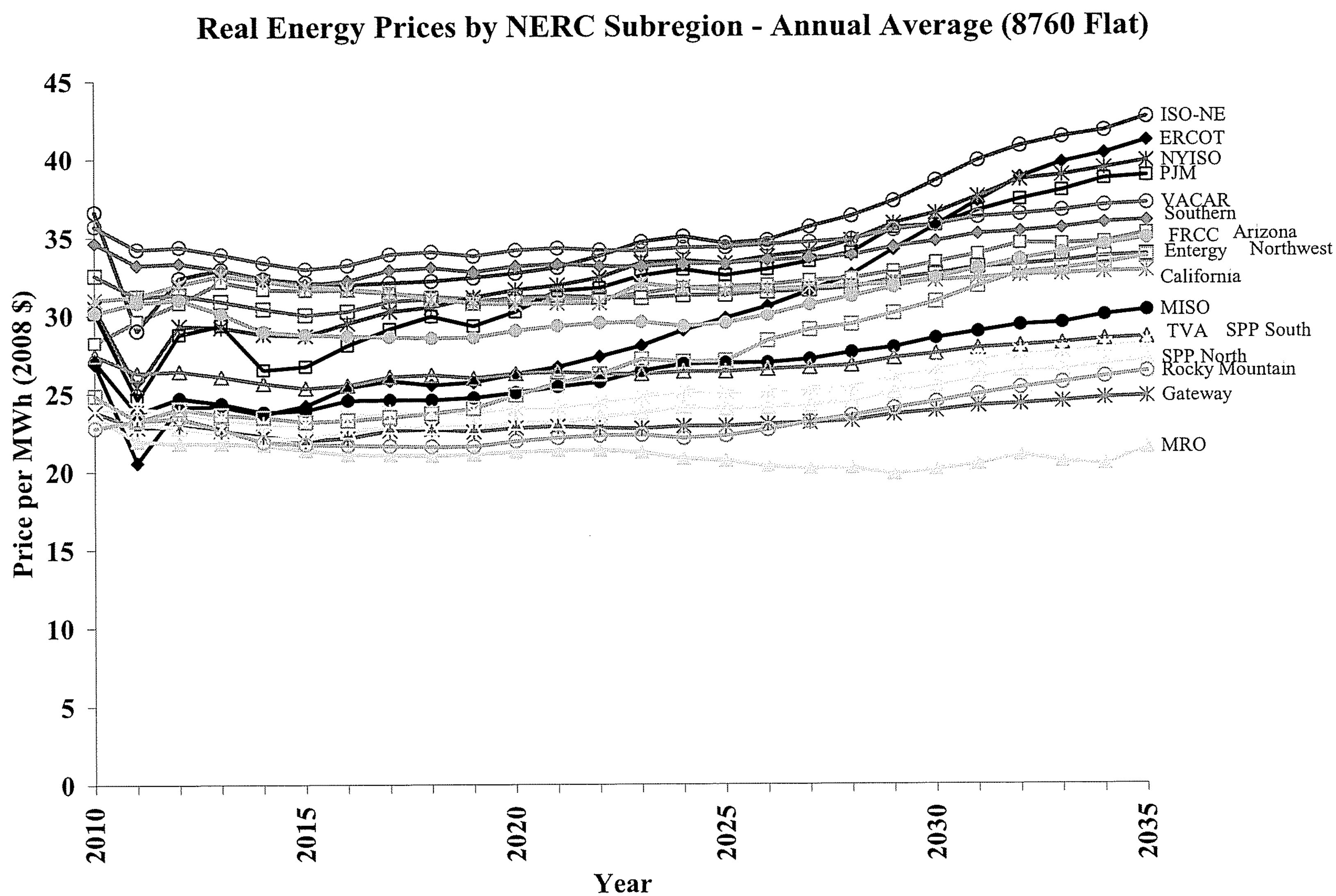
	Net 2018 Internal Demand (GW)	Adjusted Potential 2018 Capacity Resources (GW)	Adjusted Potential 2018 Reserve Margin	Cumulative Retirements by 2020 (GW)		Adjusted Potential 2018 Reserve Margin after retirements		NERC Reference 2018 Reserve Margin Level
				Basecase	Regulation	Basecase	Regulation	
ERCOT	75	85	13%	2	9	**10%**	**1%**	13%
RFC	193	230	19%	0	12	19%	**13%**	15%
MRO	48	54	14%	0	0	**14%**	**14%**	15%
NPCC	66	79	20%	0	2	19%	16%	15%
SERC	229	277	21%	0	10	21%	17%	15%
SPP	49	60	24%	0	1	23%	23%	14%
FRCC	50	63	27%	1	1	26%	25%	15%
WECC	157	211	34%	2	3	33%	32%	18%

Possible enhancements and applications

- ♦ Close scrutiny of single regions
  - Dispatch each coal plant against its own price curve
- ♦ Feedback of plant shutdowns on power prices
- ♦ Sensitivity to gas and power prices (uncertainty and feedback)
- ♦ Effect of potential CO_2 prices on retirement and operating margins
- ♦ Implications for coal shipments on major railroads

APPENDIX

Key assumptions – wholesale power prices



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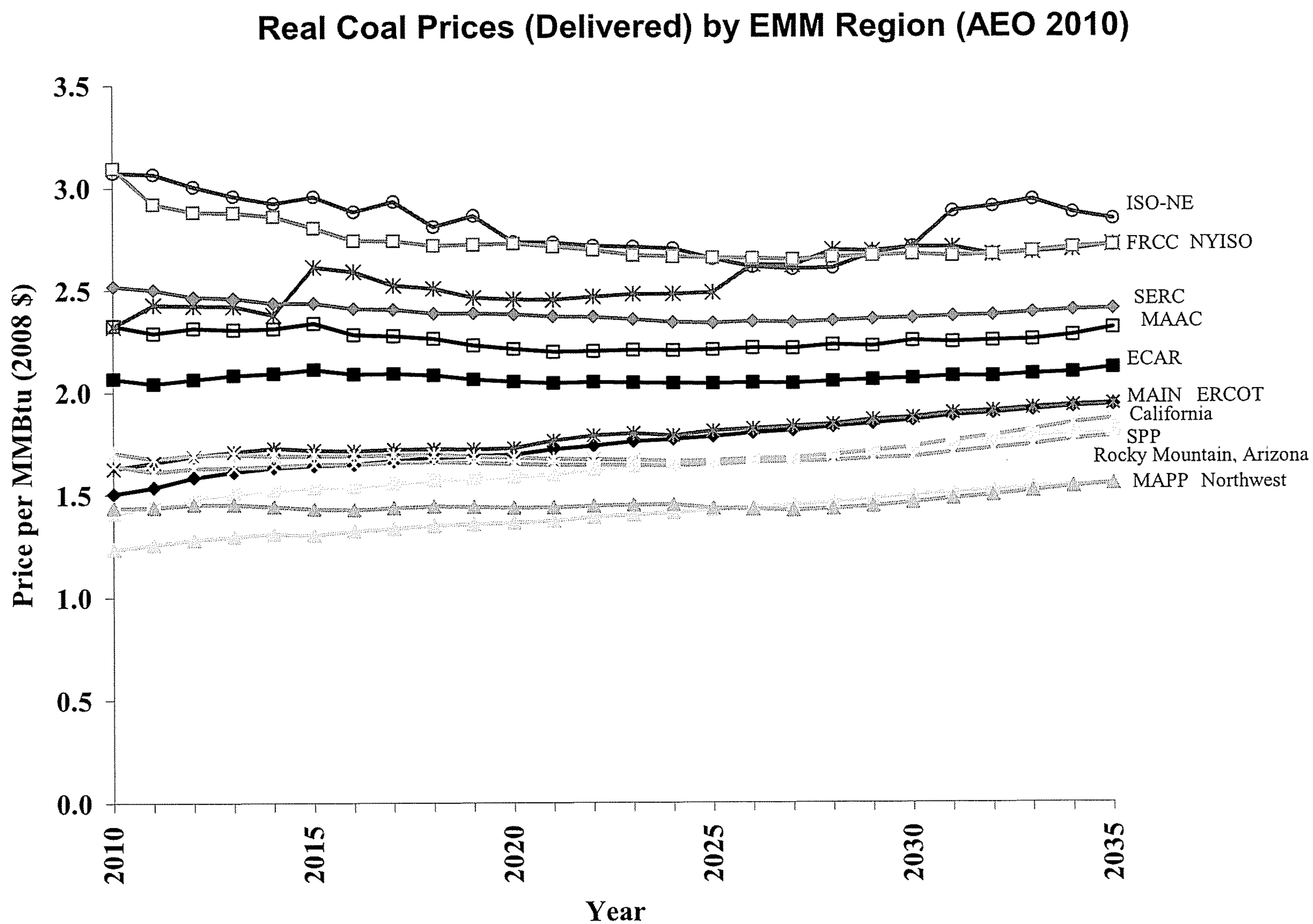
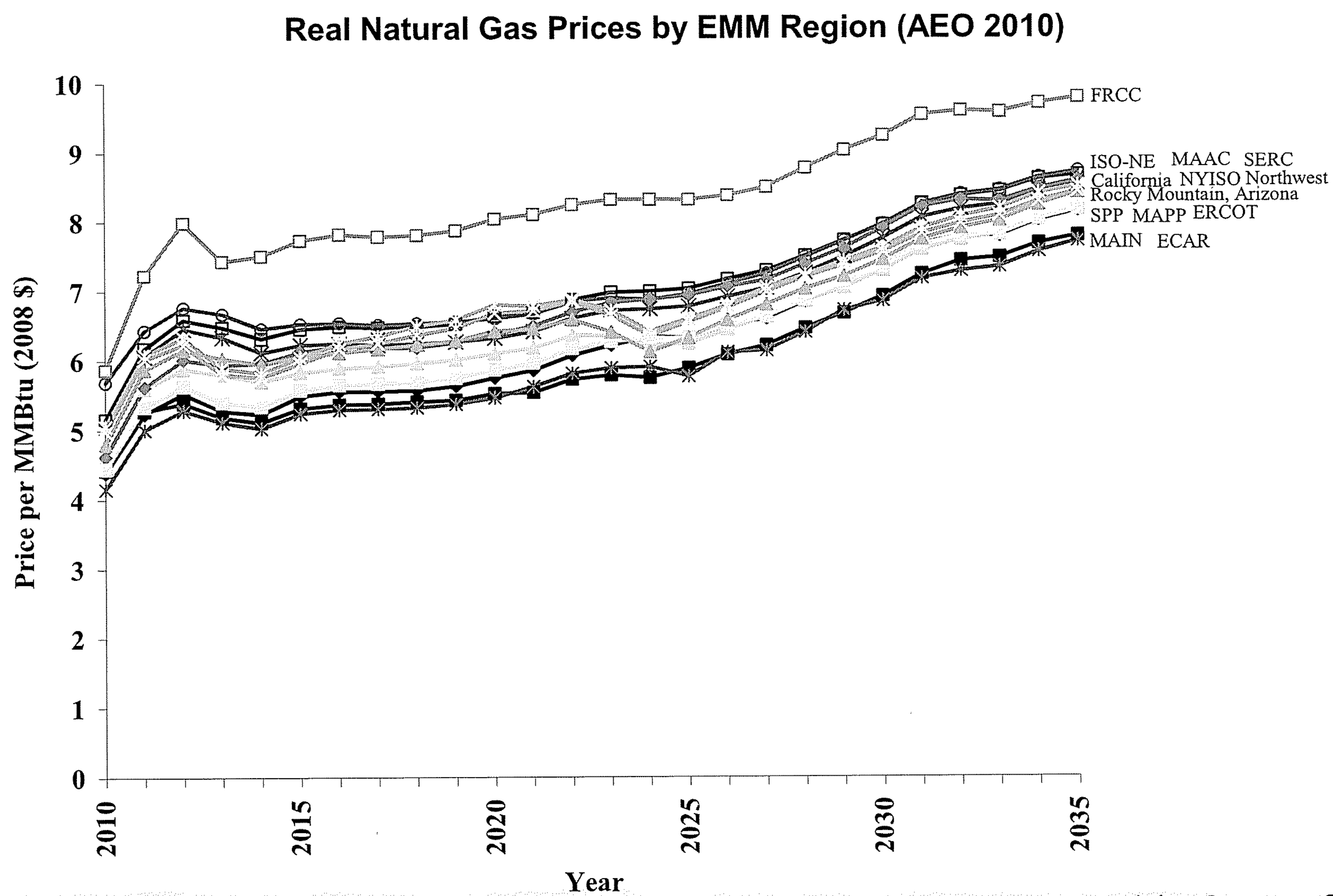
Key assumptions – coal prices



Key assumptions – natural gas prices



Key assumptions – cost of replacement power for regulated coal units by region

REPLACEMENT COST SUMMARY (NEW CC AND CT)

NERC Region	NERC Sub Region	Average NG Price (2010-2020) ($/MMBtu)	Average Fuel Costs ($/MWh)		Overnight Cost ($/kW-year)		FOM ($/kW-year)		VOM ($/MWh)		Levelized All-in Cost ($/MWh)			
			CT @ 9.5 MMBtu/MWh	CC @ 6.8 MMBtu/MWh	CT	CC	CT	CC	CT	CC	CT 10% CF	CC 30% CF	CT 20% CF	CC 80% CF
ERCOT	ERCOT	5.48	52	37	66	109	10	18	3	2	142	87	99	57
FRCC	FRCC	7.70	73	52	66	109	10	18	3	2	163	102	120	72
MRO US	MRO	5.87	56	40	66	109	10	18	3	2	146	90	102	60
NPCC	NY	6.26	59	43	66	109	10	18	3	2	149	92	106	62
NPCC	ISO NE	6.60	63	45	66	109	10	18	3	2	153	95	109	65
RFC	MISO	5.36	51	36	66	109	10	18	3	2	141	86	97	56
RFC	PJM	6.47	61	44	66	109	10	18	3	2	151	94	108	64
SERC	Gateway	6.07	58	41	66	109	10	18	3	2	148	91	104	61
SERC	TVA	6.07	58	41	66	109	10	18	3	2	148	91	104	61
SERC	VACAR	6.07	58	41	66	109	10	18	3	2	148	91	104	61
SERC	Southern	6.07	58	41	66	109	10	18	3	2	148	91	104	61
SERC	Entergy	6.07	58	41	66	109	10	18	3	2	148	91	104	61
SPP	SPP South	5.59	53	38	66	109	10	18	3	2	143	88	100	58
SPP	SPP North	5.59	53	38	66	109	10	18	3	2	143	88	100	58
WECC	CA	6.27	60	43	66	109	10	18	3	2	150	93	106	62
WECC	NWPP	6.12	58	42	66	109	10	18	3	2	148	91	105	61
WECC	AZNMSNV	6.18	59	42	66	109	10	18	3	2	149	92	105	62
WECC	RMPA	6.18	59	42	66	109	10	18	3	2	149	92	105	62

Additional Reading

"Managing Natural Gas Price Volatility: Principles and Practices Across the Industry," by Steven H. Levine and Frank C. Graves, *The Brattle Group, Inc., prepared for the American Clean Skies Foundation*, forthcoming in Spring 2011.

"Resource Adequacy and Renewable Energy in Competitive Wholesale Electricity Markets," by Serena Hesmondhalgh, Johannes P. Pfeifenberger, and David Robinson, *The Brattle Group, Inc.,* presented at the 8th Annual British Institute of Economics Academic Conference, September 23, 2010.

"Prospects for Natural Gas Under Climate Policy Legislation: Will There Be a Boom in Gas Demand?," by Steven H. Levine, Frank C. Graves, and Metin Celebi, *The Brattle Group, Inc.*, March 2010.

"Midwest ISO's Resource Adequacy Construct: An Evaluation of Market Design Elements," by Samuel A. Newell, Kathleen Spees, and Attila Hajos, *The Brattle Group, Inc.,* January 19, 2010.

"Cross-RTO Survey of Capacity Markets: What is Working and What is Not," by Attila Hajos and Samuel A. Newell, *The Brattle Group, Inc.*, November 9, 2009.

"EU Climate and Energy Policy to 2030 and the Implications for Carbon Capture and Storage: A Report for ALSTOM Power Systems," by Serena Hesmondhalgh, Toby Brown, and David Robinson, *The Brattle Group, Inc.*, March 2009.

"Volatile CO_2 Prices Discourage CCS Investment," by Metin Celebi and Frank C. Graves, *The Brattle Group, Inc.*, January 2009.

"Transforming America's Power Industry: The Investment Challenge 2010-2030," by Marc Chupka, Robert L. Earle, Peter S. Fox-Penner, and Ryan Hledik, Prepared for The Edison Foundation, November 2008.

"Review of PJM's Reliability Pricing Model (RPM)," by Johannes P. Pfeifenberger, Samuel A. Newell, Robert L. Earle, Attila Hajos, and Mariko Geronimo, *The Brattle Group, Inc.*, June 30, 2008.

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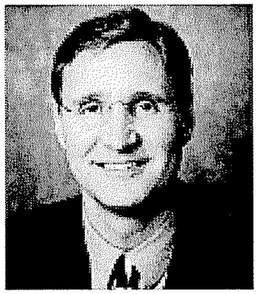

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* *The authors thank their colleagues Marc Chupka, Hannes Pfeifenberger, and Kathleen Spees for their useful comments and assistance in this study.*

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A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT

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December 16, 2010

A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT

Executive Summary

In this report, we:[1] (1) predict incremental coal plant retirements and pollution control retrofits resulting from US Environmental Protection Agency (EPA) proposed and forthcoming air regulations;[2] and (2) assess their impact on electric system reliability. The specific air regulations we considered in our analysis are the EPA's proposed Clean Air Transport Rule regulating SO_2/NO_x interstate pollution transport (Transport Rule) and forthcoming hazardous air pollutants regulations (utility MACT) described more fully in the Introduction section of this paper. Implementing these regulations will require some coal generators to install pollution control equipment in order to continue operations. However, given the recent discoveries of abundant, domestic natural gas supplies, a competing fuel for electric generation, as well as reduced electricity demand, coal plant owners may elect to retire some existing plants rather than investing the capital necessary to install pollution controls. Nonetheless, we conclude that electric system reliability can be maintained while the industry complies with EPA's air regulations.

The number of projected coal plant retirements nationwide is relatively small compared to historical US net additions of generation capacity, and the electric sector has demonstrated repeatedly the ability to expand the generation fleet at a rate well in excess of projected capacity needs. Although we predict that a handful of areas will have de minimis or modest shortfalls due to predicted retirements, adequate reserve margins can be maintained by better utilizing existing supply capacity, installing new generation, and increasing load management. Additionally, existing federal statutory, state regulatory, and regional transmission organization (RTO) market safeguards can be utilized to maintain a reliable electric system.

Some observers have expressed concern that accelerated coal unit retirements might adversely impact electric system reliability. To evaluate that concern, we:

1. Forecasted coal retirements in the US under an aggressive policy representation consistent with the Transport Rule and utility MACT (utility MACT/CAIR NO_x).[3]

[1] This report was prepared by Charles River Associates (CRA) for Exelon Corporation.

[2] Notably, approximately 6 GW of retirements are already planned, driven by low power prices which are due to low natural gas prices and low electricity demand.

[3] EPA has indicated that the Transport Rule's NO_x cap will be tightened in the near future ("Transport Rule II"), so we modeled the Clean Air Interstate Rule (CAIR) NO_x policy instead of the current Transport Rule's NO_x policy because it is more stringent and likely a better representation of Transport Rule II.

2. Provided a reliability analysis for the Eastern Interconnection[4] based on expected load growth, likely new generation additions, and projected coal retirements at the RTO level,[5] North American Electric Reliability Corporation (NERC) regional level, and NERC subregional level.

3. Identified actions that can be taken to maintain system reliability.

Our conclusion that EPA air regulations can be implemented without adversely impacting electric system reliability comports with other industry reports that have been released in the past several months.[6] Most recently, NERC published its assessment of possible impacts of four EPA regulations, including the air regulations examined in this paper. NERC concluded that of the four regulations assessed, EPA's potential 316(b) water regulations would have the greatest impact on reliability, and further urged coordinating implementation of EPA's various regulations to mitigate reliability impacts.

When considering EPA's air regulations alone, NERC actually predicts fewer retirements than we do, even under its "strict case" scenario. Additionally, NERC, as well as the M.J. Bradley & Associates/Analysis Group report, identify a suite of industry tools, some of which are discussed in this paper, that can be utilized to mitigate any reliability impact of the EPA air regulations.[7]

Specifically, our analysis reaches the following conclusions:

- **Coal plant retirements will not adversely impact reliability**. The existing US coal fleet has about 314 GW of capacity, about 265 GW of which is located in the Eastern Interconnection. When considering both the currently planned 6 GW of retirements, plus those driven by an aggressive utility MACT/CAIR NO_x policy, we project a total of 35 GW of coal retirements in the Eastern Interconnection and 39 GW nationwide

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[4] See definition of Eastern Interconnection in footnote 21. The US portion of the Eastern Interconnection contains about 73% of the electric generation capacity in the US.

[5] The RTOs in the Eastern Interconnection are: Independent System Operator (ISO) New England, the New York ISO, the PJM Interconnection, the Midwest ISO, and the Southwest Power Pool.

[6] M. J. Bradley & Associates/Analysis Group, "Ensuring a Clean, Modern Electric Generation Fleet while Maintaining Electric System Reliability," August 2010 (http://www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf); North American Electric Reliability Corporation, "2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential US Environmental Regulations," August 2010 (http://www.nerc.com/files/EPA_Scenario_Final_20101026.pdf); and ICF International, "EEI Preliminary Reference Case and Scenario Results," May 21, 2010

[7] NERC 2010 Special Reliability Scenario Assessment Report, p. 40 and M. J. Bradley/Analysis Group Report, pp. 22-23.

by 2015. To put that in perspective, the 35 GW represents less than 5% of the Eastern Interconnection's more than 730 GW of total capacity.

- These projected retirements are relatively small in comparison to historical US net additions of generation capacity. For example, during the five-year period between 1999 and 2004, the net increase in US generating capacity was 177 GW, more than four times what is projected to retire in the US by 2015.

- Notably, the average age of the projected retiring units in the Eastern Interconnection is 55 years.[8] Many of these older units are already nearing the end of their design life expectancy.

- **After projected coal retirements, all five eastern RTOs have sufficient capacity to maintain reliability without any new resources beyond those that are already under construction.** Even excluding planned new generation in the permitting and site preparation stage, and after accounting for coal retirements resulting from the aggressive utility MACT/CAIR NO_x policy, all of the eastern RTOs have more than sufficient total resources to meet overall RTO reserve margin requirements in 2015. Although we project a few localized resource needs within the RTOs, these can be addressed through existing capacity markets and other tools discussed in this paper.

- **Modest capacity needs projected in the NERC regions and subregions can be easily met**. At the NERC regional level our analysis shows the utility MACT/CAIR NO_x policy drives only de minimis capacity shortfalls in two regions and a modest shortfall in another. At the NERC subregional level, one larger – but still manageable – shortfall is expected.[9] Two other subregional shortfalls are de minimis and modest. We believe that all of these shortfalls can be met with existing industry tools, such as:

  - **New Gas Generation Construction** – Our economic modeling shows that when new capacity is required, gas-fired generation is often the most economic alternative. In fact, the existence of abundant, inexpensive domestic natural gas resources not only is a driver of retirements but also will facilitate the transition to a cleaner generation fleet. History has shown that new gas units can be planned, permitted, and constructed in short periods of time. For example, in the Virginia-Carolina NERC subregion (VACAR), which our analysis indicates has the greatest need, almost 12 GW of gas-fired capacity

[8] CRA calculated the capacity-weighted average age of the coal units that retire by 2015 in the Eastern Interconnection in its simulation of the utility MACT/CAIR NO_x policy. The result of the calculation was 55 years.

[9] This larger projected subregional shortfall would mostly exist in the absence of the forthcoming air pollution regulations assessed in this paper.

came online between 2000 and 2004, which is significantly more than its projected capacity shortfall of 6.3 GW.

- **Load Management** – Load management tools, such as demand response and energy efficiency programs, are growing rapidly and have the capability to offset some of the projected coal retirements. Some of the NERC subregions with larger capacity shortfalls also have the greatest untapped potential for substantially increasing load management resources. For example, in the VACAR region, load management accounts for 3.4% of resources at peak, while in the New England region, load management accounts for close to 10% of peak resources.

- **Coal to Gas Conversion -** Depending on the local availability of natural gas, existing coal units can be converted to natural gas for a relatively modest cost.[10] For example, in the Southeast Reliability Corporation (SERC) region, which has a de minimis projected capacity shortfall of 0.6 GW, about 11 GW of coal plants already have natural gas pipeline service and have natural gas as a secondary fuel option.

- **Alternative Technologies and Tools** - Application of alternative and lower cost pollution control technologies and other regulatory tools could realistically result in even less coal plant retirements than we predict by 2015.[11]

- **Additional regulatory safeguards exist to protect reliability.** To address any remaining reliability concerns, the EPA Administrator, the Secretary of Energy, and the President each have authority under the Clean Air Act to extend compliance by one to two years under specific circumstances. For example, in August 2005, to protect reliability, the Secretary of Energy used his authority to prohibit Mirant from retiring its Potomac River plant. Mirant subsequently retrofitted the Potomac River plant, which is still in service today.[12] Additionally, RTOs have market rules and

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[10] In its December 20, 2000 regulatory finding, EPA decided that natural gas-fired electric steam generation units are not subject to HAPs regulation (65 FR 79826). This finding did not apply to combustion turbines.

[11] The Institute of Clean Air Companies (ICAC) stated in recently filed comments, "ICAC would like to emphasize that the competition in the [air pollution control] industry in the last decade has matured and diversified the industry and has led to the development of many emission reduction technologies that are not as capital-intensive as the 'big-ticket' items of SCR, FGD, and baghouses. However, these less capital-intensive technologies can obtain significant reductions that, depending on the regulatory requirements, may allow a much more economical approach in the short-term." ICAC comments in *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers (ICI) and Process Heaters;* 75 FR 32006-32073 (June 4, 2010), filed on August 23, 2010, p. 2.

[12] In 2005, Mirant Corporation ceased operations at its Potomac River Generating Station in Alexandria, Virginia, after learning the plant's operations were causing exceedances of the National Ambient Air Quality Standards (NAAQS). In response, the Secretary of Energy responded to a petition and issued an

procedures under the Federal Energy Regulatory Commission's (FERC) jurisdiction that will serve to mitigate reliability impacts, as do state regulatory commissions in traditional cost-of-service states. Current EPA, Department of Energy (DOE), and FERC coordination should also considerably mitigate any reliability concerns.[13]

In summary, modeling an aggressive policy implementation of EPA's proposed and forthcoming air regulations, we demonstrate, consistent with other industry reports, that with prompt action and industry coordination, electric system reliability can be maintained. Of the areas we analyzed - 5 RTOs, 6 NERC Regions, and 7 NERC subregions - we project that after predicted coal retirements, most still have capacity surpluses. At the NERC regional level, we predict that two regions will have de minimis shortfalls (relative to resource adequacy requirements) and another region will have a modest shortfall. At the NERC subregional level, there are three subregions that emerge as having shortfalls – one is de minimis, one is modest, and the other is larger, but still manageable. Notably, the larger shortfall would exist even in the absence of the forthcoming EPA regulations and planning processes, new gas-fired plants, and incremental load management can easily address this shortfall.

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emergency order under Federal Power Act section 202(c) directing Mirant to operate the coal-fired plant only under certain, limited circumstances tailored to relieve the reliability risk while also mitigating the air quality issues.

[13]An interagency task force among FERC, EPA, and the White House Council on Environmental Quality already exists and has been meeting for months to consider and model solutions to address the impact of the various EPA regulations. In an October 26 *Electric Light & Power* article, FERC Chairman Jon Wellinghoff responded to the NERC 2010 Special Reliability Scenario Assessment Report by saying, "We are aware of the potential problems, and we are working in an interagency way to solve them....it doesn't raise any concerns that I wasn't already aware were there." http://www.elp.com/index/from-the-wires/wire_news_display/1290063498.html

Introduction

Proposed and Forthcoming Air Regulations

In the two decades following the Clean Air Act Amendments of 1990 (CAA), the majority of coal plants have installed pollution controls to reduce air emissions. Over the next several years, the EPA will implement regulations that will further reduce harmful air emissions. Specifically, on July 6, 2010, the EPA proposed the Clean Air Transport Rule to reduce SO_2 and NO_x "emissions within 32 states in the eastern United States that affect the ability of downwind states to attain and maintain compliance with the 1997 and 2006 fine particulate matter (PM2.5) national ambient air quality standards (NAAQS) and the 1997 ozone NAAQS."[14] The Transport Rule is intended to replace CAIR, which was remanded to EPA by the DC Circuit Court of Appeals in December 2008. At the time of writing this paper, however, CAIR is still the rule in effect since the final Transport Rule is not anticipated until the spring of 2011.

In addition, pursuant to consent orders, by the end of 2011, EPA is required by the court to issue final "utility MACT" rules regulating hazardous air pollutants (HAPs) emitted by electric generators, using maximum achievable control technology (MACT) standards as set forth in Section 112(d) of the CAA.[15] Utility MACT will likely regulate mercury, non-mercury metals (e.g., arsenic, lead, nickel, chromium), and acid gases (e.g., hydrochloric acid, hydrofluoric acid, cyanide), all of which the CAA designates as HAPs. Utility MACT will impact coal-generating units in particular,[16] causing some units to install pollution control equipment and others to retire.

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[14] 75 FR 45210 (August 2, 2010); 31 states and the District of Columbia are covered by the Transport Rule.

[15] EPA attempted to regulate HAPs from coal plants and other sources through the Clean Air Mercury Rule (CAMR), but in 2008, the court vacated the rule as invalid. Among other things, the court found that EPA was required to regulate HAP emissions from power plants using MACT standards pursuant to Section 112 of the CAA. Shortly after, the American Nurses Association and other organizations sued EPA, resulting in a consent decree requiring EPA to issue draft MACT standards by March 16, 2011, and final MACT standards by November 16, 2011.

[16] EPA is under no compulsion to establish MACT standards for gas-fired steam electric generation units. During the Clinton administration, EPA determined under section 112(n)(1)(A) that gas-fired steam electric generation units did not warrant regulation under section 112 and therefore decided not to list them as targets for the MACT standard-setting process. That decision has never been challenged in the DC Circuit. EPA's determination did not apply to combustion turbines.

Assumptions Used for Analysis

As stated above, the purpose of this analysis is to assess the retirement and reliability implications of the proposed Transport Rule and forthcoming utility MACT regulations.[17] As the utility MACT rule has not yet been proposed, we made certain assumptions for our analysis. The key unknown element of utility MACT is which technologies will be required for compliance. Many observers believe that utility MACT will require wet scrubbers, sorbent injection (e.g., activated carbon), and advanced particulate control (e.g., fabric filters) for HAPs control. Others, however, believe that MACT compliance may allow lower cost and relatively inexpensive dry scrubbing options using sorbents to capture acid gases and metals (e.g., trona with activated carbon injection).[18] For purposes of our modeling, we assumed the more expensive technologies will be required, that is, activated carbon sorbent injection (ACI), fabric filter, and wet flue gas desulfurization (FGD) scrubbers.[19]

With respect to the Transport Rule, it has a relatively strict SO_2 cap, particularly when it tightens in 2014. However, as our aggressive utility MACT representation forces scrubbers to be installed on every operating coal unit, we do not model the Transport Rule SO_2 cap because it will be met *a priori* when a unit complies with our assumed utility MACT policy. On the other hand, the NO_x requirements under CAIR are more stringent in aggregate than the state-specific requirements under the proposed Transport Rule. EPA indicated in its Transport Rule Notice of Proposed Rulemaking that further

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[17] There are other potential regulations that could impact coal unit retirement decisions. Such regulations address cooling water, 316(b), and ash containment/disposal. In this paper, we do not address or discuss the electric sector impacts of future water and ash regulations.

[18] See, e.g., the ICAC letter to Senator Thomas Carper, November 3, 2010; http://www.icac.com/files/public/ICAC_Carper_Response_110310.pdf; pp. 1, 3, in which they stated "Less resource- and time-intensive technologies are available to be quickly deployed, offering the electric generating industry the needed flexibility to comply with the proposed Clean Air Transport Rule and the upcoming utility MACT. For example, direct sorbent injection (DSI) and dry scrubbing technology installation times are approximately 12 and 24 months, respectively" and "Going forward, ICAC expects a wide range of technologies will be available to provide flexibility for utility compliance strategies. In particular, we expect greater use of both DSI and dry scrubbing technologies, such as circulating dry scrubbers (CDS) and spray dryer absorber (SDA) technology, due to future backend water and disposal requirements. The added advantages of using these technologies are fewer resources required and shorter installation times – 12 months for DSI and 24 months for a dry scrubber. Moreover, the next round of [electric generation unit] control installations will likely be on smaller coal-fired units, and DSI and dry scrubbing are well-suited to smaller footprints and high-sulfur bituminous coal applications."

[19] Selective catalytic reduction units (SCRs) are another technology that oxidizes elemental mercury into a form that can be more easily captured in a scrubber. There is the potential that SCR requirements could also be part of the utility MACT. We have not included SCRs in our utility MACT representation and have therefore not chosen the most expensive representation possible. However, our utility MACT representation is likely towards the more expensive end of the spectrum of what utility MACT might entail, particularly if wet scrubbing is not determined to be MACT.

complementary action on NO_x was forthcoming, perhaps in concert with a more strict ozone NAAQS. Thus, to represent future NO_x policy, we model the more aggressive CAIR NO_x requirements. Although we do not impose or model the CAIR requirements on a state-level because CAIR does not restrict interstate trading as the Transport Rule does, the CAIR NO_x policy is more stringent in aggregate than proposed in the Transport Rule.

As for timing, the applicable consent decree requires a final utility MACT rule by November 2011 and pollution control equipment is required to be installed within three years of utility MACT promulgation.[20] This also coincides with CAIR's tightened NO_x requirement; therefore, when evaluating retirements and reliability impacts, we used 2015 as the implementation date.

In summary, our representation of future SO_2, NO_x, and HAPs policy is aggressive and assumes the CAIR NO_x policy plus a package of ACI, fabric filter, and FGD scrubber technology requirements to represent utility MACT. Together, we call this the utility MACT/CAIR NO_x policy. The technology requirements must be met by 2015 while CAIR stays on its current schedule (which tightens in 2015). If we had performed the modeling with 2016 as the first year of implementation, the level of retirements would have been virtually the same as we found for 2015.

Methodology

We used CRA's North American Electricity and Environment Model (NEEM) to estimate coal unit retirements under the utility MACT/CAIR NO_x policy representation described above. NEEM optimizes generation operation in each major region in the US, taking into account power transfer limits among regions. NEEM optimizes retirements, unit environmental retrofits, and new capacity additions by region over a 60-year period, taking into account the operating and cost characteristics of existing capacity and the capital and operating costs of potential new capacity. Appendix B details NEEM's input assumptions on load growth, fuel costs, and pollution control equipment. We used NEEM's forecasted coal retirements as the key inputs to our 2015 reliability analysis.

[20] CAA Section 112(i).

Reliability Implications of Projected Retirements

NERC is the electric reliability organization certified by FERC to establish and enforce reliability standards for the North American bulk-power system. The eight NERC reliability regions are shown in Figure 1.

Some NERC regions are divided further into subregions as shown in Figure 2. In the eastern US, the SERC region is subdivided into five subregions (Central, Delta, Gateway, Southeastern, and VACAR), while the NPCC region is divided into two subregions (New York and New England). As can be seen from Figure 3, which shows the RTOs in the Eastern Interconnection,[21] the New York and New England subregions in NPCC correspond to the New York ISO and the New England ISO, respectively, and the Southwest Power Pool (SPP) NERC region corresponds to the SPP RTO.

Aggregate Projected Coal Retirements

The US currently has about 314 GW of coal-fired capacity installed, with about 10 GW more scheduled to come online over the next two years. Of the 314 GW of existing coal-fired capacity, 169 GW already have FGD scrubbers and 52 GW are scheduled to add FGD scrubbers over the next four years, leaving about 92 GW, or only 30% of existing coal capacity that will need to either install pollution control equipment or retire.[22]

Our analysis projects approximately 35 GW of coal retirements in the Eastern Interconnection between 2010 and 2015, which includes about 6 GW of already announced retirements. Accordingly, we project approximately 29 GW of incremental retirements as a result of the aggressive utility MACT/CAIR NO_x policy we modeled. Table 1 shows these projected retirements, the bulk of which are in the ReliabilityFirst (RFC) and SERC regions.[23]

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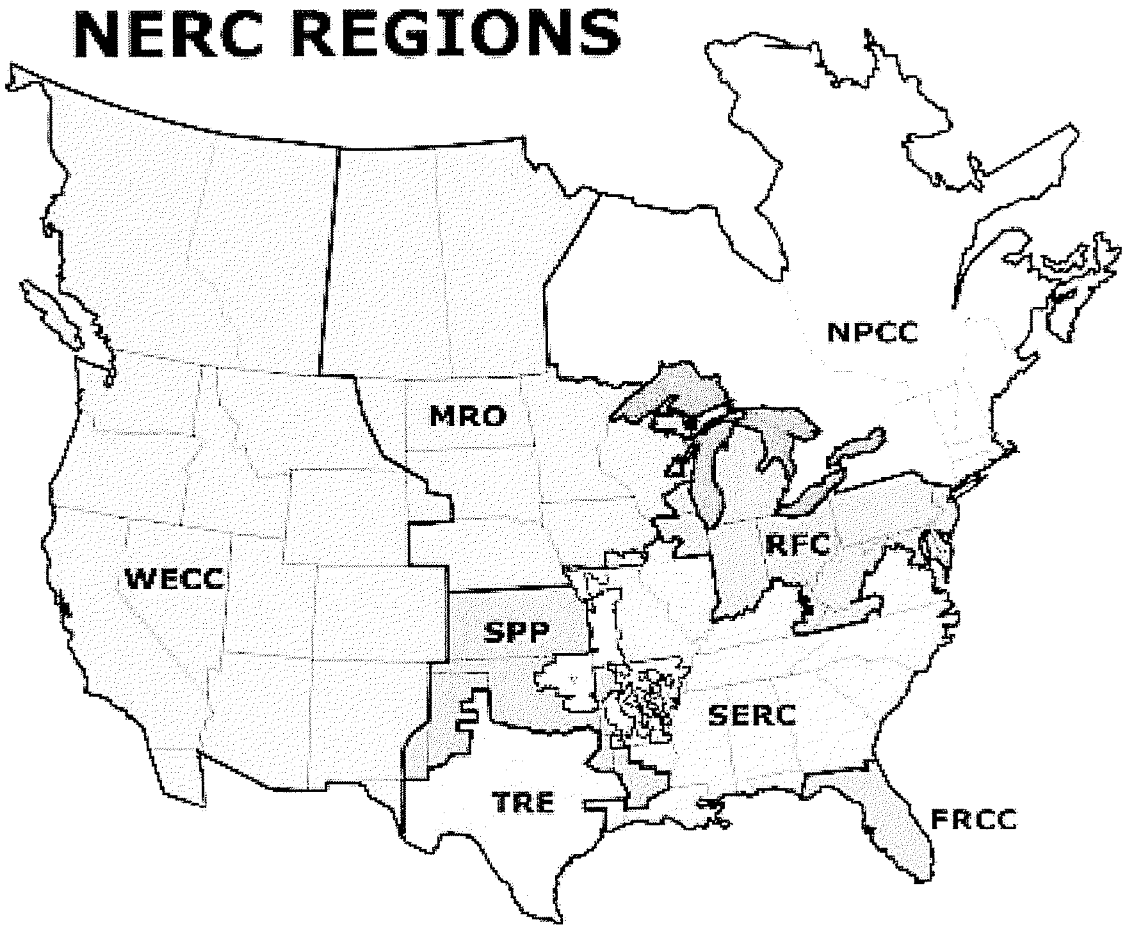
[21] The Eastern Interconnection consists of a large portion of the US and Canadian transmission system east of the Continental Divide, with the exception of a large portion of Texas, which is a separate interconnected system. Today, the Eastern Interconnection consists of six NERC reliability regions and five RTOs. All of the Eastern Interconnection transmission and generation is in one of the NERC regional reliability organizations, but only a portion of the generation and transmission is in an RTO. Although the NERC regions have responsibility for monitoring and enforcing NERC reliability standards in practice, within the RTO footprints the RTOs are ultimately responsible for taking the actions needed to ensure reliability in their control areas.

[22] New coal plants will have FGDs, SCRs, and fabric filters. Any additional controls that may be required to control HAPs at new coal plants (e.g., sorbent injection) will require little additional cost.

[23] We project only 4 GW of additional coal retirements outside of the Eastern Interconnection under the utility MACT/CAIR NO_x policy, bringing the total US projected coal retirements to 39 GW, when considering already planned retirements as well as those driven by the utility MACT/CAIR NO_x policy.

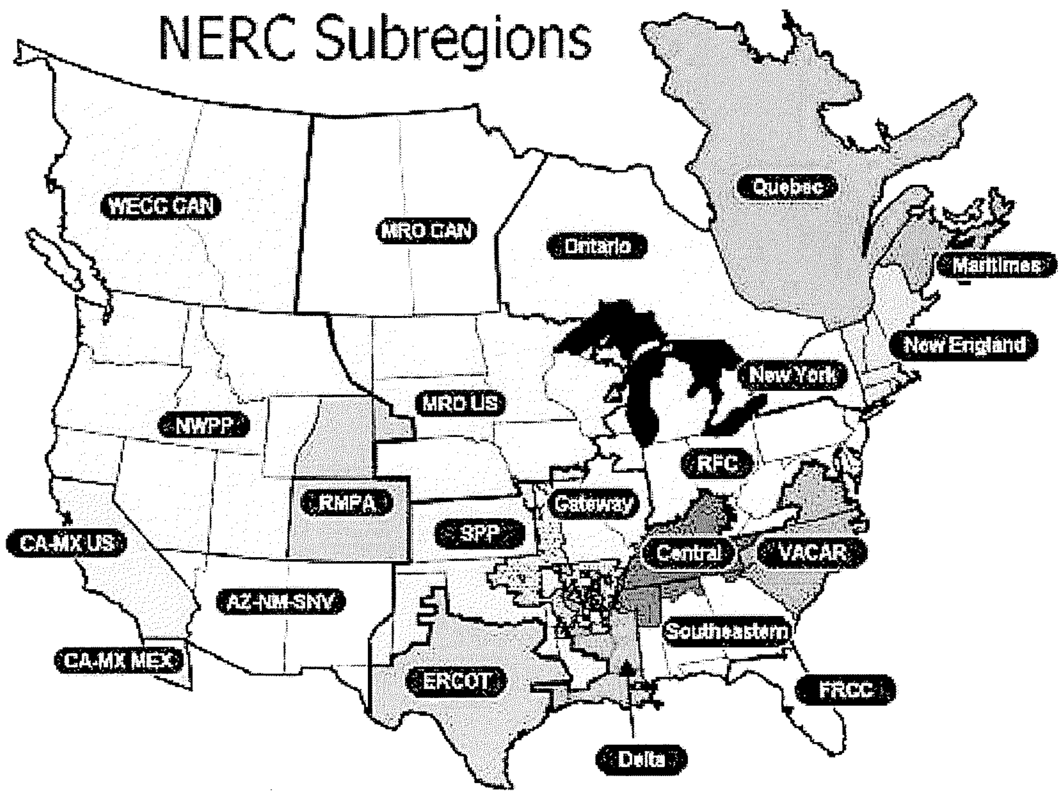
Notably, many of the already announced retirements, and projected retirements under our analysis, are driven by low natural gas prices caused primarily by the existence of abundant, inexpensive domestic natural gas resources. In other words, if we had used the higher natural gas prices that had existed only a few years ago in our modeling of the utility MACT/CAIR NO_x policy, the predicted retirement results would have been very different. Although low-priced natural gas presents economic challenges for existing plants, it will facilitate America's transition to a modern, cleaner generation fleet.

Figure 1. NERC Regions



Source: North American Electric Reliability Corporation (NERC)

Figure 2. NERC Subregions



Source: North American Electricity Reliability Corporation (NERC)

Figure 3. The Eastern Interconnection and RTOs

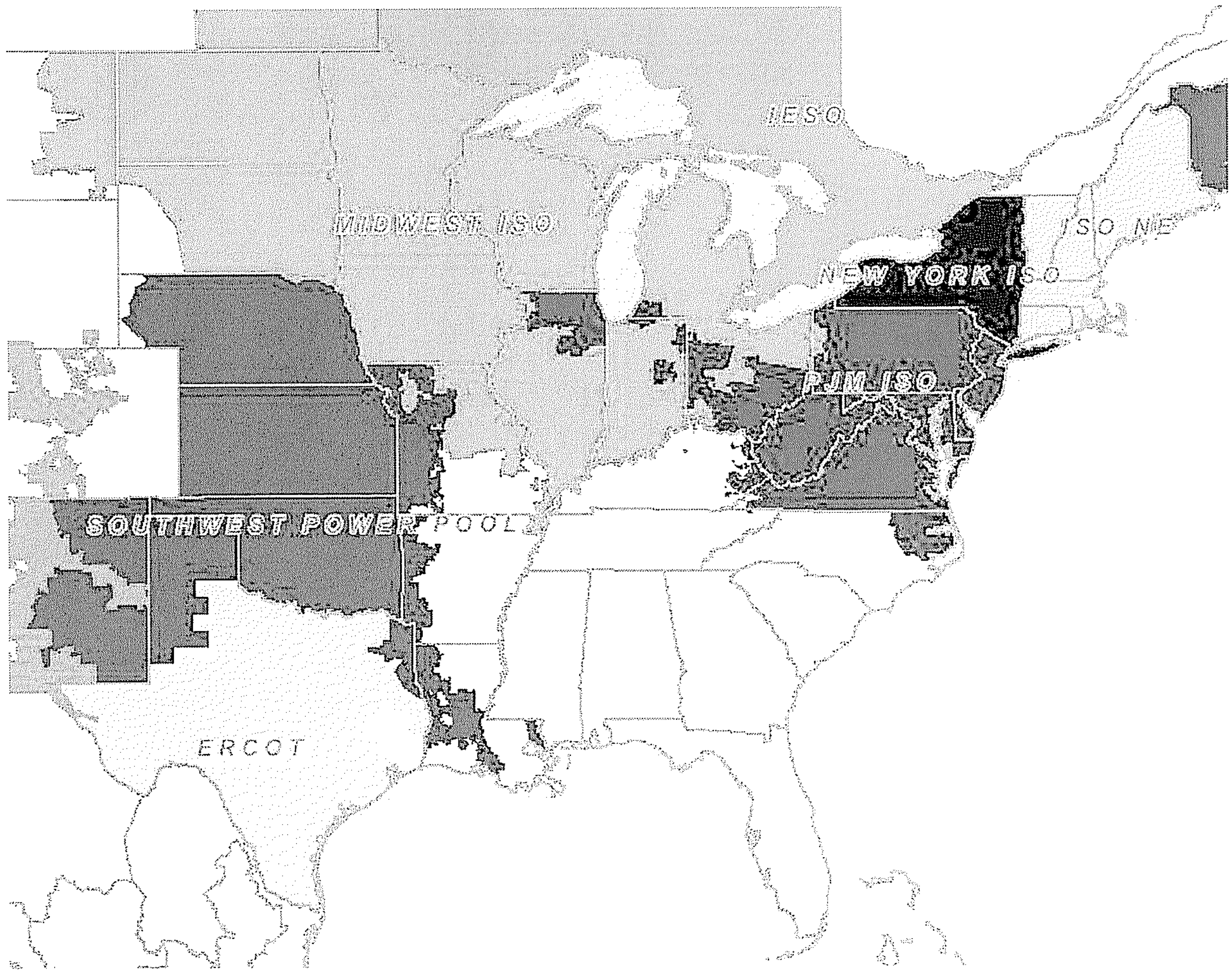


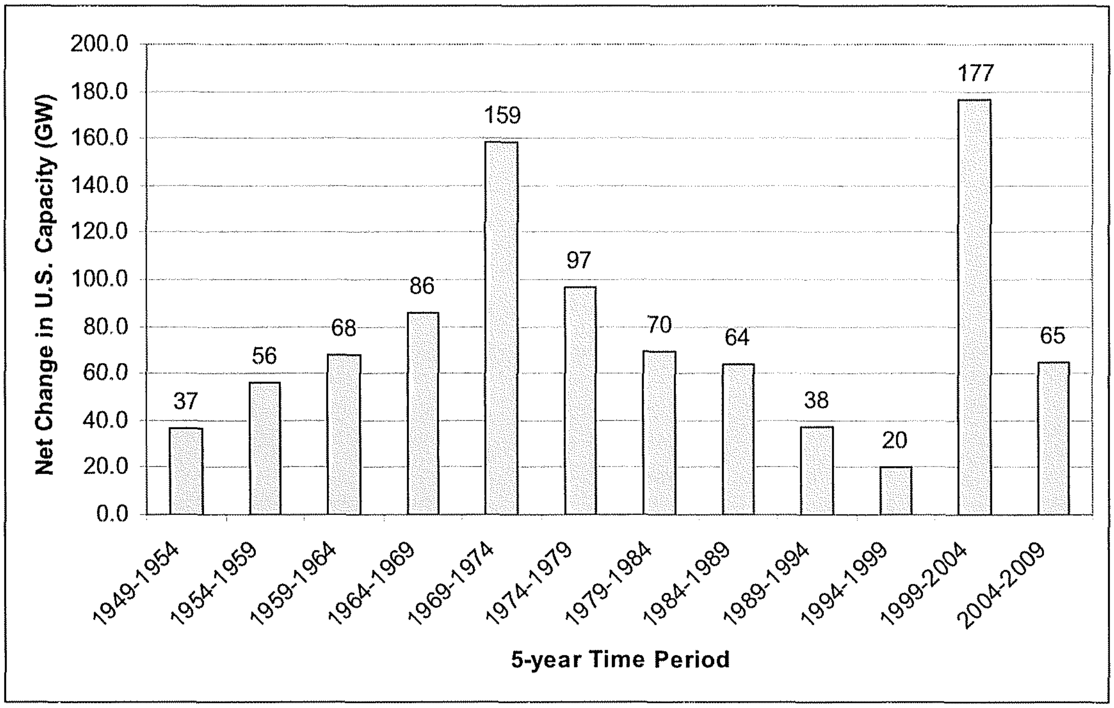
Table 1. Projected Coal Unit Retirements in the Eastern Interconnection under Utility MACT/CAIR NO_x

	Planned Retirements			Economic Retirements			Total Retirements		
NERC Region/Sub-Region	No. Units	Retired Coal Capacity (MW)	Average Size (MW)	No. Units	Retired Coal Capacity (MW)	Average Size (MW)	No. Units	Retired Coal Capacity (MW)	Average Size (MW)
Florida Reliability Coordinating Council	-	-	-	4	1,335	334	4	1,335	334
Midwest Reliability Organization	1	29	29	81	3,640	45	82	3,668	45
Northeast Power Coordinating Council	1	109	109	12	718	60	13	827	64
New England	1	109	109	5	370	74	6	479	80
New York	-	-	-	7	348	50	7	348	50
ReliabilityFirst	18	2,355	131	130	10,306	79	148	12,660	86
SERC Reliability Corp	28	3,232	115	122	12,716	104	150	15,948	106
Central	-	-	-	39	4,329	111	39	4,329	111
Delta	-	-	-	7	343	49	7	343	49
Gateway	-	-	-	10	641	64	10	641	64
Southeastern	5	750	150	30	4,407	147	35	5,157	147
VACAR	23	2,482	108	36	2,997	83	59	5,479	93
Southwest Power Pool Inc	-	-	-	17	664	39	17	664	39
Total	**48**	**5,724**	**119**	**366**	**29,378**	**80**	**414**	**35,102**	**85**

Note: Economic retirements are those that are not already planned, but are driven by environmental policy and increasing operating and maintenance costs.

To put the magnitude of the forecasted retirements in perspective, we reviewed the Energy Information Administration Annual Energy Review 2009 data, shown in Figure 4 for the entire US, indicating the historical net changes in electric generation capacity in the US over all of the five-year periods between 1949 and 2009. As the data reveal, the electric sector has repeatedly demonstrated the ability to expand the generation fleet at a rate well in excess of capacity needed to replace our projected retirements. For example, in the 1999-2004 period, the net increase in US generating capacity was 177 GW, more than four times the amount of US capacity we project to retire by 2015 due to the utility MACT/CAIR NO_x policy. As shown below, since 1949, in nine out of twelve periods the electric sector has added more capacity than is needed to replace the net projected US retirements arising from the utility MACT/CAIR NOx policy we modeled.

Figure 4. Net Changes in US Generating Capacity (GW)



Accordingly, based on the historical information in Figure 4, it is completely reasonable to expect that the 39 GW of projected coal retirements, and any incremental capacity needed due to demand growth, could be met easily with new capacity construction alone. In addition to new capacity, however, the industry possesses several other tools to manage reliability, such as increased load management programs and coal-to-gas conversion, discussed later in this paper.

Reliability Analysis at RTO Level

Our reliability analysis shows that all of the RTOs have sufficient resources to meet reserve margin requirements by 2015, even after accounting for coal retirements that result from the utility MACT/CAIR NO_x policy. This is true even if planned new additions in the permitting and site preparation stages are excluded from the calculations.

Table 2 shows the balance of loads and capacity resources for each RTO.[24] A more detailed table is provided in Appendix D. Our modeling first determined that all RTOs in the Eastern Interconnection have sufficient resources to meet reserve margin requirements by 2015 before accounting for the utility MACT/CAIR NO_x policy (see Column A). We then reduced the reserve margins to reflect the estimated coal plant retirements from the utility MACT/CAIR NO_x policy and found that reserve margin requirements would still be exceeded in all RTOs (see Column B). Finally, we added in all new additions in the permitting stage expected to be in service by 2015, which again shows that reserve margin requirements will be exceeded in all RTOs in the Eastern Interconnection (see Column C).

Table 2. Loads and Resources by 2015, RTO Level

RTO	*2015 Net Internal Demand Estimate (MW)	Required Reserve Margin (%)	Required Capacity (MW)	Projected Capacity PLUS Net Firm Transactions (MW), 2015	(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)	Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)	(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)	+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity	(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)	Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)
PJM	146,441	15.3%	168.846	178,061	9,215	7.529	1,686	2,350	4,036	2.8%
MISO	91,001	15.4%	105.015	127,088	22.073	7,074	14,999	435	15,434	17.0%
New England	26,180	15.0%	30,107	32,630	2.523	370	2,153	1.094	3,247	12.4%
New York	31,803	15.0%	36,573	38.892	2.318	348	1,970	192	2,162	6.8%
SPP	45,284	13.6%	51,442	53.409	1,966	664	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment" (for New England. New York, and SPP) For PJM, the PJM 2013/14 RPM Base Residual Auction Planning Parameters, total RTO load net of load management For MISO. 2015 Coincident Net Internal Demand, Midwest ISO Transmission Expansion Plan (MTEP) 2009

+ Planned new additions that are in the "permitted" or "site prep" status categories.

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[24] Column A shows the 2015 capacity resource surplus/(shortfall) before the coal retirements driven by the utility MACT/CAIR NO_x policy that we have estimated using NEEM. Column A reflects both planned additions (additions either under construction or in the testing phase as indicated by Energy Velocity) and planned retirements. Column B shows the surplus/(shortfall) after adjusting for our incremental coal retirement projections through 2015. Column C shows the surplus/(shortfall) after adding permitted additions (i.e., planned additions that have acquired permits or have both acquired permits and begun site preparation). Column C represents the resource adequacy surplus/(shortfall) that could be achieved under utility MACT/CAIR NO_x policy by doing nothing other than completing projects that are under construction and building those that already have been permitted. These calculations are explained further in the ***Estimating Reliability Impacts*** section in Appendix B.

Moreover, these RTOs have mechanisms in place to ensure that resource adequacy is maintained and new capacity is planned and built when needed. Each RTO has an installed reserve margin requirement and load serving entities (LSEs) are responsible for securing sufficient resources to meet those requirements. In the case of PJM and ISO New England, a centralized forward capacity market mechanism has been implemented, with the market operator acting as central buyer of capacity resources and allocating the costs back to LSEs.

In New York, the ISO has a short-term market for capacity designed to provide adequate compensation to new generation resources when needed. The monthly market is designed to support development of new capacity and provide incentives for LSEs to secure new capacity resources in order to avoid high short-term market prices.

The MISO market depends on self-supply and bilateral contracting by LSEs, supplemented by a voluntary short-term market, to meet the mandated requirements. LSEs that have not secured sufficient capacity are subject to substantial financial penalties. The MISO is also considering adopting a forward market mechanism for resource adequacy.

While SPP has no centralized capacity market, LSEs are subject to reserve margin requirements and must either develop new resources when needed or enter bilateral contracts with other suppliers.

Reliability Analysis at the NERC Regional Level

At the NERC regional level, our analysis reveals modest resource adequacy shortfalls that can be easily addressed by new capacity additions and other industry tools.

Table 3 shows the balance of loads and capacity resources for each NERC region.[25] A more detailed table is provided in Appendix D. Our modeling first determined that all NERC regions in the Eastern Interconnection have sufficient resources to meet reserve margin requirements by 2015 before accounting for the utility MACT/CAIR NO_x policy

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[25] Column A shows the 2015 capacity resource surplus/(shortfall) before the coal retirements driven by the utility MACT/CAIR NO_x policy that we have estimated using NEEM. Column A reflects both planned additions (additions either under construction or in the testing phase as indicated by Energy Velocity) and planned retirements. Column B shows the surplus/(shortfall) after adjusting for our incremental coal retirement projections through 2015. Column C shows the surplus/(shortfall) after adding in permitted additions (i.e., planned additions that have acquired permits or have both acquired permits and begun site preparation). Column C represents the resource adequacy surplus/(shortfall) that could be achieved under utility MACT/CAIR NO_x policy by doing nothing other than completing projects that are under construction and building those that already have been permitted. These calculations are explained further in the ***Estimating Reliability Impacts*** section in Appendix B.

(see Column A). When considering the utility MACT/CAIR NO_x policy, and including all planned new additions,[26] we found modest shortfalls in only three NERC regions (as shown in Column C): (1) 2,528 MW (6%) in MRO; (2) 583 MW (< 1%) in RFC; and (3) 638 MW (< 1%) in SERC.[27]

These modest shortfalls can be managed easily with construction of new gas-fired power plants and/or incremental load management. Not only can new gas units be planned, permitted, and constructed in less than three years,[28] filling most, if not all, of any capacity shortfalls, but regional shortfalls should also make construction of these units economically attractive. Any remaining shortfalls could be addressed by expanded load management programs.

Table 3. Loads and Resources by 2015, NERC Regional Level

NERC Region	*2015 Net Internal Demand Estimate (MW)	Required Reserve Margin (%)	Required Capacity (MW)	Projected Capacity PLUS Net Firm Transactions (MW), 2015	(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)	Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)	(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)	+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity	(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)	Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)
FRCC	47,330	15 0%	54,429	55,760	1,331	1,335	(4)	2,550	2,546	5 4%
MRO	42,681	15.0%	49,083	49,818	735	3,640	(2,905)	377	(2,528)	-5 9%
NPCC	60,894	15 0%	70,028	71,521	1,494	718	776	1,286	2,062	3 4%
RFC	186,008	15 0%	213,909	221,280	7,371	10,306	(2,935)	2,351	(583)	-0 3%
SERC	213,891	15 0%	245,975	252,120	6,145	12,716	(6,571)	5,934	(638)	-0.3%
SPP	45,284	13 6%	51,442	53,409	1,966	664	1,302	102	1,404	3 1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment "

+ Planned new additions that are in the "permitted" or "site prep" status categories

[26] Permitted units are included in these estimates and can be completed quickly as they confront no regulatory hurdles.

[27] The FRCC, NPCC, and SPP regions do not have resource adequacy shortfalls, even after accounting for our projected retirements due to the utility MACT/CAIR NO_x policy.

[28] For example, in August 2009, the Tennessee Valley Authority (TVA) decided to construct an 880 MW combined-cycle facility adjacent to the John Sevier plant in Tennessee. The need for the new gas plant was determined after the US District Court in Western North Carolina set an aggressive timeline for installing new emission controls for the John Sevier coal plant or retiring that plant. TVA will have the new gas capacity online by January 1, 2012, less than two-and-a-half years from the date of the decision to build.

Reliability Analysis at the NERC Subregional Level

Based on our analysis, all but one of the NERC subregions in the Eastern Interconnection have sufficient resources to meet reserve margin requirements by 2015 before accounting for the utility MACT/CAIR NO_x policy. The exception is VACAR, which is projected to have a shortfall of 5,200 MW by 2015, prior to implementation of the utility MACT/CAIR NO_x policy.

Table 4 shows our loads and resources balance at the NERC subregional level.[29] A more detailed table is provided in Appendix D. After accounting both for already announced retirements plus incremental retirements driven by the utility MACT/CAIR NOx policy, six subregions have no resource adequacy shortfalls: FRCC, NPCC-New England, NPCC-New York, SERC-Delta, SERC-Gateway, and SPP (see Column C). We project the following three SERC subregions (in addition to MRO and RFC which were already identified and discussed in the NERC Regional Level section) to have resource adequacy shortfalls:[30] (1) 1,403 MW (3%) in Central; (2) 681 MW (1%) in Southeastern; and (3) 6,322 MW (9%) in VACAR. Significantly, only about 1,100 MW of VACAR's projected 6,322 MW shortfall results from the utility MACT/CAIR NO_x policy implementation.

Just as with the NERC regional analysis, the shortfalls in all the subregions can be addressed by construction of new gas-fired power plants and/or incremental load management, even in VACAR where the capacity needs are greatest. For example, in the VACAR region there is an opportunity for expanding load management to offset much of the projected economic retirements since load management resources only represent about 3.4% of peak load.[31] As other regions of the Eastern Interconnect demonstrate, load management resources can be used to meet much higher percentages of peak load. In the New York ISO, for example, about 7.5% of capacity resources are load management resources, and in the New England ISO they represent about 10% of capacity. In PJM, a total of 14,000 MW of load management, or about 9% of peak, has been offered into the

[29] Column A shows the 2015 capacity resource surplus/(shortfall) before the coal retirements driven by the utility MACT/CAIR NO_x policy that we have estimated using NEEM. Column A reflects both planned additions (additions either under construction or in the testing phase as indicated by Energy Velocity) and planned retirements. Column B shows the surplus/(shortfall) after adjusting for our incremental coal retirement projections through 2015. Column C shows the surplus/(shortfall) after adding in permitted additions (i.e., planned additions that have acquired permits or have both acquired permits and begun site preparation). Column C represents the resource adequacy surplus/(shortfall) that could be achieved under utility MACT/CAIR NO_x policy by doing nothing other than completing projects that are under construction and building those that already have been permitted. These calculations are explained further in the ***Estimating Reliability Impacts*** section in Appendix B.

[30] The MRO and RFC subregions are identical to the MRO and RFC regions, and accordingly the shortfalls presented in Table 4 for those subregions are the same as those presented in Table 3. As already discussed, those shortfalls are modest and can be readily addressed by new capacity additions and other industry tools.

[31] NERC 2010 Summer Assessment Table 2b, p. 15.

Reliability Pricing Model (RPM) market, with almost half clearing, or about 6,800 MW clearing. Some of the increased load management resources in VACAR could come from the PJM RPM market in Dominion's region. Also notably, much of the uncleared load management resources are in locations that have a current surplus but are expected to have retirements, creating an opportunity for load management growth in those areas in the future.

New gas-fired capacity could also be added to manage any capacity shortfall. Our modeling shows that in many cases, building new gas-fired plants is an economic alternative to retrofitting older coal units with pollution control equipment. In fact, in the 2000 to 2004 period, almost 12,000 MW of gas-fired capacity came online in VACAR, about 6,000 MW greater than the projected shortfall.

Table 4. Loads and Resources by 2015, NERC Subregional Level

NERC Sub-Region	*2015 Net Internal Demand Estimate (MW)	Required Reserve Margin (%)	Required Capacity (MW)	Projected Capacity PLUS Net Firm Transactions (MW), 2015	(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)	Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)	(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)	+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity	(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)	Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)
FRCC	47,330	15.0%	54,429	55,760	1,331	1,335	(4)	2550	2,546	5.4%
MRO	42,681	15.0%	49,083	49,818	735	3,640	(2,905)	377	(2,528)	-5.9%
NPCC - New England	26,180	15.0%	30,107	32,630	2,523	370	2,153	1094	3,247	12.4%
NPCC - New York	31,803	15.0%	36,573	38,892	2,318	348	1,970	192	2,162	6.8%
RFC	186,008	15.0%	213,909	221,280	7,371	10,306	(2,935)	2351	(583)	-0.3%
SERC - Central	44,956	15.0%	51,699	53,262	1,563	4,329	(2,766)	1363	(1,403)	-3.1%
SERC - Delta	30,167	15.0%	34,692	40,111	5,419	343	5,077	513	5,590	18.5%
SERC - Gateway	19,883	11.9%	22,250	23,819	1,569	641	929	62	991	5.0%
SERC - Southeastern	52,889	15.0%	60,822	62,427	1,604	4,407	(2,802)	2121	(681)	-1.3%
SERC - VACAR	67,838	15.0%	78,014	72,814	(5,200)	2,997	(8,197)	1874	(6,322)	-9.3%
SPP	45,284	13.6%	51,442	53,409	1,966	664	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment"

+ Planned new additions that are in the "permitted" or "site prep" status categories.

Tools for Addressing Local and Regional Capacity Resource Needs

In addition to the industry tools discussed previously, such as construction of new generation and increased load management, several other tools and market and regulatory safeguards exist to alleviate any reliability issues caused by coal plant retirements. First, coal units can convert to natural gas to meet existing state pollution control requirements and anticipated utility MACT obligations. Second, in traditional cost-of-service markets, regulators can apply local regulatory protections to mitigate reliability concerns. Third, competitive electricity markets have proven, transparent rules and policies specifically designed to ensure sufficient resource adequacy and mitigate retirement impacts. Finally, existing broad statutory and regulatory safeguards can help preserve reliability in the unlikely event the tools discussed above prove inadequate.

Coal to Gas Conversion

EPA has determined that natural gas-fired electric steam generation units do not fall under HAPs regulations.[32] Thus, if a coal-fired unit were converted to natural gas, it would meet its obligations under the utility MACT. Many utilities are already doing exactly that to achieve their pollution control requirements. For example, Public Service Colorado (PSCo) planned to convert a coal unit, Arapahoe 4, to natural gas as part of a package of measures that also includes environmental retrofits, retirements, and unit replacement in response to Colorado's "Clean Air-Clean Jobs Act."[33] The Public Utilities Commission of the State of Colorado modified PSCo's plan to also convert Cherokee 4, a 352 MW coal unit to natural gas as well.[34]

Of the 264 GW of coal capacity in the Eastern Interconnection, about 41 GW have natural gas pipeline access and can use natural gas as a secondary fuel, and accordingly could pursue a similar strategy. In some circumstances, the cost of converting units can be economic[35] and the time to convert relatively short. In effect, a gas conversion

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[32] See December 20, 2000 regulatory finding (65 FR 79826). This finding does not apply to combustion turbines.

[33] See also, *Denver Post*, August 8, 2010, http://www.denverpost.com/frontpage/ci_15775014, "Xcel will start retrofitting its Denver-based Cherokee plant next year, converting 717 megawatts of generation to natural gas. The smaller Arapahoe plant would switch one unit to natural gas and another to a system designed to improve grid reliability, both by the end of 2013." "Xcel lays out natural-gas conversion plan for metro area."

[34] Final Order Addressing Emission Reduction Plan, Docket No. 10M-245E, Public Utilities Commission of the State of Colorado, December 15, 2010.

[35] "Complementary Technology and Conversion of Coal-Fired Plants to Natural Gas - Calpine will use natural gas as the primary fuel source for the Conectiv fleet, including two plants that were previously fueled by coal." Calpine Investor Relations Statement, July 1, 2010, http://phx.corporate-

replaces a coal unit with a natural gas peaking unit with about the same capacity as the original unit.

Market Safeguards

All markets in the Eastern Interconnection have procedures in place to protect electric system reliability. These market safeguard procedures include analysis and planning to enable rational and timely action to avoid capacity shortfalls. For example, in some regional wholesale competitive markets operated by RTOs, forward capacity markets facilitate advanced notice of capacity needs and provide price signals to incent new entry. In wholesale markets with vertically-integrated, traditionally regulated utilities, there is a legal obligation to serve load and state regulatory commissions require long-range, integrated resource planning.

RTO Markets

PJM and New England ISO's market-based forward capacity programs play an essential role in maintaining reliability, ensuring that any capacity shortfall is identified and addressed well in advance of any reliability issue. At the core of PJM's RPM is a region-wide Base Residual Auction (BRA), conducted about 40 months prior to each Delivery Year.[36] All existing capacity resources are required to submit an offer into each BRA, and developers may submit offers of proposed resources.

RPM provides a mechanism for including either the replacement cost or the economic cost of retrofitting existing coal facilities to comply with new environmental policies. Existing resources that face mandatory capital expenditures to comply with environmental regulations are eligible to include these costs in the offers. These resources include an adder in their capacity offer price equal to the amortized project expense "reasonably required to enable a Generation Capacity Resource … to continue operating…."[37] This "Avoidable Project Investment Recovery Rate" allows coal plants facing the new utility MACT/CAIR NO_x requirements to reflect the costs of compliance into their BRA offers. Because of the resulting higher offer prices, those offers will only

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ir.net/phoenix.zhtml?c=103361&p=irol-newsArticle&ID=1443628&highlight; "Planning for an Uncertain Future Case Study: Replacing Coal Units with Gas," Presentation at 2010 NARUC Annual Meeting, Sam Walters, Progress Energy, November 2010.

[36] Delivery Years begin on June 1 of a year and continue to May 31 of the following year. Hence, the "2012–2013 BRA," conducted in May 2009, secured capacity commitments for the twelve months beginning June 1, 2012.

[37] PJM Tariff, Attachment DD, § 6.8(a).

clear the BRA if they are the most economic alternative resource to satisfy either local or aggregate reliability needs.

RPM's facilitation of economic environmental upgrades was demonstrated when Maryland's *Healthy Air Act*[38] required substantial reductions in NO_x, SO_2, and mercury emissions from large coal-burning power plants beginning in 2010. Owners of the Maryland plants faced a choice similar to that under utility MACT: retrofit the existing facilities to comply, or shut them down. The cost of retrofitting was very high: at Mirant's plants alone, the publicly stated cost was $1.67 billion.[39] The cost of these retrofits was directly reflected in capacity offers for the 2009–2010 Delivery Year (when the *Healthy Air Act* reductions took effect) and contributed to an increase in the capacity price in Maryland.[40] These higher capacity prices, which were necessary to maintain local reliability, imposed an obligation on owners of these coal-fired plants that cleared to undertake those upgrades, funded by the higher capacity payments pledged in the future.

If an offer containing the retrofit recovery cost clears the RPM auction, the resource owner is required to make those upgrades. If it does not clear the RPM auction, and instead a less expensive resource is available to meet the region's capacity needs, the resource owner is free to file a deactivation request and retire the unit at the beginning of the Delivery Year covered by the BRA in which it did not clear.[41] The forward nature of the RPM auction provides advance notice that will help the resource owner and the RTO facilitate a smooth transition to a cleaner fleet.

Importantly, the RPM market furnishes locational capacity price signals, with premiums paid in areas with more critical resource adequacy needs, or with more costly resources available for providing resource adequacy. This locational aspect is significant in that capacity must be deliverable to load to maintain reliability. Due to limitations of the transmission system, some amount of capacity must be located near load centers. Without the locational aspect of the market, local resource adequacy needs might not be satisfied, as market-wide prices would not send price signals to support supply in the areas where it is most needed.

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[38] Annotated Code of Maryland, Environment: Title 2, Ambient Air Quality Control; Subtitle 10, Health Air Act; Sections 2-1001–2-1005.

[39] Power-Gen Worldwide, "FGD Systems Start Operating at 7 Mirant Coal-Fired Units," December 21, 2009, *available at*: http://www.powergenworldwide.com/index/display/articledisplay/371998/articles/power-engineering/projects-contracts-2/2009/12/fgd-systems-start-operating-at-7-mirant-coal-fired-units.html

[40] PJM Market Monitoring Unit, "Analysis of the 2009–2010 RPM Auction," pp. 25–26, *available at* http://www.monitoringanalytics.com/reports/Reports/2008/20092010-rpm-review.pdf.

[41] Although this is true as a general matter, in rare cases the generator may provide some location-specific reliability service, such as local-area voltage support, that may require transmission upgrades or other remedies before the unit can be deactivated.

PJM's RPM market has been a success at incenting both new generation resources and new load management. PJM reported that "[o]ver the period covering the first seven RPM Base Residual Auctions, 11,582 MW of new generation capacity was added, which was partially offset by 7,185 MW of capacity derations or retirements over the same period. Additionally, 12,967 MW of new Demand Resources were offered over the last seven auctions, an increase of more than 10,000 MW over that period, and 733 MW of new Energy Efficiency resources were offered in the 2013/2014 auction. The total net increase of installed capacity in PJM over the period of the last seven RPM auctions was 17,887 MW."[42]

In addition to RPM helping ensure adequate resources, RTOs also have market rules that can mitigate any reliability impacts of retirements. For example, PJM conducts reliability impact studies for all units that announce retirement, and requests that those identified as needed for reliability temporarily operate past their planned retirement date pursuant to "reliability must run" (RMR) agreements. To minimize any adverse environmental impacts, RMR agreements can be structured to limit a unit's operations for reliability purposes only. For example, Exelon Generation recently coordinated with PJM and the Pennsylvania Department of Environmental Protection to negotiate a consent decree and operating procedures related to an RMR agreement for its two retiring coal units, which require the units operate for reliability purposes only.[43]

Furthermore, transmission owners in RTOs have an ability to proactively manage long-range reliability issues relating to expected retirements. For example, Commonwealth Edison (ComEd), the local transmission owner in Chicago, proactively filed an application with the Illinois Commerce Commission[44] seeking permission to enhance its transmission system. In its application, ComEd noted the identified upgrades would be required to maintain system reliability in the event that two of Midwest Generation's at-risk coal units, Fisk and Crawford, were to retire.[45]

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[42] http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2013-2014-base-residual-auction-report.ashx, p. 14.

[43] The PJM Operating Procedures, which contain a copy of the consent decree, are posted at PJM's website at http://PJM.com/planning/generation-retirements.aspx.

[44] ICC Docket No. 10-0385; Commonwealth Edison Company; Application for authorization under Section 4-101 of the Illinois Public Utilities Act ("Act"), 220 ILCS § 5/4-101, or alternatively, for a Certificate of Public Convenience and Necessity, pursuant to Section 8-406 of the Act, to install, operate and maintain two new 345,000 volt electric transmission lines in Cook County, Illinois; filed June 11, 2010.

[45] Direct Testimony of Thomas W. Leeming, p. 2, lines 25-35.

Vertically Integrated Markets

In states with vertically integrated utilities, there is a legal obligation to serve load and state regulatory commissions require long-range, integrated resource plans (IRPs). For example, utilities in the VACAR region for which we project a possible 6,322 MW capacity shortfall, are state-regulated. A review of the IRPs of the major VACAR utilities[46] reveal that these companies plan to add about 2,800 MW of new gas-fired capacity before 2015, capacity we did not include in our capacity additions because the plants are not sufficiently advanced to pass our very conservative screen. Yet, these planned resources, such as Dominion's 1,100 MW Warren County Combined Cycle Plant (in the permitting phase), have state regulatory backing, which assures cost recovery. In addition, these IRPs include about 1,000 MW more load management than is shown in NERC's 2010 Summer Assessment. Thus, 3,800 MW of the potential 6,322 MW need in VACAR is already planned for under the required IRPs.

Statutory and Regulatory Safeguards

In the unlikely event that the mechanisms discussed in this paper are inadequate to mitigate reliability impacts of retirements, governmental and regulatory agencies have authority to grant delays or waivers of compliance in certain circumstances. First, EPA can exercise its statutory authority under the CAA to grant, on a case-by-case basis, extensions of time to complete pollution control installations. Under the CAA, the EPA can issue permits that grant a one-year extension beyond the normal statutory three-year period, "if such additional period is necessary for the installation of controls," providing a total of four years for compliance with the regulations.[47] Second, the President of the United States is authorized under Section 112 of the CAA to grant compliance extensions of up to two years on a case-by-case basis after a demonstration that the technology to implement utility MACT is not available. Finally, in certain emergency circumstances, the DOE has the authority under Section 202(c) of the Federal Power Act to override requirements under the CAA.[48]

Conclusions

To analyze the electric system reliability impacts of predicted coal-fired plant retirements on an RTO, NERC regional, and NERC subregional basis, we performed a detailed system modeling analysis of the Eastern Interconnection based on an aggressive policy

[46] Dominion, Duke-North Carolina, Progress-North Carolina, Santee Cooper, and SCANA.

[47] CAA Sec 112(i)(3)(B).

[48] See footnote 12 for an illustration of such a remedy.

representation of the proposed and forthcoming EPA air regulations. We conclude that implementing EPA air regulations will not compromise electric system reliability. Rather, reliability can be maintained in all RTOs, and NERC regions and subregions through coal to gas conversions, new gas-fired generation, expansion of load management programs, and established market and regulatory safeguards. Of the areas we analyzed - 5 RTOs, 6 NERC Regions, and 7 NERC subregions - we project that after predicted coal retirements, most still have capacity surpluses. At the NERC regional level, we predict that two regions will have de minimis shortfalls (relative to resource adequacy requirements) and another region will have a modest shortfall. We predict that three subregions within SERC will have shortfalls. One such shortfall is de minimis, one is modest, and only one area, the VACAR subregion, has a larger shortfall. But notably, VACAR's 6,322 MW shortfall, only 1,100 MW of which are attributable to EPA's forthcoming air pollution regulations, can be easily managed: over half of the shortfall is already planned for under the required IRPs (new capacity and load management), and the rest, approximately 2,500 MW, could be addressed through construction of new gas-fired power plants or incremental load management.

Also significantly, the industry has consistently proven its ability to expand capacity relatively quickly to meet increased demand. In nine of the twelve five-year periods from 1949 to the present, at least 39 GW of new capacity was added nationwide, with 177 GW of mostly gas-fired capacity, or more than four times the projected US coal retirements, added in the 1999-2004 period alone. Futhermore, although projected retirements may cause some localized reliability issues, RTOs and state regulators are well-equipped to deal with any that arise.

Appendix A: Background Information on Reliability

Appendix B: Modeling and Methodology

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Appendix A: Background Information on Reliability

Generation resource adequacy is an integral part of reliability. In this section, we discuss how different areas of the country maintain resource adequacy. This background is important to our examination of the utility MACT/CAIR NO_x policy's potential effect on regional reserve margins to assess whether unit retirements could adversely affect electric reliability.

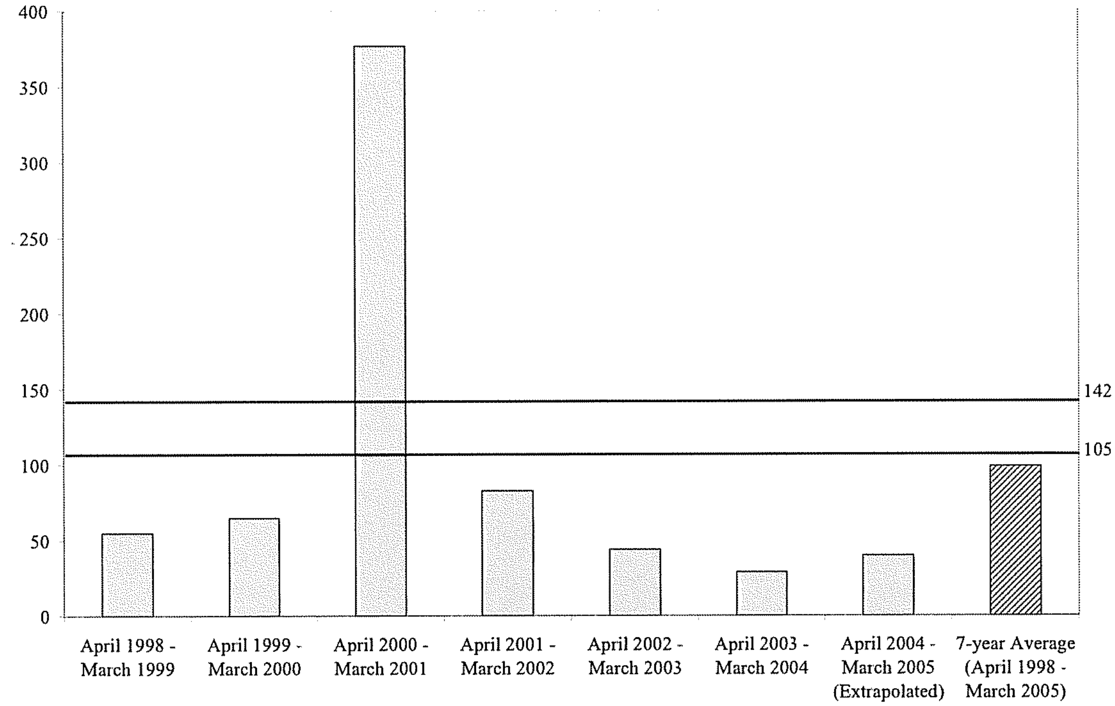
With a few notable exceptions, the electric utility industry has maintained an extremely high level of reliability. The first major reliability incident was in November 1965. Thirty million people lost power in the northeastern United States in what came to be called the "Northeast Blackout." In response, in 1968, NERC was established by the industry. Nine regional reliability organizations were formalized under the NERC umbrella, with regional planning coordination guides and operating criteria.

For almost 40 years there were no major outages in the eastern US, until August 2003, when 50 million people lost power in Northeastern and Midwestern US and Ontario. As a direct consequence of this blackout, in 2007, compliance with NERC standards, which had been voluntary, was made mandatory by the FERC. These standards primarily relate to short-term system operation and transmission system planning, with little reference to generation adequacy, which largely is left to RTOs, states and other entities.

Importantly, the two major eastern outages were not due to a lack of generation resources; both were triggered by transmission failures. The 1965 Northeast Blackout began when an improperly set protective relay shut off power after a small surge in upstate New York. The 2003 blackout occurred when high-voltage transmission lines in Ohio contacted overgrown trees. In its 2003 summer assessment, NERC reported that the NERC subregion where the transmission outage was triggered had a 28.3% reserve margin, which meant that available reserve generating capacity was significantly more than adequate.

It is possible to have a robust transmission system but have less than adequate reliability because of inadequate generation. Although resource shortages have rarely led to load shedding, it did occur in California in late 2000 and early 2001. Despite an installed capacity target in California, there was no mandate to maintain a required level of capacity. When California restructured its generation sector in 1996, it was assumed that energy prices would rise to the level needed to support new entry by independent power producers in time to maintain planning margins. While the California economy boomed, electricity demand grew rapidly, but little new generation was built because energy prices remained low and there was no other mechanism to provide ample revenue to support new entry. In fact, prices (unmitigated) would have had to rise to the high levels seen in the 2000-2001 crisis period to have provided sufficient revenue for a generator. But prior to May 2000, the California ISO market price signals were well below what a new entrant needed, and the futures markets for power were also quite weak. As a result, by 2000, available generation was well below what was required to maintain reliable service, and brownouts and blackouts occurred. Figure 5 below, which is from the FERC testimony of Dr. William Hieronymus of CRA, makes this point quite forcefully. The chart shows that energy prices both before and after the April 2000–March 2001 period were well below the $105-142/kW-year mark needed to finance an efficient new combined-cycle unit. Consequently, most merchant plant investors avoided California, and the merchant capacity that was added did not come online until after the crisis.

Figure 5. Margins Earned by Hypothetical New Combined-Cycle Unit Based on Unmitigated Prices ($1998/kW)



Source: Testimony of William H. Hieronymus in EI03-180-00, *et al,* May 13, 2005.

As discussed in the report, unlike in California, mechanisms do exist in the Eastern Interconnection —namely, capacity markets and state regulation—to ensure that ample capacity will be available to maintain reliability. Consequently, a California-type crisis triggered by inadequate supply resources is far less likely in the Eastern Interconnection, provided that unit retirements are foreseen with sufficient notice to bring any required replacement resources into service.

The Eastern Interconnection consists of a large portion of the US and Canadian transmission system east of the Continental Divide, with the exception of a large portion of Texas, which is a separate interconnected system (see Figure 3). Today, the Eastern Interconnection consists of six NERC regional reliability organizations and five RTOs. All Eastern Interconnection transmission and generation is in one of the NERC regions, but only a portion of the generation and transmission is in an RTO. Although the NERC regions have responsibility for monitoring and enforcing NERC reliability standards in practice, the RTOs are ultimately responsible for taking the actions needed to ensure reliability in their control areas.

The RTOs conduct reliability impact studies for all units that announce retirement, and can offer RMR agreements to those units needed to temporarily operate past their planned retirement date to maintain reliability. For example, on December 2, 2009, Exelon Generation submitted a notice to retire four coal units at its Cromby and Eddystone stations in Pennsylvania. PJM studied the transmission system impact and determined that these retirements would adversely affect reliability until certain upgrades to the transmission system were made. PJM asked Exelon Generation to continue to operate one unit at each station beyond May 31, 2011. PJM and Exelon negotiated an RMR rate under the PJM Tariff, and FERC approved the RMR rate subject to hearing.[49]

Additionally, three of the RTOs (ISO New England, the New York ISO, and PJM) have established capacity markets to ensure that adequate capacity is online, and the Midwest ISO and SPP are moving to establish their own capacity markets as well.[50]

These capacity markets are designed to ensure that adequate capacity is online to meet load and that new entry occurs when and where needed. These payments can be substantial. For example, for the 2013/2014 period, a capacity resource in PJM outside of MAAC[51] will receive \$27.73/MW-day (\$10.12/kW-year), while resources in MAAC will receive from \$226.15/MW-day (\$82.54/kW-year) to \$247.14/MW-day (\$90.21/kW-year), depending on the location within MAAC. Because this forward market provides a signal three years in advance developers can see the need and capacity revenues they will receive early enough to develop new resources or, conversely, if capacity revenues will be inadequate to support existing resources, allowing for an orderly deactivation of these uneconomic resources.

Forward capacity markets, like those in PJM and ISO New England, therefore serve a dual purpose with respect to existing unit retirements. Existing units facing high costs, including capital costs related to environmental upgrades, may find themselves priced out of the market if that capacity is no longer needed for reliability; consequently, these "at risk" generators may choose to retire rather than earn capacity payments insufficient to cover their costs. If that capacity *is* needed for reliability, however, the capacity market provides a transparent price signal, set by the going-forward costs of existing units (including, when needed, capital expenses for environmental upgrades). If the all-in, levelized cost of new capacity resources is below the going-forward costs of these

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[49] http://pjm.com/~/media/documents/ferc/2010-filings/pjmmotion.ashx

[50] The Midwest ISO already conducts monthly capacity auctions through which it enforces resource adequacy standards, pursuant to Module E of its tariff.

[51] MAAC is the portion of PJM that corresponds to what used to be the NERC Mid-Atlantic Area Council. The term MAAC is still used by PJM to describe the eastern part of the PJM system.

highest-cost existing generators, then the older resources will be displaced by the more economic new units.

The New England ISO, the New York ISO, and PJM capacity markets selectively draw from a common set of objectives:

- Price signals for new capacity that are observable or reasonably predictable several years in advance of actual need.[52]
- Demand curves or other mechanisms that provide stability and lead to price formation that will set the price at the net cost of new entry (Net CONE) when capacity levels are at the target reserve margin, but will be higher than Net CONE if capacity is below the target reserve margin and less than Net CONE if capacity is above the target reserve margin.[53]
- Locational price signals.

The locational aspect is quite important since in order to maintain reliability, capacity must be deliverable to load. Given limitations of the transmission system, some amount of capacity typically must be located near load centers.

In PJM there are 24 load delivery areas (LDAs), each of which can be a separate zone in PJM's RPM capacity market. The zones (consisting of LDAs) are determined by the level of imports needed to maintain a predetermined level of reliability. Capacity prices are then set at levels in each LDA that ensure not only that the overall regional planning reserve margin is met, but that the locational resource requirement of each LDA is also satisfied. Consequently, it has generally been the case that capacity prices along the Eastern seaboard, from New York City to Washington, are much higher than capacity prices in the Midwest, reflecting both the constrained west-to-east transmission system and the higher going forward-costs of generators in the east—in some cases, costs directly attributable to compliance with state air emissions regulations.[54]

Non-RTO regions, primarily in the Southeast, as well as many states in RTO areas, particularly the Midwest ISO and SPP, are served by vertically integrated utilities, municipal systems, cooperatives, and federal systems. State public utility commissions (or other regulators) set rates and allow regulated utilities to include new capacity in rate base after a demonstration that this new capacity is needed and a prudent investment. To

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[52] Although the NYISO does provide the same three-year forward pricing as the PJM and ISO-NE markets, the relative price stability and predictability created by the administrative demand curve used in the capacity market provides greater guidance to investors than, for example, the month-to-month pricing in the Midwest ISO.

[53] The ISO-NE Forward Capacity Market does not have an administrative demand curve *per se*, but has other design features intended to stabilize the capacity price near the Net CONE value.

[54] The PJM Independent Market Monitor noted that the high capacity prices in Southwest MAAC were linked to bids that included capital cost recovery for compliance with Maryland emissions laws.

establish the need and prudency of the investment, regulated utilities typically prepare IRP forecasts. These forecasts include future load growth and capacity online that together specify the need for investment in generation and transmission, and preferred solutions. State regulators then act to approve major capital projects and set regulated retail rates to cover direct costs plus a return on invested capital. While this centralized approach to capacity expansion has generally ensured that the utility maintains sufficient capacity reserve margins, many states' legislators and regulators found that the technological and other risks placed onto ratepayers would be better borne by independent power producers.

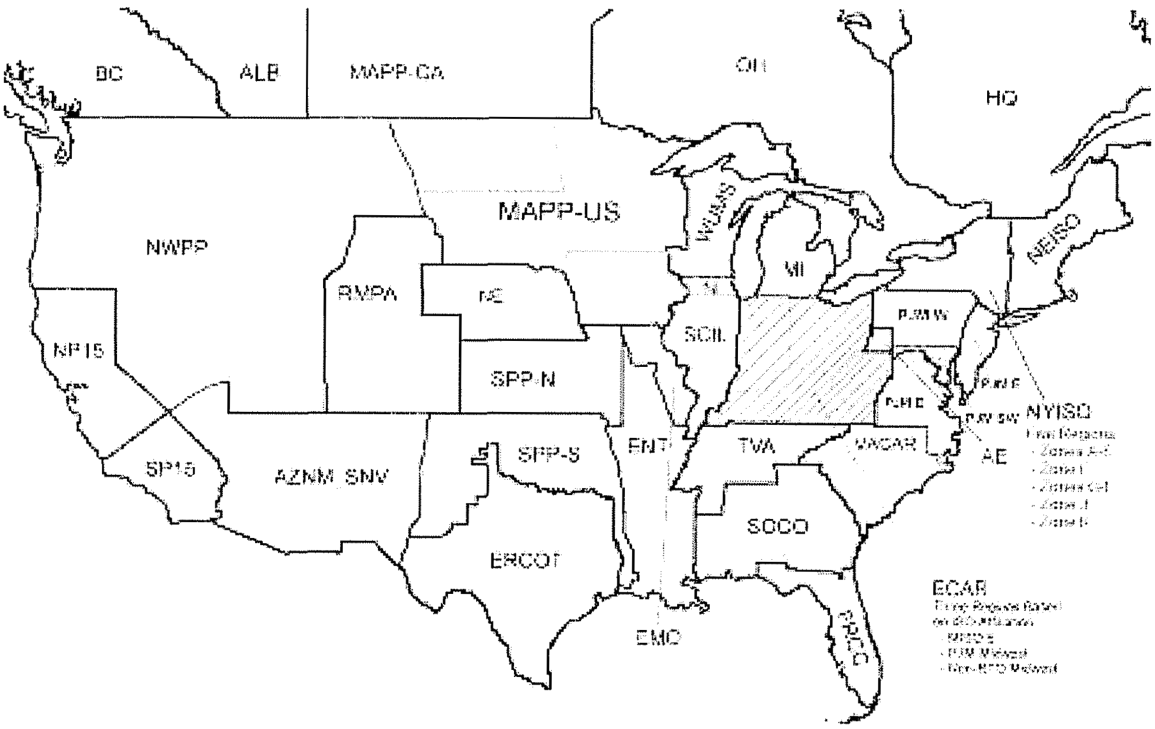
Appendix B: Modeling and Methodology

Estimating Retirements

CRA used its NEEM model to estimate coal unit retirements under the utility MACT/CAIR NO_x policy representation described in the main body of this paper. NEEM optimizes generation operation in each major region in the US, taking into account power transfer limits among regions. NEEM optimizes retirements, unit environmental retrofits, and new capacity additions by region over a 60-year period, taking into account the operating and cost characteristics of existing capacity and the capital and operating costs of potential new capacity.

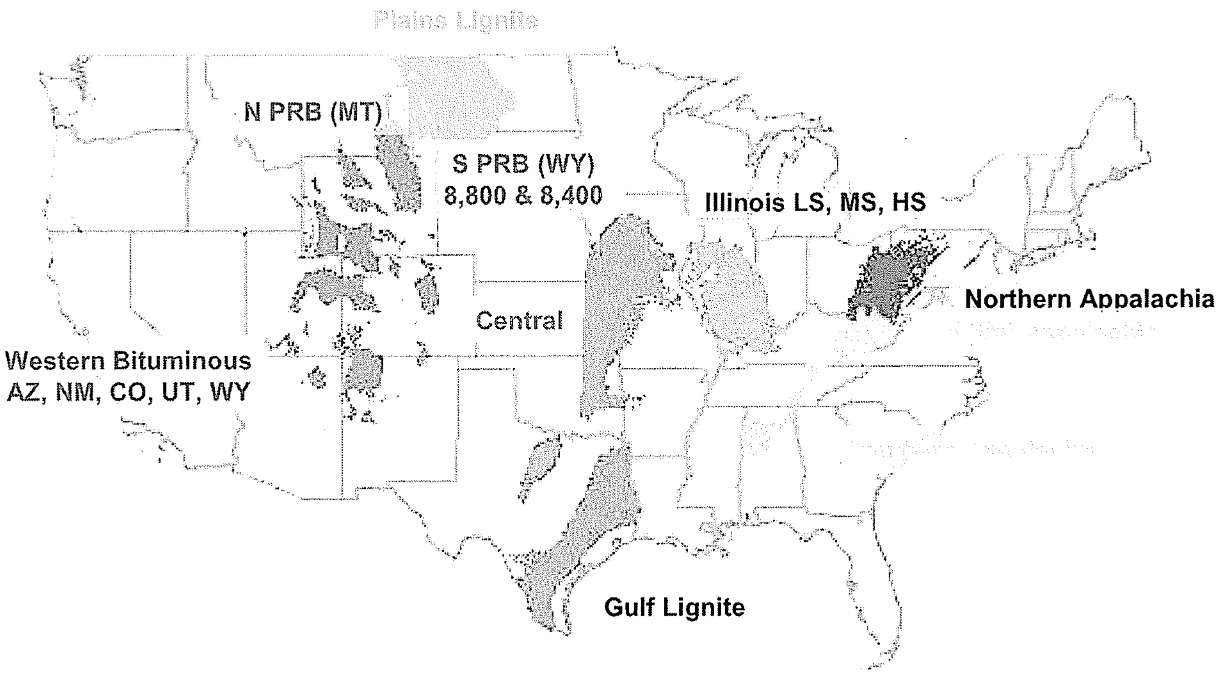
NEEM models the North American electric system as 39 regions that are connected by a network of transmission lines with region-to-region limits and, in some cases, joint import and export limits as shown in Figure 6.

Figure 6. NEEM Regions



Coal Supply - NEEM models coal supply from 23 individual curves representing distinct domestic production areas, Latin American imports, and different coal qualities (sulfur and Btu). See Figure 7 for a description of NEEM's coal supply regions.

Figure 7. NEEM Coal Supply



Pollution Control Retrofits - Coal units in NEEM can install pollution control retrofits based on economics. Control technologies are available for SO_2 (FGD), NO_x (SCR, SNCR), and mercury (ACI + fabric filter, or simply ACI if the unit already has a fabric filter). Each coal unit in NEEM is given a base Fixed O&M (FOM) cost, which is a function of its age and the combination of any existing emissions controls on the unit.[55]

Future retrofits (planned or economically determined by NEEM) result in emissions rate reductions, additional capital expenditures, an incremental FOM adder, an incremental VOM adder, and possibly heat rate and capacity penalties. The capital costs and incremental FOM for FGDs are based on Sargent & Lundy (August 2010).[56] Capital costs and incremental FOM for mercury controls are based on Cichanowicz (July 2006;

[55] EPA IPM Base Case Assumptions, EPA IPM Base Case v4.10, Chapter 4: Generating Resources, Table 4-9. (Based on FERC Form 1.)

[56] Sargent & Lundy, "IPM Model - Revisions to Cost and Performance for APC Technologies: Wet FGD Cost Development Methodology," August 2010, Table 1.

January 2010).[57] The incremental VOM for new and existing retrofits are also based on the aforementioned documentation.

Load Forecast - NEEM is a load-duration curve model. Load forecast assumptions in NEEM are derived from a combination of 2009 FERC 714 filings and 2010 ISO load forecasts (PJM, MISO, ISO-NE); minor adjustments were made for non-filing entities and some cooperatives. Load forecasts at the planning area level are aggregated to the NEEM-regional level and sorted into three seasons and 20 load blocks. Peak energy forecasts are similarly aggregated and peak coincidence factors are based on 2006 FERC 714 hourly data and 2006 ISO hourly reporting.

Fuel Prices - Natural gas and fuel oil delivered-price forecasts are based on a combination of NYMEX futures and AEO 2010 price forecasts. August 2010 NYMEX Henry Hub futures prices are blended into a longer-term AEO 2010 forecast before 2015. Delivered prices for generating units in each NEEM region are estimated using historically estimated basis differentials. Natural gas prices in NEEM vary seasonally and fuel oil prices vary annually.

New Capacity - In addition to simulating retirement of existing generators, NEEM simulates the deployment of new generating capacity to replace retirements and to meet growth requirements. New generating technologies available in 2015 include fossil units such as advanced conventional coal, natural gas combustion turbine, natural gas combined-cycle, and coal integrated gasification combined-cycle (IGCC). Renewable units such as wind turbines, solar – photovoltaic, solar – concentrated solar power, landfill gas, biomass, and geothermal are also built by the model based on economics and local and regional renewable electricity standards. Capital costs and operating characteristics for new generating capacity are primarily based on EIA Annual Energy Outlook 2009 with some CRA adjustments (e.g., transmission adders). As discussed below, we do not use NEEM's economic new builds directly in our reliability analysis.

Estimating Reliability Impacts

CRA used the following approach to estimating reliability impacts by NERC region:

1. We started with the NERC 2010 Summer Assessment's Total Internal Demand. We also calculated the difference between Total Internal Demand and Net Internal Demand as an estimate of demand side resources (in 2010 and 2015).

2. Using the 2010 Total Internal Demand, we applied growth factors to obtain the 2015 Total Internal Demand estimates by NERC region. We then subtracted the demand-side resource estimates obtained above to arrive at 2015 Net Internal

[57] J. Edward Cichanowicz, "Testimony of J. E. Cichanowicz to the Illinois Pollution Control Board: A Review of the Status of Mercury Control Technology," July 28, 2006; J. Edward Cichanowicz, "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies," January 2010.

Demand. The growth factors applied to Total Internal Demand are based on the 2010–2015 growth in Total Internal Demand from the 2009 NERC Electricity Supply & Demand (ES&D).

3. The 2015 capacity online estimate was calculated by taking the certain-existing capacity from the NERC 2010 Summer Assessment and adding planned new builds and subtracting planned retirements. The data source for new builds and retirements is Energy Velocity. The new build status categories considered were, conservatively, "under construction" or "testing." For retirements, conservatively, all status categories were considered except for "canceled."

4. Net firm transactions were then deduced from the NERC 2010 Summer Assessment and added to the 2015 capacity online estimate.

5. The 2015 resource adequacy surplus (or shortfall) was then calculated using the capacity online estimate and the Net Internal Demand estimate. This resource adequacy surplus (or shortfall) estimate is prior to the inclusion of our coal retirement estimates.

6. We then included modeled coal unit retirement estimates from NEEM and recalculated the 2015 resource adequacy surplus (or shortfall). We did not add in NEEM's economic new additions.

7. We then included planned additions that are less conservative, including those in the "permitted" or "site prep" status categories. These are new additions that are less certain than those under construction but nevertheless could occur fairly quickly as they face no significant regulatory hurdles. We recalculated the 2015 resource adequacy surplus (or shortfall).

8. Finally, we reported the forecasted number of percentage points above or below reserve margin in 2015.

Appendix C: PJM RPM Market Example

To illustrate how retrofit and replacement decisions for existing coal units will be guided by the RPM market, CRA has examined how the LDAs that have been modeled in recent RPM auctions would be affected by the retirements identified in the analysis described earlier in this report. Specifically, the analysis estimates the reliability requirements and available resources in each LDA for the BRA for the 2015/16 Delivery Year, which is the first auction for which regulations would be expected to affect capacity resource offers.

Table 5[58] shows the reliability requirements and available resources for the PJM RTO and each LDA that was included in the most recent BRA, conducted in May 2010 for the 2013/14 delivery year. The reliability requirements for 2013/14 are shown, along with the quantity of resources that were offered into the BRA. The projected supply and demand for 2015/16 is also shown, assuming that the reliability requirements will escalate with projected load growth and that the coal-fired capacity will be retired as projected under our analysis of the utility MACT/CAIR NO_x policy.

The expected retirements from the utility MACT/CAIR NO_x policy includes 7,529 MW (on a UCAP basis, which reduces the capacity of each resource to reflect the forced outage rate) of coal-fired capacity within the PJM RTO footprint. Of the total PJM capacity, 1,744 MW is located in the AEP zone, which does not participate in the RPM market, leaving 5,785 MW of planned retirements that will affect the RPM market clearing directly.

[58] Table 5 shows the supply and demand balance in terms of the unforced capacity (UCAP) metrics used by PJM. In addition, the planned retirements shown are only those from the 2013/14 auction to the 2015/16 auction.

Table 5. Impact of Projected PJM Coal Retirements 2015/16 Base Residual Auction

LDA	2013/14 Capability Year Available Resources	Reliability Requirement	Surplus/ (Shortfall)	Retirements Planned	Economic	2015/16 Capability Year Available Resources	Reliability Requirement	Surplus/ (Shortfall)
RTO (with AEP)	186,588	169,799	16,789	825	7,061	178,703	174,843	3,860
RTO (excluding AEP)	160,898	146,239	14,659	69	5,425	155,404	150,583	4,821
MAAC	72,798	71,451	1,347	-	1,503	71,295	73,538	(2,243)
SWMAAC	18,493	17,502	992	-	294	18,199	18,038	162
PEPCO	9,772	9,250	522	-	152	9,620	9,460	160
EMAAC	40,102	39,472	630	-	302	39,800	40,573	(773)
PSEG	13,902	13,099	803	-	-	13,902	13,421	480
PS-North	6,743	6,208	535	-	-	6,743	6,361	383
DPLS	3,735	2,933	802	157	15	3,563	3,016	547

All values in MW (UCAP)

Overall the PJM RTO has sufficient capacity to replace retirements, but the impact varies by subzones within the broader PJM region: in 2015/16, given current transmission limits,[59] more resources than are required to meet the LDA reliability requirement are available for each LDA except MAAC and Eastern MAAC. As long as the policy is known with sufficient lead time to allow new resources to be offered into the BRA, RPM will provide a transparent market signal for new entry. In fact, for the MAAC LDA, which would need just over 2,000 MW of new capacity under the retirement scenario, 3,700 MW of new capacity is already under development, of which just over 1,000 MW is permitted and another 600 MW is in the permitting process. Additional projects could be developed if needed between now and the time of MACT implementation.

In addition to identifying need, RPM provides a price mechanism to support resource adequacy. In the Eastern MAAC and MAAC LDAs, RPM prices will, by design, rise to levels that can support new entry, or if it is more cost-effective, support retrofitting existing coal-fired capacity to be compliant with the utility MACT.

[59] Planned new transmission such as the PATH, MAPP and Susquehanna–Roseland projects may well impact the locational capacity requirements. In addition, transmission projects can participate in the RPM market and respond to the same price signals.

Appendix D: Detailed Calculation Tables

Table 2. Loads and Resources by 2015, RTO Level

	(NID)	(RRM)	(n)	(p)	(q) Resource Increase	(r) Resource Decrease	(x) = (p) + (q) - (r)	(y) Resource Increase	(z) = (x) + (y)	(A) = (z) - (n)	(d) Resource Decrease	(e) = (z) - (d)	(B) = (e) - (n)	(f) Resource Increase	(C) = (B) + (f)	= [(e) + (f)] / NID - 1 - RRM
RTO	*2015 Net Internal Demand Estimate (MW)	Required Reserve Margin (%)	Required Capacity (MW)	**Certain-Existing Capacity (MW)	***Planned New Additions by 2015 (derated MW), Energy Velocity	# Planned Retirements by 2015 (MW), Energy Velocity	Projected Capacity in 2015 (MW)	++ Net Firm Transactions in 2010 Summer Assess. (MW)	Projected Capacity PLUS Net Firm Transactions (MW), 2015	(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)	Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)	## Retirement-Adjusted Projected Capacity PLUS Net Firm Transactions (MW), 2015	(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)	+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity	(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)	Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)
PJM	146,441	15.3%	168,846	176,362	5,154	3,454	178,061	-	178,061	9,215	7,529	170,532	1,686	2,350	4,036	2.8%
MISO	91,001	15.4%	105,015	123,821	3,470	203	127,088	-	127,088	22,073	7,074	120,014	14,999	435	15,434	17.0%
New England	26,180	15.0%	30,107	32,229	213	100	32,342	288	32,630	2,523	370	32,260	2,153	1,094	3,247	12.4%
New York	31,803	15.0%	36,573	36,668	1,386	743	37,312	1,580	38,892	2,318	348	38,543	1,970	192	2,162	6.8%
SPP	45,284	13.6%	51,442	49,777	2,407	-	52,184	1,225	53,409	1,966	664	52,745	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment" (for New England, New York, and SPP). For PJM, the PJM 2013/14 RPM Base Residual Auction Planning Parameters, total RTO load net of load management. For MISO, 2015 Coincident Net Internal Demand, Midwest ISO Transmission Expansion Plan (MTEP) 2009.

** NERC 2010 Summer Assessment for New England, New York, and SPP. PJM: 2013/14 RPM Model existing resource parameters net FERC 411 purchases and sales; MISO: 2009 Summer Assessment Total July 2009 capacity net of imports/exports.

*** This includes the "under construction" and "testing" categories in Energy Velocity. Renewables have been derated.

This includes all categories of retirements in Energy Velocity except for "cancelled."

++ Firm net imports that count toward reserve margin.

Assume no change in net firm transactions through 2015.

+ Planned new additions that are in the "permitted" or "site prep" status categories.

Table 3. Loads and Resources by 2015, NERC Regional Level

	(NID)	(RRM)	(n)	(p)	(q) Resource Increase	(r) Resource Decrease	(x) = (p) + (q) - (r)	(y) Resource Increase	(z) = (x) + (y)	(A) = (z) - (n)	(d) Resource Decrease	(e) = (z) - (d)	(B) = (e) - (n)	(f) Resource Increase	(C) = (B) + (f)	= [(e) + (f)] / NID - 1 - RRM
NERC Region	*2015 Net Internal Demand Estimate (MW)	Required Reserve Margin (%)	Required Capacity (MW)	Certain-Existing Capacity (MW), NERC 2010 Summer Assess.	**Planned New Additions by 2015 (derated MW), Energy Velocity	# Planned Retirements by 2015 (MW), Energy Velocity	Projected Capacity in 2015 (MW)	++ Net Firm Transactions in 2010 Summer Assess. (MW)	Projected Capacity PLUS Net Firm Transactions (MW), 2015	(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)	Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)	## Retirement-Adjusted Projected Capacity PLUS Net Firm Transactions (MW), 2015	(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)	+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity	(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)	Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)
FRCC	47,330	15.0%	54,429	52,989	1,550	804	53,735	2,025	55,760	1,331	1,335	54,425	(4)	2,550	2,546	5.4%
MRO	42,681	15.0%	49,083	48,750	885	83	49,553	265	49,818	735	3,640	46,178	(2,905)	377	(2,528)	-5.9%
NPCC	60,894	15.0%	70,028	68,897	1,599	843	69,653	1,868	71,521	1,494	718	70,803	776	1,286	2,062	3.4%
RFC	186,008	15.0%	213,909	217,700	5,175	3,495	219,380	1,900	221,280	7,371	10,306	210,974	(2,935)	2,351	(583)	-0.3%
SERC	213,891	15.0%	245,975	246,535	9,019	3,525	252,029	91	252,120	6,145	12,716	239,404	(6,571)	5,934	(638)	-0.3%
SPP	45,284	13.6%	51,442	49,777	2,407	-	52,184	1,225	53,409	1,966	664	52,745	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment."

** This includes the "under construction" and "testing" categories in Energy Velocity. Renewables have been derated.

This includes all categories of retirements in Energy Velocity except for "cancelled."

++ Firm net imports that count toward reserve margin.

Assume no change in net firm transactions through 2015.

+ Planned new additions that are in the "permitted" or "site prep" status categories.

Table 4. Loads and Resources by 2015, NERC Subregional Level

	(NID)	(RRM)	(n)	(p)	(q) Resource Increase	(r) Resource Decrease	(x) = (p) + (q) (r)	(y) Resource Increase	(z) = (x) + (y)	(A) = (z) - (n)	(d) Resource Decrease	(e) = (z) - (d)	(B) = (e) - (n)	(f) Resource Increase	(C) = (B) + (f)	= [(e) + (f)] / NID - 1 - RRM
NERC Sub-Region	*2015 Net Internal Demand Estimate (MW)	Required Reserve Margin (%)	Required Capacity (MW)	Certain-Existing Capacity (MW), NERC 2010 Summer Assess.	**Planned New Additions by 2015 (derated MW), Energy Velocity	# Planned Retirements by 2015 (MW), Energy Velocity	Projected Capacity in 2015 (MW)	++ Net Firm Transactions in 2010 Summer Assess. (MW)	Projected Capacity PLUS Net Firm Transactions (MW), 2015	(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)	Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)	## Retirement-Adjusted Projected Capacity PLUS Net Firm Transactions (MW), 2015	(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)	+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity	(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)	Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)
FRCC	47,330	15.0%	54,429	52,989	1,550	804	53,735	2,025	55,760	1,331	1,335	54,425	(4)	2550	2,546	5.4%
MRO	42,681	15.0%	49,083	48,750	885	83	49,553	265	49,818	735	3,640	46,178	(2,905)	377	(2,528)	-5.9%
NPCC - New England	26,180	15.0%	30,107	32,229	213	100	32,342	288	32,630	2,523	370	32,260	2,153	1094	3,247	12.4%
NPCC - New York	31,803	15.0%	36,573	36,668	1,386	743	37,312	1,580	38,892	2,318	348	38,543	1,970	192	2,162	6.8%
RFC	186,008	15.0%	213,909	217,700	5,175	3,495	219,380	1,900	221,280	7,371	10,306	210,974	(2,935)	2351	(583)	-0.3%
SERC - Central	44,956	15.0%	51,699	49,345	1,871	-	51,216	2,046	53,262	1,563	4,329	48,933	(2,766)	1363	(1,403)	-3.1%
SERC - Delta	30,167	15.0%	34,692	40,172	886	227	40,831	(720)	40,111	5,419	343	39,768	5,077	513	5,590	18.5%
SERC - Gateway	19,883	11.9%	22,250	24,369	1,600	-	25,969	(2,150)	23,819	1,569	641	23,178	929	62	991	5.0%
SERC - Southeastern	52,889	15.0%	60,822	61,779	399	758	61,420	1,007	62,427	1,604	4,407	58,020	(2,802)	2121	(681)	-1.3%
SERC - VACAR	67,838	15.0%	78,014	70,870	4,263	2,540	72,593	221	72,814	(5,200)	2,997	69,817	(8,197)	1874	(6,322)	-9.3%
SPP	45,284	13.6%	51,442	49,777	2,407	-	52,184	1,225	53,409	1,966	664	52,745	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment."

** This includes the "under construction" and "testing" categories in Energy Velocity. Renewables have been derated.

This includes all categories of retirements in Energy Velocity except for "cancelled."

++ Firm net imports that count toward reserve margin.

Assume no change in net firm transactions through 2015.

+ Planned new additions that are in the "permitted" or "site prep" status categories.

CREDIT SUISSE

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COMMENT

Impact of EPA Rules on Power Markets

Our take: Upcoming EPA policy to limit coal plant emissions is the best chance for a deregulated power market recovery, reversing fundamentals hurt by dismal commodity prices. We see opportunity with 'cleaner' generators in 'dirtier' markets like FE, AYE, EXC, and RRI. EPA rules should also boost rate base and EPS growth opportunities for Regulated Utilities – notably AEP, DTE, SO and CMS – although effective management of the regulatory process will be key.

We still see a lot of policy work on the horizon and acknowledge we may be early, but we think EPA rules will be a dominant investment theme for 2011 with heavy focus on likely stock movement in 1H11 between draft mercury rules in March and the PJM capacity auction in May. **Our favorite names to play the EPA activity are upgraded FE-AYE and Outperform RRI**. Highlights:

- **50+ GW of coal plant closures realistic.** Our base case assumes ~60 GW of coal plant closures within a total US fleet of 340 GW where 103 GW have no environmental controls and an additional 58 GW lack scrubber units key to mercury emission reductions.
- **Compliance expected from 2013-2017.** We assume delays to EPA's mandated 2015 compliance targets to reflect agency discretion and the logistical reality of replacing and upgrading so much capacity; that said, we think closures start in 2013 in response to new rules but also in acceptance that today's forward commodity prices leave many plants uneconomic before trying to cover new capex obligations.
- **$70-100 BN Capex for compliance or replacement.** We see significant investment to upgrade existing non-compliant plants and maintain regional 15% reserve margins. Higher capex will support higher structual growth opportunities for regulated utilities.
- **Reshaping fuel demand.** Coal plant retirements could lower steam coal demand by 157-324 MM tons per year (15-31%). With natural gas generation as a replacement option, demand from a 22 TCF base could grow 1.8-3.7 TCF (+8-16%) with an incremental 1.2-2.5 TCF (+5-10%) to meet 5-year power demand growth depending on generation mix.
- **Markets most impacted** will be MISO, SERC, PJM-West, and SPP, accelerating reversion to 15% reserve margins. Merchant plants in Eastern MISO and PJM-W should be the biggest winners with limited benefit in PJM-E, NEPOOL, and NYISO.
- **A 4–5 year acceleration to power market recovery.** We see EPA policy accelerating the tightening of market conditions and rebound in generation earnings by 4- 5 years, making the recovery more "investible".

Executive Summary

We think the proposed and expected rules from the EPA to lower coal plant emissions of sulfur dioxide (SOx), nitrogen oxide (NOx), mercury (Hg), and other hazardous air pollutants (HAPs) will be a significant turning point in the outlook for both merchant power plants and vertically integrated regulated utilities. The EPA rules for reducing coal plant emissions will come in two discrete rules: CATR (Clean Air Transport Rule) to shape SOx and NOx emissions and a MACT (Maximum Achievable Control Technology) rule to address mercury and other HAPs (Exhibit 1).

The CATR and MACT rules from EPA should represent a turning point for power market fundamentals

With these rules we see the need for a combination of closing non-compliant plants and making significant capital investment in others to reach compliance; either way, supply-demand fundamentals will tighten from the oversupplied conditions we see today that have contributed to depressed power prices and generator earnings.

Merchant plant closures will improve supply-demand and longer-term could help commodity prices

- For competitive power generators, the EPA rules will help to fix one of the three legs of the power investment thesis – power market supply – and could eventually help to fix another – commodity prices – by shifting the mix of power supply toward more natural gas fired generation that will increase demand (and likely pricing) for natural gas while lowering demand for domestic steam coal.
- For regulated utilities, we see the EPA rules creating an earnings growth opportunity as companies attend to their higher emitting plants through a combination of newbuild construction (we assume natural gas plants) and environmental capex to retrofit existing coal plants. Annual growth rate could increase by 1- 4% to comply with the rules depending on utility.

Regulated Utility EPS growth rates could increase 1-4% by utility

We appreciate making investment decisions on expected governmental policy carries some valid reasons for concern but think the EPA actions are more 'viable' than past expectations around Congressional action on climate change (carbon) or renewables since this EPA 'event' is mostly about enforcement of existing laws where the health and societal good benefits are of limited debate at this point. We think the industry will run into logistical challenges in meeting the EPA's proposed timelines while ensuring system reliability, leading us to assume an additional two years for compliance although we think the reprieve will be predicated on an actionable plan by owners (meaning that they will need to be busy during the entire process and can't just wait until final compliance date).

We see EPA as lower risk policy investing than waiting on Congress

Exhibit 1: EPA Calendar

RPM Auction Year	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
CATR		Apr 2011 Final Rule					
CATR	7/10/2010 CATR proposed	Compliance Period				2 Year Extension Period	
Mercury MACT		3/16/2011 Draft Rule 11/16/2011 Final Rule	Compliance Period			2 Year Extension Period	

Source: EPA, Company data, Credit Suisse estimates

Prefer Cleaner Generators in Dirtier Markets

The most compelling investment opportunities in our view will come in the de-regulated power markets where the EPA rules will help to accelerate a rebalancing in supply-demand fundamentals with particular help in regions where less remediated coal plants are common, leading us to the mantra of 'buy cleaner power generators in dirtier markets'.

Favored Integrateds are FE / AYE, IPP is RRI, Regulateds are AEP, DTE and SO

Of this, we prefer Outperform rated FirstEnergy (FE), Allegheny (AYE) and are interested in Neutral rated Exelon (EXC) amongst the Integrateds and RRI Energy (RRI) amongst the IPPs. We see good opportunity for rate base growth in coal heavy regulated utilities like AEP, DTE, SO, and CMS where considerable capex will be required although the key to retaining value for all utilities will be successful management of the regulatory process.

For the Competitive Power stocks we are updating our earnings estimates to incorporate our new baseline assumption that 60 GW of small coal plants lacking significant environmental controls are closed nationally. We do not see significant upward estimate moves until 2013 given existing hedges in place and our view that closures will be spread over 2013 – 17 time period. The biggest upside to estimates will come at FE–AYE ad EXC. Our new price targets incorporate this scenario, partly offset by a lower impact from carbon emission rules in light of the current political environment and environmental prioritization at EPA on these more readily addressable pollutants.

Integrateds with the most earnings leverage to policy are EXC, FE, and AYE but not starting until 2013

Exhibit 2: **Earnings Estimates New versus Old**

	2010	2011	2012	2013	2014	2015	2010	2011	2012	2013	2014	2015	2010	2011	2012	2013	2014	2015
AYE	1,207	1,284	1,147	1,161	1,335	1,485	1,227	1,248	1,071	1,187	1,501	1,696	2%	-3%	-7%	2%	12%	14%
D	4,958	4,849	5,054	5,424	5,607	5,905	4,959	4,779	4,970	5,464	5,744	6,111	0%	-1%	-2%	1%	2%	3%
EIX	3,779	3,987	3,913	4,223	4,590	4,851	3,684	3,879	3,907	4,299	4,732	5,013	-3%	-3%	0%	2%	3%	3%
ETR	3,829	3,856	3,815	3,817	3,810	3,900	3,728	3,713	3,639	3,719	3,737	3,834	-3%	-4%	-5%	-3%	-2%	-2%
EXC	5,966	6,128	5,282	5,349	5,481	5,856	5,966	6,077	5,209	5,542	6,156	6,874	0%	-1%	-1%	4%	12%	17%
FE	3,329	3,545	3,406	3,463	3,667	3,734	3,292	3,362	3,311	3,593	3,939	4,218	-1%	-5%	-3%	4%	7%	13%
NEE	4,787	4,944	5,451	5,778	6,058	6,435	4,787	4,939	5,402	5,764	6,045	6,432	0%	0%	-1%	0%	0%	0%
PEG	3,705	3,719	3,723	3,947	4,175	4,373	3,767	3,790	3,734	4,092	4,455	4,633	2%	2%	0%	4%	7%	6%
Average													-1%	-2%	-3%	1%	5%	7%
RRI	317	354	362	411	496	543	293	334	390	460	612	696	-7%	-6%	8%	12%	24%	28%

	Old EPS						New EPS						% Change					
	2010	2011	2012	2013	2014	2015	2010	2011	2012	2013	2014	2015	2010	2011	2012	2013	2014	2015
AYE	2.09	2.27	1.65	1.67	2.21	2.74	2.16	2.21	1.40	1.77	2.81	3.57	4%	-3%	-15%	6%	28%	30%
D	3.40	3.28	3.32	3.53	3.61	3.83	3.41	3.21	3.23	3.58	3.76	4.05	0%	-2%	-3%	1%	4%	6%
EIX	3.34	3.29	2.71	2.93	3.36	3.58	3.30	3.05	2.72	3.08	3.67	3.94	-1%	-7%	0%	5%	9%	10%
ETR	6.69	6.94	6.72	6.53	6.60	7.04	6.69	6.89	6.55	6.64	6.80	7.26	0%	-1%	-3%	2%	3%	3%
EXC	3.93	3.99	3.10	3.00	2.98	3.18	3.93	3.94	3.03	3.18	3.61	4.16	0%	-1%	-2%	6%	21%	31%
FE	3.65	3.62	3.29	3.37	3.75	3.87	3.66	3.35	3.19	3.74	4.43	5.03	0%	-7%	-3%	11%	18%	30%
NEE	4.45	4.42	4.69	4.78	5.18	5.74	4.45	4.41	4.62	4.75	5.16	5.73	0%	0%	-2%	0%	0%	0%
PEG	3.09	2.95	2.88	3.13	3.49	3.86	3.05	2.88	2.79	3.22	3.76	4.12	-1%	-2%	-3%	3%	8%	7%
Average													0%	-3%	-4%	4%	11%	14%

Source: Company data, Credit Suisse estimates

Exhibit 3: **Target Price New vs Old**

	Target Price			Tot. Return			Rating	
	Old	New	% Chg	Div Yield	Old	New	Old	New
AYE	$23.00	$28.00	22%	2.6%	1.5%	23.0%	N	O
D	$37.00	$39.00	5%	4.1%	-12.2%	-7.6%	N	N
EIX	$37.00	$37.00	0%	3.6%	9.9%	9.9%	N	N
ETR	$86.00	$81.00	-6%	4.3%	15.9%	9.4%	O	N
EXC	$46.00	$47.00	2%	4.9%	12.1%	14.4%	N	N
FE	$41.50	$43.00	4%	5.9%	17.9%	21.9%	N	O
NEE	$58.00	$58.00	0%	3.7%	10.5%	10.5%	O	O
PEG	$36.00	$36.00	0%	4.2%	15.3%	15.3%	N	N
RRI	$5.50	$6.00	9%	0.0%	58.5%	72.9%	O	O

Source: Company data, Credit Suisse estimates

Table of contents

Report Highlights

In the full length report we walk through the major issues around EPA policy in detail to provide greater context and data behind our observations and conclusion. Below are the key takeaways from our analysis:

The US Coal Fleet – What's at Risk?

See page 20 for more

We can realistically envision coal plant retirements in response to EPA rules exceeding 50 GW (50,000 MW) on the installed 340 GW fleet with another ~100 GW requiring fairly hefty investment to meet anticipated EPA emissions rules. We assume the EPA's targeted compliance dates of late 2014 / early 2015 will be ultimately extended by another 2 years to allow for the logistical challenges of meeting compliance targets (the investment projects are large and time consuming) as well as to support system reliability during the implementation process. With this time frame we assume a ratable closure of plants over the 2013-2017 period as we think the upside down economics of today's commodity price curves for natural gas and coal will lead owners to start retiring projected money losing plants earlier rather than running at a loss until the final days of the enforcement period.

We assume 60 GW of coal capacity will be closed in 2013 – 17 time period

A little more detail on these thoughts:

Today's coal fleet

Coal generation is a vital electricity resource for the US, accounting for just over half of all electricity produced. Unfortunately, the fleet is getting old (Exhibit 4) with many of the plants lacking the environmental controls necessary to meet future EPA compliance rules meaning shut-down or significant equipment upgrades will be required.

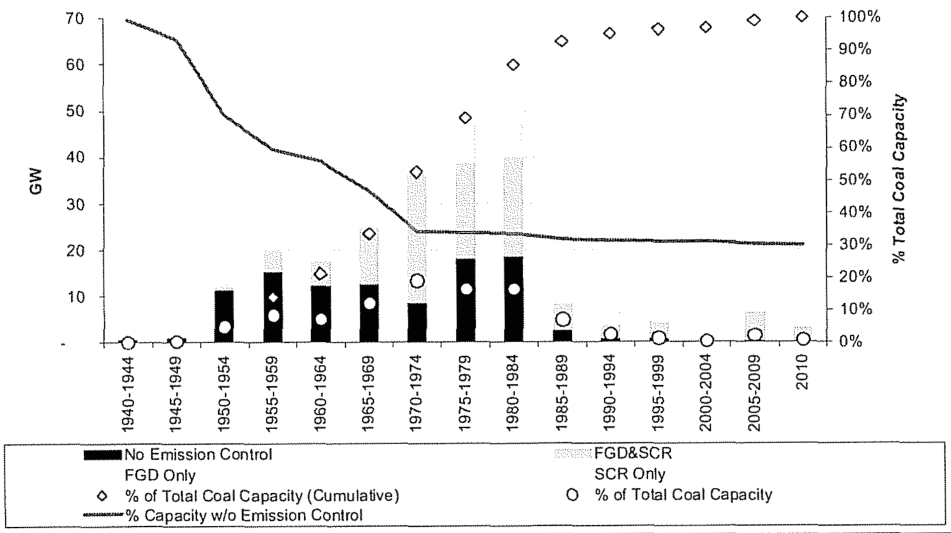
After including the 26 GW of planned upgrades over the next 5 years, the 340 GW US coal fleet will still have 103 GW lacking any major emission controls, 65 GW having a scrubber but not a SCR, 58 GW having a SCR but not a scrubber, and 115 GW having all major control equipment.

103 GW of 340 GW US coal fleet lack any emission controls

As an easy measuring stick for plant vulnerability, we focus on scrubber installations (aka FGD or flue gas desulfurization unit) since this is the most broadly effective tool for lowering mercury emission levels to meet mercury MACT standard which targets emission rates consistent with the best 12% of the fleet, or about a 90% removal rate. We see 161 GW, or 47% of the total US coal fleet, lacking scrubbers with many likely exposed to some heightened level of capital investment for scrubbers or other alternative compliance options to meet mercury reduction targets; if not, the plants look vulnerable to closure.

161 GW coal plants lack scrubbers which is a key tool for mercury reduction

Exhibit 4: Coal Plant Vintage (Including Planned Emission Control)



Source: Energy Velocity, Company data, Credit Suisse estimates

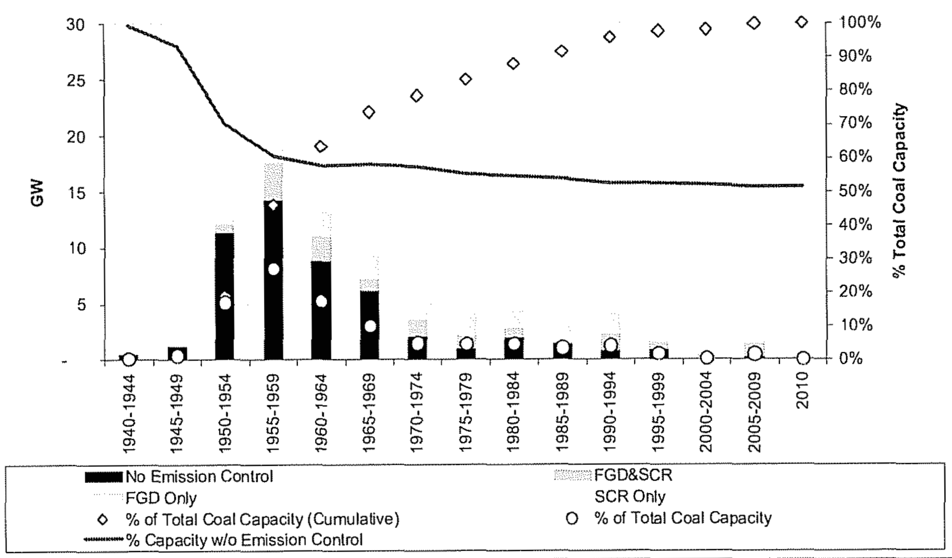
We expect part of the US coal fleet 'at risk' to be closed and part for owners to invest the capital in environmental control equipment to keep the plant going. In Exhibit 5 we narrow our focus to just look at the 'small' coal plants (<300 MW of capacity). We think this subset is important because they are the hardest to economically justify for large equipment upgrades in part because the environmental control costs are non-linear (they're more expensive on a unit of capacity basis at a small coal plant) and because these plants are generally older and less efficient in energy conversion which further strains the economic justification for reinvesting large amounts of capital.

Small coal plants are a more vulnerable subset

Of the small fleet, 50 GW are over 40 years old and have no environmental controls; if we broaden the conversation to plants lacking scrubbers, the fleet at risk grows to 69 GW (or 20% of the total US coal fleet). When we think about the fleet at risk for retirement, we find comfort in a 60 GW closure baseline in large part from the small plants at risk with the realization some will survive but many plants over 300 MW will instead face closure for equally challenged economics.

...with 69 GW lacking scrubbers of which 50 GW have no emission controls

Exhibit 5: Small Coal Plant Vintage (Including Planned Emission Control)



Source: Energy Velocity, Company data, Credit Suisse estimates

Weak forwards make investment even harder to justify

If the EPA rules were not bad enough for coal generators, we think a large chunk of the US coal fleet is vulnerable to closure simply due to crummy economics where we see coal pricing at a premium to natural gas out the forward curve when adjusting on an electricity equivalent basis (Exhibit 6 and Exhibit 7). Awful energy margins suggest to us that owners should be reevaluating their coal fleets due to pure energy economics before even taking on the burden of a capex for environmental control equipment.

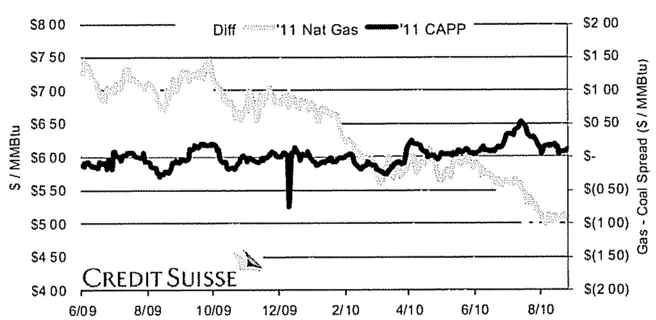
Forward coal and natural gas prices leave many coal plants uneconomic today

We have seen some operators already make this decision but many have ignored this economic reality, in our minds reflecting a combination of (a) eternal optimism that commodity prices will revert to benefit coal plants (b) coal plant dispatch decisions being made on realized commodity prices that benefit from legacy in the money hedges for both coal and transport that defers the reality of poor economics for a time and (c) some fading hope that carbon or other US policy would deliver a set of incentives to close plants and therefore less urgency to do so without remuneration.

...lending comfort to idea that closures will come before the "last possible moment" for EPA compliance

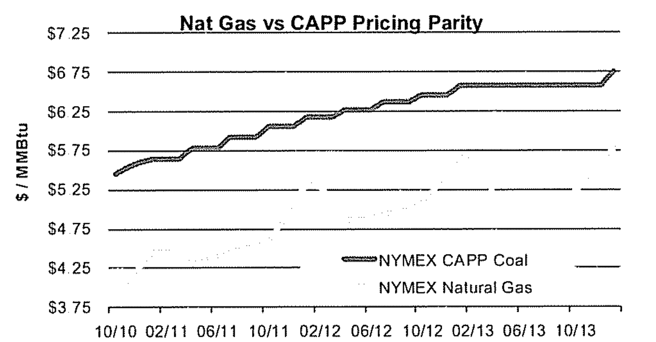
In contrast to many who think generators will wait until the last possible moment to close at risk coal plants, we think owners will be more motivated to close plants as they realize that the environmental capex obligations are unavoidable and the realized / projected energy margins are inadequate to justify running the plants (before they try to afford the capex). Clearly some game theory will exist for plants that are 'on the bubble' as owners wait for others to close which should improve market pricing but we see a realistically healthy chunk of the fleet 'under the bubble'.

Exhibit 6: **2011 CAPP Coal / NYMEX Natural Gas Parity**



Source: Company data, Credit Suisse estimates

Exhibit 7: **2010 – 13 Gas vs CAPP Pricing Parity**

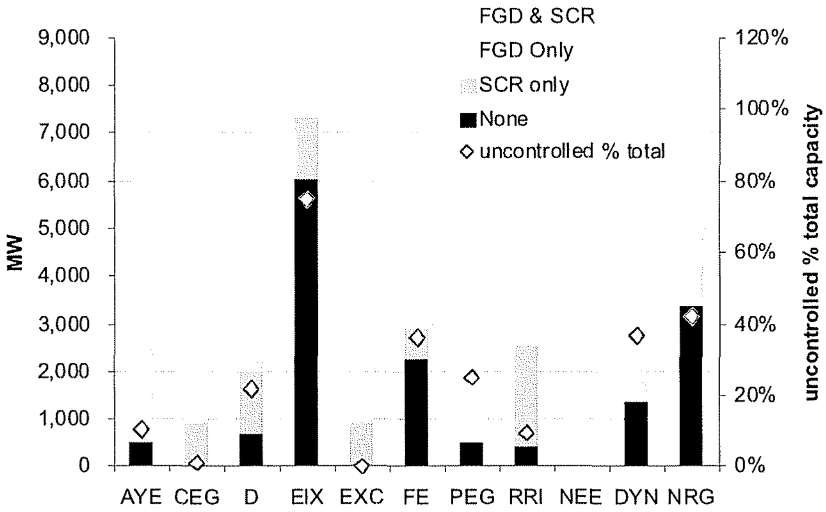


Source: Company data, Credit Suisse estimates

Whose Plants are at Risk?

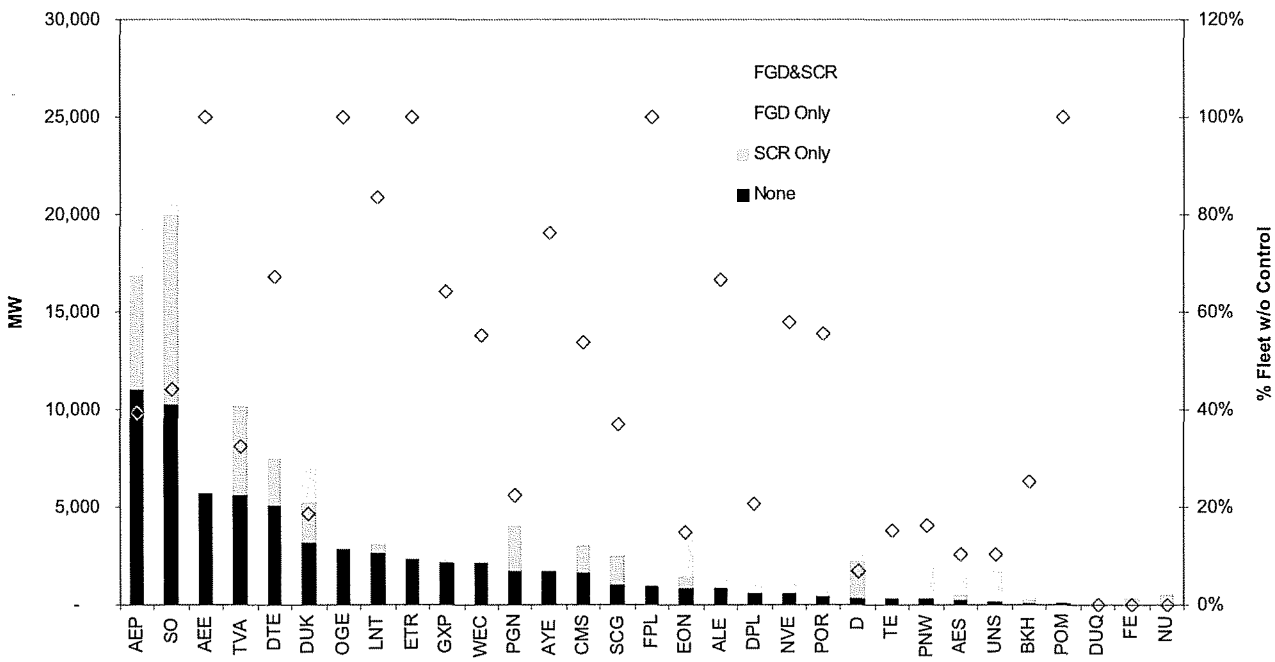
We see the company specific implications of EPA policy as interesting when considering that 15-30% of the US coal fleet is at risk of either closure or needing significant capex to stay in operation. In Exhibit 8 and Exhibit 9 we show the merchant and regulated plants, respectively, by company that we think will require attention. In Appendix IV of the appendix note to this report we show the plant by plant breakdown of each company's existing coal fleet including vital statistics like capacity, output, existing controls, etc.

Exhibit 8: **Integrateds Companies Coal Plants Capacity By Emission Control**



Source: Energy Velocity, Company data, Credit Suisse estimates

Exhibit 9: **Regulated Coal Plants Capacity By Emission Control**



Source: Energy Velocity, Company data, Credit Suisse estimates

For Merchant plants, EIX and NRG face the most gross MWs needing attention with decisions balanced between energy margins and viable compliance alternatives.

For the Regulateds, AEP, SO, and DTE will have the most work to do as far as upgrade or replacement decisions. As a percentage of existing regulated coal fleet, the most work will be at AEE and OGE.

We think the implications of coal plant vulnerability will vary widely with the regulated utilities seeing the investments as positive to rate base and earnings growth (see below).

For the merchants, the loss of capacity will be a headline concern but we interestingly see closures as an opportunity for the operators since (a) the small plants are generally low earnings contributors and (b) tightening market conditions will boost energy and capacity revenues for the surviving fleet, creating a net benefit to earnings.

Lots of Capex to Come

See page 42 for more

The obligation to either replace or retrofit such a large piece of the power generation fleet will require considerable capital investment above and beyond the industry's already elevated spending level. We see total investment this decade to meet EPA compliance realistically in the $70-100 BN range with a wider range depending on assumptions around cost to comply and decisions between retrofit versus newbuild; the range jumps to $110-150 BN if we assume plants lacking scrubbers will also need to be addressed (Exhibit 10). Looking to the regulated utility capex obligations that will drive rate base and earnings growth, capex could be in the $50-70 BN range, $80 -110 BN when tacking on plants without scrubbers (Exhibit 11).

Overall capex for upgrades and replacement could be $70 -100 BN of which $ 50 – 70 BN could be at regulated utilities

Beyond the impact and opportunity for power generators, this elevated level of spending should create opportunities for Engineering and Construction (E&C companies) as they take on the construction projects that will inevitably happen.

Watch for E&C company opportunities

Exhibit 10: **Capex Requirement (Retrofit / Replace Un-Controlled Coal Plants)**

$ BN	% of Coal Plants with No Emission Control to Retrofitted					
Blended Emission Control Cost	$/KW	0%	25%	50%	75%	100%
	300	115	96	77	57	38
	350	115	97	80	62	45
	400	115	99	83	67	51
	450	115	101	86	72	57
	500	115	102	89	77	64
	550	115	104	93	81	70
	600	115	105	96	86	77
	650	115	107	99	91	83
	700	115	109	102	96	89

Source: Company data, Credit Suisse estimates

Exhibit 11: **Capex Requirement (Retrofit / Replace All Un-Controlled Regulated Coal Plants)**

$ BN	% of Coal Plants with No Emission Control to Retrofitted					
Blended Emission Control Cost	$/KW	0%	25%	50%	75%	100%
	300	89	74	59	44	30
	350	89	75	62	48	35
	400	89	77	64	52	39
	450	89	78	67	56	44
	500	89	79	69	59	49
	550	89	80	72	63	54
	600	89	81	74	67	59
	650	89	83	77	70	64
	700	89	84	79	74	69

Source: Company data, Credit Suisse estimates

Demand for Natural Gas and Coal Likely to Change

See page 60 for more

A clear carry through impact to the commodity and equity markets will come with a rebalancing in the mix of electricity production in the US as coal plants face retirement with replacement coming primarily from natural gas fired plants. As we discussed above, not only do the coal plants face capital obligations but the forward curves today show the plants as disadvantaged relative to gas plants.

Fuel mix for the Power industry will change

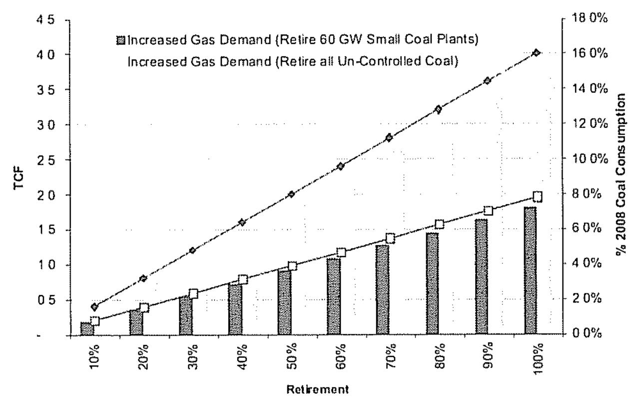
Looking at the shift in demand for natural gas and coal under our two scenarios – one that 60 GW of coal is retired and the other that all plants lacking both scrubbers and SCRs are closed at 103 GW – would point to a significant redistribution in energy demand for electricity generation.

Steam coal demand could fall by 15-31% with implementation

In Exhibit 13, coal demand in turn would fall by 157-324 MM tons annually on an Eastern equivalent tonnage basis, representing a 15 -31% drop in steam coal demand. In Exhibit 12, natural gas demand would increase in the 1.8 - 3.7 TCF / year range (7.8 -16.0% to current demand) over next 5 – 7 years just from the coal retirement cycle (before taking into account market share gains with future demand growth). Even more interesting to us, when we take into account natural gas needed to meet future power demand growth we

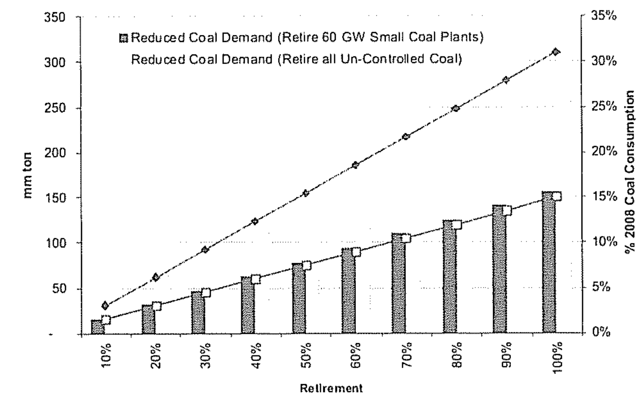
Overall natural gas demand could grow by 8-16% with plant closures on top of 5-10% growth to meet electricity demand growth could area another 1.2 – 2.5 TCF in 7 years, bringing total change in natural gas demand from the power sector to 3.0 – 4.3 TCF under the 60 GW retirement scenario (Exhibit 14 and Exhibit 15).

Exhibit 12: Natural Gas Demand Increase From Coal Plant Closure



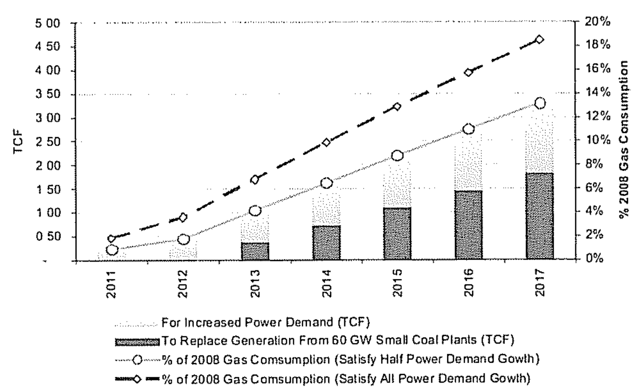
Source: Company data, Credit Suisse estimates

Exhibit 13: Coal Demand Decrease from Coal Plant Closure



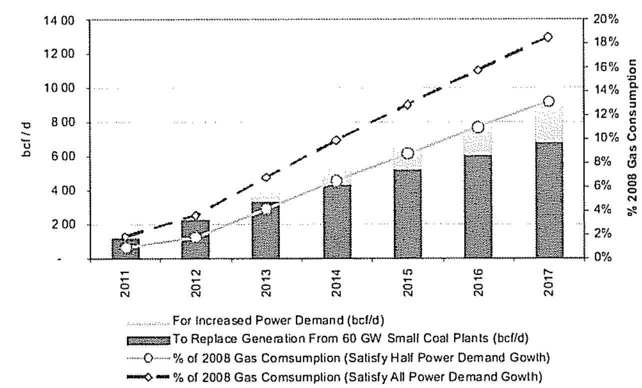
Source: Company data, Credit Suisse estimates

Exhibit 14: Increase in Gas Demand from both Coal Plant Closures and Power Demand Growth (TCF)



Source: Company data, Credit Suisse estimates

Exhibit 15: Increase in Gas Demand from both Coal Plant Closures and Power Demand Growth (bcf/d)



Source: Company data, Credit Suisse estimates

Merchant Earnings Broadly Higher with Some Outsized Winners

See page 53 for more

We could see broad based opportunity for the power generators with enforcement of the EPA rules mostly through tightening power markets that will support higher energy and capacity prices (where available). The upside will come through both a shift to higher cost plants setting the marginal price of electricity as well as a willingness to wait for the 'right' pricing signals before building new assets (most visibly with higher capacity prices), a situation that does not exist in the market today.

EPA policy will lead to tighter power markets and faster return to replacement cost economics

Our scenarios

To appreciate the market impact we ran three discrete scenarios in our economic dispatch model (supply-demand) that is built up by plant and by region on an hourly basis, allowing us to better appreciate the changes in both plant utilization and marginal plant dispatch economics that set market clearing power prices.

We also believe this approach adds to the robustness of the closure impact conversation since we see the net benefits to generators of tightening markets standing as more beneficial than the impact to them of retiring some marginal power plants. We think most EPA conversations have been too narrow in scope to talk about who is at risk due to losing capacity rather than appreciating the lift that will come to the surviving power plants. Our scenarios are:

- 35 GW are closed, representing half of the small coal fleet today that lacks scrubbers
- 60 GW are closed, representing all of the small coal plants having no environmental controls plus half of the small plants that have SCRs but no scrubbers
- 103 GW are closed, representing all the coal plants that have no environmental controls but assumes plants with either just a scrubber or just a SCR are retrofitted

We are using the 60 GW closure scenario for our updated earnings estimates which we think more reasonably captures the likely decision tree for operators. For the competitive generators we also ran this scenario on a mark-to-market (MTM) basis as well using current commodity price forwards. We are reluctant to use value the MTM scenario because we think changing market conditions will ultimately support somewhat different price outcomes.

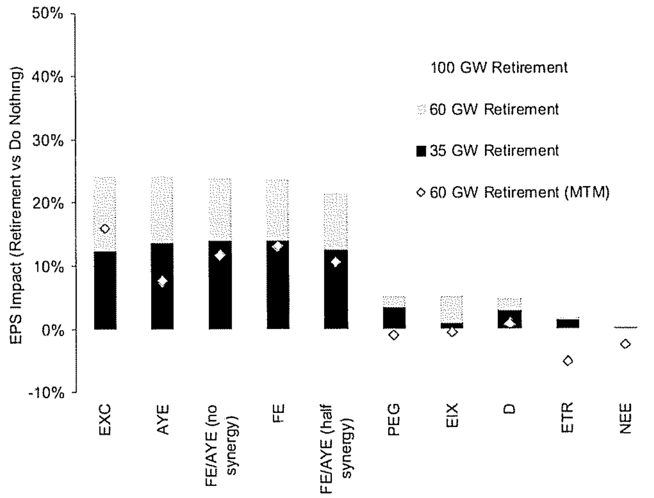
Earnings estimate implications

The most significant mantra to take from this EPA analysis is to own cleaner generators in dirtier markets, which we see as those with nuclear, CCGTs, and remediated coal plants in markets where coal is more commonly on the margin and in turn vulnerable to closure. From our earnings estimate runs, we see the biggest EPS benefits coming at FE-AYE, EXC, and RRI while the most indifferent stocks to EPA policy include NEE, ETR, and PEG as shown in Exhibit 16 and Exhibit 17.

Own "cleaner" generators in "dirties" markets

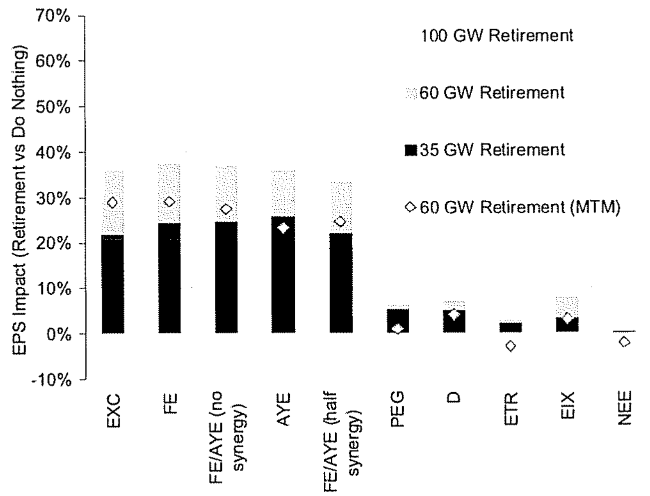
In Appendix III we show the earnings and share price implications for the different scenarios in the future.

Exhibit 16: **2014 EPS Impact from Coal Plant Retirements**



Source: Company data, Credit Suisse estimates

Exhibit 17: **2015 EPS Impact from Coal Plant Retirements**

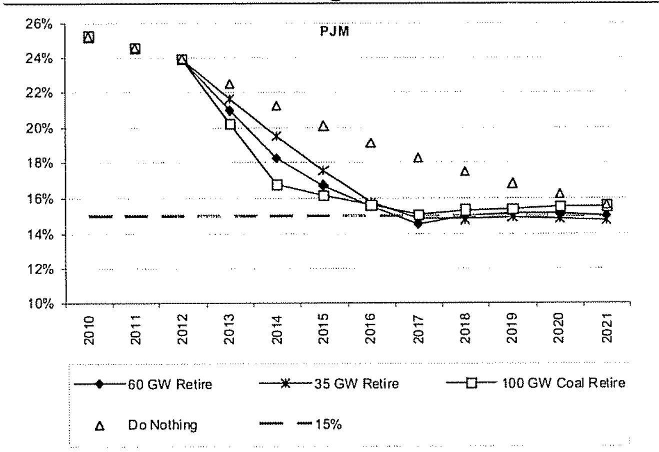


Source: Company data, Credit Suisse estimates

We should point out that EPA policy is in many ways just an acceleration in tightening power markets that we would have expected to occur over time (Exhibit 18 and Exhibit 19); the upside for the stocks is that the tangibility of closures and nearness in time to see benefit in earnings estimates will help investors, in our opinion, become more willing to pay for the recovery story in the deregulated power markets rather than obsessing over troughing earnings in 2012 and currently depressed commodity prices.

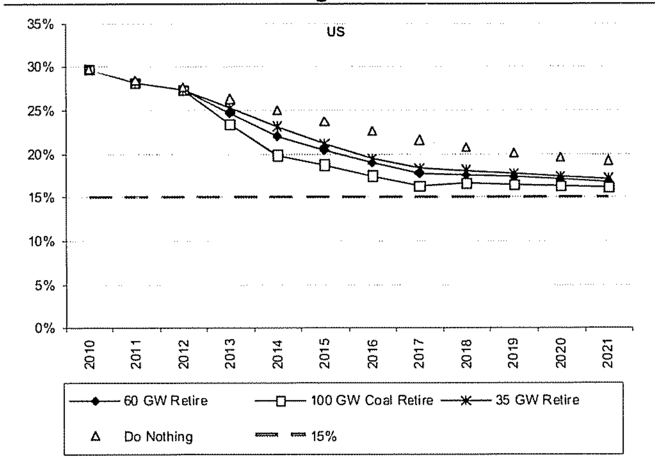
EPA rules simply accelerate an inevitable market tightening by 4- 5 years, making a recovery more investible

Exhibit 18: **PJM Reserve Margin**



Source: Company data, Credit Suisse estimates

Exhibit 19: **US Reserve Margin**



Source: Company data, Credit Suisse estimates

Regulateds: Rate Base Growth Opportunity Ahead

See page 57 for more

EPA policy could boost utility EPS growth rate by 1 – 4%

We find it easy to get caught up in the excitement of tightening deregulated power markets and simply overlook the opportunity (and maybe threat for some) to come with the new EPA rules that will necessitate either environmental capex or newbuild construction to ensure system reliability.

In Exhibit 20 we show the MWs of capacity exposed to EPA rules for each of the Regulated Utilities, splitting to show all plants lacking environmental equipment and then narrowing to show the small plants that lack equipment and more at risk to requiring new plant construction.

Regulated utility winners could be GXP, OGE and DTE although fair regulatory treatment is vital for value accretion

We can then convert the potential investment into an earnings growth opportunity over the next five years in Exhibit 20, assuming $600 / KW for environmental capex on the over 300 MW units and $900 / KW for new CCGTs to replace the smaller coal plants, using an earned ROE of 9.5% and taking into account equity dilution to fund the construction cycle maintaining a generic 50% equity layer. We appreciate that not all closed MWs will need to be replaced since many utilities have reserve margin headroom today but we think the earnings impact is illustrative of where the trend will be headed.

Using these inputs we see a potential equity issuance adjusted bump in annual EPS growth rates by 1 – 4% for the group.

Exhibit 20: **Regulated Utilities MWs exposed to EPA policy and EPS Impact**

	Generation Mix		Implied Capital Expenditures				EPS Impact			
	Un-Scrubbed Plant (Not Inc. Planned Emission Ctrl)		Replace Small Plant with CCGT $900/kW	Retrofit Big Plant $600/kW	Total Implied Capex	% Net PPE	Incremental Diluted EPS	5-Year EPS CAGR	7-Year EPS CAGR	Cumulative Earnings Growth
Ticker	Small (MW)	Large (MW)	$MM	$MM	$MM	(%)	$ / Share	%	%	%
ALE	518	365	466	219	685	42%	0.83	3.8%	2.7%	20.6%
GXP	759	1,400	683	840	1,523	23%	0.46	3.1%	2.2%	16.5%
LNT	1,210	1,425	1,089	855	1,944	33%	0.75	3.1%	2.2%	16.5%
OGE	-	2,854	-	1,712	1,712	29%	0.76	3.1%	2.2%	16.4%
AEE	564	5,090	508	3,054	3,561	20%	0.63	3.1%	2.2%	16.3%
DTE	1,661	3,391	1,495	2,034	3,530	28%	0.91	3.0%	2.1%	15.9%
AEP	4,402	6,632	3,962	3,979	7,941	23%	0.72	2.7%	2.0%	14.5%
XEL	805	4,117	724	2,470	3,194	17%	0.32	2.7%	1.9%	14.1%
SO	5,259	4,970	4,733	2,982	7,715	20%	0.43	2.7%	1.9%	14.1%
WEC	1,715	419	1,543	251	1,794	20%	0.70	2.6%	1.9%	13.9%
CMS	1,236	404	1,112	242	1,355	14%	0.25	2.6%	1.8%	13.5%
EON	443	446	399	268	667	1%	0.02	2.4%	1.7%	12.5%
SCG	1,061	-	955	-	955	11%	0.36	2.2%	1.6%	11.7%
NVE	576	-	518	-	518	6%	0.11	2.2%	1.6%	11.4%
DPL	414	230	373	138	511	18%	0.21	2.2%	1.6%	11.4%
POR	-	391	-	234	234	6%	0.15	2.1%	1.5%	11.0%
AYE	532	-	479	-	479	5%	0.14	2.1%	1.5%	10.9%
UNS	173	-	156	-	156	6%	0.19	2.0%	1.4%	10.5%
ETR	2	2,352	2	1,411	1,413	6%	0.37	2.0%	1.4%	10.3%
DUK	2,657	560	2,391	336	2,727	7%	0.10	2.0%	1.4%	10.3%
AES	302	-	271	-	271	1%	0.02	2.0%	1.4%	10.3%
PGN	747	964	672	579	1,251	6%	0.21	1.9%	1.3%	9.8%
TE	326	-	294	-	294	5%	0.07	1.9%	1.3%	9.8%
BKH	125	-	112	-	112	5%	0.14	1.9%	1.3%	9.7%
PNW	312	-	281	-	281	3%	0.13	1.8%	1.2%	9.1%
NEE	-	952	-	571	571	2%	0.07	1.7%	1.2%	8.9%
D	367	-	330	-	330	1%	0.03	1.5%	1.1%	7.6%
TVA	5,634	-	5,071	-	NA	NA	n/a	n/a	n/a	n/a
Total	31,872	36,961	28,685	22,177	45,791	10%		2.3%	1.6%	11.9%

Source: Energy Velocity, Company data, Credit Suisse estimates

We see the biggest incremental EPS growth opportunity coming at GXP, AEE, and DTE although effectively managing the regulatory process in a way that allows for timely recovery of capex will be vital to converting this investment opportunity into shareholder value. We will need to focus on the environmental capex mechanisms on a jurisdictional basis as plans are crafted by utilities to address the EPA rules.

Risks to Today's Investment Thesis

We appreciate that changes in estimates and industry outlook based on proposed and expected policy changes does engender some level of risk that the world does not play out exactly as we expect. Below we address some of the major issues that could still come up and work against the thesis.

Congressional intervention with comprehensive pollutant rules

Congress has taken up several attempts in the past to execute comprehensive energy legislation to broadly address airborne pollutants. Some believe that EPA's actions are simply to spur Federal action but it remains evident to us that Congress is nowhere near passing competing legislation. If we see Congress get involved, we think the effort will be more reactive to uproar from the coal producers and coal generators although this feels unlikely until the rules are effective, at which point we think a healthy chunk of the stock investment opportunity will be reflected in the stocks.

Separately, and not to be confused with today's SOX, NOX, and mercury conversation, the EPA has also started down the path toward regulating greenhouse gases / carbon (also commonly referred to as 'stationary sources'). Given today's low popularity for carbon rules we could see more Congressional intervention on this topic than the other airborne pollutant rules that have been on the books for years.

That said, a potential point of disruption could come from a new Congress putting limits on the EPA's budget that could impede implementation of the CATR and MACT rules although we will wait to see how much momentum this effort actually takes; our gut tells us budgetary defunding of programs will be targeted on other more highly politicized fronts.

EPA extends timeline for enforcement which we already assume.

We see some limits to the EPA's ability to delay rule implementation based on how the Clean Air Act was written and have doubts whether the administration will be in a rush to abandon another environmental lobby initiative. But, as we show in Exhibit 1, we do assume that compliance with the CATR and MACT rules will be extended beyond the legally set dates primarily for logistical and reliability reasons. And, as discussed on page 8, we also think that the dismal forward curves for commodities will provide adequate motivation for some to start closing plants earlier even if the EPA offers more timing headroom.

Use of Lesser Remediation Methodologies to meet Standards.

A few companies are pursuing cheaper remediation approach with a combination of PRB coal / baghouse / ACI / SNCR / TrONA (see page 28 for more). We can envision more uptake of this approach assuming early adopters are able to consistently demonstrate adequate pollutant removal rates but the capital costs are still not insignificant (albeit less than the scrubber / SCR / ACI approach) such that a large part of the fleet will still not be well suited for even making this investment in the current commodity price environment.

Courts remand the rules, again

We expect many lawsuits to be filed after the rules go effective (no lawsuits before) but the EPA appears to be within their legal bounds (and are actually legally obligated to take such action). We remain cautious of the litigation risk but are doubtful about injunctive relief to blockage the rules since: (a) we did not see last time with passage of CAIR (CATR's predecessor); and (b) enforcement of pollutant reduction was not the focus of last remand; the courts issues with the rules had much more to do with design and stringency than appropriateness.

Natural Gas Price Recovery

Many factors could lead to rapid natural gas price recovery, including: increased demand (see page 62 for more), natural disaster, decreased production, increased shale drilling regulations. We appreciate that all of these factors could swing the economics in such a way that reinvestment in the coal plants will trump plant closures, but in that environment we see the stocks working on a rise in power prices. Interestingly, the generators best levered to EPA policy are also the ones with the most earnings leverage to higher natural gas prices allowing the investments to win, even if for the wrong reasons.

Game Changing Technology

We believe recent heightened interest in energy efficiency, new generation methodology (like Bloom Box), evolving renewable resources, and innovative approaches to environmental remediation could all eventually significantly change power market dynamics as we view them today and the overall U.S. fleet composition. We are not aware of a game changing technology commercially at hand today, leading us to put a low probability that the thesis will not work because of some disruptive product introduction.

Definitions Tear Sheet

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MW (megawatt): a unit rate of energy conversion; 1 GW = 1000 MW; 1 MW = 1000 KW.

Plant Heat Rate: amount of fuel required to produce 1KWh of electrical output.

Market Clearing Heat Rate: marginal clearing energy price divided by natural gas price (ie Market Heat Rate = Marginal Power Price / Natural Gas)).

Reserve Margin: amount of unused available capacity of a power system.

Emissions of Concern from Coal Plants

Sulfur Dioxide (SOx): causes acid rain and atmospheric particulates

Nitrogen Oxide (NOx): causes brown haze and atmospheric particulates

Mercury (Hg): causes birth defects, central nervous and endocrine system damage

EPA Rules

CAIR (Clean Air Interstate Rule): *Issued 3/10/2005*; the predecessor **SOx** and **NOx** rule to CATR that was remanded back to the EPA due to its interstate trading program that did not adequately protect 'down wind' states. CAIR is still the ruling law until CATR is finalized.

CATR (Clean Air Transport Rule): *Proposed 7/6/2010 to be finalized 4/2011*; the to be successor of the remanded CAIR. CATR sets emission caps for **SOx** and **NOx** for 31 eastern states and DC and should satisfy the courts with its abandonment of intrastate trading (albeit fattened allowances for higher emitting states).

CAMR (Clean Air Mercury Rule): *Issued 3/15/2005*; a cap and trade program to reduce mercury by 70% that was vacated by courts due to its adapted approach not meeting Maximum Achievable Control Technology (MACT) standards as required by law .

MACT (Maximum Achievable Control Technology): A non-trading based standard that mandates targeted compliance equal to the top 12% of plants.

HAP (Hazardous Air Pollutant) MACT: *To be issued 3/2011 and finalized 11/2011*; a mercury aimed standard that is expected to require compliance levels set to no lower than the top 12% of plants, generally thought of as a ~ 90% removal level for Mercury.

Technology Remediation Choices

Eastern Coal: FGD / SCR / Activated Carbon:

- **FGD** (Flue Gas Desulfurization): a scrubber to remove **SOx** (>95% removal).
- **SCR** (Selective Catalytic Reduction): separates **NOx** into water and nitrogen and is then absorbed by a catalyst bed (>90% removal).
- **Activated Carbon**: a sorbent that bonds to **mercury** and is collected by the FGD (>90%).

Western Coal: Dry Sorbent Injection / SNCR / Baghouse / Activated Carbon:

- **DSI** (Dry Sorbent Injection): injects a dry sorbent like TrONA that bonds to **SOx** (40-70% removal traditionally; now nearing on 90%).
- **SNCR** (Selective non-catalytic Reduction): separates **NOx** into water and nitrogen but lacks absorbent catalyst bed (30% at low temperatures to 75% at high temperatures).
- **Baghouse**: fabric filter to collect particulates, including **TrONA** and Activated Carbon (99% removal).
- **Activated Carbon**: a sorbent that bonds to **mercury** collected by the baghouse (>90%).

Policy Is Coming

We appreciate EPA rules aimed at changing coal plant emissions, and in turn leading to mass closures, has been 'around the corner' for over a decade, leaving a natural level of skepticism. This time wont be any different. Our view is that the debate over the need for emission reductions or availability of viable remediation tools has been largely put to rest; the time for delays has come to an end plus the zeal in enforcement by the current Administration / EPA leadership should sustain forward progress on enforcement of rules written into law years ago. With court mandated deadlines for new rules quickly approaching, we think the industry and investors need to prepare and position for appreciably more stringent coal plant emissions rules for NOx, SOx, and Hazardous Air Pollutants (HAPs) that include mercury. Exhibit 21 shows the expected schedule for the new rules.

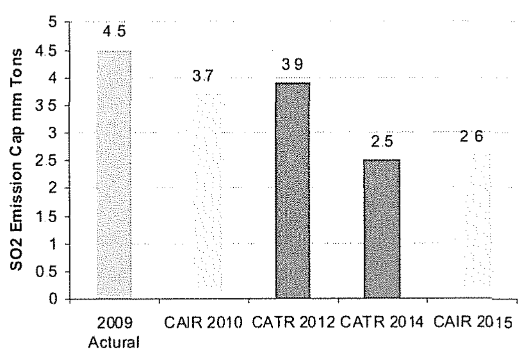
Exhibit 21: **EPA Calendar**

Timeline	Draft Rule	Final Rule	Compliance Date (Est.)	Compliance Date (Est.)
CAIR (NOx)	Jul-10	Apr-11	2012 / 2014	2 Years
CAIR (SOx)	Jul-10	Apr-11	2012 / 2014	2 Years
Mercury MACT	3/16/2011	11/16/2011	11/16/2014	2 Years

Source: Company data, Credit Suisse estimates

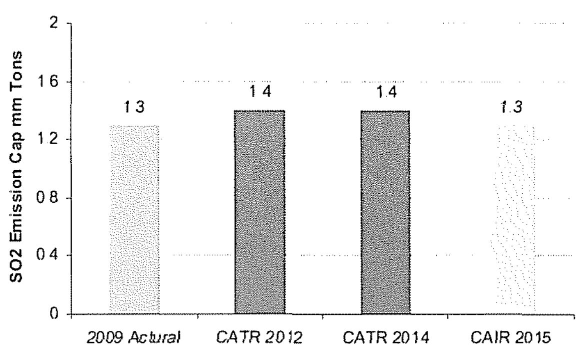
The EPA unveiled the Clean Air Transport Rule (CATR) on July 6, 2010, setting emission caps for SOx and NOx for 31 eastern states and DC. As shown in Exhibit 22 - Exhibit 23, the CATR rule imposes similar emission caps as Clean Air Interstate Rule (CAIR, which was challenged by environmentalists and remanded to EPA by the courts for re-write, hence the need for CATR) but with the target compliance date one year earlier (2014 vs 2015). We think compliance with the new rules will be a challenge for some but will ultimately not be the primary source of pain, in large part due to more readily available compliance alternatives as well as allowable trading of intrastate emission credits that could shield some plants.

Exhibit 22: **CATR vs CAIR for SOx Emission Cap (CATR states)**



Source: Company data, Credit Suisse estimates, EPA

Exhibit 23: **CATR vs CAIR for NOx Emission Cap (CATR states)**



Source: Company data, Credit Suisse estimates, EPA

The key piece of regulation in our opinion will be for Hazardous Air Pollutants, in particular mercury. The EPA is required by the courts to release a 'draft rule' on or before March 16, 2011, with a final rule expected by November 16^{th} that sets into motion a three-year grace period to become compliant - although slippage could always happen which we assume will give a two year extension for those moving forward on good faith basis. The coming EPA mercury regulation will be a national standard and will apply to each plant individually without a trading mechanism.

More importantly, as required by the Clean Air Act for Hazardous Air Pollutant, the mercury regulation will be MACT (Maximum Achievable Control Technology) based, requiring plant emission levels to be no higher than the average of the best 12% of the fleet, or a ~90% removal rate for mercury. The definition of "the fleet" is where we could see flexibility for the mercury rule as there could be multiple MACT standards for coal plants burning different types of coal or with different boiler technologies, which presumably could lower the reduction requirements for some coal plants but raise requirements for others.

How to lower emissions

The electric utility industry has been working diligently on SOx / NOx reduction since 2005 when CAIR took effect, albeit with less focus on mercury due to limited removal technologies and a longer dated compliance period relative to the original SOx / NOx rules. Nonetheless it looks to us the pending rules will be a significant turning point for the U.S. power markets which seems inevitable to be far reaching and penetrate both competitive and regulated markets.

As summarized in Exhibit 24, there are different emission control technologies for SOx / NOx with varying levels of capex / efficacy.

- We should point out that for plants burning eastern coal, scrubber (aka FGD, or Flue Gas Desulfurization unit) is the only solution for SOx reduction of more than 90%.
- In our opinion the MACT standard for mercury posts a bigger challenge for the US coal fleet, since 90+% mercury reduction has been traditionally considered possible only with a combination of scrubber, SCR, and activated carbon injection (ACI).
- Newly designed activated carbon in combination with baghouse, PRB coal, and TrONA (or other sodium bicarbonate alternatives) can achieve up to 90% mercury reduction, which arguably could be viable alternative solution to achieve MACT compliance (hot topic under debate today).

Exhibit 24: **Emission Control Technologies**

	CATR				Mercury MACT	
	Sulfur Oxide (SOx)		Nitrogen Oxide (NOx)		Mercury (Hg)	
	Scrubber	Dry Sorbent Injection	SCR	SNCR	Scrubber / SCR	Baghouse w/ ACI
Removal Rate	95%+	<70%	70-95%	30-75%	>90%	80-90%
Capex	$300 - 500 / kW	$50 / kW	$200-300 / kW	$30 - 75 / kW	$450 - 700 / kW	$150 /KW
Reagent	Limestone	TrONA	Ammonia	Ammonia or urea	Activated Carbon	Activated Carbon
Reagent Cost	-	-	0.47	0.47	0.94	0.94
Parasitic Load	3-5%	0%	0	0	3-5%	0.50%
Coal Efficiency	Eastern / Western	Western	Eastern / Western	Eastern / Western	Eastern / Western	Eastern / Western(1)

(1) Brominated Activated Carbon for Western Coal

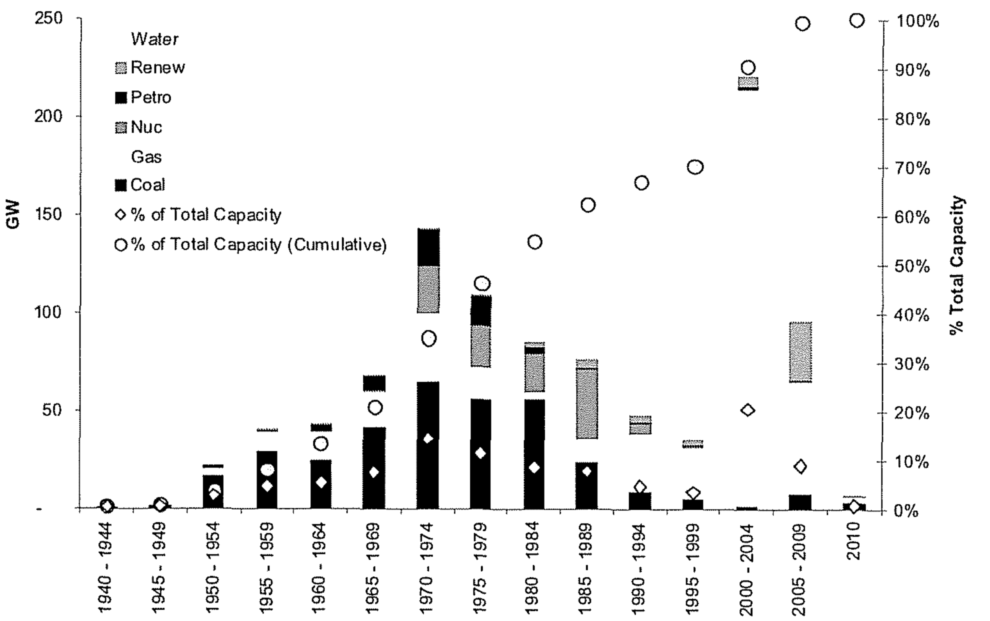
Source: Company data, Credit Suisse estimates, EPA

The Coal Fleet Has Issues

The root of the EPA conversation is understanding the US generation fleet to appreciate what is at risk with coming rules. To help put the US coal generation fleet in context, Exhibit 25 shows mix of power plant capacity by vintage year and fuel type. Half of US generation capacity is more than 30 years old with coal plants being the oldest compared to *nuclear or natural gas fired plants*.

US generation fleet is old (half was built more than 30 years ago), with coal plants being the oldest

Exhibit 25: **US Power Plants by Vintage and Fuel Type**



Source: Energy Velocity, Company data, Credit Suisse estimates

Coal Plants: Old and Emitting

Exhibit 26 shows the coal fleet today by vintage year and mix of control technologies.

- **Emitting: A large portion of the US coal fleet (103 GW or more than 30% of coal capacity) has no emission controls** at all despite significant progress made since 2005 due to lengthy design and construction process of retrofitting, significant capex requirement and persistent uncertainty around the regulatory environment. We should note in this chart we are giving credit to pipeline emission controls (those under construction or even just being planned). If only counting equipment in place today, coal capacity lacking emission controls increases to 37% of the coal fleet (128 GW).

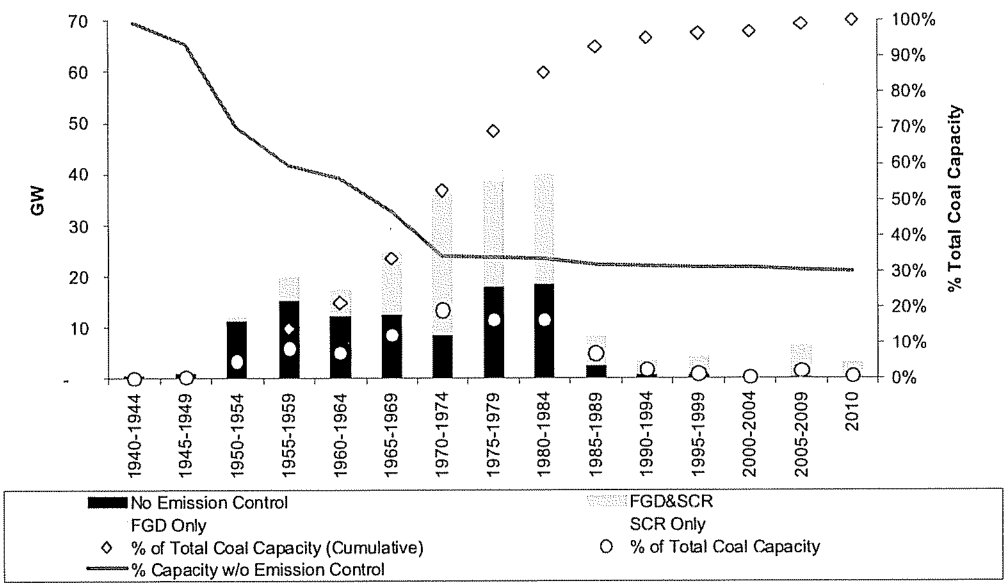
More than 30% (103 GW) of US Coal fleet has no emission control equipment installed.

- **On the bubble**: In addition to plants with no control equipments (103 GW or 30%), of the 340 GW US coal fleet 58 GW (17%) have a scrubber but not a SCR and 65 GW (19%) have a SCR but no scrubber. A number of these plants will also be exposed to reinvestment of closure decisions as well.

- **Old: 70% of the US coal fleet is over 30 years old and 33% of the fleet is over 40 years old**, in our minds further challenging the decision around making the environmental equipment upgrades necessary to sustain the fleet. Since coal plants are depreciated over 40 years much of the fleet is today largely depreciated (some offset from ongoing capex), likely leaving regulated utilities more motivated to replace or upgrade since the assets are not likely contributing much to earnings since rate base values are low.

33% of the US coal fleet (114 GW) is over 40 years old, and fully depreciated

Exhibit 26: **Coal Plant Vintage (Including Planned Emission Control)**



Source: Energy Velocity, Company data, Credit Suisse estimates

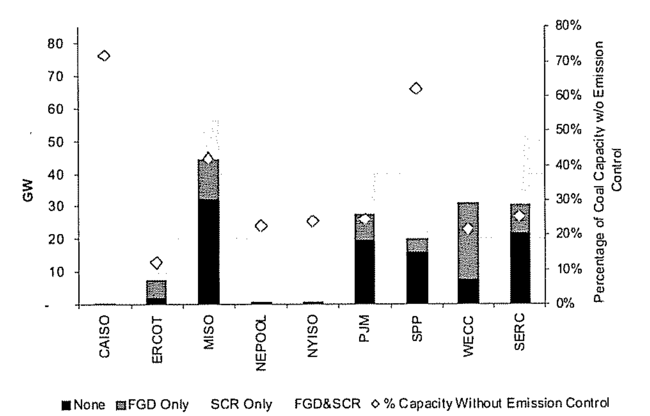
Coal Fleet Breakdown by Market

In Exhibit 27 - Exhibit 30 we show breakdown of coal fleet capacity and generation by emission profile and region to identify markets with biggest need for equipment upgrades or plant closure.

MISO, SPP, PJM and SERC are the dirtiest power markets

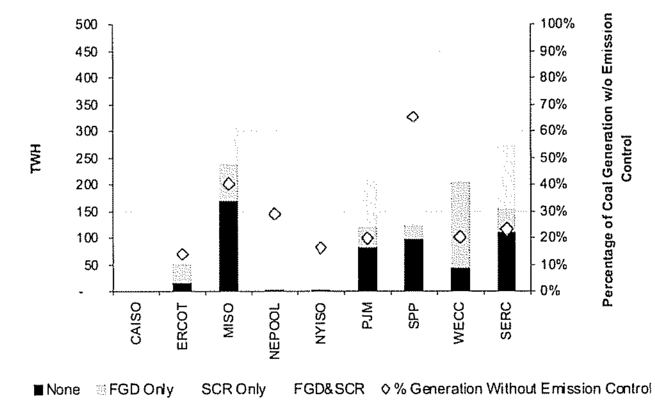
- **MISO has the biggest exposure to EPA policy** in absolute and relative terms with 32 GW lacking any controls and only 20 GW fully controlled. Potential to reshape this market with time seems high to us. PJM also has significant work ahead with 20 GW lacking any controls and 36 GW fully controlled.
- **MISO and SPP have the dirtiest relative coal fleets** with 42% and 62% capacity lacking environmental controls. More remarkably, only 27% and 40%, respectively, have bother scrubbers and SCRs in place.
- **MISO and SERC have the most coal plant capacity at risk** (32GW and 22 GW respectively), from a gross MW of capacity perspective,

Exhibit 27: **Coal Plant Capacity by Emission Control (Inc. Planned)**



Source: Energy Velocity, Company data, Credit Suisse estimates

Exhibit 28: **Coal Plant Generation by Emission Control (Inc. Planned)**



Source: Energy Velocity, Company data, Credit Suisse estimates

Exhibit 29: Table: Coal Plant Capacity by Emission Control (Inc. Planned)

	FGD&SCR	FGD Only	SCR Only	None	Total
CAISO	-	135	46	461	642
	0%	*21%*	*7%*	*72%*	
ERCOT	9,393	5,287	1,928	2,296	18,904
	50%	*28%*	*10%*	*12%*	
MISO	20,468	12,270	11,952	32,341	77,030
	27%	*16%*	*16%*	*42%*	
NEPOOL	1,343	214	666	652	2,875
	47%	*7%*	*23%*	*23%*	
NYISO	998	223	1,063	718	3,001
	33%	*7%*	*35%*	*24%*	
PJM	35,634	8,119	16,405	19,553	79,711
	45%	*10%*	*21%*	*25%*	
SPP	3,631	4,002	2,201	16,087	25,922
	14%	*15%*	*8%*	*62%*	
WECC	3,323	23,561	211	7,469	34,564
	10%	*68%*	*1%*	*22%*	
SERC	34,079	8,832	21,435	21,787	86,134
	40%	*10%*	*25%*	*25%*	
Other	5,940	2,331	2,318	1,448	12,037
	49%	*19%*	*19%*	*12%*	
Total	**114,808**	**64,973**	**58,224**	**102,814**	**340,820**
	34%	*19%*	*17%*	*30%*	

Source: Company data, Credit Suisse estimates

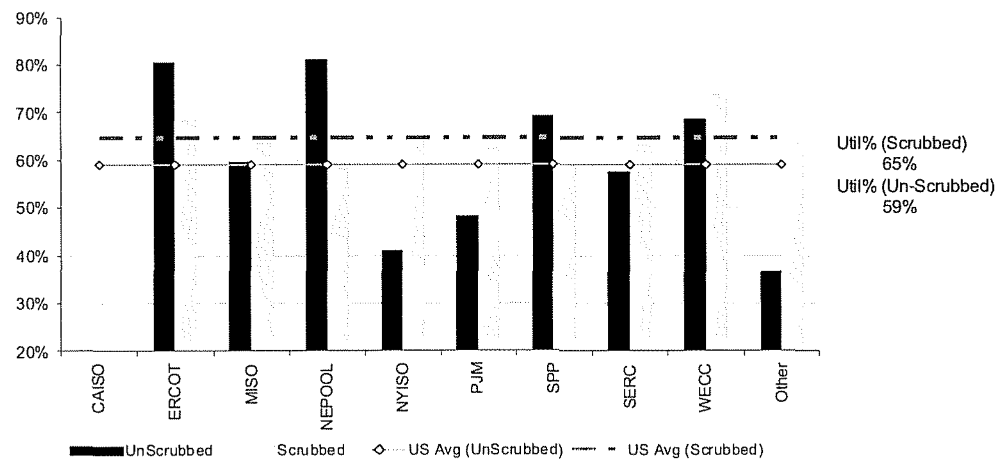
Exhibit 30: Table: Coal Plant Generation by Emission Control (Inc. Planned)

TWH	FGD&SCR	FGD Only	SCR Only	None	Total
CAISO	-	-	-	-	-
	0%	*0%*	*0%*	*0%*	
ERCOT	50	36	14	16	116
	43%	*31%*	*12%*	*14%*	
MISO	114	72	65	169	419
	27%	*17%*	*15%*	*40%*	
NEPOOL	9	-	3	5	16
	53%	*0%*	*18%*	*29%*	
NYISO	7	1	5	3	16
	43%	*7%*	*34%*	*16%*	
PJM	205	40	86	83	413
	50%	*10%*	*21%*	*20%*	
SPP	17	26	8	97	149
	12%	*18%*	*5%*	*65%*	
WECC	13	161	1	45	220
	6%	*73%*	*1%*	*20%*	
SERC	195	45	118	110	468
	42%	*10%*	*25%*	*23%*	
Other	30	15	14	5	64
	47%	*23%*	*22%*	*7%*	
Total	**639**	**396**	**314**	**532**	**1,881**
	34%	*21%*	*17%*	*28%*	

Source: Company data, Credit Suisse estimates

Contrary to conventional wisdom, generation output from un-scrubbed plants has been substantial with an observed 60% capacity factor, only about 5% lower than scrubbed plants (Exhibit 31).

Exhibit 31: Capacity Factor of Scrubbed vs Un-Scrubbed Coal Plant (2008)



Source: Energy Velocity, Company data, Credit Suisse estimates

Focus On Small Coal Plants (Older and Dirtier)

Narrowing our coal fleet focus, the coal plants most likely vulnerable to potential closure will be smaller units where the comparable cost of reaching environmental compliance is higher (equipment costs are non-linear) and the plants are broadly older, making investment even harder to justify. Exhibit 32 shows the break down of the small coal plants – measured by units below 300 MW.

- More than 70% of small coal plants (72 GW) were built over 40 years ago and should be mostly depreciated (Exhibit 35);

>70% of small coal plants are over 40 years old

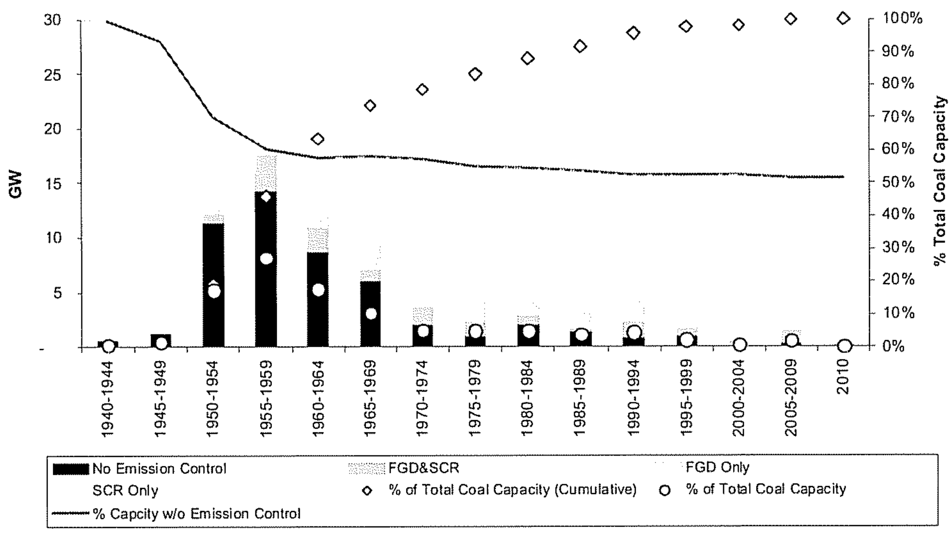
- 50% lacking any control equipment (50 GW) versus 30% for all US coal plants; the number of plants lacking scrubber is 69 GW leaving even more exposure to mercury emission rules.

50% of small coal plants have no emission controls

- Biggest exposure is in MISO, PJM, WECC, and SERC (Exhibit 35 - Exhibit 38)
- Utilization is 48% for small un-scrubbed coal plants, lower than US average but still considerable (Exhibit 39). The conventional wisdom that small plants don't run is not broadly accurate.

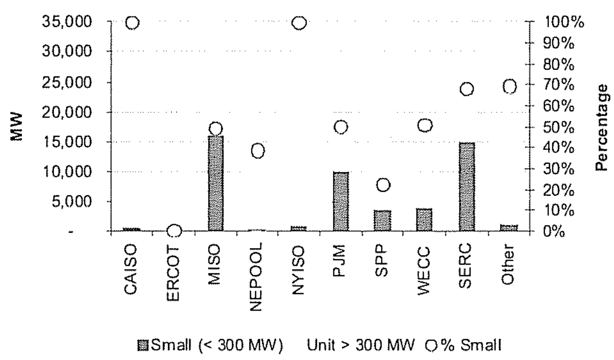
In Exhibit 35 - Exhibit 38, we show generation and capacity of small coal plants. Similar to what we saw with the larger coal units, the generation output at risk from the small plants reasonably follows installed capacity.

Exhibit 32: **Small Coal Plant Vintage (Including Planned Emission Control)**



Source: Energy Velocity, Company data, Credit Suisse estimates

Exhibit 33: Small Un-Scrubbed vs Total Un-Scrubbed Plants



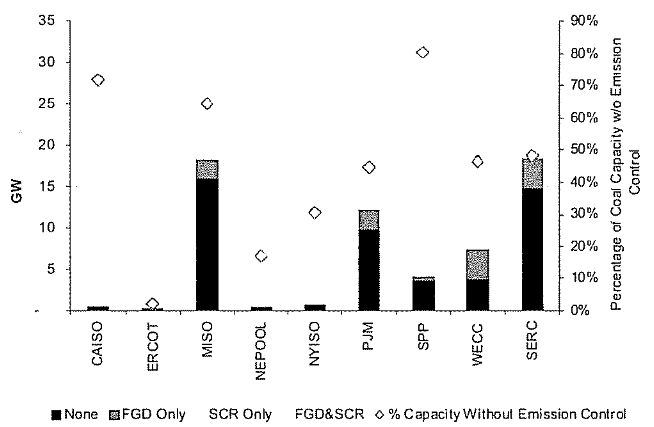
Source: Company data, Credit Suisse estimates

Exhibit 34: Table: Small Un-Scrubbed Plants (MW)

	Small (< 300 MW)	Total	% Small
CAISO	461	461	100%
ERCOT	12	2,296	1%
MISO	15,985	32,341	49%
NEPOOL	252	652	39%
NYISO	718	718	100%
PJM	9,841	19,553	50%
SPP	3,646	16,087	23%
WECC	3,785	7,469	51%
SERC	14,877	21,787	68%
Other	1,008	1,448	70%
Total	**50,586**	**102,814**	**49%**

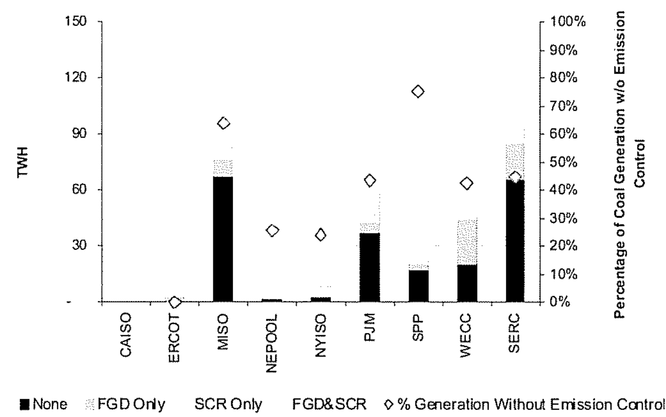
Source: Company data, Credit Suisse estimates

Exhibit 35: Small Coal Plant Capacity by Emission Control



Source: Company data, Credit Suisse estimates

Exhibit 36: Small Coal Plant Generation by Emission Control



Source: Company data, Credit Suisse estimates

Exhibit 37: Table: Small Coal Plant Capacity by Emission Control (Inc. Planned)

	FGD&SCR	FGD Only	SCR Only	None	Total
CAISO	-	135	46	461	642
	0%	*21%*	*7%*	*72%*	
ERCOT	184	349	8	12	553
	33%	*63%*	*1%*	*2%*	
MISO	2,756	2,289	3,774	15,985	24,803
	11%	*9%*	*15%*	*64%*	
NEPOOL	355	214	666	252	1,486
	24%	*14%*	*45%*	*17%*	
NYISO	343	223	1,063	718	2,346
	15%	*9%*	*45%*	*31%*	
PJM	4,940	2,375	4,865	9,841	22,021
	22%	*11%*	*22%*	*45%*	
SPP	-	569	318	3,646	4,533
	0%	*13%*	*7%*	*80%*	
WECC	554	3,605	211	3,785	8,154
	7%	*44%*	*3%*	*46%*	
SERC	4,819	3,700	7,484	14,877	30,880
	16%	*12%*	*24%*	*48%*	
Other	1,090	409	251	1,008	2,757
	40%	*15%*	*9%*	*37%*	
Total	**15,039**	**13,866**	**18,684**	**50,586**	**98,175**
	15%	***14%***	***19%***	***52%***	

Source: Company data, Credit Suisse estimates

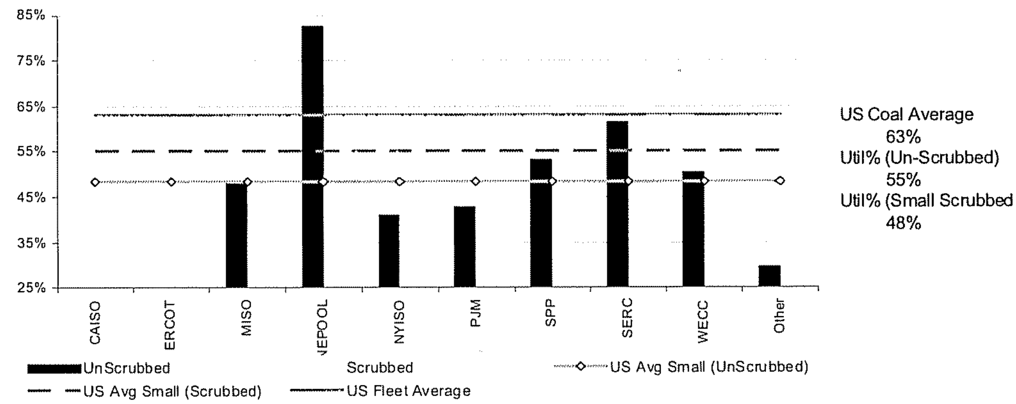
Exhibit 38: Table: Small Coal Plant Generation by Emission Control (Inc. Planned)

TWH	FGD&SCR	FGD Only	SCR Only	None	Total
CAISO	-	-	-	-	-
	0%	*0%*	*0%*	*0%*	
ERCOT	1	2	-	-	3
	25%	*75%*	*0%*	*0%*	
MISO	11	10	18	67	105
	10%	*9%*	*17%*	*64%*	
NEPOOL	2	-	3	2	7
	35%	*0%*	*39%*	*26%*	
NYISO	2	1	5	3	11
	16%	*10%*	*50%*	*24%*	
PJM	22	5	21	37	85
	25%	*6%*	*25%*	*44%*	
SPP	-	4	2	17	23
	0%	*16%*	*9%*	*75%*	
WECC	2	24	1	20	48
	5%	*49%*	*3%*	*43%*	
SERC	23	19	39	66	147
	16%	*13%*	*26%*	*45%*	
Other	4	2	1	3	10
	38%	*22%*	*14%*	*27%*	
Total	**67**	**67**	**90**	**215**	**438**
	15%	***15%***	***21%***	***49%***	

Source: Company data, Credit Suisse estimates

Remarkably, although these plants are small and old, they are significant contributors to our electricity needs: on average they are dispatched at 48%, only 15% lower than US average (63%)

Exhibit 39: **Capacity Factor of Small Plants (2008)**



Source: Company data, Credit Suisse estimates

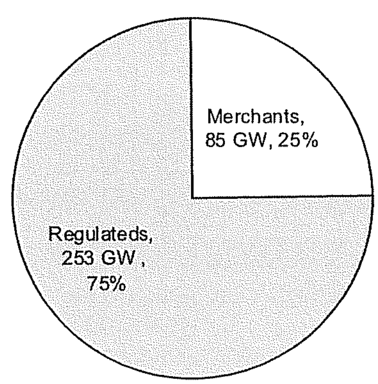
Regulated vs Merchant

We also break down coal capacity in terms of its regulatory status:

Un-scrubbed coal plants are 75% regulated

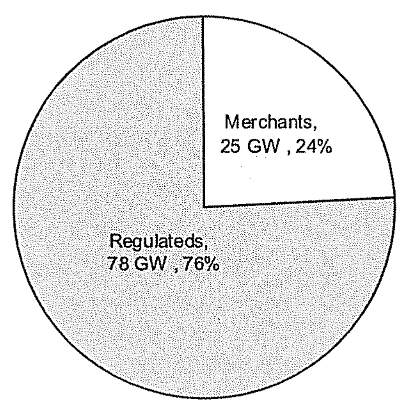
- 76% of all coal plants are regulated (Exhibit 40).
- About the same percentage (75%) of un-scrubbed coal plants are owned by regulated utilities (Exhibit 41) which shows utilities are not necessarily following a different strategy than their merchant counterparts despite the more transparent cost recovery mechanism.
- Merchant generation capacity lacking any environmental controls is most prevalent in PJM followed by MISO (Exhibit 42 - Exhibit 43).

Exhibit 40: **Coal Plants Regulateds vs Merchants**



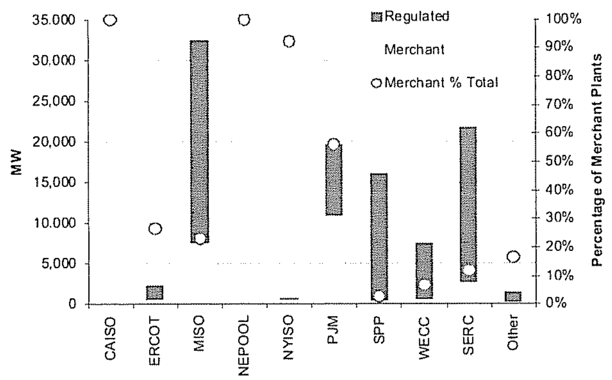
Source: Company data, Credit Suisse estimates

Exhibit 41: **Un-Scrubbed Coal Plants Regulateds vs Merchants**



Source: Company data, Credit Suisse estimates

Exhibit 42: **Coal Plants Without Emission Controls: Regulated vs Merchants Capacity**



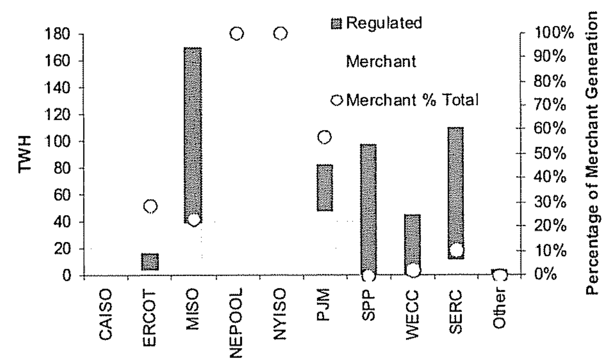
Source: Company data, Credit Suisse estimates

Exhibit 43: **Table: Coal Plants Without Emission Control: Regulated vs Merchants Capacity**

Region	Regulated	Reg. % Total	Merchant	Merchant % Total	Total
CAISO		0%	461	100%	461
ERCOT	1,684	73%	612	27%	2,296
MISO	24,775	77%	7,566	23%	32,341
NEPOOL	-	0%	652	100%	652
NYISO	54	7%	664	93%	718
PJM	8,572	44%	10,981	56%	19,553
SPP	15,609	97%	479	3%	16,087
WECC	6,960	93%	509	7%	7,469
SERC	19,143	88%	2,644	12%	21,787
Other	1,209	83%	239	17%	1,448
Total	**78,006**	**76%**	**24,808**	**24%**	**102,814**

Source: Company data, Credit Suisse estimates

Exhibit 44: **Coal Plants Without Emission Controls: Regulated vs Merchants Generation**



Source: Company data, Credit Suisse estimates

Exhibit 45: **Table: Coal Plants Without Emission Control: Regulated vs Merchants Generation**

Region	Regulated (TWH)	Reg. % Total	Merchant (TWH)	Merchant % Total	Total
CAISO	0		0		-
ERCOT	12	71%	5	29%	16
MISO	130	77%	39	23%	169
NEPOOL	-	0%	5	100%	5
NYISO	-	0%	3	100%	3
PJM	35	43%	47	57%	83
SPP	97	100%	-	0%	97
WECC	44	98%	1	2%	45
SERC	98	90%	11	10%	110
Other	5	100%	-	0%	5
Total	**421**	**79%**	**111**	**21%**	**532**

Source: Company data, Credit Suisse estimates

Emission Controls in the Pipeline

We should point out that the coal plant emission control data we have shown so far are "pro forma" to include FGDs and SCRs under construction and those with a firm installation date (Exhibit 46). In total, **33 GW of FGDs (scrubbers) and 19 GW of SCRs / SNCRs are already on the way**, reflecting the industry's effort to comply with the Clean Air Interstate Rule (to be replaced by Clean Air Transport Rule). Interestingly, most of the planned / under construction projects are for regulated power plants (81% of scrubbers) while less (64% of SCRs) - we think reflecting the more cautious approach of merchants in a lower commodity price environment where policy uncertainty has frozen investment decisions.

33GW and 19 GW of FGD and SCR are to be installed, though the installation pace is much slower than that in 2007-09.

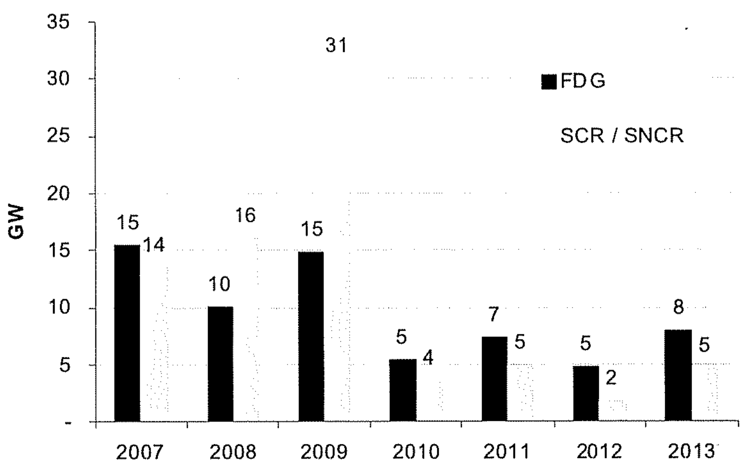
Though still at a decent pace, construction activity is slowing compared to 2007 – 2009 (Exhibit 47), in our minds reflecting less low hanging fruit that is more economical to retrofit. The current level of activity also suggests that bandwidth remains in the system to increase activity once owners are in a better informed position to make investment decisions.

Exhibit 46: **Emission Control Planned / Under Construction (MW)**

Year	All Plants		Regulated Plants		Merchant Plants	
	FGD	SCR / SNCR	FGD	SCR / SNCR	FGD	SCR / SNCR
2010	5,393	3,657	3,003	356	2,389	3,301
2011	7,421	4,901	6,181	2,119	1,240	2,782
2012	4,839	1,802	3,716	1,802	1,123	-
2013	7,974	4,671	7,106	4,671	869	-
2014	3,309	411	2,575	411	734	-
2015+	4,023	3,197	4,023	2,600	-	597
Total	**32,958**	**18,639**	**26,603**	**11,959**	**6,354**	**6,680**

Source: Company data, Credit Suisse estimates

Exhibit 47: **Emission Control Construction Activity (In Service Year)**

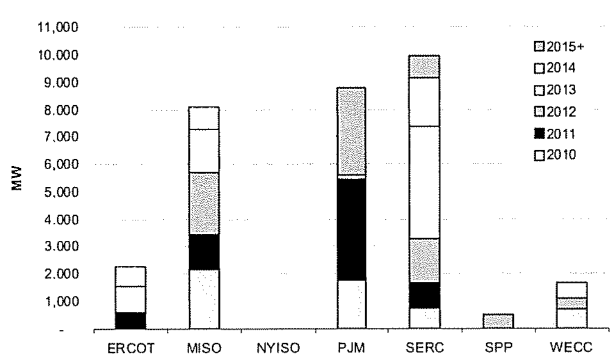


Source: Company data, Credit Suisse estimates

From a regional perspective (Exhibit 48 and Exhibit 49), planned emission controls are more concentrated in "dirtier regions" where there is higher generation capacity coming from un-scrubbed coal plants and will be under emission control limits by CATR (MISO and PJM). SERC also has significant FGD / SCRs planned, reflecting state policies to lower coal plant emission levels like the Clean Smokestacks bill passed by the North Carolina General Assembly.

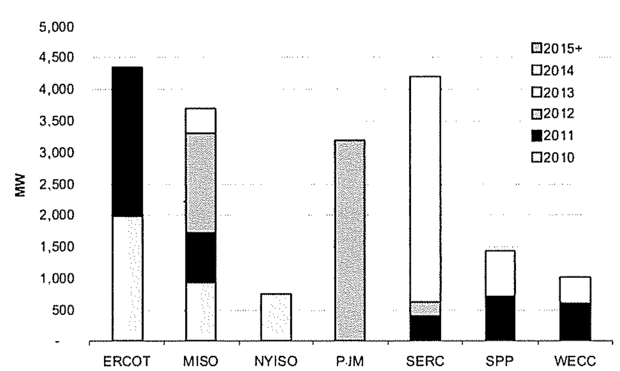
Most FGD / SCR installations are planned in MISO / PJM / SERC

Exhibit 48: **Planned FGD (Scrubbers) By Region**



Source: Company data, Credit Suisse estimates

Exhibit 49: **Planned SCR By Region**



Source: Company data, Credit Suisse estimates

Compliance Technology Options / Alternatives

There are different types of emission control technologies for SOx, NOx and mercury, each with different efficacy, capex requirement and operating cost implications. We summarize the technologies in the table below (Exhibit 50) and discuss in detail starting in Appendix I, on page 64.

Exhibit 50: **Emission Control Technologies**

	CATR				Mercury MACT	
	Sulfur Oxide (SOx)		**Nitrogen Oxide (NOx)**		**Mercury (Hg)**	
	Scrubber	**Dry Sorbent Injection**	**SCR**	**SNCR**	**Scrubber / SCR**	**Baghouse w/ ACI**
Removal Rate	95%+	<70%	70-95%	30-75%	>90%	80-90%
Capex	$300 - 500 / kW	$50 / kW	$200-300 / kW	$30 - 75 / kW	$450 - 700 / kW	$150 /KW
Reagent	Limestone	TrONA	Ammonia	Ammonia or urea	Activated Carbon	Activated Carbon
Reagent Cost	-	-	0.47	0.47	0.94	0.94
Parasitic Load	3-5%	0%	0	0	3-5%	0.50%
Coal Efficiency	Eastern / Western	Western	Eastern / Western	Eastern / Western	Eastern / Western	Eastern / Western(1)

(1) Brominated Activated Carbon for Western Coal

Source: Company data, Credit Suisse estimates

As the EPA regulations are moving toward a more holistic emission requirement - by "holistic" we mean enforcement of reduction requirements for all three major pollutants - we look at combinations of technologies that meet the limits under both CATR for SOx / NOx and MACT for mercury. Interestingly, the type of coal burned will have an impact on remediation approaches and efficacy of these approaches:

Two Options to control all three pollutants: SOx, NOx and mercury

- **Eastern Coal: FGD / SCR / Activated Carbon (ACI)**: This is the most effective approach but also the most expensive with capex in the range of $450 – 700 / KW. Unfortunately this is the only effective solution to reduce SOx for plants burning bituminous (Eastern) coal without switching to PRB coal which often requires major boiler modification and significant capex investment. The upside is that high mercury removal rates are common with this equipment suite.

FGD / SCR is expensive in capex (~$450 – 700 / KW) but cheap in operating cost ($3 / MWh)

- **Western Coal: Dry Sorbent Injection / TrONA / SNCR / Baghouse / Activated Carbon**: This approach is the cheapest for pollutant reduction in terms of capex, but only works well for sub-bituminous (Western) coal which has low sulfur content. The Baghouse / ACI reportedly can reduce up to 90% mercury emission (to be compliance with MACT) at less than 1/3 of capex required for FGD / SCR combination, although experiments are still on-going on whether the high water mark of 90% mercury reduction is consistently achievable on a long run basis. We hear optimism from select generators and consultants although meaningful doubts might lead the 'risk adjusted' decision away from this option.

Baghouse / ACI / SNCR / TrONA is cheap in capex (~$150 / KW) but expensive in operating cost ($5+ / MWh), and less effective

Since it is generally cheaper to retrofit PRB burning plants, we analyze un-scrubbed coal plants by coal type. We found approximately 62 GW of un-scrubbed plants are burning PRB coal, representing 60% of un-scrubbed capacity, which is interesting since less than 40% of total US coal plants burn PRB coal. This means disproportional coal plants burning PRB could remain un-scrubbed, most likely due to (1) low sulfur contents in PRB coal, and (2) CAIR covered 28 states mostly in the east.

We should point out, however, that about 2/3 of small un-scrubbed plants burn Eastern coal which still leaves them with only the most expensive compliance alternative. Of those small plants burning PRB, most are in MISO where even a lower capital cost investment alternative might still not make economic sense given remarkably depressed prices in the region.

Cost of Retrofit (Clean is Not Cheap)

We appreciate that our conversation about the coal fleet has provided a lot of numbers, but for some the most important numbers will be the capex required to meet EPA standards. Below we help put some numbers around the prospective investment obligations and impact to operating expenses; lower capex generally means more operating expenses.

Substantial Capital Investment

Lots of capital needed for retrofit ...

Retrofitting a coal plant with FGD and SCR ($450 – 700 / KW) is not much cheaper than constructing a brand new CCGT ($750 – 1000 / KW) before taking into account uncertainties about eventual US carbon emission policy and outlook for coal prices relative to natural gas prices.

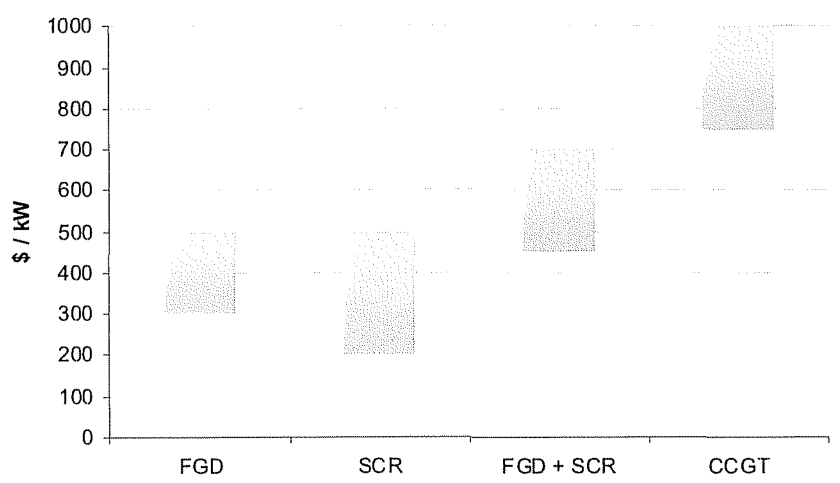
Capex for FGD ranges from $300 / KW to $500 / KW

- FGD costs range from more than $ 300 / KW for large plants with unit size over 500 MW to as high as $500 / KW for smaller unit due to economies of scale and higher difficulty in installation at more constrained locations. Putting this in context, a new CCGT costs about $750 - $1,000 / KW to construct (Exhibit 51).

Capex for SCR ranges from $150 / KW to $300 / KW

- SCRs are in the range of $150 – 300 / KW. SNCRs are cheaper (could cost as low as $13 MM per unit according to EIX), but do not reduce NOX as effectively as an SCR (0.15 lb / MMBtu NOx with SNCR vs 0.07 lb / MMBtu with SCR relative to CATR cap at 0.14 lb / MMBtu). Small plants with access to interstate NOx credits are likely users of SNCRs.
- With the most strict form of MACT, mercury reduction would most likely require retrofitting coal plants with both an FDG and SCR. Taken together with more nominal cost of activated carbon injection (ACI), the cost of mercury compliance could be $450 – 700 / KW for a un-scrubbed plant which is almost as expensive as building a new CCGT. If there were to be a separate MACT for sub-bituminous coal burning plants set at a lower than 90% standard, installation of a baghouse might be sufficient at $150 / kW although this would likely mean a higher level of compliance for Eastern (bituminous) coal burners that would make the investment decision harder for even larger coal plants.

Exhibit 51: **Capex Requirement**



Source: Company data, Credit Suisse estimates

In Exhibit 52 we show some recently completed retrofit projects and associated costs which largely jive with the numbers discussed above.

Exhibit 52: **Recent FGD / SCR Investment Capex**

Company	Plant	Retrofit	Capacity (MW)	Total Capex	$/KW
AYE	Fort Martin	FGD	1107	522.7	$ 472
	Hatfield	FGD	1710	786.2	$ 460
FPL	Scherer 4	SCR, FGD	646	392.6	$ 608
	St Johns River Power 1	SCR	177	45	$ 254
	St Johns River Power 2	SCR	177	45	$ 254
TE	Big Bend	SCR	1599	279	$ 174
PEG	Mercer	SCR	648	129	$ 199
D	Brayton	SCR	879	139	$ 158

Source: Company data, Credit Suisse estimates

Meaningful Increase in Operating Cost

Retrofitting is not only spendy on the investment capex side, but could also meaningfully increase operating costs. **Scrubbers and SCRs increase operating costs at a coal plant by $3 - 4 / MWh.** The increased O&M primarily comes from (1) cost of reagents including limestone, Urea and Activated Carbon; (2) 3-5% parasitic load which is for electricity consumed to run the environmental controls and (3) increased labor and material handling costs. **The Baghouse / TrONA alternative, while cheaper in terms of capex, could cost more than $5 / MWh.**

FGD & SCR increases operating cost by $2- 3/ MWh

We show our assumptions and calculation for each of the cost items mentioned above in Exhibit 53. We should point out our calculation only provides a point of reference with actual costs varying depending on different boiler technologies, location of the plants (transportation costs) and combination of emission control equipment installed.

TrONA and Activated Carbon could cost more than $5 / MWh

- **SOx Reduction**

Limestone is most often used sorbent in the FGD system for SOx capture in the flue gas. The ratio of limestone to SOx is 1.7:1 based on how they react with each other chemically.

Various reagents needed to reduce emission (we need a Chemistry refresher for this!)

Limestone for SOx reduction

For plants burning lower sulfur sub-bituminous coal (PRB), an alternative solution for SOx reduction is to use **Dry Sorbent Injection** with **TrONA** as reagent since it requires significantly lower upfront capex investment, decent efficacy (up to 70% removal which could get SOx emission levels to 0.24 lb / MMBtu for coal plants burning low sulfur PRB with 0.8 lb / MMBtu sulfur content, and 0.15 lb/ MMBtu if burning ultra compliance coal containing 0.5 lb / MMBtu SOx, such as those used by EIX's Midwest Gen fleet). As a reference to these reduction levels, CATR phase II SOx cap implies ~ 0.25 lb / MMBtu SOx emission. TrONA becomes less efficient and prohibitively expensive for bituminous coal with sulfur content higher than 2 lb / MMBtu. A major swing factor in this cost will be transportation since the sodium bicarbonate comes from the PRB region which involves high movement costs.

- **NOx: Ammonia / Urea**

Both SCR and SNCR use Ammonia as reagent although Urea also works in an SNCR.

Ammonia / Urea for NOx reduction

- **Mercury Reduction: Activated Carbon**

Activated Carbon is a form of carbon that has been processed to be extremely porous to have a very large surface area available for absorption. It can be used with Baghouses (primary function is to control Particulate Matter emission, for detail see page 64) or in conjunction with FGD for mercury removal. The cost of activated carbon almost doubles if

Activated Carbon for mercury reduction

it is used for PRB coal since to be effective for PRB coal, the activated carbon has to be treated with Halogen such as Chlorine or Bromine to be able to capture elemental mercury found in PRB coal.

Exhibit 53: **Reagents Cost / MWh**

	Pollutant Removal	SO2 Wet FGD	SO2 DSI	Mercury Sub-Bituminous	Mercury Bituminous	NOx	
	Reagents	**Limestone**	**TrONA**	**Brominated Activated Carbon**	**Activated Carbon**	**Ammonia**	
(1)	Pollutant Content (lb / mmbtu) *(1)*	2.5	0.8	0.001	0.001	0.45	
(2)	Heat Content of Coal (btu / lb)	12500	8800	12,500	8,800	12,500	
(3)	Heat rate of Coal Plant (mmbtu / mwh)	10	10	10	10	10	
(4)	Reagent to Pollutant ratio (lb / lb)	1.7	7	15,000	10,000	3.50	
(5)	Reagent Cost ($/ton)	20	125	4,000	2,000	60	
(6)	Pollutant generated (lb / mwh) *(2)*	25	8	0.01	0.01	4.50	(1) x (3)
(7)	Reagent required (lb / mwh)	42.5	56	0.47	0.3	15.75	(4) x (6)
(8)	Reagent required (ton / mwh)	0.02	0.03	0.0002	0.0002	0.01	(7) / 2000
(9)	**Reagent Cost ($/mwh)**	**0.43**	**3.50**	**0.94**	**0.30**	**0.47**	(8) x (5)

(1) gram / mmbtu for mercury
(2) gram / mwh for mercury

Source: Company data, Credit Suisse estimates

- **Parasitic Load**

Scrubbers / SCRs / baghouses require electricity to run which takes away the plants ability to sell as much power while retaining all the cost. FGD / SCR reduces plant's net capacity by approximately 3 – 5%, which equates to $1.5 – 2.5 / MWH in lost energy / capacity revenue (Exhibit 54). Baghouse needs less power to run (less than 1% parasitic load) costing ~ $0.26 / MWH.

Last but not least – Halogen! Halogen is needed for mercury removal from PRB coal

Exhibit 54: **Cost of Parasitic Load / MWH**

	Parasitic Load	FDG / SCR	Baghouse	
(11)	Parasitic Load	3%	1%	
(12)	Plant Revenue ($ / MWH)	48	48	
(13)	Lost Energy Margin ($/ MWH)	1.44	0.24	(11) x (12)
(14)	Capacity Revenue ($ / MW-Day)	50	50	
(15)	Lost Capacity Revenue ($/ MWH)	0.10	0.02	(14)*(11)/24/0.65
(16)	**Total Lost in Margin**	**1.54**	**0.26**	(15) + (13)

Source: Company data, Credit Suisse estimates

- **Put Everything Together**

In addition to variable costs, there is also increased fixed cost for additional labor and material handling. We estimate $2 MM per year (based on incremental needs of 20 full time employees at $100,000 fully loaded cost per person). Adding everything together (Exhibit 55), we are seeing more than $3 / MWH in increase operating cost of FGD / SCR and $5 + / MWh for Baghouse / TrONA. We need to emphasize that the higher operating costs are incremental to the carrying cost of the equipment investment, further stressing the retrofit economics.

Exhibit 55: **Emission Control Operating Cost**

Total Operating Cost	FGD / SCR	TrONA / Baghouse
Limestone Cost / MWh	0.43	-
TrONA Cost / MWh		3.50
Activated Carbon / MWh	0.30	0.94
Ammonia / MWh	0.47	0.47
Parasitic Load Cost / MWh	1.54	0.26
Total Variable Cost / MWh	**2.73**	**5.17**
Fixed Cost for Labor and Material Handling ($MM)	2.00	2.00
Allocated Fixed Cost per MWh ($/MWh)	0.70	0.70
Total Cost / MWh	**$ 3.44**	**$ 5.87**

Source: Company data, Credit Suisse estimates

The Economics of Retrofit vs Newbuild

We have seen a number coal plant retirement announcements and attribute the increase to a combination of awful energy margin for the plants in a high coal price / low gas price environment with expected EPA rules acting as the final straw. The pace of announcements seem to have pick up after EPA issued CATR in early July this year. In August and September First Energy (FE), Tennessee Valley Authority (TVA), and Duke Energy (DUK) announced plans to mothball or retire more than 4000 MW of coal plants. The momentum seems to indicate companies are looking out to final remediation costs and deciding to close smaller plants while keeping larger plants alive for the time being.

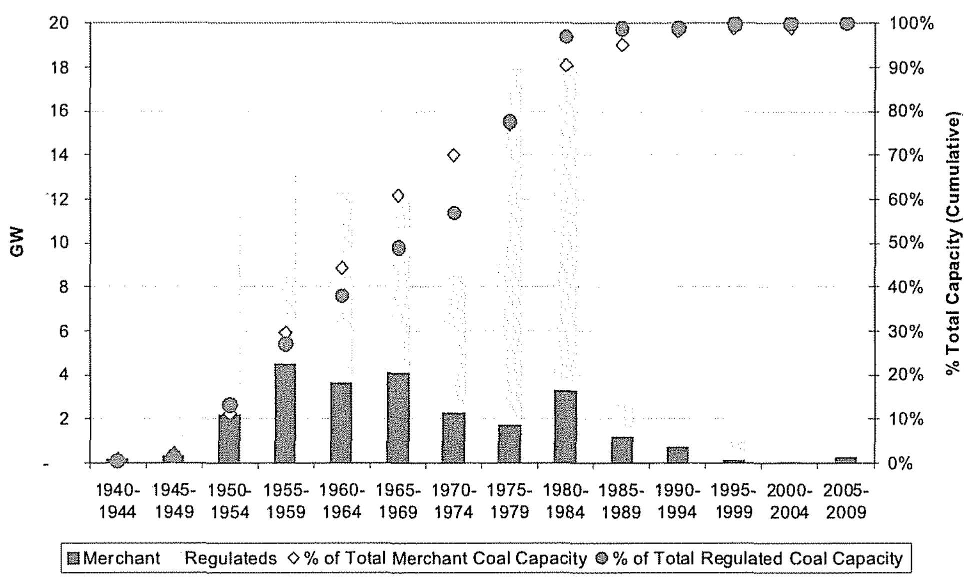
4000+ MW of coal plant mothballing / closures announced this summer

More than 50 GW Coal Capacity Could Retire

Of the 103 GW of coal plants with no emission controls, more than 78% (or almost 80 GW) are over 30 years old (Exhibit 56) with about half (50 GW) less than 300 MW in size (Exhibit 59). Considering the magnitude of capacity exposed, we think 50+ GW of coal plants will face closure. When we tack on plants without scrubbers (58 GW), unique plant circumstances, and commodity forwards favoring natural gas as cheap to coal (Exhibit 57) we see room for even more capacity at risk.

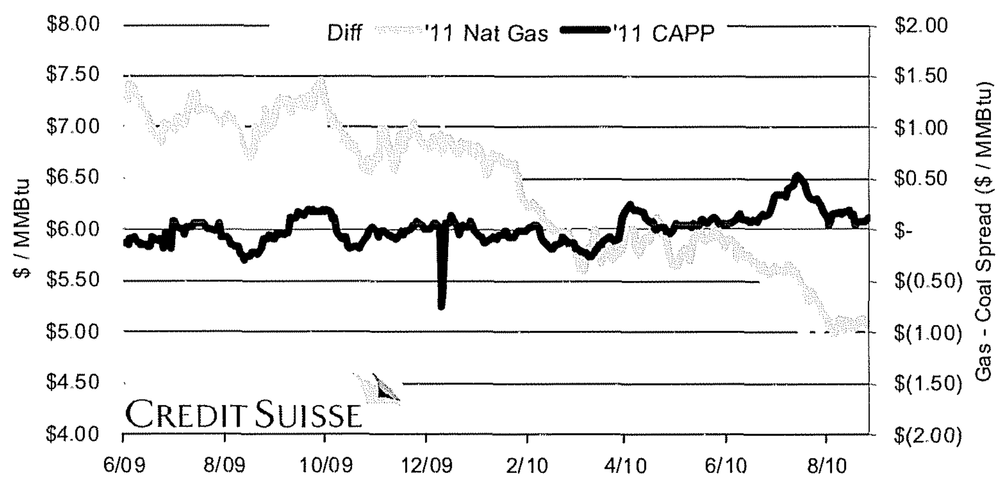
We see at least 50 GW of coal plants as prime candidates for closure

Exhibit 56: **Coal Plants Lacking Emission Controls Vintage**



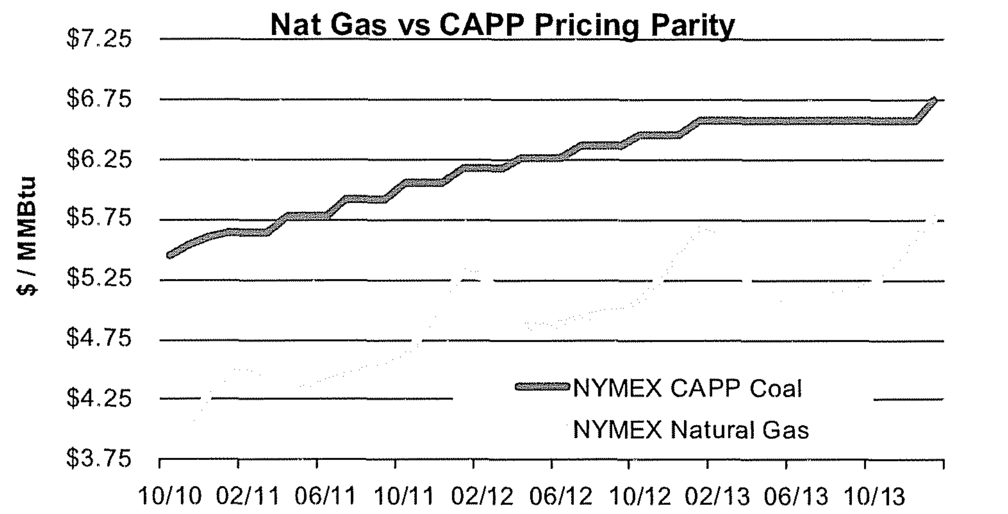
Source: Company data, Credit Suisse estimates

Exhibit 57: **2011 CAPP Coal / NYMEX Natural Gas Parity**



Source: Company data, Credit Suisse estimates

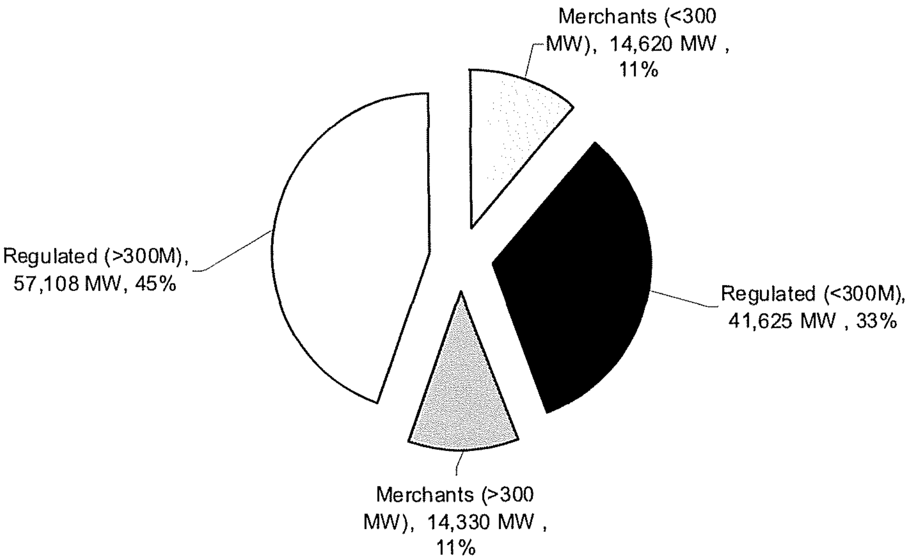
Exhibit 58: **2010 - 13 CAPP Coal / Natural Gas Parity**



Source: Company data, Credit Suisse estimates

We have spent time in our report discussing at length the configuration of the US generation fleet and the plants likely most vulnerable to closure – those lacking major environmental controls and especially the subset of smaller plants. Exhibit 59 shows an easy to appreciate breakdown of the plants at risk as we see the fleet today after taking into consideration the pending and planned environmental equipment upgrades slated for the next 5 years.

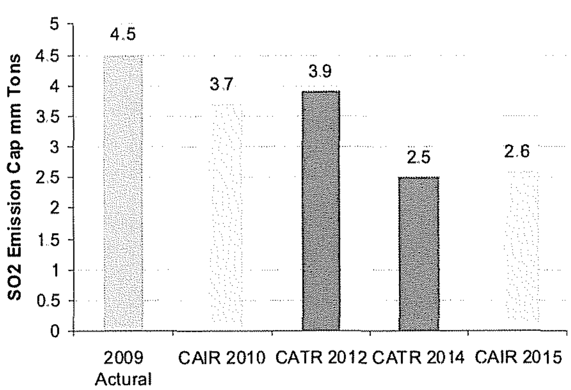
Exhibit 59: Breakdown of Coal Plants with No Emission Controls



Source: Company data, Credit Suisse estimates

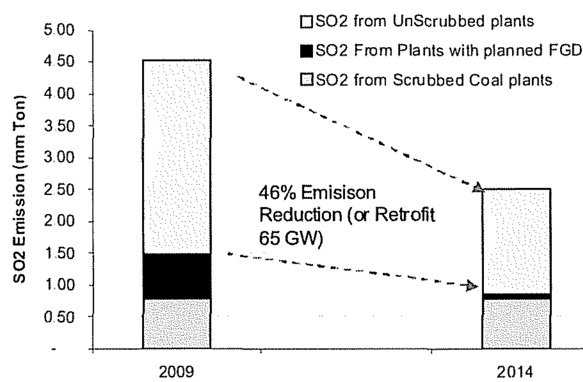
While we think mercury rules will be more transformative due to more demanding compliance standards, a look at just the already proposed SOx targets is helpful to appreciate what lies ahead. As shown in Exhibit 60: CATR rules require significant SOx emission reductions. With more than 67% of SOx emission in 2009 from plants with no FGD installed or planned, we estimate that to be in compliance with CATR's phase II SOX cap of 2.5 mm tons, emissions from plants with no FGD will need to be reduced by 46% (Exhibit 61) which would require 51% of these plants (65 GW in CATR states) to have FGD installed assuming 90% SOX reduction. The MW to be retrofitted will be lower if some coal plants are shutdown.

Exhibit 60: CATR SOx Emission Cap



Source: Company data, Credit Suisse estimates, EPA

Exhibit 61: Implication of SOx Emissions Cap



Source: Company data, Credit Suisse estimates, EPA

Exhibit 62: **Announced Coal Retirements**

Announcement Date	Company	Total MW					
8/18/2009	PGN	397					
	Unit Name	Capacity (MW)	Retirement Year	In Service Year	2008 Generatior (MWh)	2008 Coal Burn ('000 tons)	2008 Capacity Factor
	H.F. Lee	397	2017	1951	1,582	713	45%
12/1/2009	PGN	1088					
	L.V. Sutton	600	2017	1954	2,885	1,317	55%
	Cape Fear	316	2017	1956	1,816	779	66%
	W.H. Weatherspoon	172	2017	1949	735	360	49%
9/1/2009	DUK	1841					
	Unit Name	Capacity (MW)	Retirement Year	In Service Year	2008 Generatior (MWh)	2008 Coal Burn ('000 tons)	2008 Capacity Factor
	Buck 3,4	113	2011	1941	238	585	24%
	Cliffside 1-4	198	2011	1940	474	537	27%
	Dan River 1-3	276	2012	1949	1,030	467	43%
	Riverbend 8-11	64	2012	1955	NA	NA	NA
	Buck 7-9	62	2012	1956	NA	NA	NA
	Dan River 4-6	48	2012	1952	NA	NA	NA
	Riverbend 4-7	454	2015	1952	1,953	861	49%
	Buck 5,6	256	2015	1953	1,066	516	48%
	Lee 1-3	370	2014	1952	1,583	712	49%
9/4/2009	AEP	3470					
	Unit Name	Capacity (MW)	Retirement Year	In Service Year	2008 Generatior (MWh)	2008 Coal Burn ('000 tons)	2008 Capacity Factor
	Philip Sporn 5	440	2010	1960	1,833	1,061	48%
	Conesville 3	165	2012	1962	797	834	55%
	Muskingum River 2, 4	395	2012	1956	2,284	1,411	66%
	Muskingum River 1, 3	395	2014	1955	2,473	1,411	71%
	Picway 5	90	2015	1955	329	173	42%
	Glen Lyn 6	235	2015	1944	1,108	592	54%
	Glen Lyn 5	90	2015	1957	295	148	37%
	Kammer 1-3	600	2017	1958	3,115	1,403	59%
	Sporn 1-4	580	2018	1950	3,108	1,564	61%
	Tanners Creek 1-3	480	2019	1952	2,664	1,361	63%
2/3/2010	NRG	334					
	Unit Name	Capacity (MW)	Retirement Year	In Service Year	2008 Generatior (MWh)	2008 Coal Burn ('000 tons)	2008 Capacity Factor
	Indian River 1-3	334	2011	1957	1,119	888	38%
12/2/2009	EXC	746					
	Unit Name	Capacity (MW)	Retirement Year	In Service Year	2008 Generatior (MWh)	2008 Coal Burn ('000 tons)	2008 Capacity Factor
	Cromby	147	2011	1954	599	228	47%
	Eddystone 1-2	599	2012	1960	1,859	873	35%
3/8/2010	XEL	1408					
	Unit Name	Capacity (MW)	Retirement Year	In Service Year	2008 Generatior (MWh)	2008 Coal Burn ('000 tons)	2008 Capacity Factor
	Valmont	186	2017	1964	1,185	491	73%
	Cherokee	717	2022	1957	4,535	2,089	72%
	Pawnee	505	2017	1981	3,527	1,787	80%
8/12/2010	FE	1588					
	Unit Name	Capacity (MW)	Retirement Year	In Service Year	2008 Generatior (MWh)	2008 Coal Burn ('000 tons)	2008 Capacity Factor
	Bay Shore 2-4	499	2011	1959	NA	2,216	NA
	Eastlake 1-4	577	2011	1953	3,594	3,964	71%
	Ashtabulsa	256	2011	1958	1,192	718	53%
	Lake Shore	256	2011	1962	1,162	718	52%
8/19/2010	BKH	43					
	Unit Name	Capacity (MW)	Retirement Year	In Service Year	2008 Generatior (MWh)	2008 Coal Burn ('000 tons)	2008 Capacity Factor
	W.N Clark	42.5	2010	1955	MA	156	NA
9/9/2010	BKH	35					
	Osage Power Plant	34.5	2010	1948	NA	NA	NA
8/24/2010	TVA	1161					
	Unit Name	Capacity (MW)	Retirement Year	In Service Year	2008 Generatior (MWh)	2008 Coal Burn ('000 tons)	2008 Capacity Factor
	John Sevier 1,2	356	2015	1955	2,390	1,005	77%
	Widows Creek 1-6	678	2015	1953	3,660	2,198	62%
	Shawnee 10	127	2015	1955	865	467	78%

Source: Company data, Credit Suisse estimates

The Decision: Live or Let Die

Given the expensive and soon to be "mandatory" nature of emission controls, we think the question to ask for companies with uncontrolled coal plants will be if they are planning to retire / mothball or retrofit plants in the coming years. **Our analysis indicates the current commodity price environment does not support retrofit for either regulated or merchant coal plants**, *although the retirement decision-making process is different for* regulated or merchant coal plants and we show our thought process in Exhibit 63.

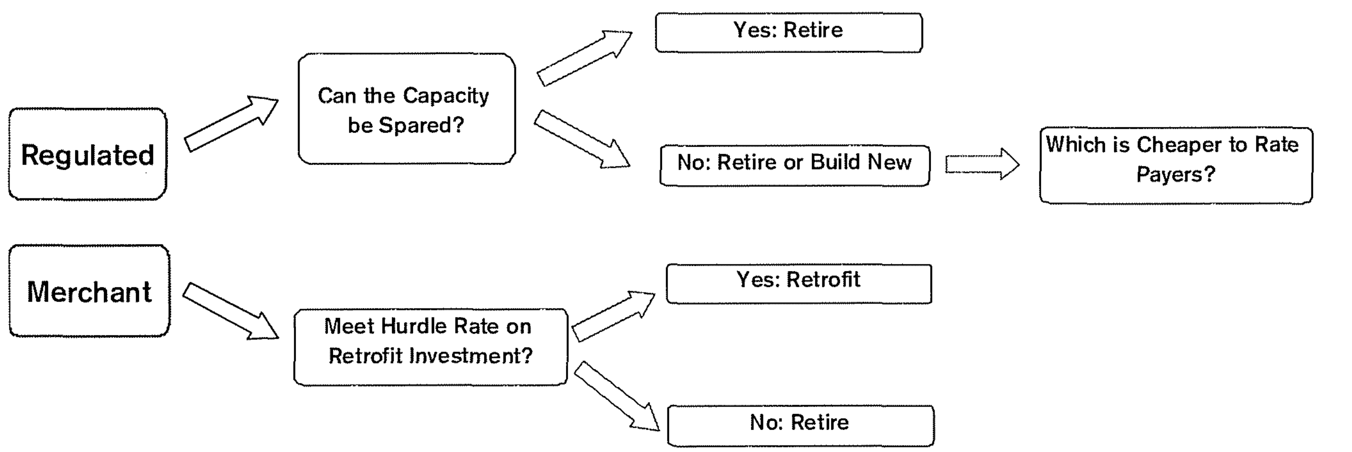
Retrofit decision making process could be different for merchant vs regulated coal plants …

As regulated utilities generally can pass through investment capex in customer rates if it is the cheaper alternative (especially if required by federal or state regulations), the decision for regulated coal plants is straight forward: companies should compare the impact on rates of retrofit versus building new generation. The other issue to consider will be reliability concerns although with a time cushion replacement generation is a viable alternative.

For merchant generators, retrofit investment should be no different than any other type of investment – namely, the investment has to be NPV positive and should meet a reasonable IRR or ROE hurdle rate. What makes this decision hard is the high level of *uncertainty in the current power market: not only in terms of commodity prices that drive* electricity but also the potential impact of legislation EPA policy that addresses carbon emissions. The other complication is that the retrofit / closure decision will not occur in a vacuum such that plants "on the bubble" for investment could be attractively economic as other plants are pulled from the market. In house power market forecasters will be busy.

… Our analysis indicates current commodity environment does not support retrofit for either regulated or merchant coal plants

Exhibit 63: **Plant Retirement / Retrofit Decision Tree**



Source: Company data, Credit Suisse estimates

Merchant Coal Plants: To Invest or To Retire?

Whether the retrofit requires only installation of an FGD, an SCR or both, the initial capex investment will be sizable. To decide whether or not to retrofit, the companies need to form a view on:

For merchants, whether or not to retrofit will depend on return on investment

- Forward natural gas and power prices;
- Cost of coal and rail transport in the future; and

- Utilization factor of the coal plant taking into consideration the cost of generation, forward prices and retirement of other coal plants in the vicinity.

Return on investment depends on natural gas price, coal price and utilization factor of the plants

With countless hours devoted to better understanding market pricing dynamics, we must admit none of the factors mentioned above is easy to forecast. Consequently, we think mothballing or reducing plant runtime to seasonal dispatch will probably be the more popular choice near-term which essentially buys time before a final decision, in hopes that more clarity will emerge from the market. That said, Phase I of CATR is quickly approaching with commencement in 2012 and Phase II in 2014; considering that designing, permitting and building a scrubber can easily take four years, the luxury of waiting is not that bountiful today. We expect companies owning merchant coal plants to make up their mind after EPA publishes the draft rule on mercury on March 16th, 2011.

Based on current forward commodity prices (Exhibit 57) where coal generation is uneconomic out the curve relative to natural gas, we see a more compelling argument for retirement than retrofit. Somewhat to our surprise generators are not responding to observed commodity prices today, but this can best be explained by operators dispatch patterns which are based on existing power and coal price hedges which buoy economics above break-even (effectively they are giving up the positive NPV of the 'in the money' hedges).

For merchants, we see more compelling argument for retiring than retrofit given current power market forwards

For retrofit, $25 / MWh or more dark spread is required for 12% ROE

We show required dark spreads to earn a 12% ROE on the retrofit investment assuming different levels of capex, remaining life and dispatch factor of the plant (Exhibit 64). Major takeaways from this exercise:

- Assuming the coal plant's initial investment has been completely recovered, our analysis shows for scrubber / SCR to be economical (12% return on equity) at $600 / KW combined cost, **a dark spread of $25 / MWH is required for a coal plant with 20 year remaining life, +$50/MW-Day capacity prices and 70% utilization rate.** Current dark spread forwards for PJMW and MISO are in the teens (Exhibit 66 - Exhibit 69), which does not support the investment decision. Even for plants with a 40 year remaining life, the required dark spread is over $20 / MWH, which still makes the investment decision a tough choice.
- But if our math is right, retiring 60 GW un-scrubbed coal plants will add $5 -10 / MWH to power prices and at least that much to dark spreads (see page 47 for detail), which helps swing the decision to retrofit for newer and bigger coal plants.
- **78% of the 103 GW un-scrubbed coal plants are older than 30 years** (built before 1980) and 52% older than 40 years as shown in Exhibit 56, signaling to us more plants are likely to be retired rather than retrofitted.
- We use a capacity payment of $50 / MW-Day in our "economical dark spread" calculation, which admittedly could be higher if coal plants begin to retire en masse. **At $200 / MW-day, it "only" requires $19 / MWH dark spread for scrubber / SCR installation to be economical** (same assumption of $600 / KW cost and 20 year remaining life), which gets us closer to today's forwards.
- The capacity price assumption is an interesting variable; since not all merchants have the capacity payment we think the investment decision could prove more difficult in energy only markets since the visibility to earning a target return is more difficult.
- Useful life of the coal plant is also a relevant conservation to us since the time horizon is heavily dependent upon assumptions about New Source Review (NSR) enforcement as well as carbon rules; a 40-year life extension would largely make impossible the Administration's goal of an 80% reduction of US carbon emission by 2050.

Exhibit 64: **Dark Spread Required for 12% ROE (Eastern Coal)**

		Remaining Life							
		5	10	15	20	25	30	35	40
Retrofit Capex $/KW	300	26.5	21.4	19.7	18.9	18.4	18.1	17.8	17.6
	400	31.9	25.2	23.0	21.8	21.2	20.7	20.4	20.2
	500	37.4	29.0	26.2	24.8	23.9	23.4	23.0	22.7
	600	42.8	32.8	29.4	27.7	26.7	26.0	25.6	25.2
	700	48.3	36.5	32.6	30.7	29.5	28.7	28.1	27.7
	800	53.8	40.3	35.8	33.6	32.3	31.4	30.7	30.2

		Capacity Payment ($ / MW- Day)							
		25	50	75	100	125	150	175	200
Retrofit Capex $/KW	300.0	20.4	18.9	17.4	16.0	14.5	13.1	11.6	10.2
	400.0	23.3	21.8	20.4	18.9	17.5	16.0	14.6	13.1
	500.0	26.2	24.8	23.3	21.9	20.4	19.0	17.5	16.0
	600.0	29.2	27.7	26.3	24.8	23.3	21.9	20.4	19.0
	700.0	32.1	30.7	29.2	27.7	26.3	24.8	23.4	21.9
	800.0	35.1	33.6	32.1	30.7	29.2	27.8	26.3	24.9

Source: Company data, Credit Suisse estimates

For plants burning sub-bituminous (PRB) coal, we use $150 / KW for emission controls assuming alternative TrONA / ACI / baghouse solution is ultimately to be MACT compliant by EPA. We found the dark spreads required are lower but should note that many of these plants do not collect any, or at least significant, capacity payments which in turn still necessitates dark spreads closing in on $20/MWh.

For PRB burning plants, we still see $20 / MWh or more dark spread required for 12% ROE, given lack of capacity market

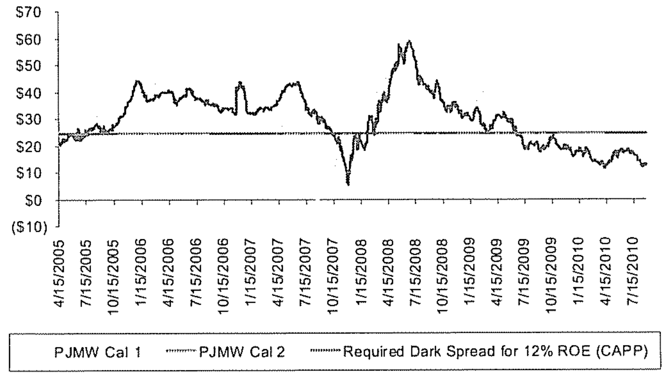
Exhibit 65: **Dark Spread Required for 12% ROE (Western Coal)**

		Remaining Life							
		5	10	15	20	25	30	35	40
Retrofit Capex $/KW	150	23.0	20.5	19.7	19.3	19.1	18.9	18.8	18.7
	250	28.3	24.2	22.9	22.2	21.8	21.5	21.3	21.2
	350	33.7	27.9	26.0	25.1	24.5	24.1	23.8	23.6
	450	39.0	31.6	29.2	27.9	27.2	26.7	26.3	26.1
	550	44.4	35.3	32.3	30.8	29.9	29.3	28.9	28.5
	650	49.7	39.0	35.4	33.7	32.6	31.9	31.4	31.0

		Utilization							
		50%	55%	60%	65%	70%	75%	80%	85%
Retrofit Capex $/KW	150	21.0	20.5	20.0	19.6	19.3	19.0	18.8	18.5
	250	25.1	24.1	23.4	22.7	22.2	21.7	21.3	20.9
	350	29.1	27.8	26.7	25.8	25.1	24.4	23.8	23.3
	450	33.1	31.5	30.1	28.9	27.9	27.1	26.3	25.6
	550	37.1	35.1	33.4	32.0	30.8	29.7	28.8	28.0
	650	41.1	38.8	36.8	35.1	33.7	32.4	31.3	30.4

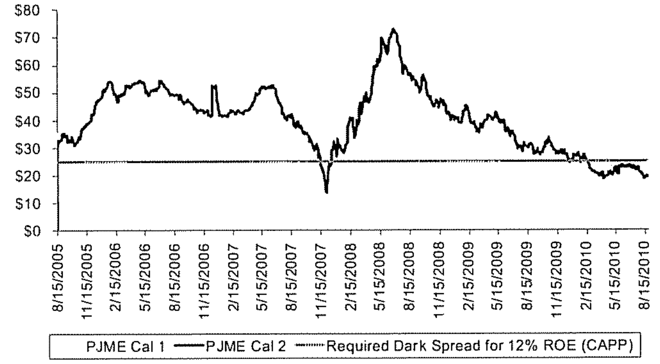
Source: Company data, Credit Suisse estimates

Exhibit 66: **PJMW Dark Spread**



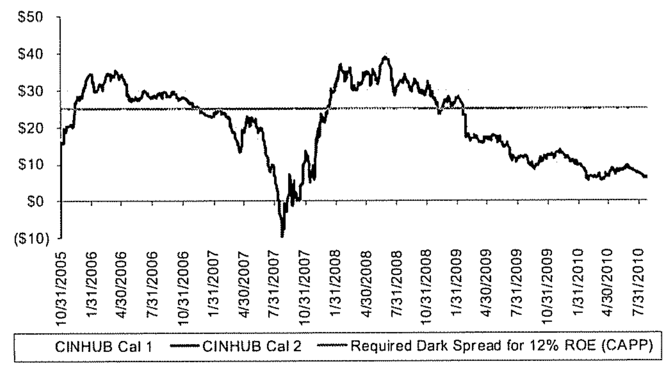
Source: Company data, Credit Suisse estimates

Exhibit 67: **PJME Dark Spread**



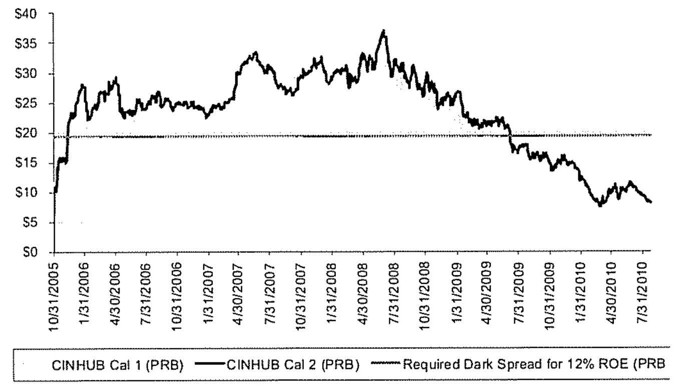
Source: Company data, Credit Suisse estimates

Exhibit 68: **MISO Dark Spread (CAPP)**



Source: Company data, Credit Suisse estimates

Exhibit 69: **MISO Dark Spread (PRB Coal)**



Source: Company data, Credit Suisse estimates

Regulated Coal Plants: Retrofit or Build New?

Regulated utilities need to assess grid integrity when making any retirement decision

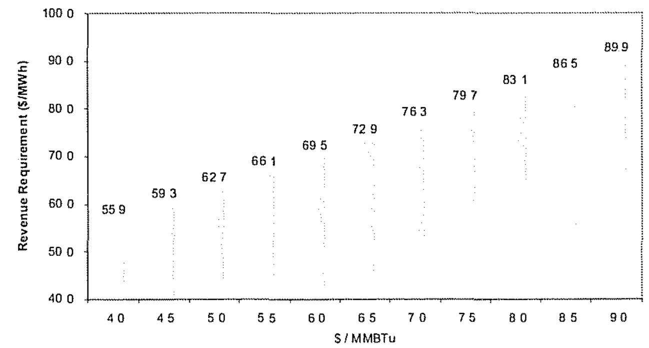
Regulated utilities have a very different challenge when approaching the retrofit versus newbuild decision since the basic mandate of a utility is to provide reliable electric service at a reasonable cost. A simple upgrade or closing analysis for a merchant generator is not an adequate response for a regulated utility. Here management must take a more holistic approach to assessing the investment decision considering system integrity and reliability at a more demanding standard than de-regulated generators. The upshot for the utilities is, however, that most old coal plants are fully / mostly depreciated today so approved investments will be additive to earnings power.

To help frame the investment decisions we analyze the customer rate impact comparing retrofitting and construction of a brand new CCGT (calculation as shown in Exhibit 73). We use the best retrofit decision (combination of FGD / SCR) since full compliance will lessen future policy risk. In Exhibit 70 and Exhibit 71, we show energy equivalent price to earn a 12% ROE on the two investments; Exhibit 72 marries these two exhibits by showing the $ / MWh intersection point with changing fuel cost assumptions. **Our key observations:**

- **.If we assume the forward curve is correct** (below $6/ MMBTU for gas and above $80 / ton for CAPP coal), **revenue requirements for a new CCGT investment are clearly lower than retrofit.**
- **If long term gas price is $7 / MMBTU or above, retrofit would be the cheaper option.**
- We think the observed volatility in commodity prices in recent years will complicate this trade off significantly and lead many utilities to 'split the baby' by doing a mix of newbuild CCGT and coal plant retrofits.

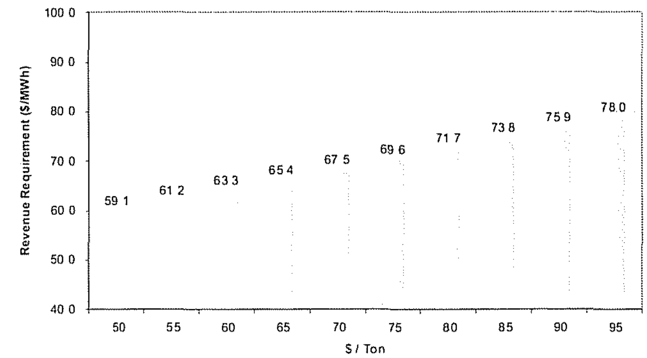
Current forwards clearly support building CCGT vs retrofit, although commodity price volatility in recent years and fuel diversification concerns may adds incentive to retrofit

Exhibit 70: **Revenue Requirement for CCGT ($/MWh)**



Source: Company data, Credit Suisse estimates

Exhibit 71: **Revenue Requirement for Retrofit ($/MWh)**



Source: Company data, Credit Suisse estimates

Exhibit 72: **Difference in Revenue Requirement ($/MWH) CCGT New Build vs Retrofit**

		Coal Price ($/ton)									
		50	55	60	65	70	75	80	85	90	95
Gas Price ($ / MMBtu)	4.0	(3.2)	(5.3)	(7.4)	(9.5)	(11.6)	(13.7)	(15.8)	(17.9)	(20.0)	(22.1)
	4.5	0.2	(1.9)	(4.0)	(6.1)	(8.2)	(10.3)	(12.4)	(14.5)	(16.6)	(18.7)
	5.0	3.6	1.5	(0.6)	(2.7)	(4.8)	(6.9)	(9.0)	(11.1)	(13.2)	(15.3)
	5.5	7.0	4.9	2.8	0.7	(1.4)	(3.5)	(5.6)	(7.7)	(9.8)	(11.9)
	6.0	10.4	8.3	6.2	4.1	2.0	(0.1)	(2.2)	(4.3)	(6.4)	(8.5)
	6.5	13.8	11.7	9.6	7.5	5.4	3.3	1.2	(0.9)	(3.0)	(5.1)
	7.0	17.2	15.1	13.0	10.9	8.8	6.7	4.6	2.5	0.4	(1.7)
	7.5	20.6	18.5	16.4	14.3	12.2	10.1	8.0	5.9	3.8	1.7
	8.0	24.0	21.9	19.8	17.7	15.6	13.5	11.4	9.3	7.2	5.1
	8.5	27.4	25.3	23.2	21.1	19.0	16.9	14.8	12.7	10.6	8.5
	9.0	30.8	28.7	26.6	24.5	22.4	20.3	18.2	16.1	14.0	11.9

Source: Company data, Credit Suisse estimates

We show simple income statement for both a CCGT and a coal plant with retrofit to help illustrate our observations (Exhibit 73).

Exhibit 73: Assumptions and Revenue Requirement Calculation

	Assumptions (CCGT)			Retrofit Assumptions	
	Capacity (MW)	500		Capacity (MW)	500
	Gas Price ($/MMBtu)	6.50		Gas Price ($/MMBtu)	6.50
				Coal Price	70.00
				Coal Transportation	20.00
				Coal Price ($ / Ton)	90.00
	Heat Rate	6.80		Heat Rate	10.50
	Utilization	65%		Utilization	70%
				Parasitic Load	3%
	Capital Cost ($/ KW)	900		Capital Cost ($/ KW)	600
	Market Heat Rate	8.5		Market Heat Rate	8.5
	O&M / MWh	5.00		O&M / MWh	10.00
				Addt'l O&M / MWh (Retrofit)	3.00
	Tax Rate	35%		Tax Rate	35%
	Interest Rate	6.5%		Interest Rate	6.5%
	Equity Capital Structure	50%		Equity Capital Structure	50%
	Depreciable year	40		Depreciable year	20
	Capex ($MM)	450		**Capex ($MM)**	300
	Generation / Year (GWH)	2,847		Generation / Year (GWH)	3,066
	Income Statement ($MM)			**Income Statement ($MM)**	
+	Revenue	207	+	Revenue	207
-	Fuel Cost	126	-	Fuel Cost	116
	Gross Margin	**82**		**Energy Gross Margin**	**91**
-	O&M	14	-	O&M	39
-	Depreciation	11	-	Depreciation	15
-	Interest Expense	15	-	Interest Expense	10
-	Income Tax	15	-	Income Tax	10
	Net Income	**27**		**Net Income**	**18**
	Required ROE	12.0%		Required ROE	12.0%
	Revenue Requirement $/MWh	72.88		Revenue Requirement $/MWh	67.51

Source: Company data, Credit Suisse estimates

Retrofit / Replacement Capex for the Industry

Our analysis indicates the current commodity price environment does not support retrofit for either regulated or merchant coal plant. Absent a major shift in commodity price forwards, we think retirement is the right choice for most un-scrubbed coal plants. The uncertainty in carbon policy will also make the decision to retire more compelling. That said, factors that will change the pricing environment and move the needle towards retrofitting do exist.

To clean up all un-scrubbed coal plants, we estimate retrofit capex in the range of $38 -89 BN., while replace all with CCGT will cost $96 – 127 BN.

- **On the revenue side:** retirement of a portion of coal plants will tighten reserve margins and should improve both energy, and capacity payment (discussed in detail on page 47). We see significant upside in energy and capacity prices in PJM specifically, if 60 GW of un-scrubbed coal plants were to retire nationally which helps make retrofitting the remaining un-scrubbed fleet a more economical choice. We think the key for the industry is to be rational – the paradigm shift in pricing will not happen if everyone waits for others to close down coal plants.

- **On the input side**: reduction in coal demand as a result of less generation from coal plants could significantly change the supply / demand dynamics of the coal market and dampen the rising coal cost.

To retrofit all of the 128 GW currently un-scrubbed coal plants, we estimate capex requirements of $38 - 89 BN. To replace all of them with CCGTs, total investment would be in the $96 – 127 BN range. Putting this number in context, we should note annual industry capex is approximately $85 BN / year.

In Exhibit 74 we show potential capex for the electric utility industry assuming 25%, 50%, 75% and 100% of coal plants with no emission control are retrofitted with both FGD and SCR and the rest replaced by CCGTs. In Exhibit 75, we focus on regulated plants only.

Exhibit 74: **Total investment sensitivity to retrofit (add FGD and SCR) coal fleet lacking emission controls**

$ BN	% of Coal Plants with No Emission Control to be Scrubbed					
	$/KW	0%	25%	50%	75%	100%
Blended Emission Control Cost	300	115	96	77	57	38
	350	115	97	80	62	45
	400	115	99	83	67	51
	450	115	101	86	72	57
	500	115	102	89	77	64
	550	115	104	93	81	70
	600	115	105	96	86	77
	650	115	107	99	91	83
	700	115	109	102	96	89

Source: Company data, Credit Suisse estimates

Exhibit 75: **Total investment sensitivity to retrofit (add FGD and SCR) regulated Coal fleet lacking emission controls**

$ BN	% of Coal Plants with No Emission Control to be Scrubbed					
	$/KW	0%	25%	50%	75%	100%
Blended Emission Control Cost	300	89	74	59	44	30
	350	89	75	62	48	35
	400	89	77	64	52	39
	450	89	78	67	56	44
	500	89	79	69	59	49
	550	89	80	72	63	54
	600	89	81	74	67	59
	650	89	83	77	70	64
	700	89	84	79	74	69

Source: Company data, Credit Suisse estimates

FGD / Scrubber Exposure

Obviously, if we were to expand our retrofit universe to reach full compliance at also the partially scrubbed plants (i.e. those with only FGD or only SCR) the capex requirement will be much higher. In Exhibit 76 and Exhibit 77, we show capex requirement of over $100 BN for the industry and in the range of $75 – 110 BN if focusing on the regulated coal fleet only.

Exhibit 76: **Total Investment Sensitivity to Add FGDs and SCRs on Coal Fleet Lacking one or both Emission Controls**

$ BN	SCR				
	$/ KW	75	150	225	300
FGD	300	73	87	101	115
	350	83	97	111	124
	400	92	106	120	134
	450	102	116	130	144
	500	112	126	140	154
	550	122	136	150	164
	600	132	145	159	173
	650	141	155	169	183
	700	151	165	179	193

Source: Company data, Credit Suisse estimates

Exhibit 77: **Total Investment Sensitivity to Add FGDs and SCRs on Regulated Coal Fleet Lacking one or both Emission Controls**

$ BN	SCR				
	$/ KW	75	150	225	300
FGD	300	54	65	75	86
	350	61	72	83	93
	400	68	79	90	100
	450	75	86	97	108
	500	83	93	104	115
	550	90	101	111	122
	600	97	108	118	129
	650	104	115	126	136
	700	111	122	133	144

Source: Company data, Credit Suisse estimates

Impact on Power Market: Scenarios, Power Prices and Reserve Margins

The revenue impact for generators from large scale coal plant closures will be two fold: (1) energy prices should rise when un-scrubbed coal plants are removed leaving marginal price setters less efficient, and (2) increase in capacity payment as reserve margins tighten faster than otherwise expected. For the impact on the capacity prices, we focus on PJM since it is the only region with both a capacity market and a sizable un-scrubbed coal fleet.

Scenario Summary

We examined five scenarios with variations in magnitude and timing of coal plant closure in order to assess potential power market implications.

Three coal retirement scenarios: 35 GW, 60 GW and 100 GW

- **(1) 60 GW Retirement**: Retire all small plants with no emission controls and half of those lacking scrubbers ratably within 5 years from 2013 to 2017, assuming EPA allows room to negotiate on timing for rule compliance. We think small units broadly will struggle to justify large capital investment leading to more closures than conventional wisdom although realistically some small units will survive while other bigger plants will not.

The 60 GW retirement scenario is our base case.

- **(2) 35 GW Retirement**: Retire half of small plants without scrubbers (~70 GW) ratably from 2013 to 2017. We see this scenario as leaving tremendous burden on plant retrofits that feels unrealistic with the current commodity price outlook.
- **(3) 100 GW Retirement**: a more extreme case where all 103 GW coal plants lacking any environmental controls are shut down ratably by 2017. We see this scenario more as indicative of an extreme possibility; realistically closure rate of this level would also pull from the 58 GW of plants lacking scrubbers and 65 GW of those lacking SCRs. We think commodity prices would likely reset enough before reaching this closure level to keep it from happening.
- **(4) MTM 60 GW retirement**: Same sets of coal plant closures as scenario (1), but instead of using Credit Suisse price deck for natural gas, we use current forwards for this scenario;
- **(5) Do nothing case** where EPA rules does not lead to any cola plant retirements.

We should note in our scenario (1), (2) and (4) we use a broader definition of plants at risk to include those with an SCR or an SNCR installed but no scrubbers given: **(a)** the crummy economics of these high heat rate plants, **(b)** their at risk nature of many as provided by companies so far, and **(c)** the high capex for scrubber installation due to high cost structure. For scenario (3) we dial back the at risk fleet to plants with no emission control technology in part to reflect the view that some bigger plants with SCRs will survive.

Exhibit 78: **Retirement and Newbuild Assumptions**

Capacity (MW)	Retirement (2013-17)			Newbuild Projection (2013-17)		
MW to Retire	60 GW	35 GW	100 GW	60 GW	35 GW	100 GW
PJM	24,474	12,237	19,553	5,000	1,050	11,000
ERCOT	16	8	2,296	0	0	0
ISO New England	585	293	652	0	0	0
ISO New York	1,249	625	718	0	0	0
MISO	17,872	8,936	32,341	5,250	0	19,000
SERC	18,619	9,310	21,787	13,500	4,750	24,000
SPP	3,805	1,903	16,087	0	0	9,750
US	**59,928**	**29,964**	**102,814**	**23,750**	**5,800**	**64,500**

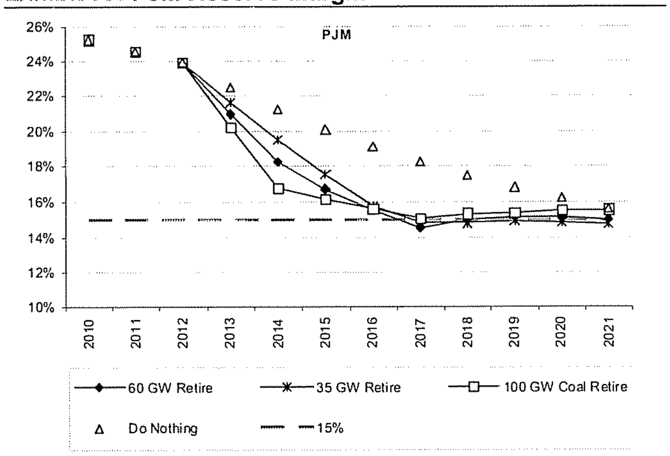
Source: Company data, Credit Suisse estimates

Reserve Margin Implications – Regaining 4 Years

In Exhibit 79 - Exhibit 84 we show reserve margins using the four scenarios we discussed above. We should note that without coal plant retirement reserve margins for all markets are above 15% (the typical target level for ISOs) and remain so until late this decade. Coal plant retirements "reset" the supply stack of the power market and serves to remove excess capacity. In all retirement cases, the regional power markets with dirty coal exposure (notably MISO, SERC, SPP and PJM) will reach the desired 15% reserve margin 4 years or more earlier than "do nothing" and will need newbuild construction in order to maintain the reserve margin at 15%. Markets with little un-scrubbed coal plants such as NEPOOL, NYISO, ERCOT, and CAISO, however, will see limited impact.

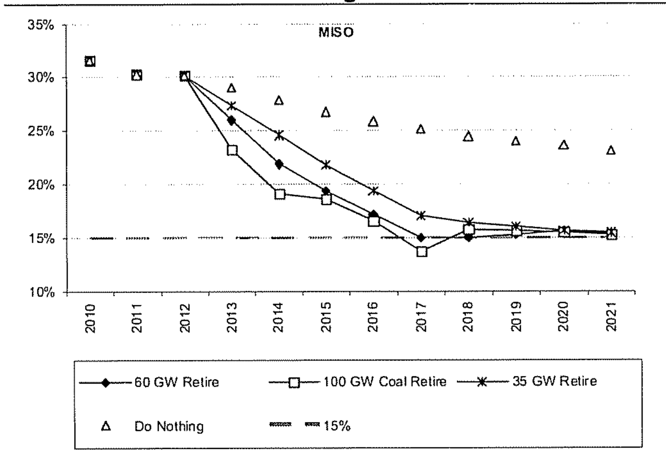
In PJM, MISO, and SERC, reserve margin will reach the 15% long run target 4 or more years earlier under our retirement scenarios than baseline

Exhibit 79: **PJM Reserve Margin**



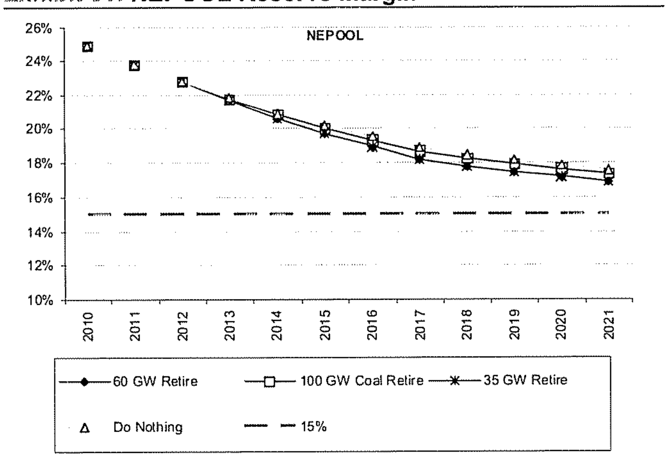
Source: Company data, Credit Suisse estimates

Exhibit 80: **MISO Reserve Margin**



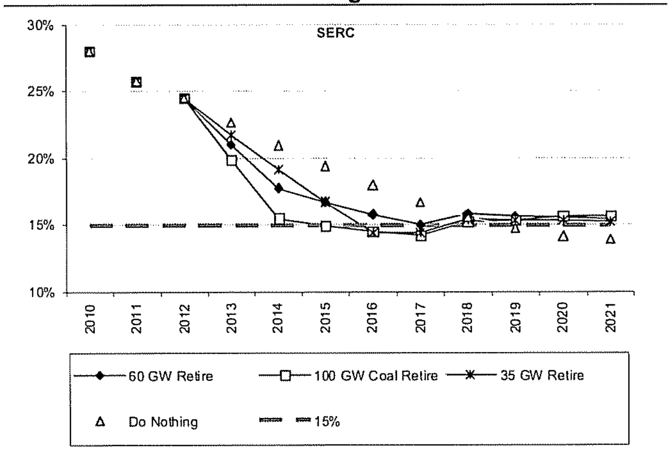
Source: Company data, Credit Suisse estimates

Exhibit 81: **NEPOOL Reserve Margin**



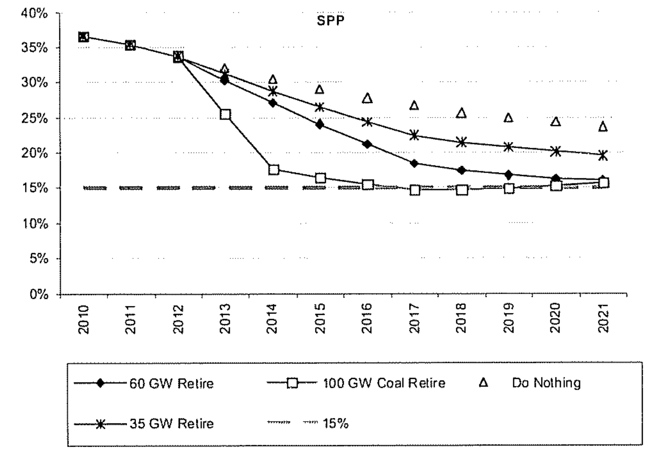
Source: Company data, Credit Suisse estimates

Exhibit 82: **SERC Reserve Margin**



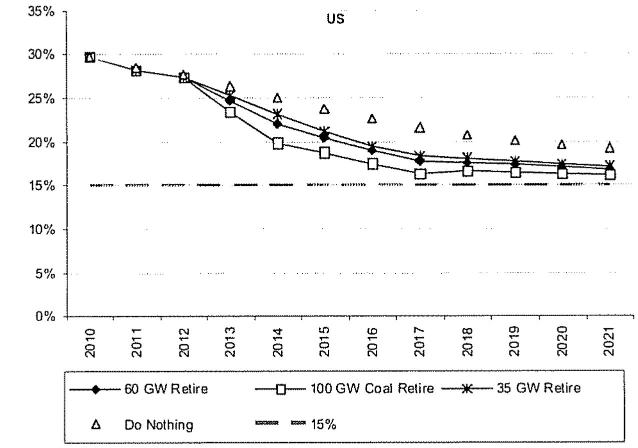
Source: Company data, Credit Suisse estimates

Exhibit 83: **SPP Reserve Margin**



Source: Company data, Credit Suisse estimates

Exhibit 84: **US Reserve Margin**



Source: Company data, Credit Suisse estimates

Newbuild Requirement

We approached newbuild requirement with the goal of maintaining a 15% reserve margin under our three coal plant closure scenarios. With most reserve margins over 20% today, we see new plants construction requirement to maintain a 15% balanced market at less than our projected retirements which should help make the compliance less onerous from a capital perspective. Importantly, as shown in Exhibit 86, the new plant construction obligations are not totally onerous in a historical context under any of the scenarios, helping to de-risk some natural fears of EPA policy.

With reserve margin over 20% today, we need less newbuild than retirement MW to maintain 15% reserve margin

- **60 GW Retirement**: As most regional markets have a reserve margin in excess of 20% today due to last decades' significant capacity additions and two years in a row of negative demand growth in 2008/9, **new capacity required to keep the reserve margin above 15% is a smaller number (~24 GW) than total capacity at risk of retirement**. In addition, we see the need for newbuild mostly after or in 2015 with PJM, MISO, and SERC having the biggest needs.

24 GW newbuild is required if 60 GW small coal plants were to retire

- **35 GW Retirement (half small coal plants lacking FGD)**: we see only ~ 6 GW newbuild needed in 2017 to maintain reserve margin above 15%.
- **100 GW All Un-Scrubbed Coal Retirement**: 64 GW were to be built to support a 15% reserve margin. We think the planning for permit / construction needs to start today, to allow adequate time for newbuild (Exhibit 87 - Exhibit 92).

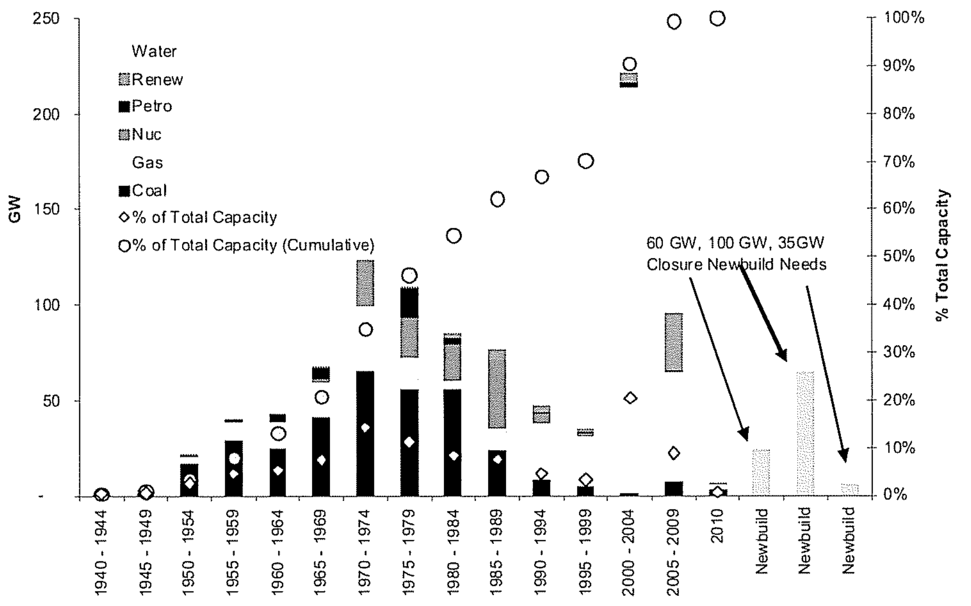
64 GW newbuild is required if small un-scrubbed coal plants were to retire

Exhibit 85: **Capacity to be Retired vs Newbuild**

Capacity (MW)	Retirement (2013-17)			Newbuild Projection (2013-17)		
MW to Retire	60 GW	35 GW	100 GW	60 GW	35 GW	100 GW
PJM	24,474	12,237	19,553	5,000	1,050	11,000
ERCOT	16	8	2,296	0	0	0
ISO New England	585	293	652	0	0	0
ISO New York	1,249	625	718	0	0	0
MISO	17,872	8,936	32,341	5,250	0	19,000
SERC	18,619	9,310	21,787	13,500	4,750	24,000
SPP	3,805	1,903	16,087	0	0	9,750
US	**59,928**	**29,964**	**102,814**	**23,750**	**5,800**	**64,500**

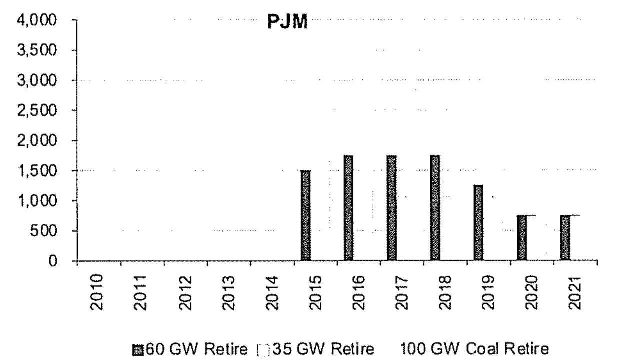
Source: Company data, Credit Suisse estimates

Exhibit 86: 1940 – Present Capacity Addition



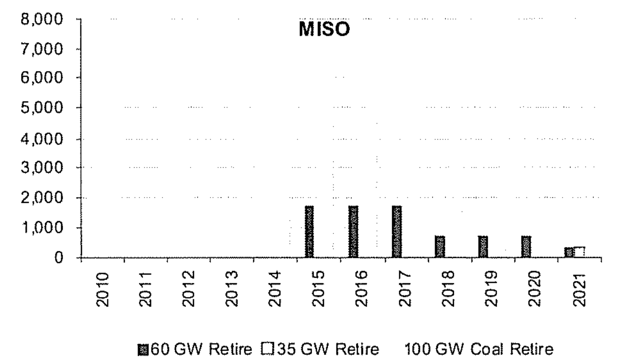
Source: Energy Velocity Company data, Credit Suisse estimates

Exhibit 87: PJM Newbuild



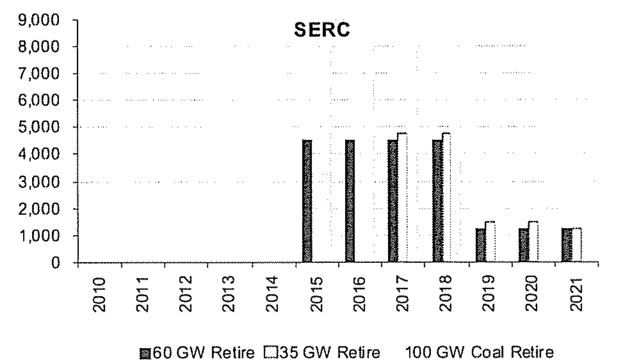
Source: Company data, Credit Suisse estimates

Exhibit 88: MISO Newbuild



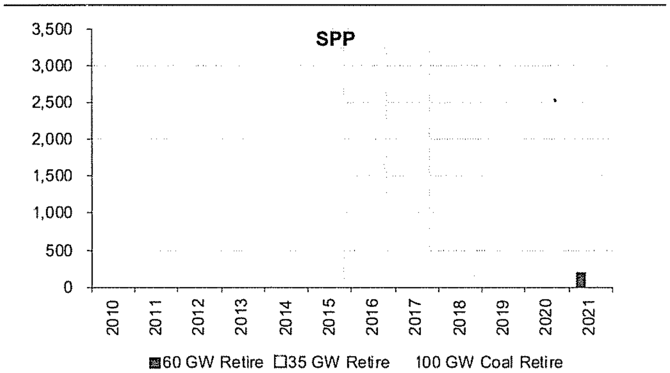
Source: Company data, Credit Suisse estimates

Exhibit 89: SERC Newbuild



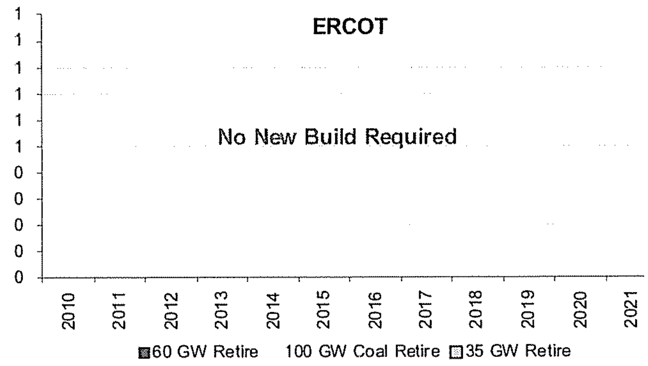
Source: Company data, Credit Suisse estimates

Exhibit 90: SPP Newbuild



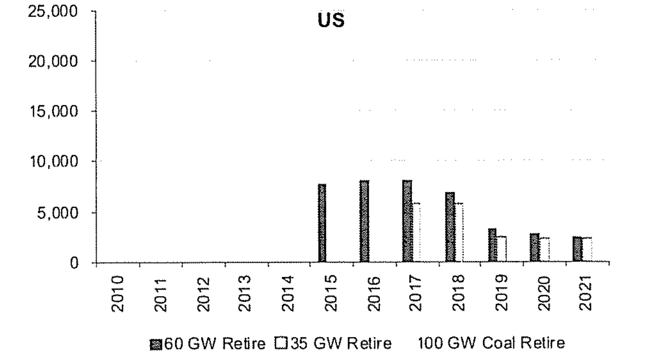
Source: Company data, Credit Suisse estimates

Exhibit 91: **ERCOT Newbuild**



Source: Company data, Credit Suisse estimates

Exhibit 92: **US Newbuild**



Source: Company data, Credit Suisse estimates

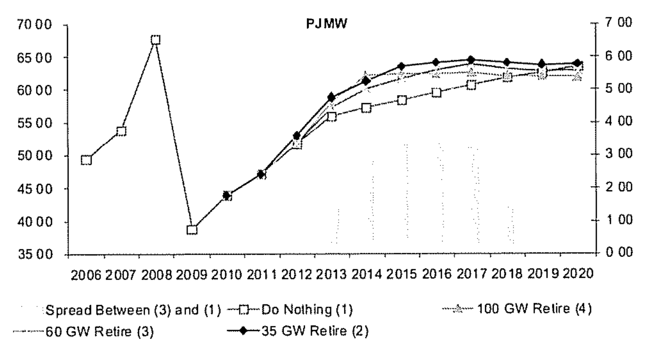
Impact on Energy Prices

In Exhibit 93 - Exhibit 96 we show the impact on power prices under our four scenarios. As reserve margins tightens faster with coal retirements, we see power prices $5 -- 10 / MWh higher than the "do nothing" scenario in regions with dirty coal plant exposures until later in this decade when market equilibrium rise to the point of sustaining a balanced 15% reserve margin and market clearing power prices should converge on the different scenarios. We should note PJM is the most relevant deregulated market since MISO, SPP, and SERC are mostly regulated and plant closure behavior will likely be different while markets such as NEPOOL, NYISO, CAISO and ERCOT have limited dirty coal exposure.

$5 / MWh or more increase in ATC power prices in PJMW and MISO but negligible in other de-regulated regions

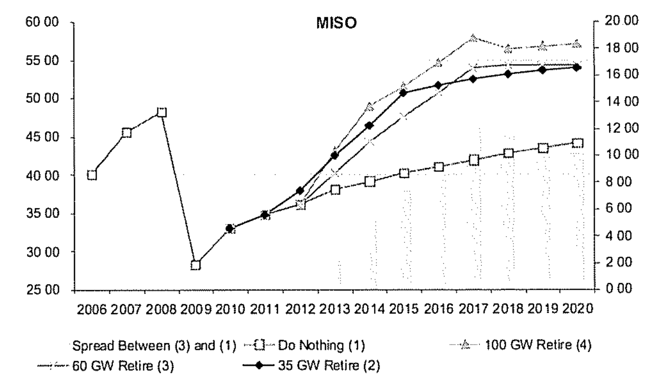
Looking at Exhibit 94 we model a fairly significant step up in electricity prices for MISO given the huge density of at risk coal units; in reality we see pricing help in the competitive Western Illinois market but do not expect as broad of a price step up considering how heavily regulated most of MISO is today (77% of at risk fleet) leaving more of the spending to come with rate base growth overwriting market pricing signals.

Exhibit 93: **PJMW Power Price**



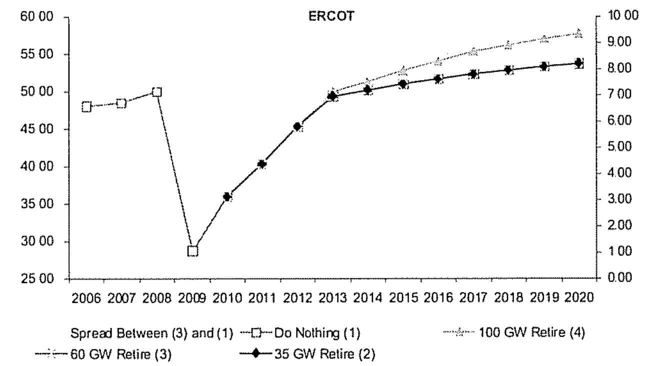
Source: Company data, Credit Suisse estimates

Exhibit 94: **MISO Power Price**



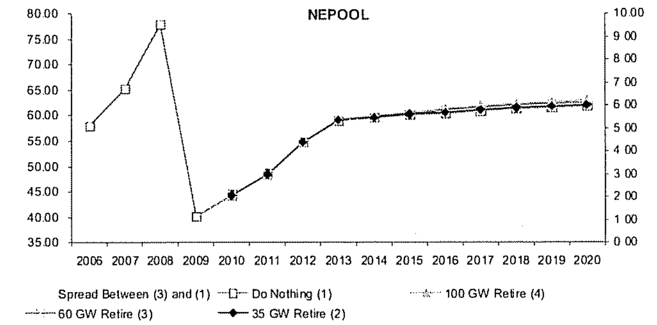
Source: Company data, Credit Suisse estimates

Exhibit 95: **ERCOT Power Price**



Source: Company data, Credit Suisse estimates

Exhibit 96: **NEPOOL Power Price**



Source: Company data, Credit Suisse estimates

Impact on Capacity Payments

We see changes in power prices with shifting supply-demand fundamentals as important but think capacity prices are essential, not to be overlooked particularly in the RTO region of PJM. **We see RTO capacity payments rebounding toward $100 / MW-day for next auction as plants are targeted for closure or at least bid at their real economic cost.**

We think RTO capacity payment will rebound to $100 / MW-Day in the next PJM RPM auction

As we look at potential closure scenarios, we see much of the economic support to newbuild construction or environmental retrofit decisions dependent up on capacity payment. To help simplify a more complicated calculation, we use the historical relationship between CONE (Const of New Entry) and reserve margin as shown in Exhibit 97, to calculate future capacity prices as we shift reserve margin assumptions in response to our retirement scenarios.

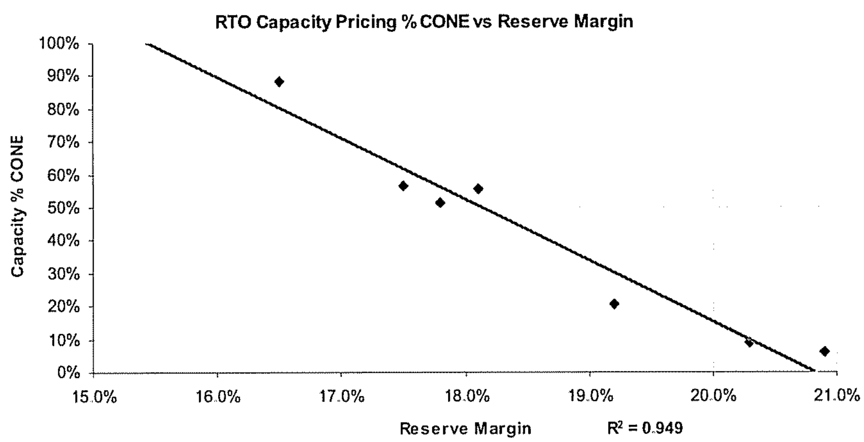
We forecast capacity payment from relationship between reserve margin and capacity payment as percentage of net CONE

Exhibit 97: **Historical RPM Auction Results for RTO**

	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
Capacity Price ($/MW-Day)	40.80	111.92	102.04	174.29	110.00	16.46	27.73
Reserve Margin	19.20%	17.50%	17.80%	16.50%	18.10%	20.90%	20.30%
CONE ($/MW-Day)	197.29	197.83	197.83	197.83	197.83	276.09	317.95
Capacity Price % of CONE	21%	57%	52%	88%	56%	6%	9%

Source: PJM, Credit Suisse estimates

Exhibit 98: **RTO Capacity Price % CONE vs Reserve Margin**



Source: Company data, Credit Suisse estimates

Reserve Margin Forecast

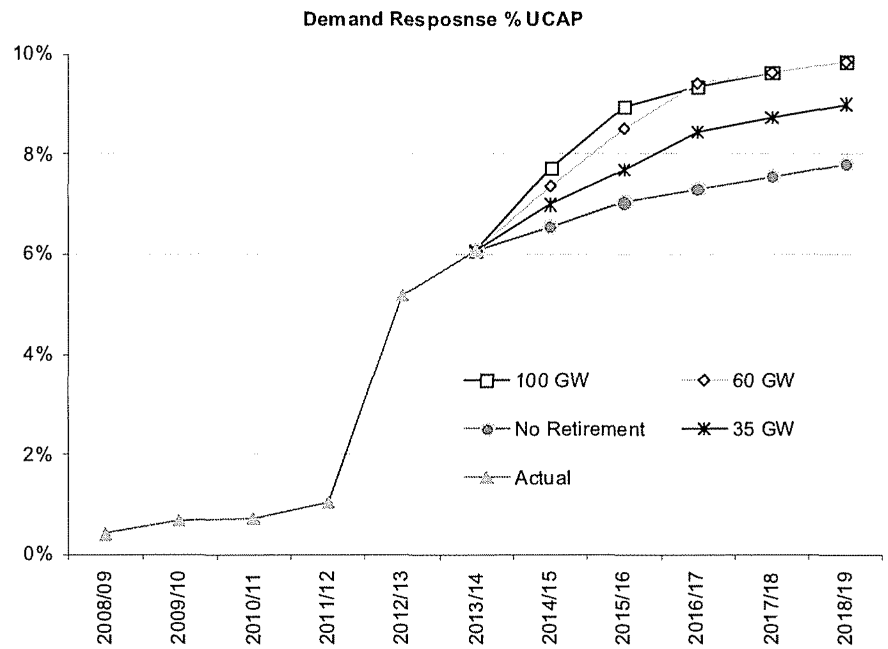
One of the two major drivers in capacity price calculation is the reserve margin forecast which will benefit with time from demand growth and coal plant retirement, partly offset by demand response market share gains.

Growth in Demand Response could mitigate decrease in reserve margin from coal plant closure…

We think demand growth is an important and often overlooked market driver. Demand response grew from 1.4 GW in the '11/'12 planning year to more than 9 GW in '13/'14 in RTO alone. Even with fast growth so far, we can see more to come as demand response accounted for only 6.1% of cleared capacity in RTO for 2013/14, while significantly higher at 8.7% and 7.5% of cleared capacity for MAAC and EMAAC. There were 3.6+ GW of Demand Response offered but not clearing the last auction at $28 / MW-day for RTO. We think as plant closures tighten reserve margins and create a signal for higher capacity payments, we will see more demand response clear the auction. We would not be surprised if in the long run demand response grows to account for close to 10% of system resource (Exhibit 99) as basically seen in MAAC and NEPOOL. The growth in Demand Response will slow the sharp decrease in reserve margins if looking at plant closures in a vacuum.

We see demand growth account for 10% of system resource given adequate price signal

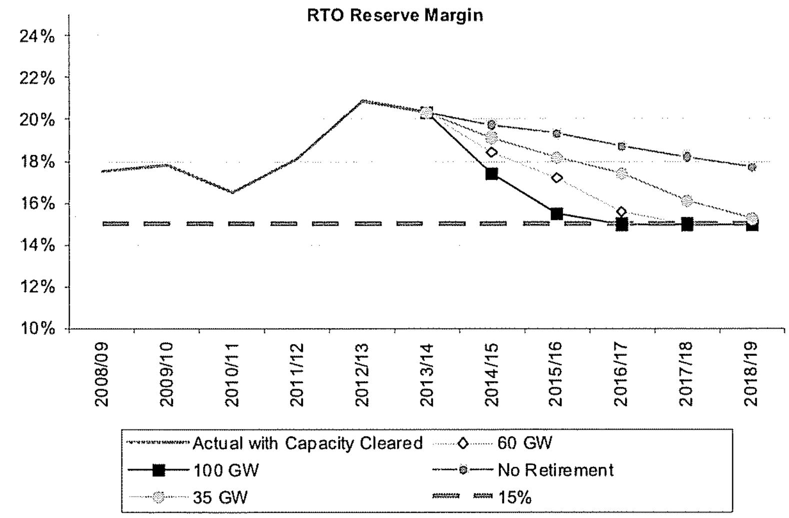
Exhibit 99: Demand Response Under Different Retirement Scenario



Source: Company data, Credit Suisse estimates

Putting plant closure and demand response growth together, we forecast reserve margins in RTO under our four scenarios (Exhibit 100). Even with growth in demand response, reserve margins could reach 15% as early as 2015/16 with actual timing depending on magnitude / rate of coal plant closure.

Exhibit 100: RTO Reserve Margin



Source: Company data, Credit Suisse estimates

Net CONE

The other variable to consider for capacity payment is net CONE, which is revenue requirement necessary to earn an economic return on new plant investment less expected energy margin from running the plant. Below we show the ROE for both CCGT and a gas peaker at different energy / capacity prices (Exhibit 101 and Exhibit 102). We found in the $ 6 / 7 gas environment (which we think is right range for long run natural gas price), **the capacity payment needs to be $225 – 250 / MW-day to support a 10% ROE**, which is clearly a long way away from current gas forwards in the 5's and the last capacity auction below $30 / MW-Day.

We see $225 – 250 / MW-Day as reasonable range for net CONE …

Exhibit 101: CCGT New Build ROE @ $900 / KW, 8.5 Market HR, 6.8 Plant HR, 65% Utilization

Gas Px	Power Px	Spark Spread	Capacity $ / MW-Day									
$ / MMBTu	$/MWh	$/MWh	-	50	75	100	125	150	175	200	225	250
4.0	34.0	6.8	-3.5%	-2.2%	-1.0%	0.3%	1.5%	2.8%	4.0%	5.3%	6.5%	7.8%
4.5	38.3	7.7	-2.8%	-1.5%	-0.3%	1.0%	2.2%	3.5%	4.7%	6.0%	7.2%	8.5%
5.0	42.5	8.5	-2.1%	-0.8%	0.4%	1.7%	2.9%	4.2%	5.4%	6.7%	7.9%	9.2%
5.5	46.8	9.4	-1.4%	-0.1%	1.1%	2.4%	3.6%	4.9%	6.1%	7.4%	8.6%	9.9%
6.0	51.0	10.2	-0.7%	0.6%	1.8%	3.1%	4.3%	5.6%	6.8%	8.1%	9.3%	10.6%
6.5	55.3	11.1	0.0%	1.3%	2.5%	3.8%	5.0%	6.3%	7.5%	8.8%	10.0%	11.3%
7.0	59.5	11.9	0.7%	2.0%	3.2%	4.5%	5.7%	7.0%	8.2%	9.5%	10.7%	12.0%
7.5	63.8	12.8	1.4%	2.7%	3.9%	5.2%	6.4%	7.7%	8.9%	10.2%	11.4%	12.7%
8.0	68.0	13.6	2.1%	3.4%	4.6%	5.9%	7.1%	8.4%	9.6%	10.9%	12.1%	13.4%
8.5	72.3	14.5	2.8%	4.1%	5.3%	6.6%	7.8%	9.1%	10.3%	11.6%	12.8%	14.1%
9.0	76.5	15.3	3.5%	4.8%	6.0%	7.3%	8.5%	9.8%	11.0%	12.3%	13.5%	14.8%

Source: Company data, Credit Suisse estimates

Exhibit 102: **Gas Peaker ROE @ $700 / KW, 11 On Peak Market HR, 9 Plant HR, 15% Utilization**

Gas Px	Power Px	Spark Spread	Capacity $ / MW-Day									
$ / MMBTu	$/MWh	$/MWh	-	50	75	100	125	150	175	200	225	250
4.0	44.0	8.00	-4.0%	-2.4%	-0.8%	0.8%	2.4%	4.0%	5.6%	7.3%	8.9%	10.5%
4.5	49.5	9.00	-3.8%	-2.2%	-0.5%	1.1%	2.7%	4.3%	5.9%	7.5%	9.1%	10.7%
5.0	55.0	10.00	-3.5%	-1.9%	-0.3%	1.3%	2.9%	4.5%	6.1%	7.7%	9.4%	11.0%
5.5	60.5	11.00	-3.3%	-1.7%	-0.1%	1.6%	3.2%	4.8%	6.4%	8.0%	9.6%	11.2%
6.0	66.0	12.00	-3.0%	-1.4%	0.2%	1.8%	3.4%	5.0%	6.6%	8.2%	9.8%	11.5%
6.5	71.5	13.00	-2.8%	-1.2%	0.4%	2.0%	3.6%	5.3%	6.9%	8.5%	10.1%	11.7%
7.0	77.0	14.00	-2.5%	-0.9%	0.7%	2.3%	3.9%	5.5%	7.1%	8.7%	10.3%	11.9%
7.5	82.5	15.00	-2.3%	-0.7%	0.9%	2.5%	4.1%	5.7%	7.4%	9.0%	10.6%	12.2%
8.0	88.0	16.00	-2.1%	-0.4%	1.2%	2.8%	4.4%	6.0%	7.6%	9.2%	10.8%	12.4%
8.5	93.5	17.00	-1.8%	-0.2%	1.4%	3.0%	4.6%	6.2%	7.8%	9.5%	11.1%	12.7%
9.0	99.0	18.00	-1.6%	0.0%	1.6%	3.3%	4.9%	6.5%	8.1%	9.7%	11.3%	12.9%

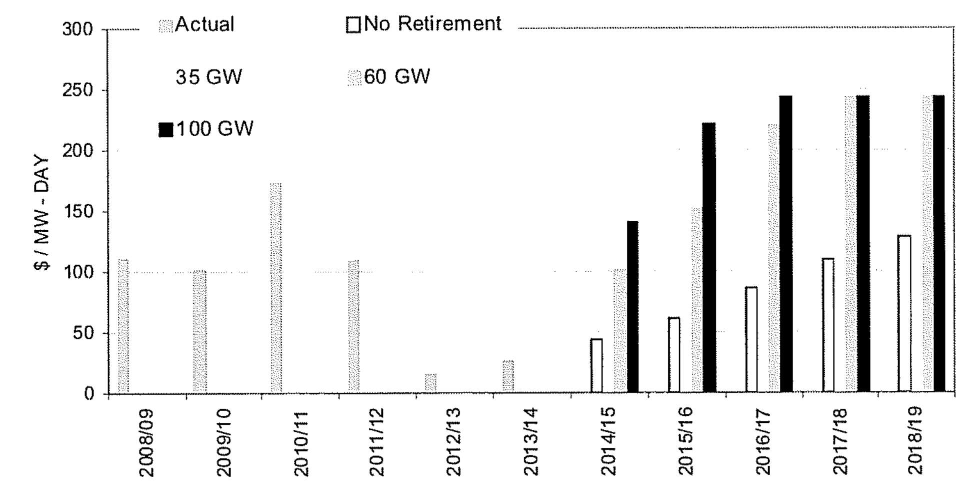
Source: Company data, Credit Suisse estimates

Capacity Payment Forecast

Based on our forecasts for reserve margins and net CONE, we show capacity prices under a range of outcomes (Exhibit 103). We see capacity payments approaching $100 / MW-day for the next auction if generators make responsible economic decisions and start to retire low quality coal plants in 2013 (under our 60 GW retirement scenario). Under the all un-scrubbed coal plant closure (100 GW) scenario, our reserve margins reaches 15% in 16/17, boosting RTO capacity payments to about as high as EMAAC prices.

We forecast RTO capacity payment close to $100 / MW-Day for '14/15 planning year under our "60 GW" retirement scenarios

Exhibit 103: **RTO Capacity Revenue Forecast**



Source: Company data, Credit Suisse estimates

Earnings Impact

From the increase in capacity payments alone, we see a significant lift in earnings for companies with RTO exposure. Edison International (EIX) is the only company in our coverage universe that stands to lose if it were to shut down all un-scrubbed coal fleet when required capex by the mercury MACT becomes prohibitive assuming their proposed alternative compliance approach does not work; we think this is a punitive outcome for EIX but does reflect the challenge and uncertainty associated with environmental control compliance strategies. In Exhibit 104 we show the increase in EBITDA and EPS from our scenario assuming 60 GW are closed and Exhibit 105 shows impact from all un-scrubbed coal plants closure (100 GW).

Exhibit 104: **EPS / EBITDA Impact (60 GW Coal Plants Closure versus "Do Nothing")**

EBITDA Impact	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
AYE	122	187	270	260	207	199
D	39	58	82	76	56	54
EIX	100	153	218	208	162	155
EXC	199	313	464	467	395	382
FE	252	396	582	580	485	468
NEE	15	24	36	36	31	30
PEG	-	-	-	-	-	-
RRI	49	69	98	79	37	32

EPS Impact	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
AYE	0.47	0.72	1.03	1.00	0.79	0.76
D	0.04	0.06	0.09	0.08	0.06	0.06
EIX	0.20	0.30	0.44	0.41	0.32	0.31
EXC	0.20	0.31	0.46	0.46	0.39	0.38
FE	0.54	0.84	1.24	1.24	1.03	1.00
NEE	0.02	0.04	0.06	0.06	0.05	0.05
PEG	-	-	-	-	-	-
RRI	0.09	0.13	0.18	0.14	0.07	0.06

RTO Capacity ($ / MW-Day)						
60 GW Retire	101.16	151	220	243	243	243
Do Nothing	44.29	61	87	109	129	133

Source: Company data, Credit Suisse estimates

Exhibit 105: **EPS / EBITDA Impact (100 GW Coal Plants Closure versus "Do Nothing")**

EBITDA Impact	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
AYE	209	338	319	261	208	200
D	60	89	72	44	19	16
EIX	77	35	(96)	(235)	(370)	(376)
EXC	341	565	551	473	403	389
FE	425	693	662	550	449	432
NEE	26	44	43	36	31	30
PEG	-	-	-	-	-	-
RRI	107	175	163	130	99	95

EPS Impact	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
AYE	0.80	1.30	1.22	1.00	0.80	0.77
D	0.07	0.10	0.08	0.05	0.02	0.02
EIX	0.15	0.07	(0.19)	(0.47)	(0.74)	(0.75)
EXC	0.34	0.56	0.54	0.46	0.40	0.38
FE	0.91	1.48	1.41	1.17	0.96	0.92
NEE	0.04	0.07	0.07	0.06	0.05	0.05
PEG	-	-	-	-	-	-
RRI	0.20	0.32	0.30	0.24	0.18	0.17

RTO Capacity ($ / MW-Day)						
100 GW Retire	141	222	243	243	243	243
Do Nothing	44	61	87	109	129	133

Source: Company data, Credit Suisse estimates

Mostly Winners and Bigger Winners

Rarely in our experience do the words 'we're from the government and we're here to help' translate into widespread opportunity to profit but our math would suggest EPA policy action could help basically all of our companies although some are positioned to benefit much more than others. The typical response to such a statement is that "aren't those closing plants at risk" which they are for those plants, but rarely does a company only own small, high polluting plants. By culling the herd of bad plants, the good plants can more than offset the losses. For regulated utilities this is mostly a game of rate base growth to the level regulators will allow a fair recovery on capital to be spent.

Integrateds and Independent Power Producers

Biggest winners are FE, AYE, EXC and RRI

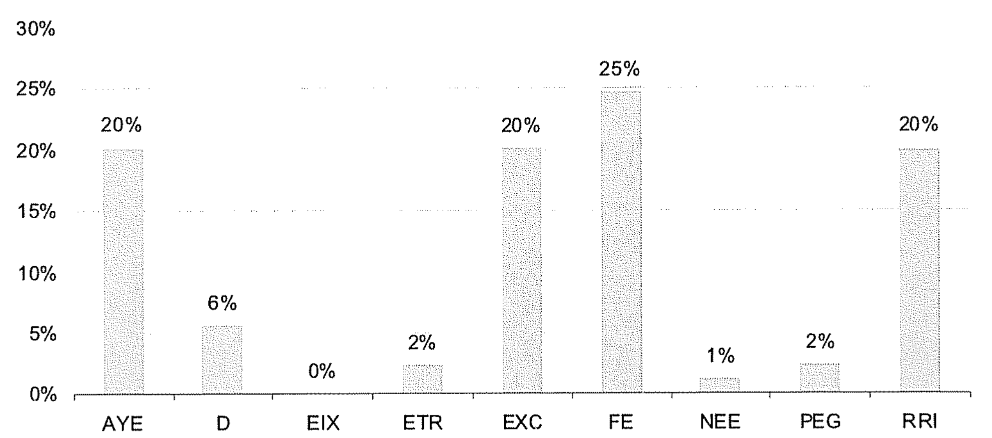
Intuitively, in deregulated markets the companies that benefit most from EPA regulation and associated coal plant retirement are those with clean plants in dirty markets. We see FE, AYE, EXC, and RRI being the biggest winners from coal plant closures while gas-on-gas market participants PEG, ETR and NEE are likely to see the least impact.

Sensitivities to plant Closures

To fully appreciate each stocks sensitivities to various closure outcomes we ran three ranging scenarios (i) 35 GW closure, representing half of the small coal fleet today that lacks scrubbers, (ii) 60 GW closure, representing all of the small coal plants lacking environmental controls plus half of the small plants that have SCRs but no scrubbers, and (iii) 103 GW closure, representing all the coal plants that lack all environmental controls but assumes plants with either just a scrubber or just a SCR are retrofitted. *See Appendix III for 2010-20 company-by-company earnings sensitivities.*

From these scenarios we are able to see where the greatest sensitivities lie and in Exhibit 106 we see biggest beneficiaries are within the coal heavy Western PJM; specifically FE, AYE, EXC and RRI.

Exhibit 106: **Impact on Valuation**



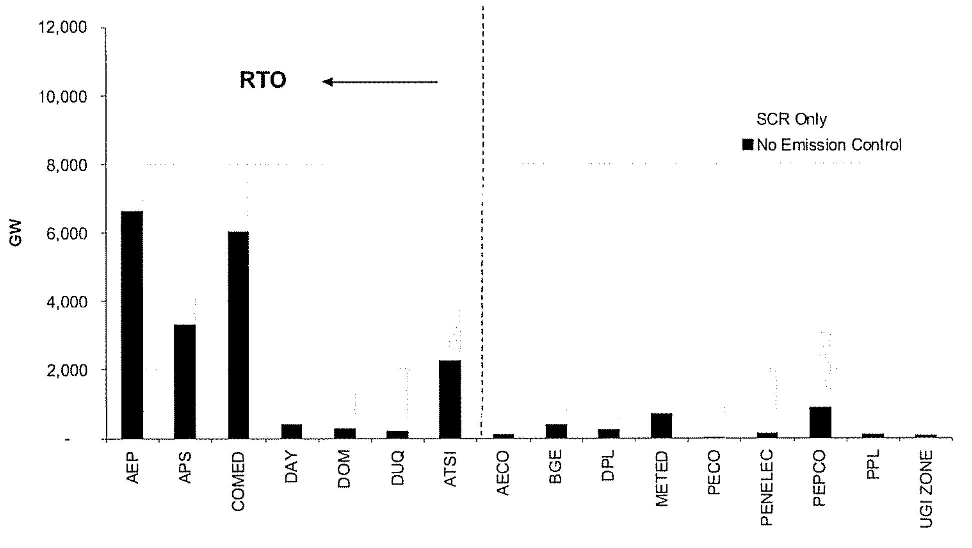
Source: Company data, Credit Suisse estimates

Double digit increase in target price for FE, EXC and AYE

PJM – West is the Best

PJM's RTO market looks to be the obvious winner from EPA policy with Exhibit 107 illustrating the sizable coal fleets at risk with the standout opportunities being within AYE's APS and FE's ATSI zones.

Exhibit 107: **Un-Scrubbed Coal Capacity in PJM Zones**



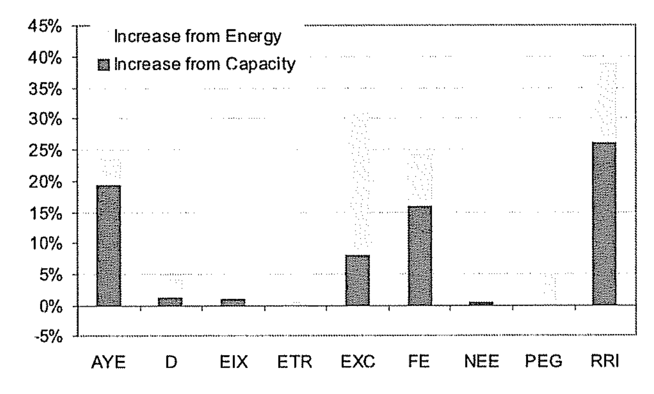
Source: Company data, Credit Suisse estimates

Capacity vs Energy

PJM's de-regulated market offers both energy and capacity payment. The purpose of the capacity market is to put into place proper incentives for newbuild by offering 3-year forward capacity payments (aka monetary signal) to help facilitate and de-risk needed newbuild. We believe that the least efficient coal plant will be retired first which is likely not to nudge energy prices anywhere near newbuild economics so therefore require capacity markets to fill the gap in order to maintain the requisite 15% reserve margin (capacity markets are further discussed on page 48).

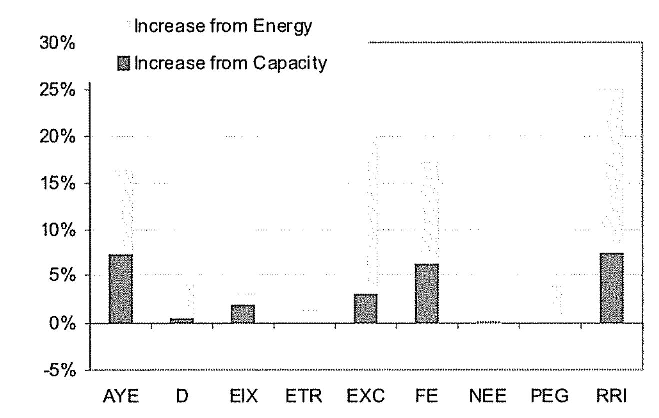
Exhibit 108 and Exhibit 109 help illustrate the source of revenues between energy and capacity and again RTO located providers benefit more on a relative basis given the currently depressed capacity payment vs the higher priced eastern PJM participants. Also when breaking apart the energy and capacity the more coal heavy names like AYE and RRI benefit more from capacity payments as their fuel costs inflate with market power price however EXC and FE's lower cost nuclear plant benefit more from energy.

Exhibit 108: **2015 EBITDA Impact (All Un-Scrubbed Coal Retire)**



Source: Company data, Credit Suisse estimates

Exhibit 109: **2015 EBITDA Impact (60 GW Small Coal Retire)**

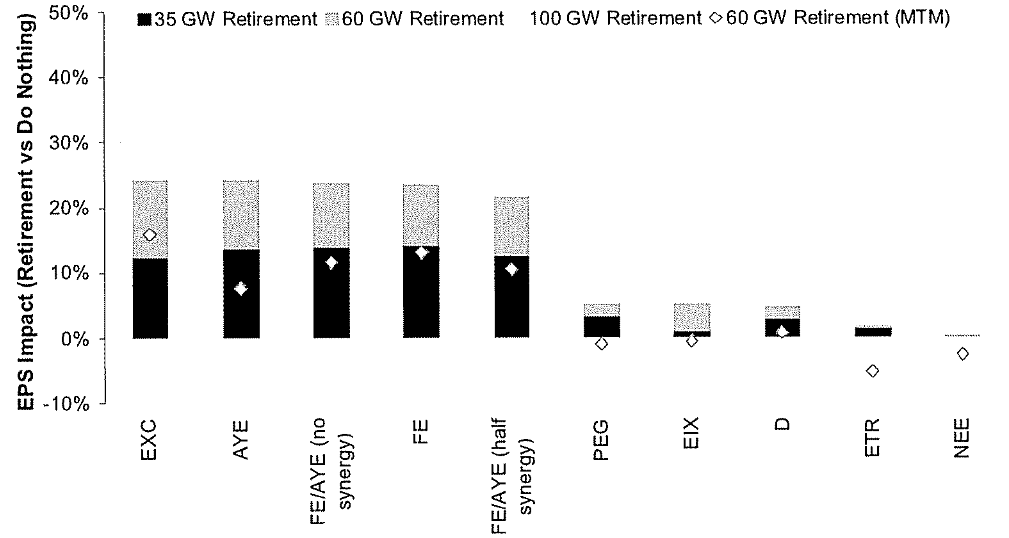


Source: Company data, Credit Suisse estimates

Year by Year Earnings Impact

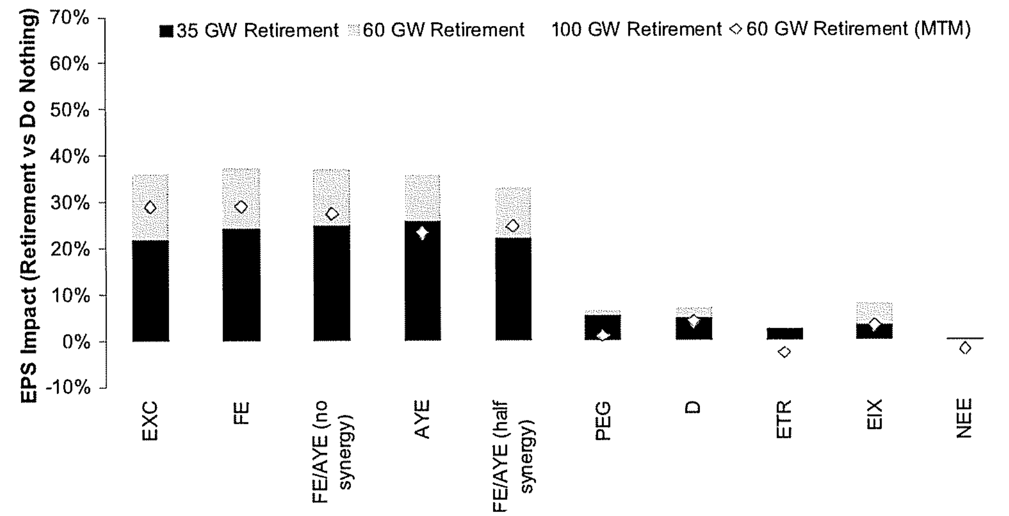
In Exhibit 110 - Exhibit 112 we show earnings impact in 2014/15/16 under our coal closure scenarios.

Exhibit 110: **2014 EPS Impact From Coal Plant Retirements**



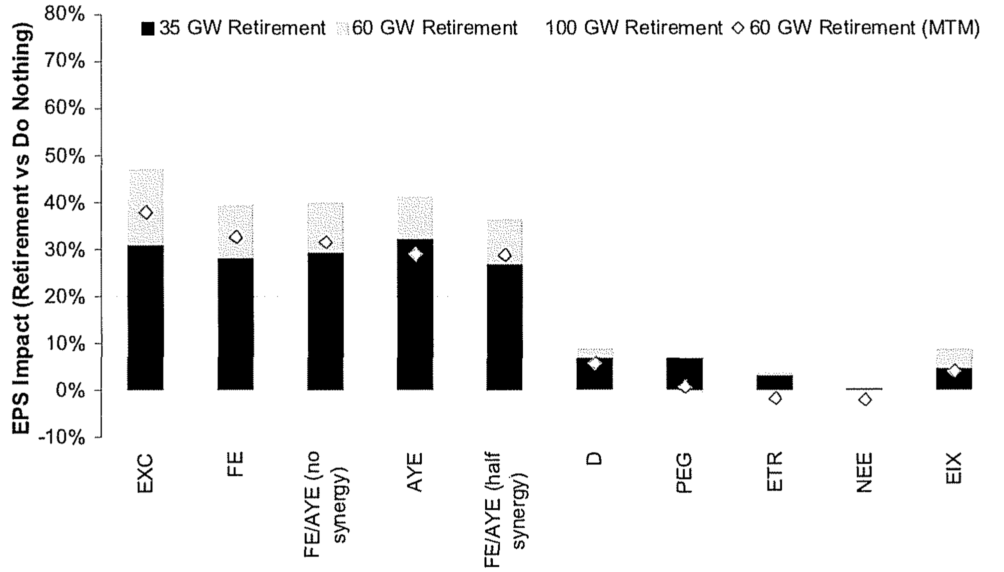
Source: Company data, Credit Suisse estimates

Exhibit 111: **2015 EPS Impact From Coal Plant Retirements**



Source: Company data, Credit Suisse estimates

Exhibit 112: **2016 EPS Impact From Coal Plant Retirements**



Source: Company data, Credit Suisse estimates

Regulated Companies

EPA policy could be catalyst for next build cycle for the regulated companies

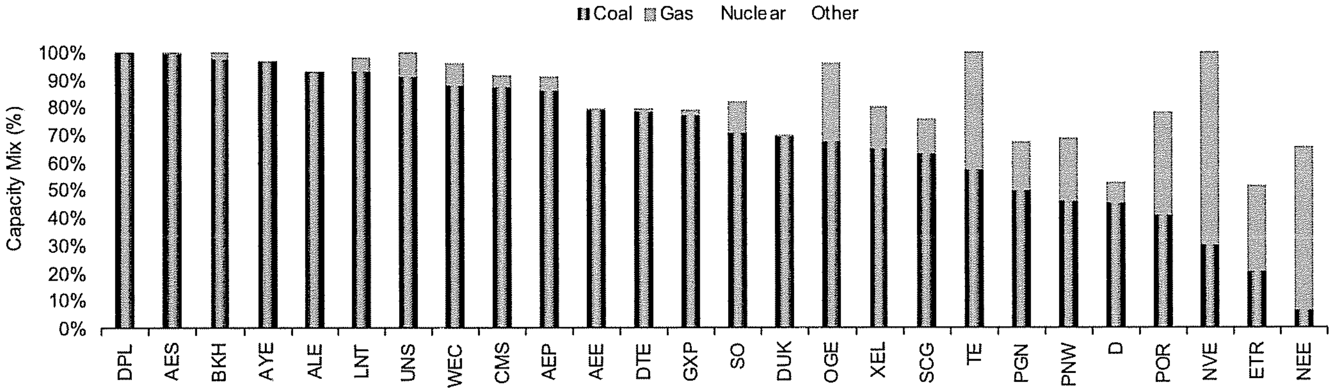
We see likely EPA policy as a catalyst to the next rebuild cycle with the decision tree being much different than for its competitive peers since Regulateds will take a broader look at system reliability and fuel diversity when making decisions between newbuild and retrofit. On average we see the EPA rules as prospectively boosting EPS growth rates by ~2% for the group through higher levels of spending net of equity funding (Exhibit 114), with 3+% growth prospects of ALE, GXP, LNT, OGE and DTE.

The Regulated Approach

Coal generation is clearly the backbone of today's regulated utility fleet – as shown in Exhibit 113 – which will make the reinvest versus replace decision different than the approach taken by merchant generators. We think the decision making process for Regulateds will be more holistic in nature and incorporate considerations beyond near-term economics; most notably: (a) benefits of diversified fuel mix, (b) local politics and dependence of local economy on fuel type, meaning shutting down coal facilities in Virginia or other coal heavy states seems less likely with retrofit a more palatable alternative, and (c) sourcing and infrastructure in place of current fuel supply with mine-mouth coal plants likely having more staying power.

As it pertains to the regulatory process, each PUC presides over cost of capital mechanisms, allowed rate base, accounting mechanisms, and all other items that broadly determine the utility's customer rates. Recovery of environmental remediation is unique in every jurisdiction but broadly environmental compliance costs are passed directly to customers (treated like fuel expense) although larger scale capital programs will likely require rate cases to help de-risk and solidify terms of the spending. A full rate case normally takes 6-18 months.

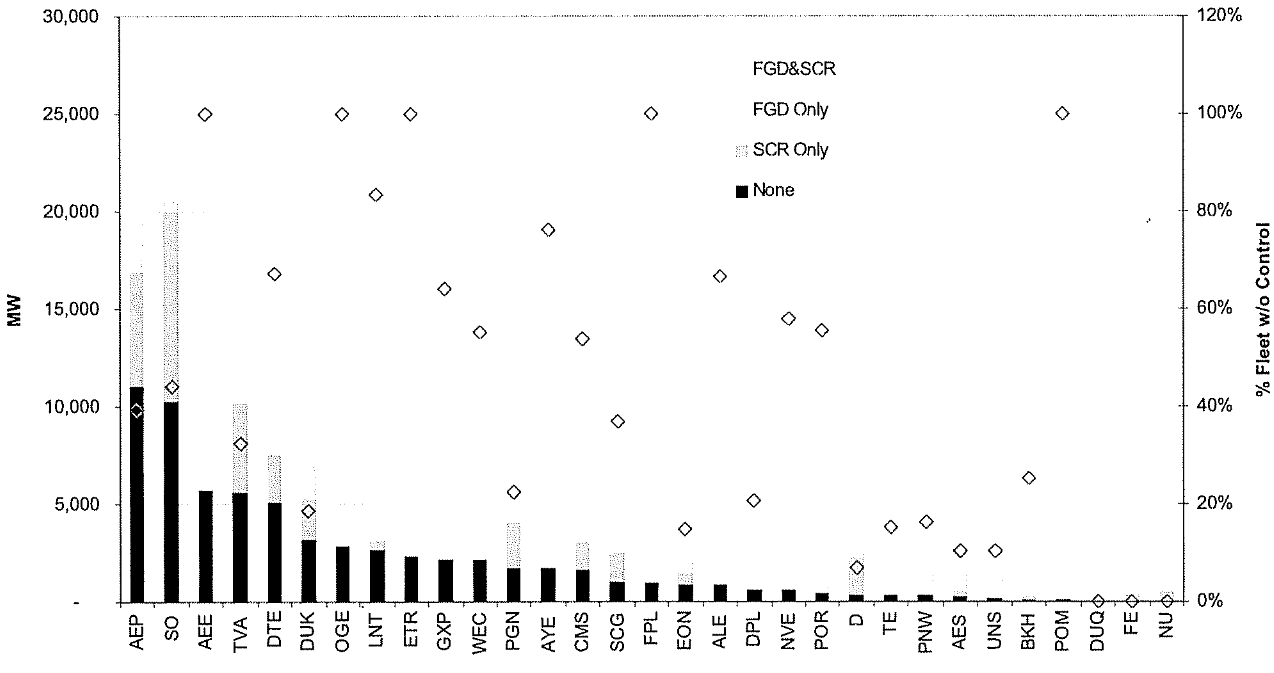
Exhibit 113: **Regulated Generation Capacity Mix (%)**



Source: SNL Financial

Looking to the clean versus dirty coal conversation, Exhibit 114 shows the respective regulated company's coal plant emission profiles. Not surprisingly, the biggest coal users AEP and SO have the biggest un-scrubbed coal capacity.

Exhibit 114: **Regulated Utilities Coal Plants By Emission Control**



Source: Company data, Credit Suisse estimates

Impact on Growth from Environmental Remediation

Consistent with our approach to competitive markets, our analysis in Exhibit 115 provides a 'middle of the road impact' scenario for the regulated companies assuming all small coal plants lacking any emission controls will be replaced by CCGTs and all big plants with no controls will be retrofitted with a scrubber and SCR.

ALE, GXP see the biggest earnings growth from the EPA policy; AEP, DTE and SO also benefit significantly

We should note the math in Exhibit 115 - Exhibit 118 assumes the utilities are willing to maintain current reserve margins; with many markets currently over supplied the utilities might use some plant closures to simply better balance their supply-demand dynamics.

Exhibit 115 calculates implied EPS growth lift and incremental growth rates using the calculated replacement capex along with an earned 9.5% ROE on new environmental investment, 50% equity ratio, and retention ratio of 25% of net income to offset future equity issuance needs (or a 75% payout ratio). The biggest winners on earnings growth are those with higher percentages of un-scrubbed coal.

Exhibit 115: Capex / EPS Impact

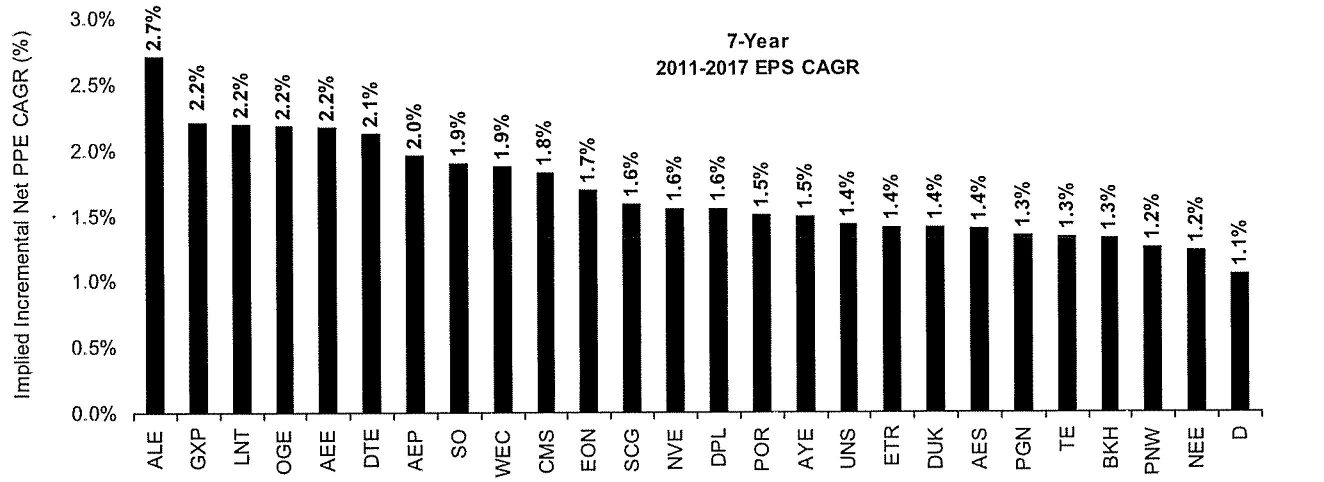
	Generation Mix		Implied Capital Expenditures				EPS Impact			
	Un-Scrubbed Plant (Not Inc. Planned Emission Ctrl)		Replace Small Plant with CCGT *$900/kW*	Retrofit Big Plant *$600/kW*	Total Implied Capex	% Net PPE	Incremental Diluted EPS	5-Year EPS CAGR	7-Year EPS CAGR	Cumulative Earnings Growth
Ticker	**Small (MW)**	**Large (MW)**	**$MM**	**$MM**	**$MM**	**(%)**	**$ / Share**	**%**	**%**	**%**
ALE	518	365	466	219	685	42%	0.83	3.8%	2.7%	20.6%
GXP	759	1,400	683	840	1,523	23%	0.46	3.1%	2.2%	16.5%
LNT	1,210	1,425	1,089	855	1,944	33%	0.75	3.1%	2.2%	16.5%
OGE	-	2,854	-	1,712	1,712	29%	0.76	3.1%	2.2%	16.4%
AEE	564	5,090	508	3,054	3,561	20%	0.63	3.1%	2.2%	16.3%
DTE	1,661	3,391	1,495	2,034	3,530	28%	0.91	3.0%	2.1%	15.9%
AEP	4,402	6,632	3,962	3,979	7,941	23%	0.72	2.7%	2.0%	14.5%
SO	5,259	4,970	4,733	2,982	7,715	20%	0.43	2.7%	1.9%	14.1%
WEC	1,715	419	1,543	251	1,794	20%	0.70	2.6%	1.9%	13.9%
CMS	1,236	404	1,112	242	1,355	14%	0.25	2.6%	1.8%	13.5%
EON	443	446	399	268	667	1%	0.02	2.4%	1.7%	12.5%
SCG	1,061	-	955	-	955	11%	0.36	2.2%	1.6%	11.7%
NVE	576	-	518	-	518	6%	0.11	2.2%	1.6%	11.4%
DPL	414	230	373	138	511	18%	0.21	2.2%	1.6%	11.4%
POR	-	391	-	234	234	6%	0.15	2.1%	1.5%	11.0%
AYE	532	-	479	-	479	5%	0.14	2.1%	1.5%	10.9%
UNS	173	-	156	-	156	6%	0.19	2.0%	1.4%	10.5%
ETR	2	2,352	2	1,411	1,413	6%	0.37	2.0%	1.4%	10.3%
DUK	2,657	560	2,391	336	2,727	7%	0.10	2.0%	1.4%	10.3%
AES	302	-	271	-	271	1%	0.02	2.0%	1.4%	10.3%
PGN	747	964	672	579	1,251	6%	0.21	1.9%	1.3%	9.8%
TE	326	-	294	-	294	5%	0.07	1.9%	1.3%	9.8%
BKH	125	-	112	-	112	5%	0.14	1.9%	1.3%	9.7%
PNW	312	-	281	-	281	3%	0.13	1.8%	1.2%	9.1%
NEE	-	952	-	571	571	2%	0.07	1.7%	1.2%	8.9%
D	367	-	330	-	330	1%	0.03	1.5%	1.1%	7.6%
TVA	5,634	-	5,071	-	NA	NA	n/a	n/a	n/a	n/a
Total	**31,872**	**36,961**	**28,685**	**22,177**	**45,791**	**10%**		**2.3%**	**1.6%**	**11.9%**

Source: Company data, Credit Suisse estimates

A Growth Opportunity

In seeking to measure opportunity from likely EPA regulation, we measure prospective growth on an asset and earnings per share basis. In this analysis we assume a 5-year compliance cycle (2013-2017) but annualize over a 7-year period (2011-17) on the belief that EPA remediation will move slowly at first and then be fully implemented once EPA policy is finalized.

Exhibit 116: 2011-2017 EPS CAGR

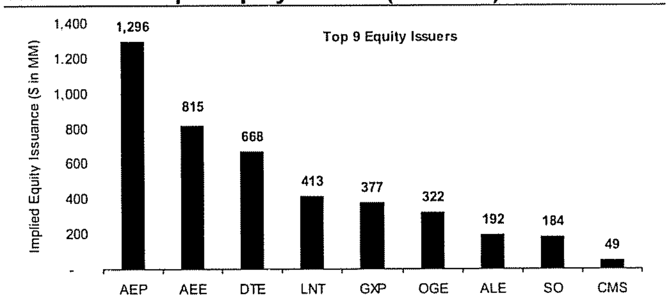


Source: Company data, Credit Suisse estimates

Equity Issuance

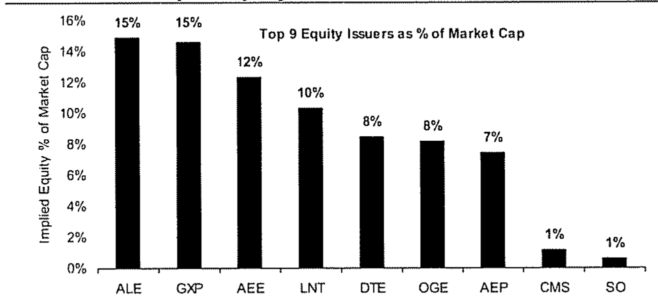
Exhibit 117 and Exhibit 118 highlight the top 9 expected equity issuances required to support the environmental related capex in absolute and relative to market cap terms. Clearly EPA capex could crowd-out other spending priorities which would lessen the funding needs shown but we think the analysis provides an interesting look at future funding requirements on an even footing.

Exhibit 117: Top 9 Equity Issuers (absolute)



Source: Company data, Credit Suisse estimates

Exhibit 118: Top 9 Equity Issuers Relative to Market Cap



Source: Company data, Credit Suisse estimates

Impact on Coal and Natural Gas Demand

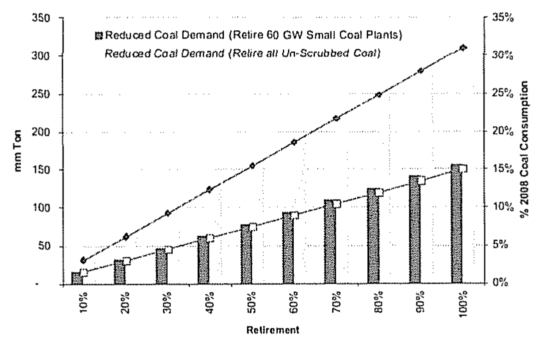
While we focus much of our work on the impact of EPA regulation on the power sector, implementation of CATR for SOx / NOx and MACT for mercury will have flow through implications for long-term natural gas and coal demand.

Coal Demand Clearly At Risk

8 – 15% of US steam coal market could disappear

We think EPA regulations, especially the mercury MACT standard, will lead to a decline in US steam coal consumption as some portion of non-compliant plants are retired rather than retrofitted. As shown in Exhibit 119 and Exhibit 119, using 2008 data we see 324 MM tons (or 31%) of the ~1 BN tons US steam coal market was from coal plants lacking any environmental controls. Narrowing the analysis to small coal plants (60 GW), coal consumption was 157 MM tons / year or 15% of US stream coal market.

Exhibit 119: Impact on Coal Demand from Coal Plant Retirement



Source: Company data, Credit Suisse estimates

Exhibit 120: Impact on Coal Demand from Coal Plant Retirement

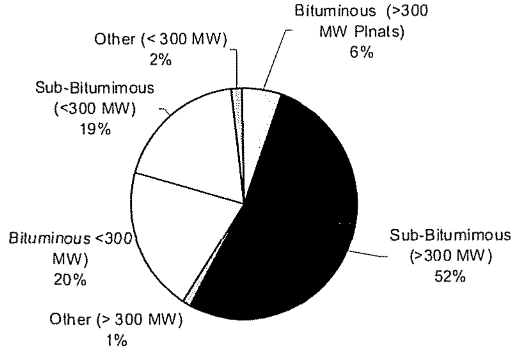
Retirement Percentage	100 GW Reduced Coal Demand	100 GW % 2008 Coal Comsumption	60 GW Reduced Coal Demand	60 GW % 2008 Coal Comsumption
10%	32	3%	16	2%
20%	65	6%	31	3%
30%	97	9%	47	5%
40%	129	12%	63	6%
50%	162	16%	78	8%
60%	194	19%	94	9%
70%	227	22%	110	11%
80%	259	25%	125	12%
90%	291	28%	141	14%
100%	324	31%	157	15%

Source: Company data, Credit Suisse estimates

We think there could be an argument made for higher impact to the sub-bituminous coal market since it represents more than 70% of coal consumed by un-scrubbed coal plants in 2008 (Exhibit 121), most likely as a result of western coal's lower sulfur contents, and western states not covered by CAIR. With the coming mercury MACT standard, coal plants in western states will be required to install emission control which they have been able to avoid so far. That said, as western states are mostly regulated, the investment decision could be hard to predict.

More interesting, however, is the breakdown of coal supply at risk when looking to the smaller plants which we think are more vulnerable to closure in Exhibit 122 and Exhibit 123 . Here we see half of the coal supply at risk is from bituminous (eastern) coal.

Exhibit 121: Coal Consumption by Coal Plants with No Emission Controls



Source: Company data, Credit Suisse estimates

Exhibit 122: Un-Controlled Coal Plant by Type of Coal Burned (MW)

Region	Bituminous (Eastern) Coal	Sub-Bituminous (Western) Coal	Other	Total
California ISO	293	38	130	461
ERCOT ISO	-	2,284	12	2,296
Midwest ISO	6,633	24,812	897	32,341
New England ISO	252	400	-	652
New York ISO	718	-	-	718
PJM ISO	12,802	6,152	599	19,553
SPP	539	15,547	2	16,087
WECC	2,270	5,200	-	7,469
SERC	13,846	7,185	757	21,787
Other	996	452	-	1,448
Total	**38,349**	**62,070**	**2,396**	**102,814**
%	*37%*	*60%*	*2%*	*100%*

Source: Energy Velocity, Company data, Credit Suisse estimates

Exhibit 123: Un-Controlled Plants Coal Burn by Type of Coal (MM ton)

Region	Bituminous (Eastern) Coal	Sub-Bituminous (Western) Coal	Other	Total
California ISO	1	0	0	1
ERCOT ISO	-	10	0	10
Midwest ISO	15	90	4	110
New England ISO	1	2	-	2
New York ISO	1	-	-	1
PJM ISO	25	20	3	48
SPP	2	58	-	60
WECC	7	20	-	26
SERC	30	30	1	61
Other	2	2	-	3
Total	**84**	**231**	**9**	**324**
% Regional Supply	*26%*	*71%*	*3%*	*100%*

Source: Energy Velocity, Company data, Credit Suisse estimates

Exhibit 124: Un-Controlled Small Coal Plant by Type of Coal Burned (MW)

Region	Bituminous (Eastern) Coal	Sub-Bituminous (Western) Coal	Other	Total
California ISO	293	38	130	461
ERCOT ISO	-	-	12	12
Midwest ISO	5,221	10,345	419	15,985
New England ISO	252	-	-	252
New York ISO	718	-	-	718
PJM ISO	8,962	644	235	9,841
SPP	539	3,106	2	3,646
WECC	1,781	2,003	-	3,785
SERC	12,821	1,299	757	14,877
Other	556	452	-	1,008
Total	**31,143**	**17,888**	**1,555**	**50,586**
%	*62%*	*35%*	*3%*	*100%*

Source: Energy Velocity, Company data, Credit Suisse estimates

Exhibit 125: Un-Controlled Small Plants Coal Burn by Type of Coal (MM ton)

Region	Bituminous (Eastern) Coal	Sub-Bituminous (Western) Coal	Other	Total
California ISO	1	0	0	1
ERCOT ISO	-	-	0	0
Midwest ISO	11	35	1	47
New England ISO	1	-	-	1
New York ISO	1	-	-	1
PJM ISO	16	2	2	21
SPP	2	11	-	13
WECC	5	7	-	13
SERC	28	5	1	34
Other	1	2	-	3
Total	**66**	**62**	**5**	**133**
% Regional Supply	*49%*	*47%*	*4%*	*100%*

Source: Energy Velocity, Company data, Credit Suisse estimates

Exhibit 126: Total Coal Plant by Type of Coal Burned (MW)

Region	Bituminous (Eastern) Coal	Sub-Bituminous (Western) Coal	Other	Total
California ISO	401	38	203	642
ERCOT ISO	-	7,659	11,245	18,904
Midwest ISO	27,424	44,774	4,833	77,030
New England ISO	2,475	400	-	2,875
New York ISO	1,938	1,063	-	3,001
PJM ISO	61,910	11,972	5,829	79,711
SPP	539	23,236	2,147	25,922
WECC	10,570	23,363	630	34,564
SERC	65,080	18,046	3,008	86,134
Other	9,966	1,445	627	12,037
Total	**180,302**	**131,996**	**28,522**	**340,820**
%	*53%*	*39%*	*8%*	*100%*

Source: Energy Velocity, Company data, Credit Suisse estimates

Exhibit 127: Coal Burn by Type of Coal (MM ton)

Region	Bituminous (Eastern) Coal	Sub-Bituminous (Western) Coal	Other	Total
California ISO	1	0	0	2
ERCOT ISO	-	32	51	83
Midwest ISO	71	156	26	253
New England ISO	7	2	-	8
New York ISO	5	4	-	9
PJM ISO	143	41	20	204
SPP	2	86	9	97
WECC	34	87	2	123
SERC	155	71	8	235
Other	24	6	1	31
Total	**441**	**485**	**117**	**1,044**
% Regional Supply	*42%*	*46%*	*11%*	*100%*

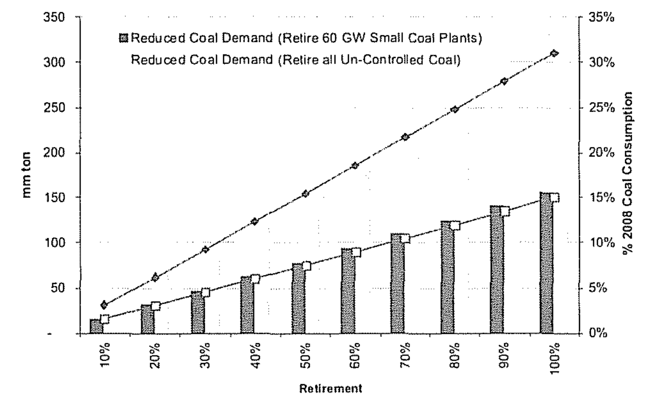
Source: Energy Velocity, Company data, Credit Suisse estimates

Natural Gas Demand Could Find a 5%+ bump

Increase in Gas Demand could be 1.8 – 3.7 TCF / year

As coal plants respond to CATR by closure or retrofit to be in compliance with 2012 / 2014 Phase I/II SOx cap, we expect incremental gas demand as early as 2012, although given phase I cap is only 18% lower than 2009 emission levels (versus 2014 target of 44% lower) we think the bigger impact to gas markets will probably begin in 2013. In Exhibit 128 and Exhibit 129 we show the change in natural gas demand assuming replacement of at risk coal plants with higher efficiency CCGTs. From this we see a 1.8 – 3.7 TCF increase in gas demand (+8-16% US gas consumption) all else equal.

Exhibit 128: Impact on Gas Demand from Coal Plant Retirement



Source: Company data, Credit Suisse estimates

Exhibit 129: Impact on Gas Demand from Coal Plant Retirement

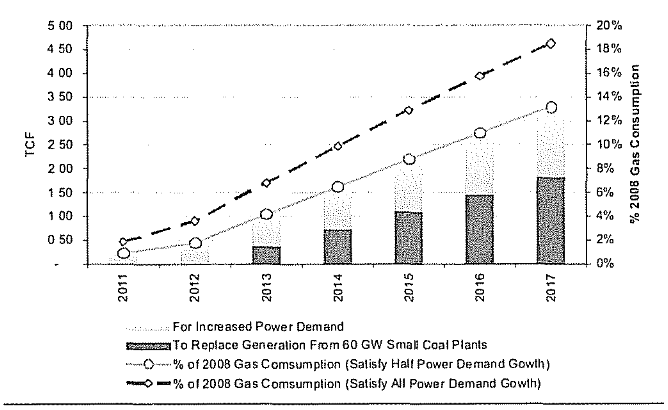
Retirement Percentage	100 GW Increased Nat Gas Demand (TCF)	100 GW % 2008 Gas Comsumption	60 GW Increased Nat Gas Demand (TCF)	60 GW % 2008 Gas Comsumption
10%	0.37	1.6%	0.18	0.8%
20%	0.74	3.2%	0.36	1.6%
30%	1.12	4.8%	0.54	2.3%
40%	1.49	6.4%	0.73	3.1%
50%	1.86	8.0%	0.91	3.9%
60%	2.23	9.6%	1.09	4.7%
70%	2.61	11.2%	1.27	5.5%
80%	2.98	12.8%	1.45	6.3%
90%	3.35	14.4%	1.63	7.0%
100%	3.72	16.0%	1.82	7.8%

Source: Company data, Credit Suisse estimates

Plus More Demand From Power Usage Growth

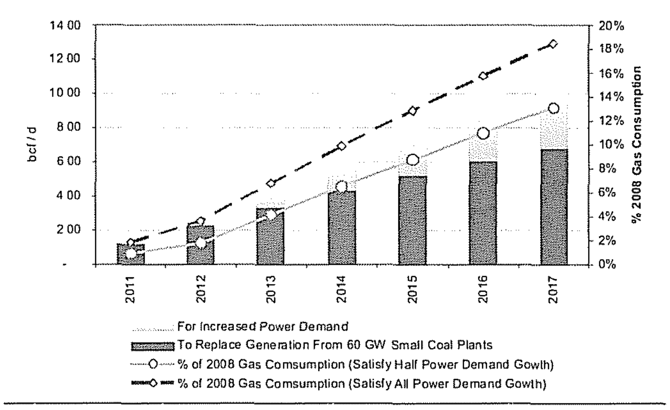
Gas fired generation will also need to satisfy incremental power demand (we think ~1.5% a year), which on a 7 year outlook would add another ~ 2.5 TCF on natural gas demand assuming natural gas is used to meet all power demand growth. Under a more realistic scenario that includes wind generation growth we see gas consumption accounting for half of the incremental power growth. Exhibit 130 and Exhibit 131 show the demand growth by year. The two growth rate outcomes reflect (a) over 60 GW coal plant retirements closure scenarios, and (b) half of market share for natural gas to meet electricity demand growth (we like the half assumption today). Raising overall natural gas growth by 13% in next seven years could create some interesting changes in pricing dynamics.

Exhibit 130: Incremental Natural Gas Demand from Power Demand Growth and Coal Plant Retirement (TCF)



Source: Company data, Credit Suisse estimates

Exhibit 131: Incremental Natural Gas Demand from Power Demand Growth and Coal Plant Retirement (bcf / d)



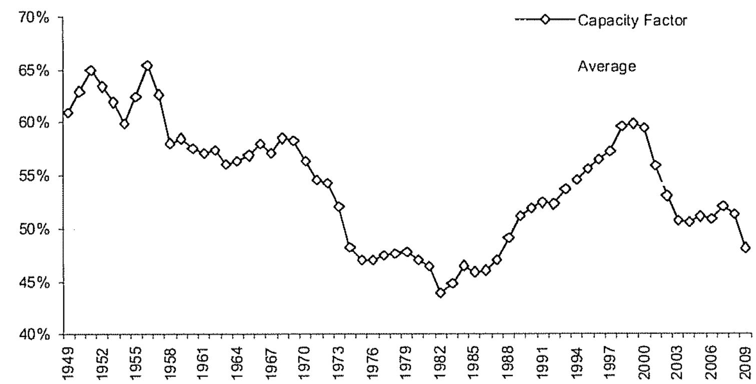
Source: Company data, Credit Suisse estimates

Can the Lost Coal Generation Be Replaced by CCGTs?

In 2009, capacity factor for the US generation fleet was below historical average, which prompted us to ask the question – can the existing fleet accommodate coal plant retirement? As coal plants are generally base load providers, nuclear plants are dispatched at nearly 100% of the time excluding refueling outages, and the intermittent nature of renewables makes them unsuitable as base load, we focus on Combined Cycle gas plants within the existing fleet to backfill lost capacity and output due to coal plant retirements.

In Exhibit 132 we calculate the required increase in capacity factor for combined cycle gas plants to completely back fill for un controlled coal generation. We found with the exception of MISO and SPP, most regions conceptually seem to be able to absorb the generation loss by dispatching CCGTs more, however, this exercise does not take into account the reserve margin requirements at peak demand, which in our mind, will be the driving factor for new construction when coal retirement starts.

Exhibit 132: US Generation Fleet Capacity Factor



Source: EIA, Energy Velocity, Credit Suisse estimates

Exhibit 133: Can Increased Runtime from Combined Cycle Replace Retired Coal Plants

CCGT	2009 Capacity (GW)	2008 Util% pro-forma	2008 Generation from Un-Scrubbed Coal (TWH)	CCGT Util% Increase to Backfill Lost Coal	CCGT Util%
California ISO	14	47%	-	0%	47%
ERCOT ISO	33	36%	16	6%	42%
Midwest ISO	14	12%	169	134%	146%
New England ISO	14	32%	5	4%	36%
New York ISO	9	37%	3	3%	40%
PJM ISO	26	16%	83	36%	52%
SPP	12	24%	97	94%	119%
SERC	41	25%	110	31%	55%
WECC	31	40%	45	17%	57%
Other	25	28%	5	2%	30%
Total	**219**	**29%**	**532**	**28%**	**57%**

CCGT	2010-13 Capacity Addition (GW)	2013 Capacity	2008 Util% (pro forma)	2008 generation from Un-Scrubbed Coal (TWH)	2008 -13 Demand Growth (TWH)	CCGT Util%
California ISO	5	19	47%	-	1	47%
ERCOT ISO	1	34	36%	16	32	52%
Midwest ISO	0	14	12%	169	17	159%
New England ISO	0	14	32%	5	(1)	35%
New York ISO	1	10	37%	3	(2)	38%
PJM ISO	2	28	16%	83	14	55%
SPP	-	12	24%	97	7	126%
SERC	-	41	25%	110	48	69%
WECC	9	40	40%	45	12	56%
Other	2	28	28%	5	8	33%
Total	**21**	**240**	**29%**	**532**	**147**	**62%**

Source: EIA, Company data, Credit Suisse estimates

Appendix I - Emission Control Technologies

We appreciate significant pages and words have been devoted to discussing the implications of EPA policy and the inevitable need for significant investment in order for plants to attain allowable emissions levels. To help put some intellectual context around how these standards are to be met, we thought an explanation of how the equipment that will be added actually works would be helpful.

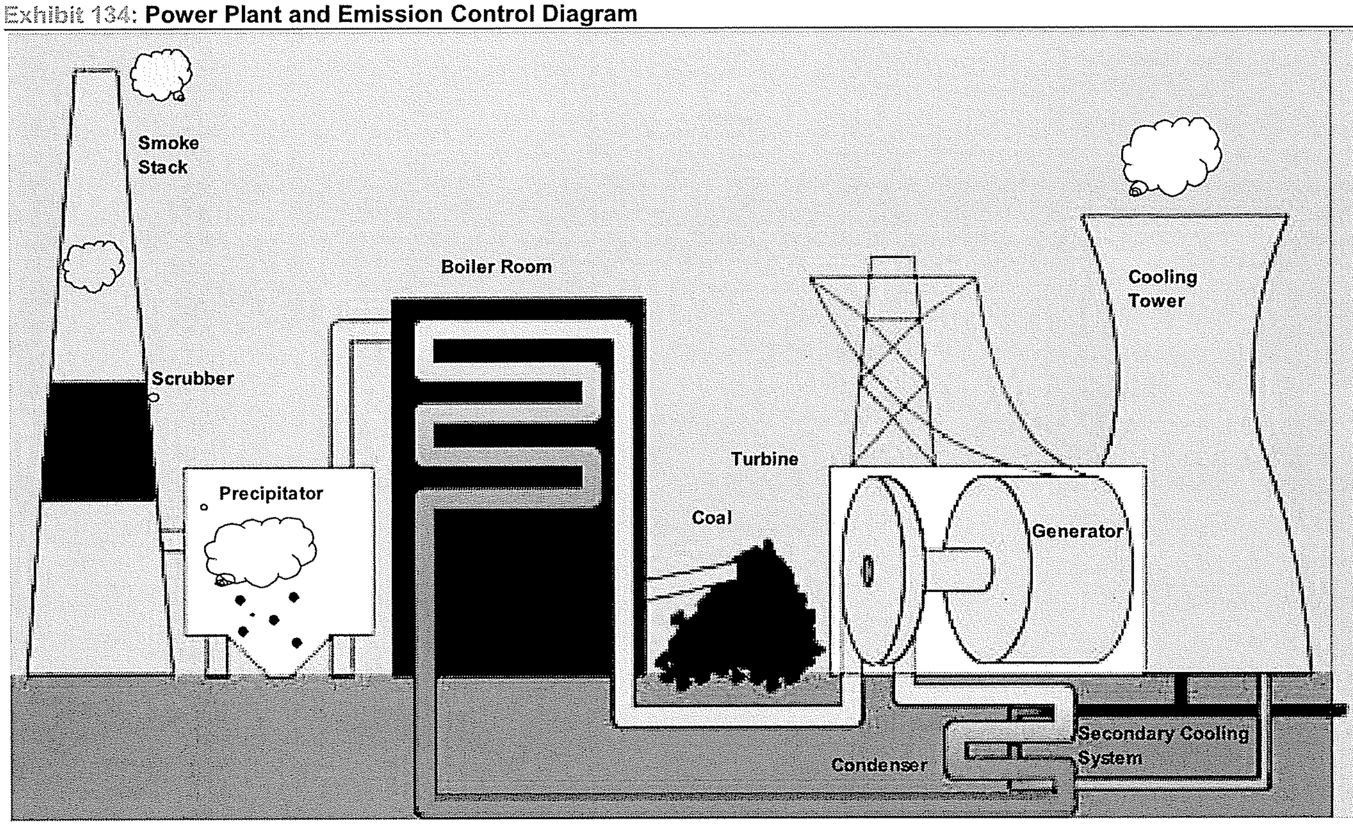
How does coal plant generate electricity from burning coal?

Exhibit 134 provides an easy to follow diagram of a coal plant. Following the exhibit from the center to the right, coal is moved into the boiler room where it is ignited, heating water in the water pipe covered walls of the boiler. The water turns to steam which is then delivered to the generator, turning the 'engine' and producing electricity which is then delivered to the electricity grid. Part of the steam is captured for re-use and part is released into the atmosphere through the cooling tower – for those who have driven by a power plant, the clouds billowing from the plants are generally released steam and not shocking amounts of pollutants (although coal plants do emit pollutants as well).

Going left from the boiler room, the waste product from coal combustion is delivered to a precipitator to capture large particles and is then delivered up through the smoke stack and ideally a scrubber where finer and more focused pollutant matter is captured. The remaining post combustion waste exits the top of the smoke stack into the atmosphere.

That out of the way, we can now focus on how the different pieces of the environmental control system works and what we are trying to eliminate.

Exhibit 134: Power Plant and Emission Control Diagram



http://www.its-about-time.com/investinesart/coalplantvirtualtour.swf

Source: Its-about-time.com

What we want to remove and why

Coal generators are leading emitters of three major pollutants Sulfur Dioxide (SOx), Nitrogen Oxide (NOx), and mercury (Hg), each of which have specific environmental impacts that should in good conscience be reduced:

- Sulfur Dioxide (SOx): acid rain and atmospheric particulates,
- Nitrogen Dioxide and Nitrogen Monoxide (NOx): brown haze and atmospheric particulates, and
- Mercury (Hg): birth defects, central nervous and endocrine system damage

Before drudging through the details of remediation, Exhibit 135 highlights the mechanisms we believe are best poised to remediate both SOx and NOx emissions under the CATR rules and mercury under the MACT rule. Interestingly, the type of coal burned will have an impact on remediation approaches and efficacy of these approaches.

Eastern Coal:

- **FGD / SCR / Activated Carbon**: This is the most effective approach but also most expensive (capex in the range of $450 –700 / KW) and, unfortunately, the only effective solution to reduce SOx for plants burning eastern coal.

Western Coal:

- **Dry Sorbent Injection (TrONA) / SNCR / Baghouse / Activated Carbon.** This is the cheapest for pollutants reduction in terms of capex, but dry sorbent injection only works well for lower sulfur western coal with performance levels still somewhat open for debate.

Exhibit 135: **Emission Control Technologies**

	CATR				Mercury MACT	
	Sulfur Oxide (SOx)		Nitrogen Oxide (NOx)		Mercury (Hg)	
	Scrubber	Dry Sorbent Injection	SCR	SNCR	Scrubber / SCR	Baghouse w/ ACI
Removal Rate	95%+	<70%	70-95%	30-75%	>90%	80-90%
Capex	$300 - 500 / kW	$50 / kW	$200-300 / kW	$30 - 75 / kW	$450 - 700 / kW	$150 /KW
Reagent	Limestone	TrONA	Ammonia	Ammonia or urea	Activated Carbon	Activated Carbon
Reagent Cost	-	-	0.47	0.47	0.94	0.94
Parasitic Load	3-5%	0%	0	0	3-5%	0.50%
Coal Efficiency	Eastern / Western	Western	Eastern / Western	Eastern / Western	Eastern / Western	Eastern / Western(1)

(1) Brominated Activated Carbon for Western Coal

Source: Company data, Credit Suisse estimates, EIA

SOx Emission Control

There are three commonly used SOx remediation alternatives available today: (a) dry scrubbers, (b) wet scrubbers, and (c) dry sorbent injection.

Wet and Dry Scrubbers

The term scrubber generally describes pollution control devices that use a sorbent to remove sulfur dioxide (SOx) from flue gases through chemical reactions. Retrofitting a coal plant with a scrubber is not much different than building an on-site chemical plant. The formal name for scrubber is flue gas desulfurization (FGD) unit and a scrubber is classified as either "wet" or "dry".

Wet Scrubbers

- In the wet scrubbing process, a liquid sorbent (such as limestone) is sprayed into the scrubber and comes into contact with SOx in the flue gas. Through chemical reactions a wet slurry waste containing sulfur is created, which is then captured.

- Wet scrubbing can achieve very high levels of SOx reductions, routinely ~95% with some up to 99% removal. Approximately 85% of the FGD systems installed in the US are wet scrubbers.

Dry Scrubbers

- In a dry scrubber, particles of dry sorbent (such as slaked lime) instead of liquid sorbent are injected into the flue gas. The flue gas leaving the absorber is not saturated with moisture, hence the name "dry".
- Dry scrubbing has traditionally achieved respectable levels of SOx control (up to 80% removal).

Dry Sorbent Injection (DSI) / TrONA

- DSI system injects dry sorbent (generally sodium or calcium based reagents, such as **TrONA**) into the flue gas that bonds with SOx and can be collected in gathering devices, such as baghouses or electrostatic precipitators.
- TrONA is one of the more often used reagents and is also commonly used to produce detergent. TrONA looks bountiful today with deposits exceeding 100 billion tons in the Green River Basin, Wyoming.
- DSI systems have traditionally achieved more modest levels of SOx removal in the range of 40-70%, although new designs have reached removal rates up to 90% SOx when mixed with lower sulfur PRB coal.
- DSI systems are usually easily retrofitted to existing coal plants and have lower capital costs (approximately $50 / KW). Offsetting this is the increased quantity of soluble compound in the fly ash that may prevent the fly ash from being sold as a concrete additive.

NOx Emission Control

There are two primary sources of NOx when burning fossil fuels: fuel and thermal NOx, Fuel NOx results from the combustion of nitrogen in the coal, while thermal NOx is formed when nitrogen in the air reacts with oxygen during combustion.

Selective Catalytic Reduction (SCR)

- The basic principle of SCR is the **reduction** of NOx to nitrogen and water by the reaction of NOx and ammonia within a **catalyst** bed, hence the name "selective catalytic reduction". Commonly used catalysts include titanium oxides, vanadium oxides, platinum and palladium.
- An SCR can provide headline reductions in NOx emissions approaching 100% but in practice commercial SCR systems can meet control targets of over 90%.

Selective Non-Catalytic Reduction (SNCR)

- An SNCR is similar in principle to SCR in that it uses an ammonia based chemical process to reduce NOx into nitrogen and water. The difference is that SNCR does not have a catalyst bed (hence the name "non-catalytic reduction"), which decreases its remediation levels to 30% at low temperatures to 75% at high temperatures (versus SCR steady state removal of >90%).

No solid or liquid waste is produced from either method.

Low NOx Burner (LNB)

- Low NOx Burners reduce NOx production by delaying the mix of fuel with air, allowing the early stage of combustion to take place at a low air / fuel ratio which lowers the temperature of combustion and reduces generation of NOx. LNB is frequently supplemented with Open Fire Air (OFA), which is air introduced into the furnace downstream of the low NOx burner to LNB to reduce carbon monoxide and unburned carbon in coal ash. With LNB and OFA, NOx reductions vary from 60 – 70%.

Particulate Matter (PM) Control

Separate from SOx and NOx, the Clean Air Act requires the EPA to set National Ambient Air Quality Standards (NAAQS) for particulate matters. The reason why we bring it up is that the pollutant control devises that capture Particulate Matter are helpful in mercury removal.

Electrostatic Precipitators (ESP)

- Electrostatic precipitators have been used for particulate control since 1923. They use an intense electric field that drives the negatively charged particular matters to the collecting electrodes.
- ESP's removal efficiency is determined by its size, treatment time, and the ratio of the surface area of the collection electrodes. Electrostatic precipitator's overall collection efficiencies can exceed 99.9% and efficiencies in excess of 99.5% are common.

Fabric Filters (Baghouses)

- Fabric filter is conceptually simple and acts like the name implies – a system of tightly woven fabric that flue gas passes through and leaves particulates collected in the fabric. The capture systems are quite large; for an average 250 MW plant the baghouse is a compilation of up to 5,000 discrete bags that stretch 20-30 feet long and 5-12 inches in diameter. Baghouses are often are capable of 99.9% removal efficiencies.

Mercury

The DOE reports that ~37% of the coal borne mercury is removed during coal cleaning processes (pre-burn) and about 50% of the remaining mercury is captured by the industry's existing pollution control systems. Capturing the remaining mercury emissions can be achieved through two approaches: activated carbon injection or multi-pollutant control.

Multi-Pollutant Control

- Mercury control can generally achieved by a suite of pollution control of SOx, NOx and particulate matter. A mercury removal rate of >90% has been experienced at coal plants equipped with FGD, SCR and Electrostatic Precipitators / Baghouse. Adding Activated Carbon further increases the mercury removal rate.

Activated Carbon Injection (ACI)

- This is one of the simplest approaches to controlling mercury emissions from coal plants. In this process mercury in the flue gas attaches to the large porous area of activated carbon which then is collected by either an ESP or baghouse. Generally speaking, baghouses with activated carbon can achieve a mercury removal rate up to 90% although the costs are high. Using ESP, the removal rate will be lower (<70%).

Important thing to know here is baghouse or an ESP is needed if the plant uses activated carbon to reduce mercury

- For this process to be effective for PRB coal, activated carbon has to be treated with Halogen such as Chlorine or Bromine (Chlorine is naturally occurring in coal, but its concentration is much lower in PRB coal than in eastern coal) which can be quite expensive (could double the cost).

Appendix II - EPA Regulation

EPA, under Obama administration, has become increasingly visible in shaping the nations environmental policy. We think the two pieces of regulations for coal emission that EPA is working on today (Clean Air Transport Rule and mercury MACT Standard) will be the catalyst for the industry's next investment cycle and play an integral role in deciding the future asset mix of US generation flee. We discuss their respective background below.

Clean Air Transport Rule (CATR)

By way of background, on **March 10, 2005**, EPA issued Clean Air Interstate Rule, a rule that capped emission of sulfur dioxide (SOx) and nitrogen oxides (NOx) in 28 eastern United States and District of Columbia. CAIR features a cap and trade program for SOx and NOx allowing purchase of allowances to offset emission.

CAIR was remanded to EPA by court since its cap and trade program failed to protect downwind states

Litigation began soon after CAIR was put in place from both environmentalists and the utility industry. On **December 23, 2008**, in the case of *North Carolina v. EPA,* the U.S. Court of Appeals for the D.C. Circuit ruled on petitions for review of CAIR, including their provisions establishing the CAIR NOx and SOx trading programs. The court deemed CAIR "flawed" as EPA can not provide evidence the cap and trade program improves air quality for down wind states. The Court remanded the rules to EPA without vacating them, which leaves CAIR and the trading programs in place until next version of CAIR (CATR) is finalized.

EPA issued Clean Air Transport Rule (CATR) proposal on July 6th, 2010, setting emission caps for SOx and NOx for 31 eastern states and DC. As shown in Exhibit 136 and Exhibit 137, the CATR rule imposes similar emission cap as CAIR but with compliance date one year earlier (2014 vs 2015). Without the national trading program, states with higher emissions that were allocated higher allowance in the SOx / NOx trading program will be under higher pressure to catch up giving difference in existing emission level. As shown in Exhibit 138, Ohio, Pennsylvania, Indiana, and Georgia are the top emission states in terms of contribution to the national SOX inventory.

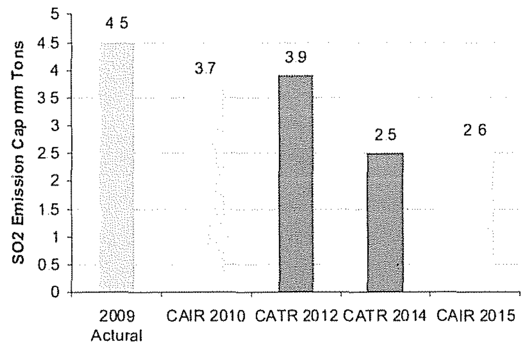
OH, PA, GA will have more work to do for CATR compliance

Implementation of CATR will be in two phases. In 2012, CATR states need to have SOX emission below Phase I cap (3.9 MM tons or 0.39 lb / MMBtu); by 2014 CATR will further reduce national SOX emissions to 2.5 MM tons (Phase II, 0.25 lb / MMBtu).

CATR does not target significant NOx reductions. In 2012, CATR states are required to be compliant with Phase I cap (1.4 MM tons) which is higher than 2009 actual emission level 1.3 MM tons. The story does not end here however, as the EPA believes additional NOx reduction will be needed to achieve ozone standards. Therefore the agency plans to propose Transport II in summer 2011 and finalize in summer 2012. There is no assurance how low the NOx cap could go but industry sources generally agree the risk is bounded,

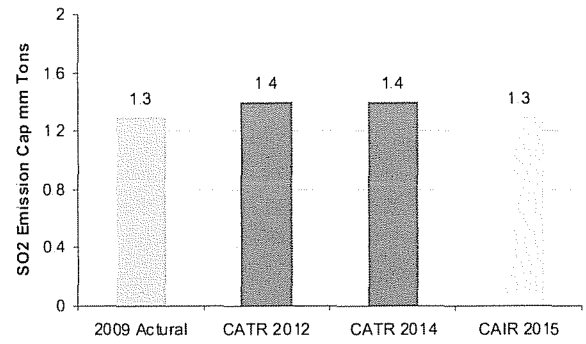
In terms of time frames, CATR allows Inter-year trading which means utilities can borrow ahead which provides cushion in compliance timing. Also worth noting, CATR will have limited regional trading for SOx and NOx but not at the national level since trading allows emission generated in upwind states to be offset by allowance bought from downwind states, and the court found the lack of locational emission protection to be flawed.

Exhibit 136: CATR vs CAIR for SOX Emission Cap (CATR states)



Source: Company data, Credit Suisse estimates, EPA

Exhibit 137: CATR vs CAIR for NOx Emission Cap (CATR states)



Source: Company data, Credit Suisse estimates, EPA

Mercury Rule

On **March 15, 2005,** EPA issued CAMR (Clean Air Mercury Rule) to permanently cap and reduce mercury emissions from coal-fired power plants for the first time.

The goal of CAMR was to reduce utility emissions of mercury from 48 tons a year to 15 tons, a reduction of nearly 70% in a two step approach with full compliance targeted for 2018.

On **February 8, 2008**, the D.C. Circuit vacated CAMR on the ground that EPA violated the Clean Air Act Section 112 as section 112 requires regulation of emissions of hazardous air pollutants, including Mercury, through enforcement of Maximum Achievable Control Technology (MACT) Standard as opposed to the adopted cap and trade approach. Again, the goal of the court decision was to better address localized pollutants which were lost in a cap and trade system.

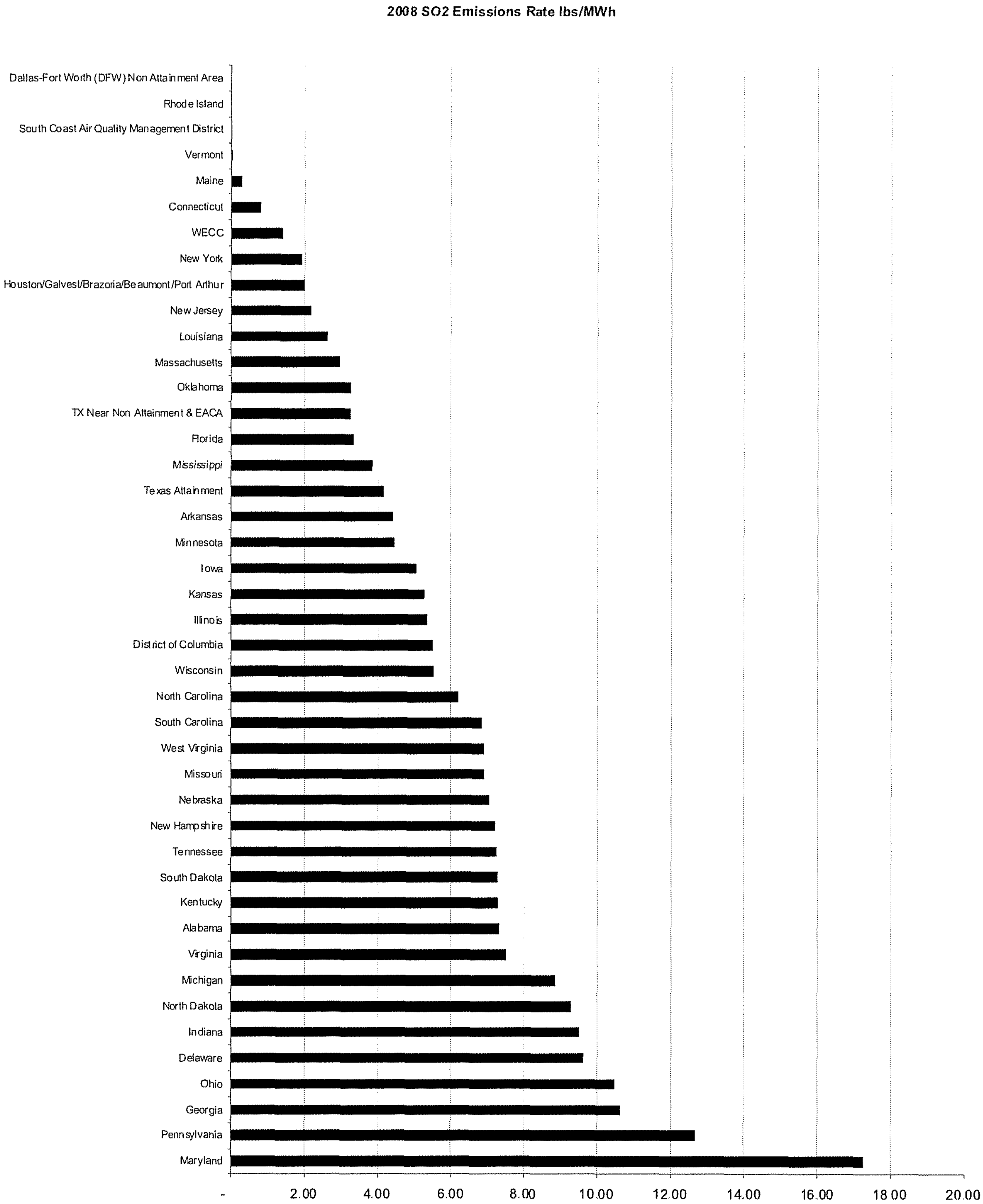
CAMR was vacated since Clean Air Act requires hazardous pollutant regulation to be MACT based

EPA is drafting a new mercury rule with a mandatory date of March 16th, 2011 or earlier. The new rule must conform with the MACT (Maximum Achievable Control Technology) Standard which means each unit over 25 MW must be as good as the average of the top 12% of plants, generally thought of as a ~ 90% removal level. The MACT rule will not allow for credit trading between plants although some relief could come (selectively) if the EPA sets different compliance standards for different coal plant configurations like size, boiler pressure / temperature or coal mix, which would allow some to comply below 90%, while others would be held to a higher MACT standard.

Once the rulemaking process is complete (EPA is shooting to finalize the rule by November 16th, 2011), affected utilities would have three years (by 2015) to comply with the standard.

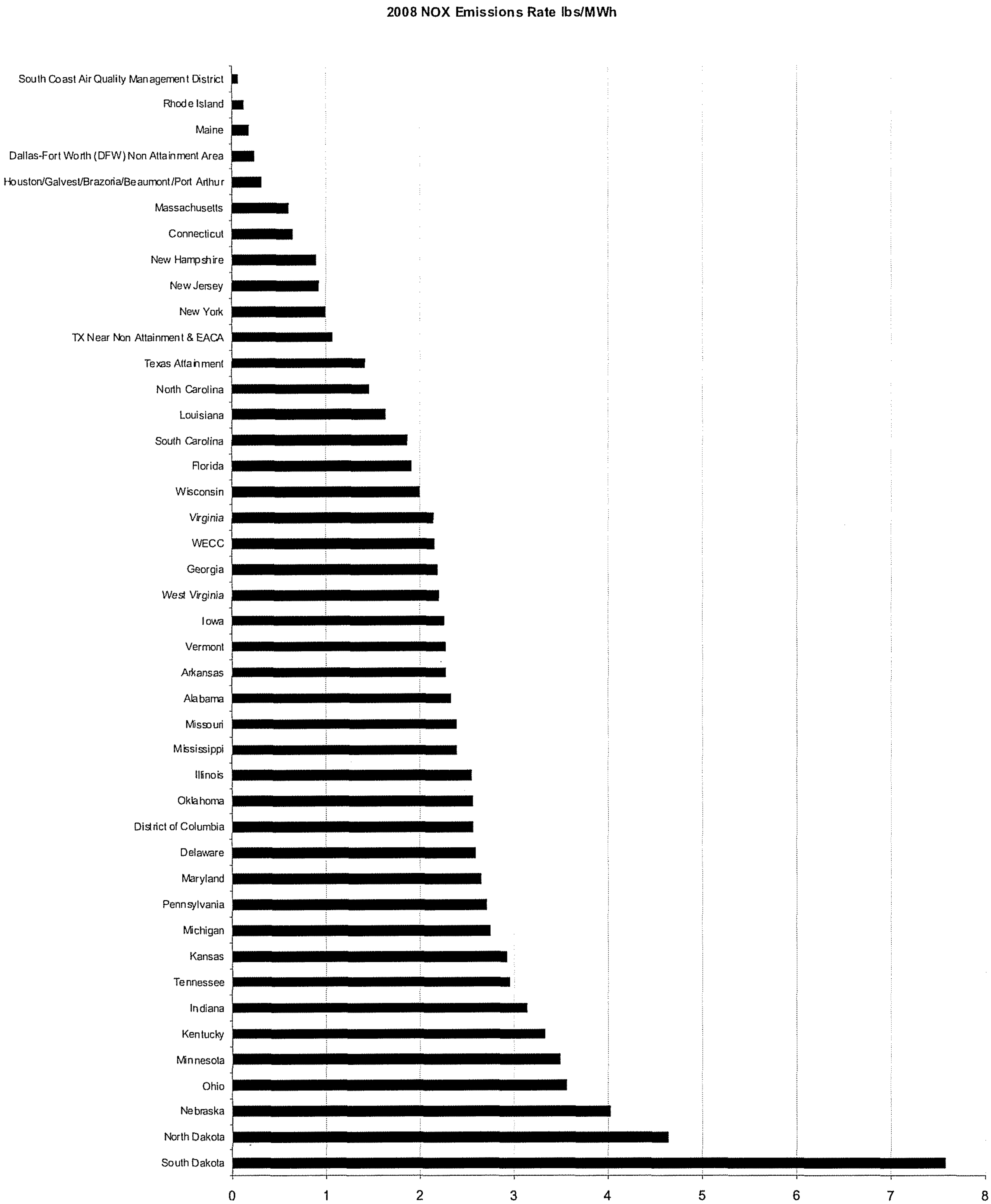
We expect Mercury rule to have profound impact on the electric industry, requiring significant capex based on the suite of equipment needed to demonstrably reach high removal rate.

Exhibit 138: 2008 State Level SOX Emission (lbs / MWh)



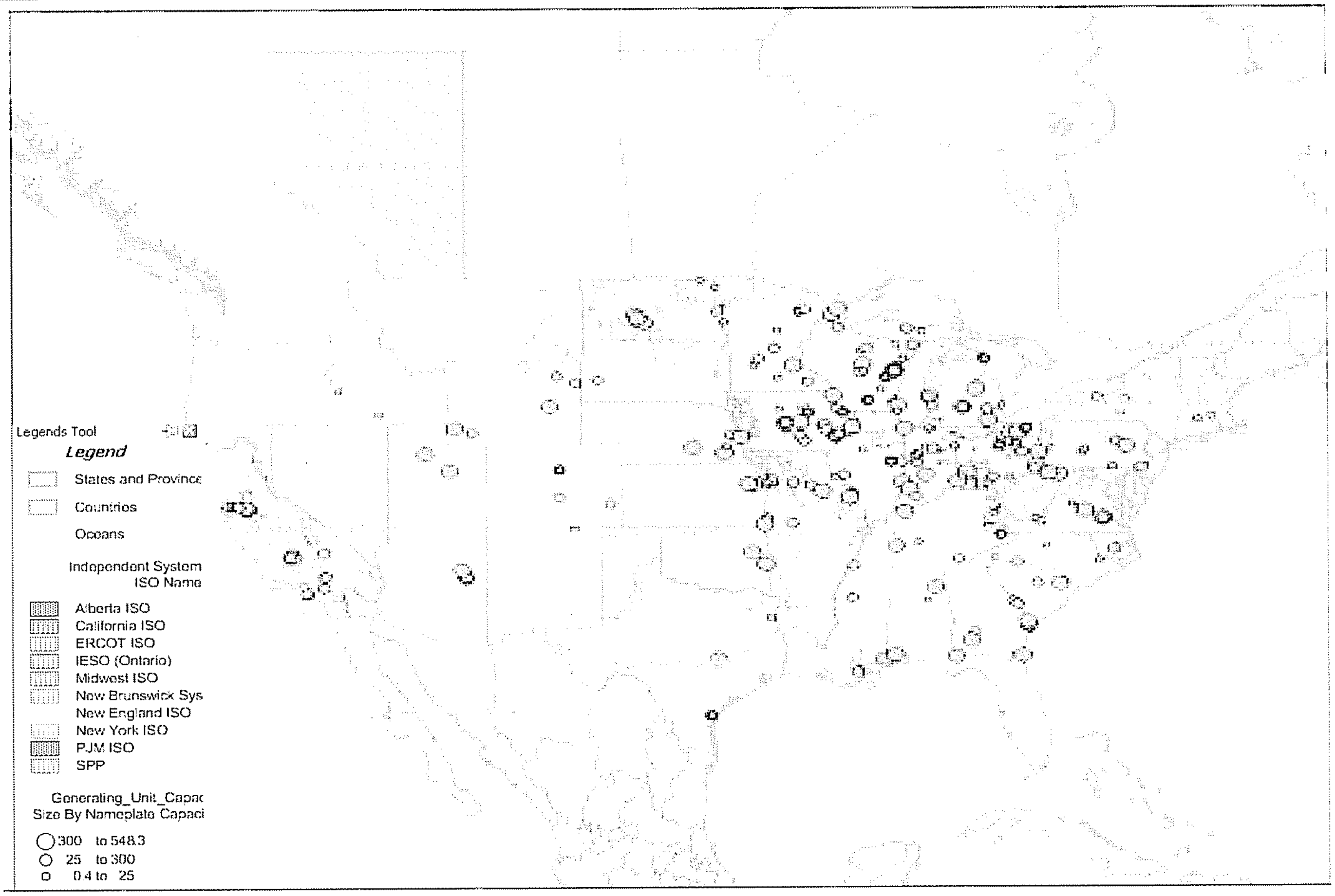
Source: Company data, Credit Suisse estimates, Energy Velocity

Exhibit 139: **2008 State Level NOx Emission (lbs / MWh)**



Source: Company data, Credit Suisse estimates, Energy Velocity

Exhibit 140: **Location of Un-Scrubbed Coal Plants**



Source: Energy Velocity, Credit Suisse estimates

Appendix III – Earnings Under Closure Scenarios

Exhibit 141: 2010 – 2020 EPS (No Retirements)

No Retirements	EPS										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	2.16	2.21	1.40	1.67	2.27	2.63	3.16	3.63	3.61	4.21	4.59
D	3.41	3.21	3.23	3.52	3.59	3.78	3.95	4.10	4.31	4.45	4.57
EIX	3.30	3.05	2.72	3.05	3.49	3.65	3.93	4.26	4.25	4.62	4.73
ETR	6.69	6.89	6.55	6.58	6.68	7.07	7.19	7.38	7.59	8.01	8.01
EXC	3.93	3.94	3.03	2.95	2.91	3.05	3.28	3.49	3.66	3.95	3.95
FE	3.66	3.32	3.08	3.33	3.58	3.66	4.50	4.45	4.76	5.17	5.49
NEE	4.45	4.41	4.62	4.75	5.15	5.72	6.18	6.54	6.78	7.30	7.18
PEG	3.04	2.88	2.77	3.13	3.58	3.87	4.15	4.31	4.55	4.71	4.92
FE/AYE (no synergy)	3.55	3.32	2.81	3.11	3.53	3.74	4.57	4.71	4.93	5.46	5.84
FE/AYE (half synergy)	3.55	3.46	3.09	3.46	3.91	4.16	5.00	5.15	5.37	5.91	6.29
RRI											

Source: Company data, Credit Suisse estimates

Exhibit 142: 2010 – 2020 EBITDA (No Retirements)

No Retirements	EBITDA										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	1,227	1,248	1,071	1,159	1,350	1,459	1,597	1,680	1,640	1,748	1,795
D	4,959	4,779	4,970	5,415	5,588	5,871	6,101	6,321	6,564	6,731	6,870
EIX	3,684	3,879	3,907	4,284	4,635	4,865	5,085	5,291	5,421	5,551	5,640
ETR	3,728	3,713	3,637	3,703	3,705	3,784	3,789	3,807	3,826	3,895	3,860
EXC	5,966	6,077	5,207	5,295	5,415	5,735	6,113	6,442	6,679	7,029	7,073
FE	3,292	3,349	3,255	3,401	3,548	3,604	4,011	3,985	4,131	4,308	4,437
NEE	4,787	4,939	5,402	5,762	6,040	6,425	6,702	6,892	7,048	7,227	7,007
PEG	3,764	3,786	3,720	4,018	4,311	4,456	4,583	4,593	4,668	4,682	4,707
FE/AYE (no synergy)	4,520	4,597	4,327	4,560	4,898	5,062	5,608	5,665	5,771	6,056	6,233
FE/AYE (half synergy)	4,520	4,687	4,502	4,785	5,138	5,327	5,873	5,930	6,036	6,321	6,498
RRI	293	334	390	437	515	557	592	633	663	678	689

Source: Company data, Credit Suisse estimates

Exhibit 143: 2010 – 2020 P/E (No Retirements)

No Retirements	P/E										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	10.8x	10.5x	16.6x	13.9x	10.3x	8.8x	7.4x	6.4x	6.4x	5.5x	5.1x
D	13.0x	13.8x	13.7x	12.5x	12.3x	11.7x	11.2x	10.8x	10.3x	9.9x	9.7x
EIX	10.6x	11.4x	12.8x	11.4x	10.0x	9.5x	8.9x	8.2x	8.2x	7.5x	7.4x
ETR	11.5x	11.2x	11.8x	11.7x	11.5x	10.9x	10.7x	10.4x	10.1x	9.6x	9.6x
EXC	10.9x	10.9x	14.2x	14.6x	14.8x	14.1x	13.1x	12.3x	11.7x	10.9x	10.9x
FE	10.1x	11.2x	12.0x	11.1x	10.4x	10.1x	8.2x	8.3x	7.8x	7.2x	6.8x
NEE	12.2x	12.3x	11.8x	11.4x	10.5x	9.5x	8.8x	8.3x	8.0x	7.4x	7.6x
PEG	10.6x	11.2x	11.7x	10.3x	9.1x	8.4x	7.8x	7.5x	7.1x	6.9x	6.6x
FE/AYE (no synergy)	10.4x	11.2x	13.2x	11.9x	10.5x	9.9x	8.1x	7.9x	7.5x	6.8x	0.0x
FE/AYE (half synergy)	10.4x	10.7x	12.0x	10.7x	9.5x	8.9x	7.4x	7.2x	6.9x	6.3x	0.0x
RRI											

Source: Company data, Credit Suisse estimates

Exhibit 144: 2010 – 2020 EV/EBITDA (No Retirements)

No Retirements	EV/EBITDA										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	6.4x	6.6x	7.8x	7.5x	6.6x	6.1x	5.4x	5.0x	5.0x	4.6x	4.3x
D	8.7x	9.2x	9.2x	8.7x	8.7x	8.4x	8.2x	8.0x	7.8x	7.6x	7.6x
EIX	7.1x	7.1x	7.4x	7.2x	7.0x	6.8x	6.5x	6.3x	6.1x	5.8x	5.6x
ETR	6.8x	7.0x	7.2x	6.9x	6.8x	6.6x	6.5x	6.3x	6.2x	6.0x	5.9x
EXC	6.5x	6.6x	7.9x	8.1x	8.1x	7.9x	7.5x	7.2x	7.0x	6.6x	6.6x
FE	8.1x	7.9x	8.2x	8.1x	7.8x	7.8x	7.0x	7.0x	6.7x	6.4x	6.1x
NEE	8.7x	8.9x	8.6x	8.3x	8.0x	7.6x	7.2x	6.9x	6.6x	6.3x	6.4x
PEG	6.7x	6.8x	7.1x	6.5x	6.0x	5.8x	5.5x	5.3x	5.1x	5.0x	4.9x
FE/AYE (no synergy)	7.7x	7.6x	8.2x	8.0x	7.5x	7.3x	6.6x	6.4x	6.3x	5.9x	5.6x
FE/AYE (half synergy)	7.7x	7.5x	7.9x	7.6x	7.2x	6.9x	6.3x	6.2x	6.0x	5.6x	5.4x
RRI	10.2x	8.4x	6.7x	6.1x	5.1x	4.7x	4.3x	3.9x	3.5x	3.2x	3.2x

Source: Company data, Credit Suisse estimates

Exhibit 145: 2010 – 2020 EPS Impact (60 GW Retirement 2013-2017)

60 GW Retirement						EPS					
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	2.16	2.21	1.40	1.77	2.81	3.57	4.46	5.14	4.86	5.26	5.47
D	3.41	3.21	3.23	3.58	3.76	4.05	4.30	4.51	4.68	4.79	4.88
EIX	3.30	3.05	2.72	3.08	3.67	3.94	4.28	4.59	4.42	4.66	4.66
ETR	6.69	6.89	6.55	6.64	6.80	7.26	7.46	7.73	7.96	8.40	8.41
EXC	3.93	3.94	3.03	3.18	3.61	4.16	4.82	5.39	5.48	5.70	5.63
FE	3.66	3.35	3.19	3.74	4.43	5.03	6.27	6.36	6.50	6.71	6.78
NEE	4.45	4.41	4.62	4.75	5.16	5.73	6.20	6.56	6.80	7.33	7.20
PEG	3.05	2.88	2.79	3.22	3.76	4.12	4.41	4.55	4.69	4.77	4.91
FE/AYE (no synergy)	3.55	3.34	2.90	3.45	4.37	5.11	6.38	6.71	6.70	7.00	7.12
FE/AYE (half synergy)	3.55	3.48	3.17	3.80	4.75	5.54	6.82	7.15	7.15	7.45	7.58
RRI											
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0%	0.0%	0.0%	6.1%	24.3%	35.7%	41.0%	41.6%	34.5%	24.9%	19.1%
D	0.0%	0.0%	0.0%	1.5%	4.7%	7.0%	8.8%	9.9%	8.6%	7.7%	6.9%
EIX	0.0%	0.0%	0.0%	0.9%	5.2%	7.8%	8.7%	7.8%	4.1%	0.9%	-1.5%
ETR	0.0%	0.0%	0.1%	0.9%	1.8%	2.7%	3.7%	4.7%	4.9%	4.9%	5.0%
EXC	0.0%	0.0%	0.1%	7.8%	24.2%	36.2%	47.0%	54.4%	49.7%	44.4%	42.3%
FE	0.0%	0.8%	3.8%	12.2%	23.7%	37.4%	39.4%	43.0%	36.7%	29.9%	23.5%
NEE	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%	0.2%	0.3%	0.3%	0.3%	0.4%
PEG	0.1%	0.1%	0.6%	3.0%	5.2%	6.3%	6.3%	5.6%	3.1%	1.2%	-0.2%
FE/AYE (no synergy)	0.0%	0.6%	3.0%	10.9%	23.8%	36.9%	39.8%	42.3%	35.9%	28.2%	21.9%
FE/AYE (half synergy)	0.0%	0.6%	2.8%	9.8%	21.5%	33.2%	36.4%	38.8%	33.0%	26.1%	20.5%
RRI											

Source: Company data, Credit Suisse estimates

Exhibit 146: 2010 – 2020 EBITDA Impact (60 GW Retirement 2013-2017)

60 GW Retirement						EBITDA					
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	1,227	1,248	1,071	1,187	1,501	1,696	1,899	2,000	1,874	1,911	1,903
D	4,959	4,779	4,970	5,464	5,744	6,111	6,414	6,684	6,887	7,023	7,131
EIX	3,684	3,879	3,907	4,299	4,732	5,013	5,259	5,450	5,488	5,542	5,572
ETR	3,728	3,713	3,639	3,719	3,737	3,834	3,856	3,893	3,914	3,985	3,949
EXC	5,966	6,077	5,209	5,542	6,156	6,874	7,666	8,297	8,349	8,544	8,420
FE	3,292	3,362	3,311	3,593	3,939	4,218	4,785	4,793	4,831	4,891	4,891
NEE	4,787	4,939	5,402	5,764	6,045	6,432	6,711	6,903	7,059	7,239	7,019
PEG	3,767	3,790	3,734	4,092	4,455	4,633	4,762	4,750	4,748	4,699	4,681
FE/AYE (no synergy)	4,520	4,610	4,383	4,781	5,440	5,914	6,684	6,792	6,704	6,803	6,795
FE/AYE (half synergy)	4,520	4,700	4,558	5,006	5,680	6,179	6,949	7,057	6,969	7,068	7,060
RRI	293	334	390	460	612	696	755	794	771	745	723
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0%	0.0%	0.0%	2.4%	11.2%	16.3%	18.9%	19.0%	14.2%	9.4%	6.0%
D	0.0%	0.0%	0.0%	0.9%	2.8%	4.1%	5.1%	5.7%	4.9%	4.3%	3.8%
EIX	0.0%	0.0%	0.0%	0.3%	2.1%	3.0%	3.4%	3.0%	1.2%	-0.2%	-1.2%
ETR	0.0%	0.0%	0.0%	0.4%	0.8%	1.3%	1.8%	2.2%	2.3%	2.3%	2.3%
EXC	0.0%	0.0%	0.0%	4.7%	13.7%	19.9%	25.4%	28.8%	25.0%	21.6%	19.0%
FE	0.0%	0.4%	1.7%	5.7%	11.0%	17.0%	19.3%	20.3%	16.9%	13.5%	10.2%
NEE	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%
PEG	0.1%	0.1%	0.4%	1.9%	3.3%	4.0%	3.9%	3.4%	1.7%	0.4%	-0.6%
FE/AYE (no synergy)	0.0%	0.3%	1.3%	4.8%	11.1%	16.8%	19.2%	19.9%	16.2%	12.3%	9.0%
FE/AYE (half synergy)	0.0%	0.3%	1.2%	4.6%	10.5%	16.0%	18.3%	19.0%	15.5%	11.8%	8.7%
RRI	0.0%	0.0%	0.0%	5.3%	18.8%	25.0%	27.5%	25.5%	16.4%	9.9%	5.0%

Source: Company data, Credit Suisse estimates

Exhibit 147: 2010 – 2020 P/E Impact (60 GW Retirement 2013-2017)

60 GW Retirement						P/E					
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	10.8x	10.5x	16.6x	13.1x	8.3x	6.5x	5.2x	4.5x	4.8x	4.4x	4.2x
D	13.0x	13.8x	13.7x	12.4x	11.8x	10.9x	10.3x	9.8x	9.4x	9.2x	9.1x
EIX	10.6x	11.4x	12.8x	11.3x	9.5x	8.8x	8.1x	7.6x	7.9x	7.5x	7.5x
ETR	11.5x	11.2x	11.8x	11.6x	11.3x	10.6x	10.3x	10.0x	9.7x	9.2x	9.2x
EXC	10.9x	10.9x	14.2x	13.5x	11.9x	10.3x	8.9x	8.0x	7.8x	7.5x	7.6x
FE	10.1x	11.1x	11.6x	9.9x	8.4x	7.4x	5.9x	5.8x	5.7x	5.5x	5.5x
NEE	12.2x	12.3x	11.8x	11.4x	10.5x	9.5x	8.8x	8.3x	8.0x	7.4x	7.5x
PEG	10.6x	11.2x	11.6x	10.0x	8.6x	7.9x	7.3x	7.1x	6.9x	6.8x	6.6x
FE/AYE (no synergy)	10.4x	11.1x	12.8x	10.8x	8.5x	7.2x	5.8x	5.5x	5.5x	5.3x	5.2x
FE/AYE (half synergy)	10.4x	10.7x	11.7x	9.8x	7.8x	6.7x	5.4x	5.2x	5.2x	5.0x	4.9x
RRI											
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0x	0.0x	0.0x	-0.8x	-2.0x	-2.3x	-2.1x	-1.9x	-1.7x	-1.1x	-0.8x
D	0.0x	0.0x	0.0x	-0.2x	-0.6x	-0.8x	-0.9x	-1.0x	-0.8x	-0.7x	-0.6x
EIX	0.0x	0.0x	0.0x	-0.1x	-0.5x	-0.7x	-0.7x	-0.6x	-0.3x	-0.1x	0.1x
ETR	0.0x	0.0x	0.0x	-0.1x	-0.2x	-0.3x	-0.4x	-0.5x	-0.5x	-0.5x	-0.5x
EXC	0.0x	0.0x	0.0x	-1.1x	-2.9x	-3.7x	-4.2x	-4.3x	-3.9x	-3.3x	-3.2x
FE	0.0x	-0.1x	-0.4x	-1.2x	-2.0x	-2.8x	-2.3x	-2.5x	-2.1x	-1.7x	-1.3x
NEE	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x
PEG	0.0x	0.0x	-0.1x	-0.3x	-0.5x	-0.5x	-0.5x	-0.4x	-0.2x	-0.1x	0.0x
FE/AYE (no synergy)	0.0x	-0.1x	-0.4x	-1.2x	-2.0x	-2.7x	-2.3x	-2.3x	-2.0x	-1.5x	5.2x
FE/AYE (half synergy)	0.0x	-0.1x	-0.3x	-1.0x	-1.7x	-2.2x	-2.0x	-2.0x	-1.7x	-1.3x	4.9x
RRI											

Source: Company data, Credit Suisse estimates

Exhibit 148: 2010 – 2020 EV/EBITDA Impact (60 GW Retirement 2013-2017)

60 GW Retirement						EV/EBITDA					
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	6.4x	6.6x	7.8x	7.3x	5.9x	5.1x	4.4x	4.0x	4.2x	3.9x	3.8x
D	8.7x	9.2x	9.2x	8.6x	8.4x	8.0x	7.7x	7.5x	7.4x	7.3x	7.2x
EIX	7.1x	7.1x	7.4x	7.2x	6.8x	6.6x	6.3x	6.0x	5.9x	5.7x	5.6x
ETR	6.8x	7.0x	7.2x	6.9x	6.8x	6.5x	6.3x	6.2x	6.0x	5.8x	5.7x
EXC	6.5x	6.6x	7.9x	7.7x	7.0x	6.4x	5.7x	5.1x	5.0x	4.8x	4.7x
FE	8.1x	7.9x	8.1x	7.6x	6.9x	6.4x	5.6x	5.5x	5.3x	5.2x	5.1x
NEE	8.7x	8.9x	8.6x	8.3x	8.0x	7.6x	7.2x	6.8x	6.6x	6.3x	6.4x
PEG	6.7x	6.8x	7.1x	6.4x	5.8x	5.5x	5.2x	5.1x	5.0x	4.9x	4.9x
FE/AYE (no synergy)	7.7x	7.6x	8.1x	7.6x	6.7x	6.1x	5.3x	5.1x	5.0x	4.9x	4.8x
FE/AYE (half synergy)	7.7x	7.5x	7.8x	7.2x	6.4x	5.8x	5.1x	4.9x	4.9x	4.7x	4.6x
RRI	10.2x	8.4x	6.7x	5.6x	3.8x	2.9x	2.1x	1.5x	1.2x	1.1x	1.1x
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0x	0.0x	0.0x	-0.2x	-0.7x	-1.0x	-1.0x	-1.0x	-0.8x	-0.6x	-0.5x
D	0.0x	0.0x	0.0x	-0.1x	-0.3x	-0.4x	-0.4x	-0.5x	-0.4x	-0.4x	-0.4x
EIX	0.0x	0.0x	0.0x	0.0x	-0.2x	-0.2x	-0.3x	-0.3x	-0.2x	-0.1x	0.0x
ETR	0.0x	0.0x	0.0x	0.0x	-0.1x	-0.1x	-0.1x	-0.2x	-0.2x	-0.2x	-0.2x
EXC	0.0x	0.0x	0.0x	-0.4x	-1.1x	-1.5x	-1.8x	-2.0x	-2.0x	-1.8x	-1.8x
FE	0.0x	0.0x	-0.2x	-0.5x	-0.9x	-1.3x	-1.4x	-1.5x	-1.4x	-1.2x	-1.0x
NEE	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x
PEG	0.0x	0.0x	0.0x	-0.1x	-0.2x	-0.3x	-0.3x	-0.2x	-0.2x	-0.1x	0.0x
FE/AYE (no synergy)	0.0x	0.0x	-0.1x	-0.4x	-0.8x	-1.2x	-1.3x	-1.4x	-1.2x	-1.0x	-0.9x
FE/AYE (half synergy)	0.0x	0.0x	-0.1x	-0.4x	-0.8x	-1.1x	-1.2x	-1.3x	-1.1x	-1.0x	-0.8x

Source: Company data, Credit Suisse estimates

Exhibit 149: 2010 – 2020 EPS Impact (35 GW Retirement 2013-2017)

35 GW Retirement						EPS					
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	2.16	2.21	1.40	1.73	2.57	3.30	4.18	4.92	5.04	5.71	6.02
D	3.41	3.21	3.22	3.56	3.69	3.97	4.22	4.44	4.66	4.81	4.91
EIX	3.30	3.05	2.72	3.04	3.52	3.77	4.11	4.44	4.42	4.74	4.76
ETR	6.69	6.89	6.55	6.63	6.78	7.23	7.41	7.67	7.90	8.33	8.34
EXC	3.93	3.94	3.03	3.07	3.27	3.72	4.29	4.84	5.13	5.51	5.54
FE	3.66	3.34	3.14	3.57	4.08	4.55	5.76	5.97	6.44	6.74	7.00
NEE	4.45	4.41	4.62	4.75	5.16	5.73	6.19	6.56	6.80	7.32	7.20
PEG	3.05	2.88	2.78	3.19	3.69	4.08	4.44	4.60	4.79	4.88	5.03
FE/AYE (no synergy)	3.55	3.33	2.86	3.31	4.02	4.66	5.90	6.33	6.72	7.18	7.48
FE/AYE (half synergy)	3.55	3.47	3.13	3.66	4.40	5.08	6.33	6.77	7.17	7.64	7.94
RRI											
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0%	0.0%	0.0%	3.6%	13.6%	25.7%	32.3%	35.4%	39.5%	35.5%	31.0%
D	0.0%	-0.1%	-0.2%	0.9%	2.8%	4.9%	6.7%	8.2%	8.1%	8.0%	7.5%
EIX	0.0%	0.0%	0.0%	-0.4%	0.9%	3.2%	4.6%	4.3%	4.0%	2.6%	0.7%
ETR	0.0%	0.0%	0.1%	0.7%	1.4%	2.2%	3.0%	3.8%	4.0%	4.0%	4.2%
EXC	0.0%	0.0%	0.0%	4.2%	12.3%	21.8%	30.7%	38.5%	40.3%	39.7%	40.0%
FE	0.0%	0.5%	2.1%	7.1%	14.0%	24.3%	28.0%	34.1%	35.3%	30.5%	27.6%
NEE	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%
PEG	0.1%	0.1%	0.4%	1.8%	3.3%	5.3%	6.9%	6.7%	5.2%	3.6%	2.4%
FE/AYE (no synergy)	0.0%	0.3%	1.7%	6.4%	13.9%	24.7%	29.1%	34.3%	36.3%	31.6%	28.2%
FE/AYE (half synergy)	0.0%	0.3%	1.6%	5.7%	12.6%	22.2%	26.7%	31.5%	33.4%	29.3%	26.2%
RRI											

Source: Company data, Credit Suisse estimates

Exhibit 150: 2010 – 2020 EBITDA Impact (35 GW Retirement 2013-2017)

35 GW Retirement						EBITDA					
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	1,227	1,248	1,071	1,176	1,435	1,631	1,837	1,958	1,926	2,014	2,017
D	4,959	4,777	4,963	5,444	5,682	6,041	6,341	6,621	6,873	7,040	7,162
EIX	3,684	3,879	3,907	4,277	4,652	4,928	5,179	5,382	5,502	5,600	5,639
ETR	3,728	3,713	3,638	3,716	3,731	3,825	3,843	3,877	3,898	3,969	3,933
EXC	5,966	6,077	5,208	5,428	5,791	6,425	7,135	7,772	8,073	8,442	8,424
FE	3,292	3,356	3,287	3,514	3,780	4,004	4,567	4,639	4,834	4,940	5,025
NEE	4,787	4,939	5,402	5,764	6,044	6,431	6,710	6,902	7,058	7,238	7,018
PEG	3,766	3,788	3,729	4,064	4,401	4,607	4,783	4,786	4,815	4,777	4,762
FE/AYE (no synergy)	4,520	4,604	4,358	4,690	5,215	5,635	6,405	6,598	6,760	6,954	7,042
FE/AYE (half synergy)	4,520	4,694	4,533	4,915	5,455	5,900	6,670	6,863	7,025	7,219	7,307
RRI	293	334	390	447	560	652	727	785	812	815	805
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0%	0.0%	0.0%	1.4%	6.3%	11.8%	15.1%	16.6%	17.4%	15.2%	12.4%
D	0.0%	0.0%	-0.1%	0.5%	1.7%	2.9%	3.9%	4.7%	4.7%	4.6%	4.2%
EIX	0.0%	0.0%	0.0%	-0.2%	0.4%	1.3%	1.9%	1.7%	1.5%	0.9%	0.0%
ETR	0.0%	0.0%	0.0%	0.3%	0.7%	1.1%	1.4%	1.8%	1.9%	1.9%	1.9%
EXC	0.0%	0.0%	0.0%	2.5%	6.9%	12.0%	16.7%	20.6%	20.9%	20.1%	19.1%
FE	0.0%	0.2%	1.0%	3.3%	6.5%	11.1%	13.9%	16.4%	17.0%	14.7%	13.2%
NEE	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
PEG	0.0%	0.1%	0.2%	1.1%	2.1%	3.4%	4.4%	4.2%	3.1%	2.0%	1.2%
FE/AYE (no synergy)	0.0%	0.2%	0.7%	2.8%	6.5%	11.3%	14.2%	16.5%	17.1%	14.8%	13.0%
FE/AYE (half synergy)	0.0%	0.2%	0.7%	2.7%	6.2%	10.7%	13.6%	15.7%	16.4%	14.2%	12.5%
RRI	0.0%	0.0%	0.0%	2.2%	8.7%	17.1%	22.7%	24.0%	22.5%	20.3%	16.9%

Source: Company data, Credit Suisse estimates

Exhibit 151: 2010 – 2020 P/E Impact (35 GW Retirement 2013-2017)

35 GW Retirement						P/E					
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	10.8x	10.5x	16.6x	13.4x	9.0x	7.0x	5.6x	4.7x	4.6x	4.1x	3.9x
D	13.0x	13.8x	13.7x	12.4x	12.0x	11.1x	10.5x	10.0x	9.5x	9.2x	9.0x
EIX	10.6x	11.4x	12.8x	11.4x	9.9x	9.2x	8.5x	7.8x	7.9x	7.3x	7.3x
ETR	11.5x	11.2x	11.8x	11.6x	11.4x	10.7x	10.4x	10.1x	9.8x	9.2x	9.2x
EXC	10.9x	10.9x	14.2x	14.0x	13.1x	11.5x	10.0x	8.9x	8.4x	7.8x	7.8x
FE	10.1x	11.1x	11.8x	10.4x	9.1x	8.2x	6.4x	6.2x	5.8x	5.5x	5.3x
NEE	12.2x	12.3x	11.8x	11.4x	10.5x	9.5x	8.8x	8.3x	8.0x	7.4x	7.5x
PEG	10.6x	11.2x	11.7x	10.2x	8.8x	7.9x	7.3x	7.0x	6.8x	6.6x	6.4x
FE/AYE (no synergy)	10.4x	11.1x	12.9x	11.2x	9.2x	8.0x	6.3x	5.9x	5.5x	5.2x	5.0x
FE/AYE (half synergy)	10.4x	10.7x	11.8x	10.1x	8.4x	7.3x	5.9x	5.5x	5.2x	4.9x	4.7x
RRI											
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0x	0.0x	0.0x	-0.5x	-1.2x	-1.8x	-1.8x	-1.7x	-1.8x	-1.4x	-1.2x
D	0.0x	0.0x	0.0x	-0.1x	-0.3x	-0.5x	-0.7x	-0.8x	-0.8x	-0.7x	-0.7x
EIX	0.0x	0.0x	0.0x	0.1x	-0.1x	-0.3x	-0.4x	-0.3x	-0.3x	-0.2x	0.0x
ETR	0.0x	0.0x	0.0x	-0.1x	-0.2x	-0.2x	-0.3x	-0.4x	-0.4x	-0.4x	-0.4x
EXC	0.0x	0.0x	0.0x	-0.6x	-1.6x	-2.5x	-3.1x	-3.4x	-3.4x	-3.1x	-3.1x
FE	0.0x	-0.1x	-0.3x	-0.7x	-1.3x	-2.0x	-1.8x	-2.1x	-2.0x	-1.7x	-1.5x
NEE	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x
PEG	0.0x	0.0x	0.0x	-0.2x	-0.3x	-0.4x	-0.5x	-0.5x	-0.4x	-0.2x	-0.2x
FE/AYE (no synergy)	0.0x	0.0x	-0.2x	-0.7x	-1.3x	-2.0x	-1.8x	-2.0x	-2.0x	-1.6x	5.0x
FE/AYE (half synergy)	0.0x	0.0x	-0.2x	-0.6x	-1.1x	-1.6x	-1.6x	-1.7x	-1.7x	-1.4x	4.7x
RRI											

Source: Company data, Credit Suisse estimates

Exhibit 152: 2010 – 2020 EV/EBITDA Impact (35 GW Retirement 2013-2017)

35 GW Retirement						EV/EBITDA					
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	6.4x	6.6x	7.8x	7.4x	6.2x	5.3x	4.6x	4.2x	4.1x	3.8x	3.6x
D	8.7x	9.2x	9.2x	8.7x	8.5x	8.1x	7.8x	7.6x	7.4x	7.3x	7.2x
EIX	7.1x	7.1x	7.4x	7.2x	7.0x	6.7x	6.4x	6.1x	5.9x	5.7x	5.6x
ETR	6.8x	7.0x	7.2x	6.9x	6.8x	6.5x	6.3x	6.2x	6.0x	5.8x	5.7x
EXC	6.5x	6.6x	7.9x	7.8x	7.5x	6.9x	6.2x	5.7x	5.4x	5.0x	4.9x
FE	8.1x	7.9x	8.2x	7.8x	7.3x	6.9x	6.0x	5.8x	5.5x	5.3x	5.1x
NEE	8.7x	8.9x	8.6x	8.3x	8.0x	7.6x	7.2x	6.9x	6.6x	6.3x	6.4x
PEG	6.7x	6.8x	7.1x	6.4x	5.9x	5.6x	5.2x	5.1x	4.9x	4.8x	4.8x
FE/AYE (no synergy)	7.7x	7.6x	8.1x	7.7x	7.0x	6.5x	5.6x	5.3x	5.1x	4.8x	4.7x
FE/AYE (half synergy)	7.7x	7.5x	7.8x	7.4x	6.7x	6.2x	5.4x	5.1x	4.9x	4.7x	4.5x
RRI	10.2x	8.4x	6.7x	5.9x	4.6x	3.8x	3.1x	2.6x	2.1x	1.9x	1.9x
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0x	0.0x	0.0x	-0.1x	-0.4x	-0.7x	-0.8x	-0.8x	-0.9x	-0.8x	-0.7x
D	0.0x	0.0x	0.0x	0.0x	-0.2x	-0.3x	-0.3x	-0.4x	-0.4x	-0.4x	-0.4x
EIX	0.0x	0.0x	0.0x	0.0x	0.0x	-0.1x	-0.1x	-0.1x	-0.1x	-0.1x	-0.1x
ETR	0.0x	0.0x	0.0x	0.0x	-0.1x	-0.1x	-0.1x	-0.1x	-0.2x	-0.2x	-0.2x
EXC	0.0x	0.0x	0.0x	-0.2x	-0.6x	-1.0x	-1.3x	-1.5x	-1.6x	-1.6x	-1.7x
FE	0.0x	0.0x	-0.1x	-0.3x	-0.5x	-0.9x	-1.0x	-1.2x	-1.2x	-1.1x	-1.0x
NEE	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x
PEG	0.0x	0.0x	0.0x	-0.1x	-0.1x	-0.2x	-0.3x	-0.3x	-0.2x	-0.2x	-0.1x
FE/AYE (no synergy)	0.0x	0.0x	-0.1x	-0.2x	-0.5x	-0.8x	-1.0x	-1.1x	-1.2x	-1.0x	-0.9x
FE/AYE (half synergy)	0.0x	0.0x	-0.1x	-0.2x	-0.5x	-0.8x	-0.9x	-1.0x	-1.1x	-1.0x	-0.9x
RRI	0.00	0.00	0.00	(0.15)	(0.50)	(0.91)	(1.19)	(1.33)	(1.40)	(1.36)	(1.28)

Source: Company data, Credit Suisse estimates

Exhibit 153: 2010 – 2020 EPS Impact (100 GW Retirement 2013-2017)

100 GW Retirement	EPS										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	2.16	2.21	1.40	1.84	3.20	4.01	4.63	4.90	4.56	4.98	5.13
D	3.41	3.21	3.23	3.58	3.80	4.05	4.23	4.34	4.47	4.59	4.68
EIX	3.30	3.05	2.72	3.15	3.73	3.74	3.67	3.58	3.39	3.63	3.60
ETR	6.69	6.89	6.55	6.61	6.73	7.15	7.31	7.53	7.76	8.18	8.19
EXC	3.93	3.94	3.03	3.46	4.20	4.79	5.39	5.82	5.75	6.03	5.99
FE	3.66	3.37	3.27	3.98	4.88	5.60	6.64	6.41	6.38	6.52	6.57
NEE	4.45	4.41	4.62	4.76	5.17	5.75	6.24	6.62	6.88	7.43	7.33
PEG	3.05	2.89	2.80	3.28	3.89	4.18	4.42	4.52	4.66	4.75	4.89
FE/AYE (no synergy)	3.55	3.35	2.96	3.65	4.86	5.71	6.72	6.65	6.49	6.76	6.84
FE/AYE (half synergy)	3.55	3.49	3.23	4.00	5.23	6.13	7.15	7.09	6.94	7.21	7.30
RRI											
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0%	0.0%	0.0%	10.4%	41.3%	52.4%	46.5%	34.9%	26.2%	18.2%	11.8%
D	0.0%	0.0%	0.0%	1.7%	5.9%	7.1%	6.8%	5.8%	3.8%	3.1%	2.4%
EIX	0.0%	0.0%	0.0%	3.0%	6.9%	2.3%	-6.6%	-15.9%	-20.2%	-21.5%	-23.9%
ETR	0.0%	0.0%	0.0%	0.4%	0.8%	1.2%	1.6%	2.0%	2.1%	2.2%	2.3%
EXC	0.0%	0.0%	0.1%	17.2%	44.4%	57.0%	64.5%	66.5%	57.1%	52.7%	51.4%
FE	0.0%	1.4%	6.3%	19.5%	36.3%	53.1%	47.4%	44.1%	34.1%	26.3%	19.7%
NEE	0.0%	0.0%	0.0%	0.1%	0.4%	0.6%	0.9%	1.2%	1.5%	1.8%	2.1%
PEG	0.2%	0.2%	1.0%	4.8%	8.7%	7.9%	6.4%	4.9%	2.4%	0.8%	-0.6%
FE/AYE (no synergy)	0.0%	1.0%	5.0%	17.5%	37.6%	52.9%	47.1%	41.1%	31.8%	23.7%	17.2%
FE/AYE (half synergy)	0.0%	1.0%	4.6%	15.7%	34.0%	47.6%	43.1%	37.7%	29.3%	22.0%	16.0%
RRI											

Source: Company data, Credit Suisse estimates

Exhibit 154: 2010 – 2020 EBITDA Impact (100 GW Retirement 2013-2017)

100 GW Retirement	EBITDA										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	1,227	1,248	1,071	1,207	1,607	1,804	1,930	1,932	1,799	1,848	1,833
D	4,959	4,779	4,970	5,471	5,784	6,113	6,343	6,530	6,701	6,844	6,957
EIX	3,684	3,879	3,907	4,334	4,762	4,902	4,934	4,921	4,972	5,048	5,084
ETR	3,728	3,713	3,638	3,710	3,719	3,806	3,818	3,844	3,865	3,935	3,900
EXC	5,966	6,077	5,210	5,837	6,772	7,514	8,210	8,654	8,531	8,776	8,675
FE	3,292	3,371	3,347	3,708	4,147	4,472	4,929	4,784	4,745	4,779	4,773
NEE	4,787	4,939	5,402	5,767	6,054	6,447	6,734	6,938	7,103	7,293	7,077
PEG	3,769	3,792	3,742	4,138	4,550	4,677	4,762	4,722	4,721	4,683	4,664
FE/AYE (no synergy)	4,520	4,619	4,419	4,915	5,754	6,276	6,859	6,717	6,544	6,626	6,606
FE/AYE (half synergy)	4,520	4,709	4,594	5,140	5,994	6,541	7,124	6,982	6,809	6,891	6,871
RRI	293	331	385	516	719	773	790	778	730	705	677
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0%	0.0%	0.0%	4.1%	19.0%	23.7%	20.9%	15.0%	9.7%	5.7%	2.1%
D	0.0%	0.0%	0.0%	1.0%	3.5%	4.1%	4.0%	3.3%	2.1%	1.7%	1.3%
EIX	0.0%	0.0%	0.0%	1.2%	2.7%	0.8%	-3.0%	-7.0%	-8.3%	-9.1%	-9.9%
ETR	0.0%	0.0%	0.0%	0.2%	0.4%	0.6%	0.8%	1.0%	1.0%	1.0%	1.0%
EXC	0.0%	0.0%	0.1%	10.2%	25.1%	31.0%	34.3%	34.3%	27.7%	24.9%	22.7%
FE	0.0%	0.7%	2.8%	9.0%	16.9%	24.1%	22.9%	20.1%	14.9%	10.9%	7.6%
NEE	0.0%	0.0%	0.0%	0.1%	0.2%	0.3%	0.5%	0.7%	0.8%	0.9%	1.0%
PEG	0.1%	0.1%	0.6%	3.0%	5.5%	5.0%	3.9%	2.8%	1.1%	0.0%	-0.9%
FE/AYE (no synergy)	0.0%	0.5%	2.1%	7.8%	17.5%	24.0%	22.3%	18.6%	13.4%	9.4%	6.0%
FE/AYE (half synergy)	0.0%	0.5%	2.0%	7.4%	16.6%	22.8%	21.3%	17.7%	12.8%	9.0%	5.7%
RRI	0.0%	-0.7%	-1.2%	17.9%	39.4%	38.8%	33.4%	23.0%	10.2%	4.1%	-1.7%

Source: Company data, Credit Suisse estimates

Exhibit 155: **2010 – 2020 P/E Impact (100 GW Retirement 2013-2017)**

100 GW Retirement						**P/E**					
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	10.8x	10.5x	16.6x	12.6x	7.3x	5.8x	5.0x	4.7x	5.1x	4.7x	4.5x
D	13.0x	13.8x	13.7x	12.3x	11.6x	10.9x	10.5x	10.2x	9.9x	9.6x	9.5x
EIX	10.6x	11.4x	12.8x	11.1x	9.3x	9.3x	9.5x	9.7x	10.3x	9.6x	9.7x
ETR	11.5x	11.2x	11.8x	11.7x	11.4x	10.8x	10.5x	10.2x	9.9x	9.4x	9.4x
EXC	10.9x	10.9x	14.2x	12.4x	10.2x	9.0x	8.0x	7.4x	7.5x	7.1x	7.2x
FE	10.1x	11.0x	11.3x	9.3x	7.6x	6.6x	5.6x	5.8x	5.8x	5.7x	5.6x
NEE	12.2x	12.3x	11.8x	11.4x	10.5x	9.4x	8.7x	8.2x	7.9x	7.3x	7.4x
PEG	10.6x	11.2x	11.6x	9.9x	8.3x	7.8x	7.3x	7.2x	7.0x	6.8x	6.6x
FE/AYE (no synergy)	10.4x	11.1x	12.5x	10.1x	7.6x	6.5x	5.5x	5.6x	5.7x	5.5x	5.4x
FE/AYE (half synergy)	10.4x	10.6x	11.5x	9.3x	7.1x	6.0x	5.2x	5.2x	5.3x	5.1x	5.1x
RRI											
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0x	0.0x	0.0x	-1.3x	-3.0x	-3.0x	-2.3x	-1.7x	-1.3x	-0.9x	-0.5x
D	0.0x	0.0x	0.0x	-0.2x	-0.7x	-0.8x	-0.7x	-0.6x	-0.4x	-0.3x	-0.2x
EIX	0.0x	0.0x	0.0x	-0.3x	-0.6x	-0.2x	0.6x	1.5x	2.1x	2.1x	2.3x
ETR	0.0x	0.0x	0.0x	0.0x	-0.1x	-0.1x	-0.2x	-0.2x	-0.2x	-0.2x	-0.2x
EXC	0.0x	0.0x	0.0x	-2.1x	-4.5x	-5.1x	-5.1x	-4.9x	-4.3x	-3.8x	-3.7x
FE	0.0x	-0.2x	-0.7x	-1.8x	-2.8x	-3.5x	-2.6x	-2.5x	-2.0x	-1.5x	-1.1x
NEE	0.0x	0.0x	0.0x	0.0x	0.0x	-0.1x	-0.1x	-0.1x	-0.1x	-0.1x	-0.2x
PEG	0.0x	0.0x	-0.1x	-0.5x	-0.7x	-0.6x	-0.5x	-0.3x	-0.2x	-0.1x	0.0x
FE/AYE (no synergy)	0.0x	-0.1x	-0.6x	-1.8x	-2.9x	-3.4x	-2.6x	-2.3x	-1.8x	-1.3x	5.4x
FE/AYE (half synergy)	0.0x	-0.1x	-0.5x	-1.5x	-2.4x	-2.9x	-2.2x	-2.0x	-1.6x	-1.1x	5.1x
RRI											

Source: Company data, Credit Suisse estimates

Exhibit 156: **2010 – 2020 EV/EBITDA Impact (100 GW Retirement 2013-2017)**

100 GW Retirement						**EV/EBITDA**					
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	6.4x	6.6x	7.8x	7.2x	5.4x	4.7x	4.3x	4.1x	4.3x	4.1x	4.0x
D	8.7x	9.2x	9.2x	8.6x	8.3x	8.0x	7.8x	7.7x	7.6x	7.5x	7.4x
EIX	7.1x	7.1x	7.4x	7.1x	6.8x	6.7x	6.7x	6.8x	6.7x	6.6x	6.5x
ETR	6.8x	7.0x	7.2x	6.9x	6.8x	6.5x	6.4x	6.3x	6.1x	5.9x	5.8x
EXC	6.5x	6.6x	7.9x	7.2x	6.3x	5.7x	5.1x	4.8x	4.7x	4.4x	4.4x
FE	8.1x	7.9x	8.0x	7.3x	6.5x	6.0x	5.3x	5.4x	5.3x	5.2x	5.2x
NEE	8.7x	8.9x	8.6x	8.3x	8.0x	7.6x	7.1x	6.8x	6.5x	6.2x	6.3x
PEG	6.7x	6.8x	7.0x	6.3x	5.7x	5.5x	5.2x	5.1x	5.0x	4.9x	4.9x
FE/AYE (no synergy)	7.7x	7.6x	8.0x	7.3x	6.3x	5.7x	5.1x	5.1x	5.1x	4.9x	4.9x
FE/AYE (half synergy)	7.7x	7.4x	7.7x	7.0x	6.0x	5.4x	4.9x	4.9x	4.9x	4.7x	4.7x
RRI	10	8	7	5	3	2	2	2	1	1	1
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0x	0.0x	0.0x	-0.3x	-1.2x	-1.3x	-1.1x	-0.9x	-0.7x	-0.5x	-0.3x
D	0.0x	0.0x	0.0x	-0.1x	-0.3x	-0.4x	-0.4x	-0.3x	-0.2x	-0.2x	-0.1x
EIX	0.0x	0.0x	0.0x	-0.1x	-0.2x	-0.1x	0.2x	0.5x	0.7x	0.8x	0.9x
ETR	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	-0.1x	-0.1x	-0.1x	-0.1x	-0.1x
EXC	0.0x	0.0x	0.0x	-0.8x	-1.8x	-2.2x	-2.4x	-2.4x	-2.3x	-2.2x	-2.2x
FE	0.0x	-0.1x	-0.2x	-0.7x	-1.3x	-1.8x	-1.6x	-1.6x	-1.4x	-1.2x	-1.0x
NEE	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	0.0x	-0.1x	-0.1x	-0.1x	-0.1x
PEG	0.0x	0.0x	0.0x	-0.2x	-0.3x	-0.3x	-0.3x	-0.2x	-0.1x	-0.1x	0.0x
FE/AYE (no synergy)	0.0x	0.0x	-0.2x	-0.6x	-1.3x	-1.6x	-1.5x	-1.4x	-1.2x	-1.0x	-0.8x
FE/AYE (half synergy)	0.0x	0.0x	-0.2x	-0.6x	-1.2x	-1.5x	-1.4x	-1.3x	-1.1x	-0.9x	-0.7x
RRI	0.0x	0.1x	0.1x	-1.1x	-2.0x	-2.2x	-2.4x	-2.4x	-2.1x	-1.9x	-1.8x

Source: Company data, Credit Suisse estimates

Exhibit 157: **2010 – 2020 EPS Impact (60 GW Retirement 2013-2017) – MTM**

60 GW Retirement MTM						**EPS**					
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	2.16	2.11	1.18	1.43	2.44	3.24	4.07	4.70	4.40	4.77	4.93
D	3.41	3.20	3.17	3.43	3.62	3.94	4.18	4.38	4.54	4.66	4.75
EIX	3.30	2.99	2.59	2.87	3.47	3.77	4.10	4.39	4.22	4.45	4.45
ETR	6.69	6.85	6.31	6.09	6.33	6.87	7.06	7.31	7.52	7.94	7.94
EXC	3.93	3.93	2.97	2.97	3.37	3.94	4.52	5.02	5.10	5.32	5.24
FE	3.66	3.17	2.88	3.36	4.05	4.72	5.96	6.05	6.18	6.39	6.44
NEE	4.45	4.41	4.53	4.63	5.02	5.60	6.05	6.42	6.59	7.10	7.01
PEG	3.03	2.73	2.62	2.99	3.54	3.90	4.18	4.29	4.42	4.48	4.58
FE/AYE (no synergy)	3.55	3.17	2.58	3.03	3.94	4.76	6.00	6.31	6.29	6.58	6.67
FE/AYE (half synergy)	3.55	3.31	2.85	3.38	4.32	5.18	6.43	6.75	6.73	7.03	7.13
RRI											
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0%	-4.3%	-16.0%	-14.1%	7.6%	23.2%	28.8%	29.5%	21.9%	13.2%	7.3%
D	0.0%	-0.2%	-1.7%	-2.8%	0.7%	4.1%	5.7%	6.9%	5.4%	4.8%	4.0%
EIX	0.0%	-1.9%	-4.6%	-6.1%	-0.6%	3.1%	4.1%	3.2%	-0.5%	-3.6%	-6.0%
ETR	0.0%	-0.6%	-3.6%	-7.4%	-5.2%	-2.9%	-1.8%	-1.0%	-1.0%	-0.9%	-0.9%
EXC	0.0%	-0.4%	-1.8%	0.5%	15.9%	28.9%	37.8%	43.8%	39.3%	34.8%	32.4%
FE	0.0%	-4.7%	-6.4%	0.9%	13.1%	29.0%	32.5%	36.0%	29.9%	23.7%	17.4%
NEE	0.0%	-0.1%	-2.0%	-2.6%	-2.6%	-2.1%	-2.1%	-1.9%	-2.7%	-2.8%	-2.4%
PEG	-0.3%	-5.4%	-5.5%	-4.6%	-1.0%	0.8%	0.7%	-0.3%	-2.8%	-4.9%	-6.8%
FE/AYE (no synergy)	0.0%	-4.6%	-8.3%	-2.4%	11.7%	27.4%	31.5%	33.9%	27.5%	20.5%	14.3%
FE/AYE (half synergy)	0.0%	-4.4%	-7.6%	-2.2%	10.5%	24.6%	28.8%	31.1%	25.3%	19.0%	13.4%
RRI											

Source: Company data, Credit Suisse estimates

Exhibit 158: **2010 – 2020 EBITDA Impact (60 GW Retirement 2013-2017) – MTM**

60 GW Retirement MTM						**EBITDA**					
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	1,227	1,222	1,010	1,097	1,404	1,622	1,819	1,918	1,796	1,836	1,827
D	4,959	4,773	4,918	5,327	5,616	6,017	6,312	6,580	6,776	6,922	7,033
EIX	3,684	3,850	3,843	4,189	4,633	4,936	5,178	5,366	5,407	5,462	5,491
ETR	3,728	3,701	3,572	3,571	3,615	3,736	3,762	3,795	3,816	3,885	3,851
EXC	5,966	6,060	5,150	5,315	5,913	6,660	7,378	7,950	8,013	8,221	8,102
FE	3,292	3,274	3,164	3,421	3,776	4,097	4,670	4,683	4,722	4,790	4,791
NEE	4,787	4,936	5,342	5,682	5,957	6,356	6,635	6,833	6,960	7,135	6,941
PEG	3,756	3,657	3,599	3,913	4,298	4,498	4,625	4,609	4,608	4,560	4,530
FE/AYE (no synergy)	4,520	4,495	4,174	4,518	5,180	5,719	6,489	6,601	6,519	6,626	6,618
FE/AYE (half synergy)	4,520	4,585	4,349	4,743	5,420	5,984	6,754	6,866	6,784	6,891	6,883
RRI		301	338	383	546	644	698	733	713	689	667
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0%	-2.1%	-5.7%	-5.3%	4.0%	11.2%	14.0%	14.2%	9.5%	5.0%	1.8%
D	0.0%	-0.1%	-1.0%	-1.6%	0.5%	2.5%	3.5%	4.1%	3.2%	2.8%	2.4%
EIX	0.0%	-0.7%	-1.7%	-2.2%	0.0%	1.5%	1.8%	1.4%	-0.3%	-1.6%	-2.6%
ETR	0.0%	-0.3%	-1.8%	-3.6%	-2.4%	-1.3%	-0.7%	-0.3%	-0.3%	-0.2%	-0.2%
EXC	0.0%	-0.3%	-1.1%	0.4%	9.2%	16.1%	20.7%	23.4%	20.0%	17.0%	14.6%
FE	0.0%	-2.2%	-2.8%	0.6%	6.4%	13.7%	16.4%	17.5%	14.3%	11.2%	8.0%
NEE	0.0%	-0.1%	-1.1%	-1.4%	-1.4%	-1.1%	-1.0%	-0.9%	-1.2%	-1.3%	-0.9%
PEG	-0.2%	-3.4%	-3.3%	-2.6%	-0.3%	1.0%	0.9%	0.3%	-1.3%	-2.6%	-3.7%
FE/AYE (no synergy)	0.0%	-2.2%	-3.5%	-0.9%	5.7%	13.0%	15.7%	16.5%	13.0%	9.4%	6.2%
FE/AYE (half synergy)	0.0%	-2.2%	-3.4%	-0.9%	5.5%	12.3%	15.0%	15.8%	12.4%	9.0%	5.9%
RRI		-9.6%	-13.3%	-12.4%	5.9%	15.7%	17.9%	15.9%	7.5%	1.6%	-3.2%

Source: Company data, Credit Suisse estimates

Exhibit 159: 2010 – 2020 P/E Impact (60 GW Retirement 2013-2017) – MTM

60 GW Retirement MTM	P/E										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	10.8x	11.0x	19.7x	16.2x	9.5x	7.2x	5.7x	4.9x	5.3x	4.9x	4.7x
D	13.0x	13.8x	13.9x	12.9x	12.2x	11.2x	10.6x	10.1x	9.7x	9.5x	9.3x
EIX	10.6x	11.6x	13.4x	12.1x	10.0x	9.2x	8.5x	7.9x	8.2x	7.8x	7.8x
ETR	11.5x	11.3x	12.2x	12.6x	12.2x	11.2x	10.9x	10.5x	10.2x	9.7x	9.7x
EXC	10.9x	10.9x	14.4x	14.5x	12.7x	10.9x	9.5x	8.5x	8.4x	8.1x	8.2x
FE	10.1x	11.7x	12.9x	11.0x	9.2x	7.9x	6.2x	6.1x	6.0x	5.8x	5.8x
NEE	12.2x	12.3x	12.0x	11.7x	10.8x	9.7x	9.0x	8.5x	8.2x	7.7x	7.8x
PEG	10.7x	11.9x	12.4x	10.8x	9.2x	8.3x	7.7x	7.5x	7.3x	7.2x	7.1x
FE/AYE (no synergy)	10.4x	11.7x	14.4x	12.2x	9.4x	7.8x	6.2x	5.9x	5.9x	5.6x	5.6x
FE/AYE (half synergy)	10.4x	11.2x	13.0x	11.0x	8.6x	7.2x	5.8x	5.5x	5.5x	5.3x	5.2x
RRI											
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0x	0.5x	3.2x	2.3x	-0.7x	-1.7x	-1.6x	-1.5x	-1.2x	-0.6x	-0.3x
D	0.0x	0.0x	0.2x	0.4x	-0.1x	-0.5x	-0.6x	-0.7x	-0.5x	-0.5x	-0.4x
EIX	0.0x	0.2x	0.6x	0.7x	0.1x	-0.3x	-0.4x	-0.3x	0.0x	0.3x	0.5x
ETR	0.0x	0.1x	0.4x	0.9x	0.6x	0.3x	0.2x	0.1x	0.1x	0.1x	0.1x
EXC	0.0x	0.0x	0.3x	-0.1x	-2.0x	-3.2x	-3.6x	-3.7x	-3.3x	-2.8x	-2.7x
FE	0.0x	0.6x	0.8x	-0.1x	-1.2x	-2.3x	-2.0x	-2.2x	-1.8x	-1.4x	-1.0x
NEE	0.0x	0.0x	0.2x	0.3x	0.3x	0.2x	0.2x	0.2x	0.2x	0.2x	0.2x
PEG	0.0x	0.6x	0.7x	0.5x	0.1x	-0.1x	-0.1x	0.0x	0.2x	0.4x	0.5x
FE/AYE (no synergy)	0.0x	0.5x	1.2x	0.3x	-1.1x	-2.1x	-1.9x	-2.0x	-1.6x	-1.2x	5.6x
FE/AYE (half synergy)	0.0x	0.5x	1.0x	0.2x	-0.9x	-1.8x	-1.7x	-1.7x	-1.4x	-1.0x	5.2x
RRI											

Source: Company data, Credit Suisse estimates

Exhibit 160: 2010 – 2020 EV/EBITDA Impact (60 GW Retirement 2013-2017) – MTM

60 GW Retirement MTM	EV/EBITDA										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AYE	6.4x	6.7x	8.3x	8.0x	6.4x	5.5x	4.7x	4.3x	4.5x	4.3x	4.2x
D	8.7x	9.2x	9.3x	8.9x	8.6x	8.2x	7.9x	7.7x	7.5x	7.4x	7.4x
EIX	7.1x	7.2x	7.6x	7.4x	7.0x	6.7x	6.4x	6.2x	6.1x	5.9x	5.8x
ETR	6.8x	7.0x	7.3x	7.2x	7.0x	6.7x	6.6x	6.4x	6.3x	6.1x	6.0x
EXC	6.5x	6.6x	8.0x	8.0x	7.4x	6.6x	6.0x	5.5x	5.4x	5.1x	5.1x
FE	8.1x	8.1x	8.5x	8.0x	7.3x	6.7x	5.9x	5.8x	5.6x	5.5x	5.4x
NEE	8.7x	8.9x	8.7x	8.4x	8.2x	7.7x	7.3x	7.0x	6.7x	6.5x	6.6x
PEG	6.7x	7.0x	7.4x	6.8x	6.1x	5.8x	5.5x	5.4x	5.3x	5.3x	5.3x
FE/AYE (no synergy)	7.7x	7.8x	8.5x	8.1x	7.1x	6.4x	5.6x	5.4x	5.3x	5.2x	5.1x
FE/AYE (half synergy)	7.7x	7.7x	8.2x	7.7x	6.8x	6.1x	5.3x	5.2x	5.1x	5.0x	4.9x
RRI	10.2x	9.4x	8.0x	7.1x	4.7x	3.5x	2.8x	2.3x	1.9x	1.7x	1.8x
% Chg from No Retirements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AYE	0.0x	0.2x	0.5x	0.5x	-0.2x	-0.6x	-0.7x	-0.7x	-0.5x	-0.3x	-0.2x
D	0.0x	0.0x	0.1x	0.2x	0.0x	-0.2x	-0.3x	-0.3x	-0.3x	-0.2x	-0.2x
EIX	0.0x	0.1x	0.1x	0.2x	0.0x	-0.1x	-0.1x	-0.1x	0.0x	0.1x	0.2x
ETR	0.0x	0.0x	0.1x	0.3x	0.2x	0.1x	0.1x	0.1x	0.1x	0.1x	0.1x
EXC	0.0x	0.0x	0.1x	0.0x	-0.7x	-1.2x	-1.5x	-1.7x	-1.6x	-1.5x	-1.5x
FE	0.0x	0.2x	0.3x	0.0x	-0.5x	-1.0x	-1.1x	-1.2x	-1.1x	-0.9x	-0.7x
NEE	0.0x	0.0x	0.1x	0.1x	0.1x	0.1x	0.1x	0.1x	0.2x	0.2x	0.1x
PEG	0.0x	0.3x	0.3x	0.2x	0.1x	0.0x	0.0x	0.1x	0.2x	0.3x	0.4x
FE/AYE (no synergy)	0.0x	0.2x	0.3x	0.1x	-0.4x	-0.9x	-1.0x	-1.1x	-0.9x	-0.7x	-0.6x
FE/AYE (half synergy)	0.0x	0.2x	0.3x	0.1x	-0.4x	-0.8x	-0.9x	-1.0x	-0.9x	-0.7x	-0.5x
0											
RRI	0.0x	1.0x	1.3x	1.0x	-0.5x	-1.1x	-1.5x	-1.6x	-1.5x	-1.5x	-1.3x

Source: Company data, Credit Suisse estimates

Companies Mentioned *(Price as of 22 Sep 10)*
Allegheny Energy Inc. (AYE, $23.25, OUTPERFORM, TP $28.00)
Alliant Energy Corp. (LNT, $35.95)
Ameren Corp. (AEE, $27.81)
American Electric Power Co., Inc. (AEP, $36.43, OUTPERFORM, TP $40.00)
Black Hills Corporation (BKH, $30.26)
Calpine (CPN, $12.49)
CenterPoint Energy, Inc. (CNP, $15.41)
Central Vermont Pub Serv (CV, $19.98)
CMS Energy (CMS, $18.01, OUTPERFORM [V], TP $17.50)
Con Edison (ED, $48.52, NEUTRAL, TP $48.00)
Constellation Energy Group Inc. (CEG, $32.00, RESTRICTED)
Dominion Resources (D, $44.21, NEUTRAL, TP $39.00)
DPL (DPL, $25.76)
DTE Energy (DTE, $46.12, NEUTRAL, TP $47.00)
Duke Energy (DUK, $17.98, NEUTRAL, TP $17.00)
Dynegy Inc. (DYN, $4.63, RESTRICTED [V])
Edison International (EIX, $34.81, NEUTRAL, TP $37.00)
El Paso Electric Co (EE, $23.24)
Entergy Corporation (ETR, $77.05, NEUTRAL, TP $81.00)
Exelon Corporation (EXC, $42.92, NEUTRAL, TP $47.00)
FirstEnergy (FE, $37.07, OUTPERFORM, TP $43.00)
Great Plains Energy (GXP, $18.92)
Integrys Energy Group Inc. (TEG, $50.73)
ITC Holdings Corp (ITC, $60.83, OUTPERFORM, TP $63.00)
Minnesota Power Inc. (ALE, $35.91)
Mirant Corporation (MIR, $9.75)
NextEra Energy Inc. (NEE, $54.31, OUTPERFORM, TP $58.00)
Northeast Util (NU, $29.24)
NRG Energy (NRG, $21.01, RESTRICTED)
NSTAR (NST, $38.67)
NV Energy Inc (NVE, $12.88, NEUTRAL, TP $13.00)
OGE (OGE, $40.21)
Pepco Holdings Inc. (POM, $18.40, RESTRICTED)
PG&E Corporation (PCG, $45.17, NEUTRAL, TP $45.00)
Pinnacle West Capital Corp. (PNW, $40.92, OUTPERFORM, TP $40.00)
Progress Energy (PGN, $44.42, NEUTRAL, TP $40.00)
Public Services New Mexico (PNM, $11.12)
Public Svc Ent (PEG, $32.40, OUTPERFORM, TP $36.00)
RRI Energy Inc. (RRI, $3.47, OUTPERFORM [V], TP $6.00)
SCANA Corporation (SCG, $40.20)
Sempra Energy (SRE, $53.60)
Southern Company (SO, $37.47, NEUTRAL, TP $37.00)
TECO Energy (TE, $17.28, NEUTRAL, TP $16.00)
Unisource Energy Corp (UNS, $32.88, NEUTRAL, TP $34.00)
Wisconsin Energy (WEC, $57.85)

Disclosure Appendix

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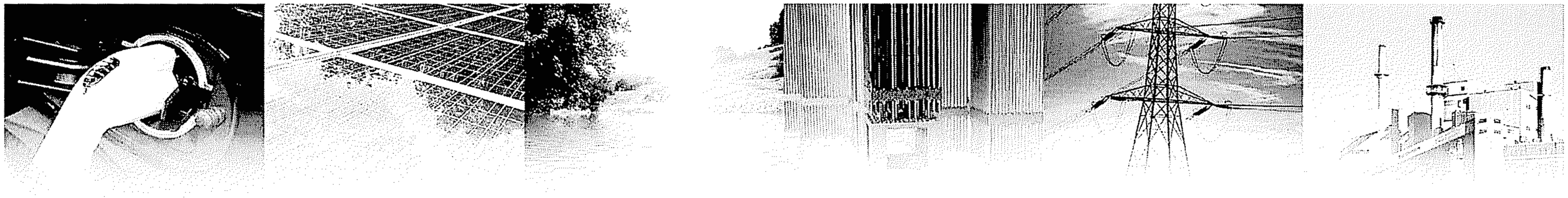

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Analysis of Current and Pending EPA Regulations on the U.S. Electric Sector

May 31, 2012

PRISM 2.0: Regional Energy and Economic Model Development and Initial Application

Develop a new energy-economy model of the U.S. with a special focus on the electric power sector:

U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model (completed)

Develop appropriate sectoral data and detail in electric power production and in energy demand, taking into account regional differences in generating costs and resources, especially for renewables, carbon capture and storage, and land use

Perform detailed analysis:

1st Phase – Current and Pending Environmental Controls (completed)
2nd Phase – Clean Energy Standard proposals (Summer 2012)
3rd Phase – preliminary analysis on the Impact of CO_2 Constraints on the Electric Power Sector (Fall 2012)

Communicate results at on-site member briefings and via public reports and presentations

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US-REGEN Model Description

General Equilibrium Economy Model

- Aggregate Economic Representation
- Energy Markets for Oil, Natural Gas, Coal, & Bioenergy
- Foreign Exchange
- Landuse (Ag and Forest)

Energy Demand (Electric & Non-Electric)

- Energy Efficiency across Commercial, Industrial, & Residential Sectors
- Transportation: Detailed model of vehicle technologies and intermodal choices

Electric Sector Module

- CO_2 Mitigation Technologies
- Environmental Controls: Air, Water, Land
- Transmission

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Key Messages

- The confluence of multiple environmental control requirements requiring retrofits on existing coal-fired power plants has significant implications for asset management and generation planning decisions, and substantial effects on electricity generation costs
- Decisions about whether to retrofit or retire existing coal-fired power plants are complex, with multiple uncertainties, interactions, and implications for electricity generators and the broader economy
- With phased compliance more time can facilitate testing and application of new and existing lower-cost technologies with significant savings, and with little change in overall emission reductions

Baseline Scenario

- Economic growth and energy supply and demand based on EIA's Annual Energy Outlook 2011
- Economic and electric power unit data based on 2009 and 2010 datasets, respectively, 2010 is the model's base year
- Electric sector policies, and assumptions:
  - Include state RPS Programs
  - State (CA, RGGI) or federal (CAA) GHG regulations not included
  - Include Cross-State Air Pollution Rule (CSAPR) by 2015 Aims to Reduce SO_2 emissions by 73 percent and NOx emissions by 54 percent from 2005 levels. Final rule.
  - New coal additions limited to units currently under construction

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Reference (Environmental Controls) Scenario

- Starting from the Baseline Scenario, then adding
- Electric Sector Policies
  - Mercury and Air Toxics Standard (MATs) Rule by 2015, more stringent SO_2, and SO_3 control by 2018) (Dry/wet scrubbing with increased particulate control)
  - Ozone and haze regulations by 2018 (Stringent NOx control with SCRs for all coal)
  - SO_2 NAAQS, haze regulations by 2018
  - Clean Water Act (CWA) 316(b) Controls by 2018 (closed-cycle cooling on facilities with intake flow > 125)
  - Coal Combustion Residuals (CCRs) Controls by 2020 (RCRA Subtitle D "non-hazardous")

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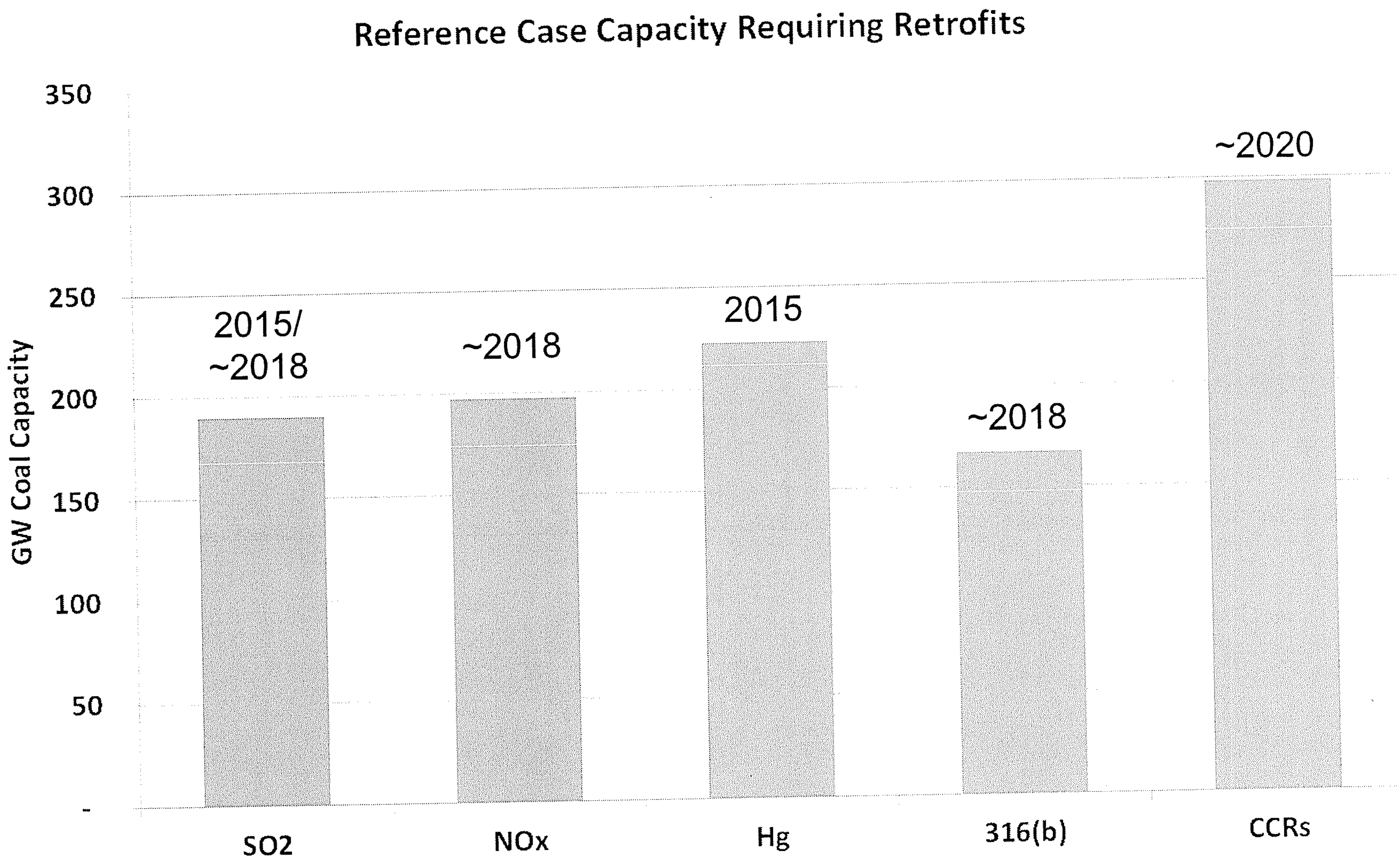
Hundreds of GW of Existing Coal Units Facing Multiple Compliance Obligations by 2015



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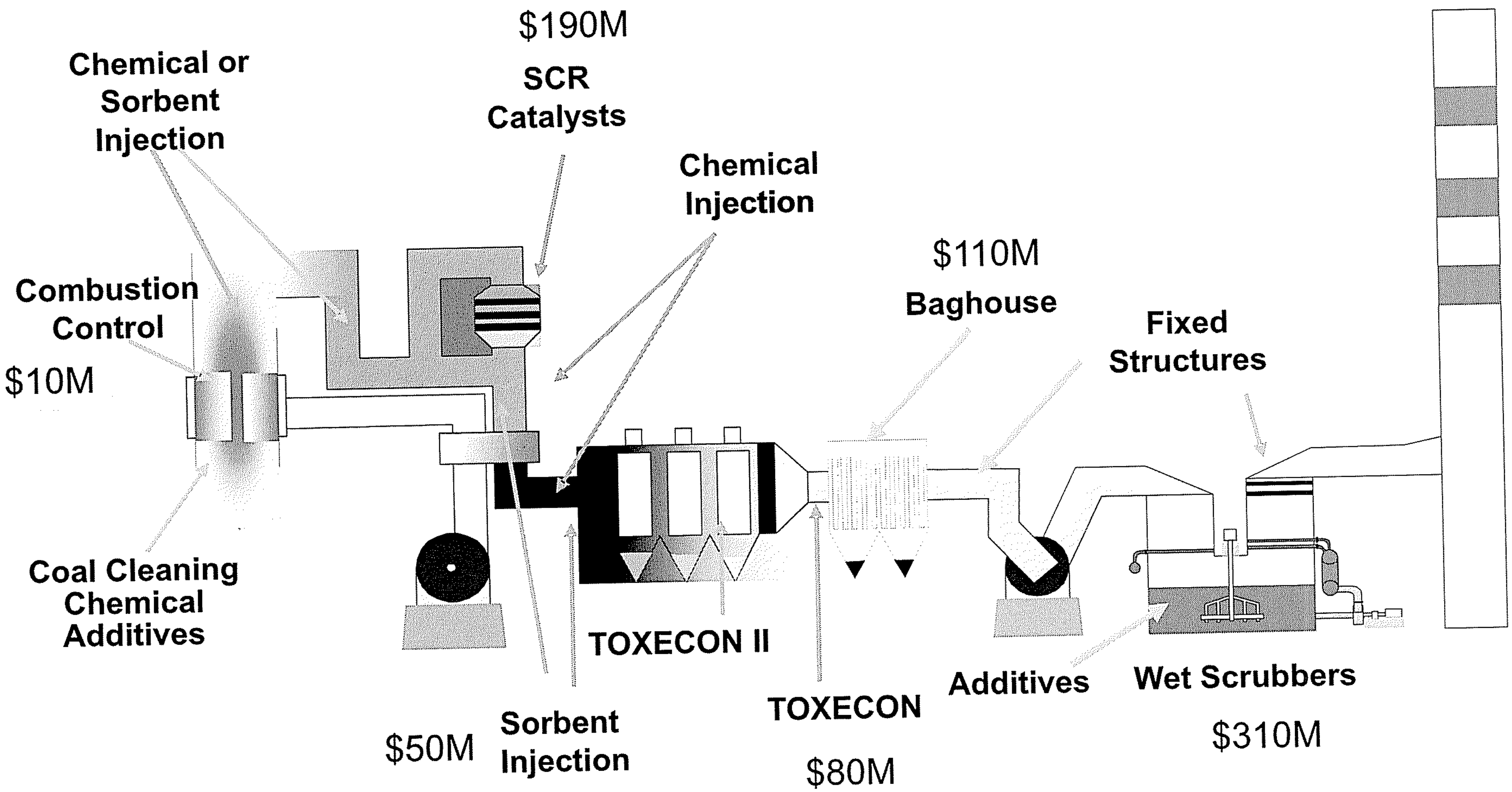
Controlling Emissions from Power Plants

Example Costs – 400 MW, Bituminous Coal



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Integrated Analysis of Retrofit Decision in Light of Full Set of Air (non-GHG), Water, Ash Policies

- Full Control policy defined as stringent control of SO_2, NOx, Hg, entrainment (316b), and coal combustion residuals (CCRs) but not recent proposed CO_2 performance standards.
- Assume asset owner make single retrofit-retire decision in 2015 based on full mix of requirements.
- Retrofit cost scenarios reflect broad cost and policy uncertainty:
  - Ref uses reference costs
  - Flex has lower costs, less stringent aquatic entrainment controls, less retrofit cost escalation, and additional time for compliance for SO_2 and NOx to allow for newer control technology options
  - High costs with less policy flexibility to choose low-cost technologies and higher retrofit cost escalation to meet stringent deadlines

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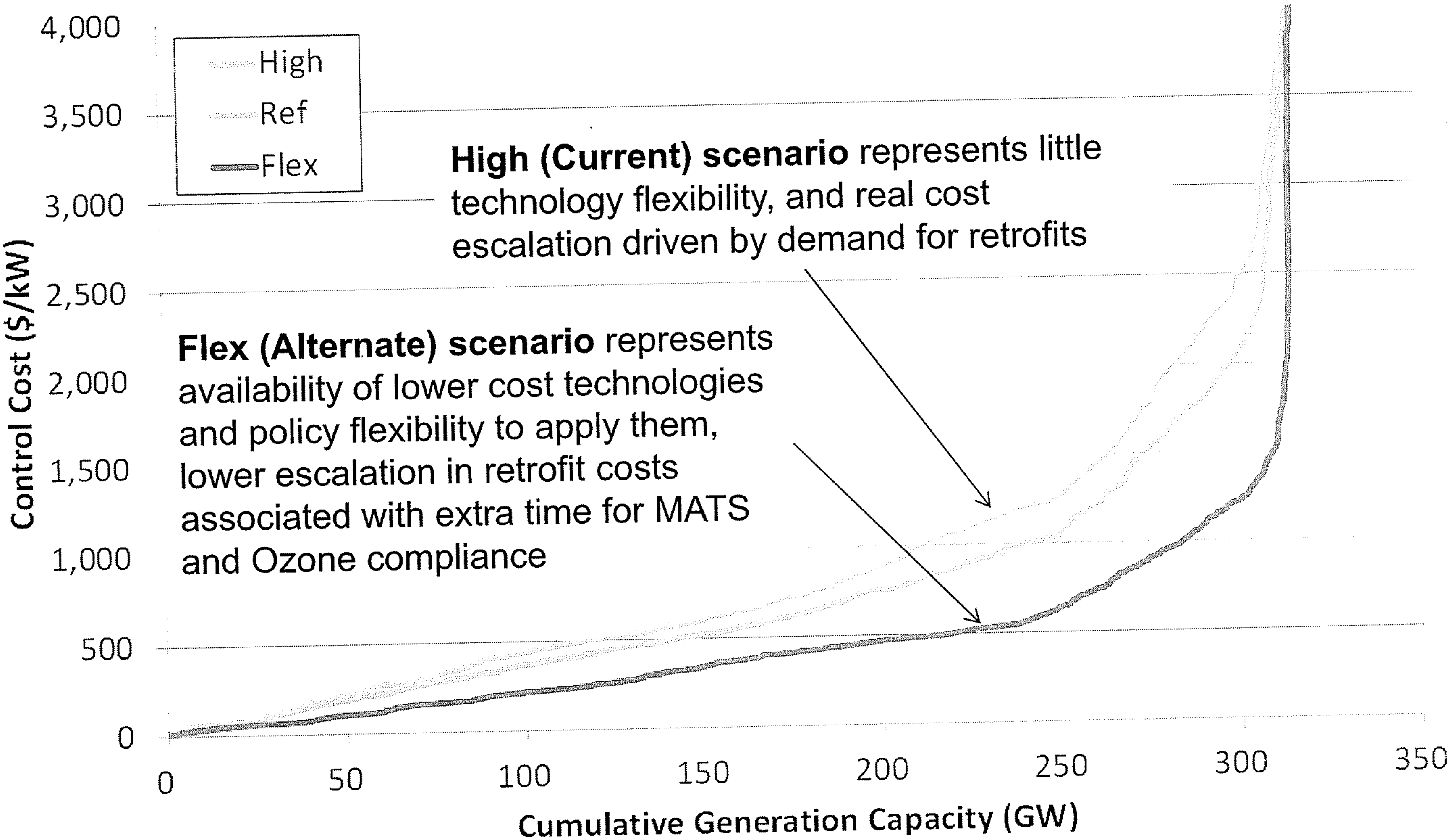
Scenarios Represent Uncertainty Ranges in Costs for Technology, Policy, and Escalation



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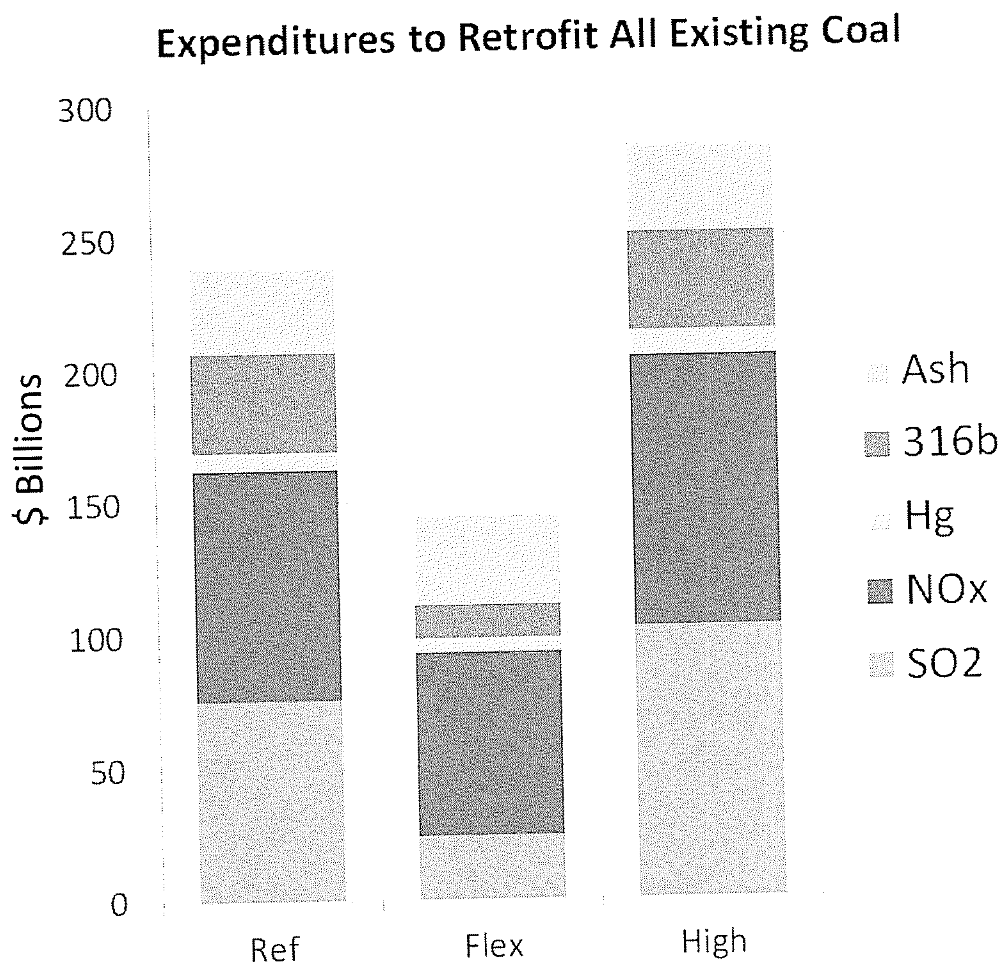
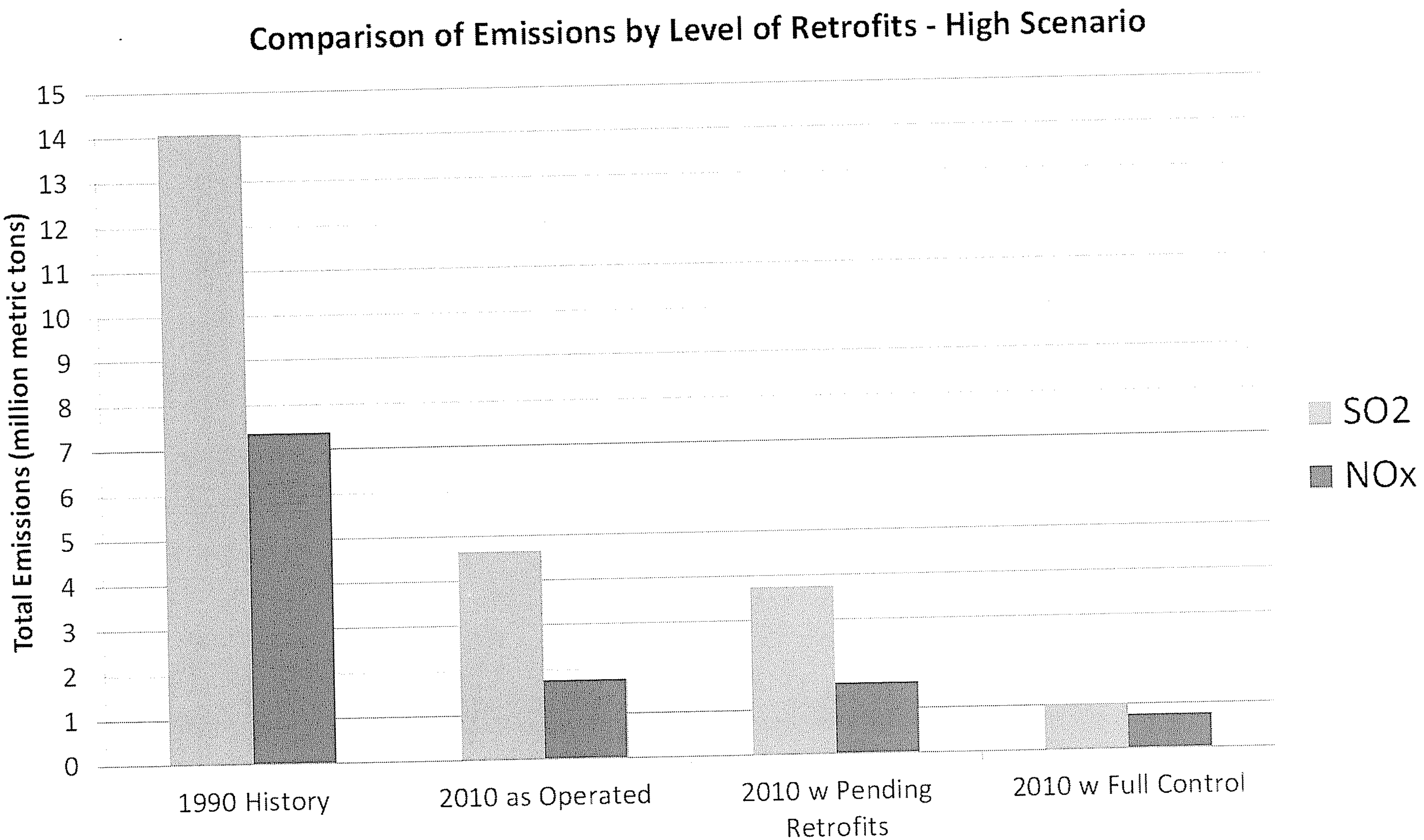
Cost to Retrofit Entire Fleet Uncertain but Several $100 Billions

- Chart show investment cost to retrofit entire existing fleet (sum of unit costs input to model)
- Existing coal
  - 316 GW
  - 40% of electric supply
  - 1,100 generating units
  - Diverse size/age mix
- Age, size, and market impact retrofit/retire decisions
- Many units poor candidates for environmental retrofits
- ~ 40 GW of coal retirements announced to date



Comparisons Show How Retrofits Will Cut Emissions



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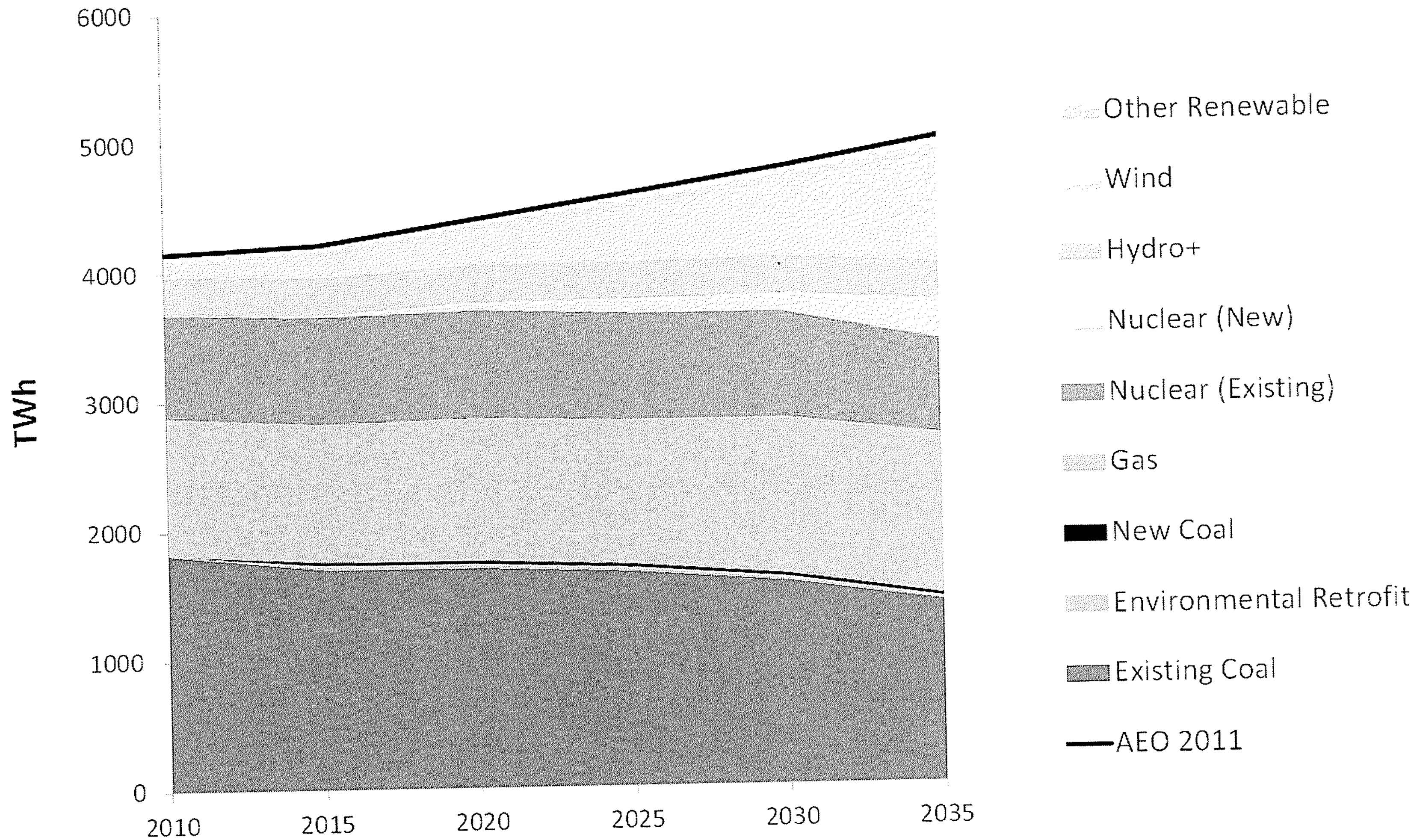
U.S. Electric Generation in Baseline



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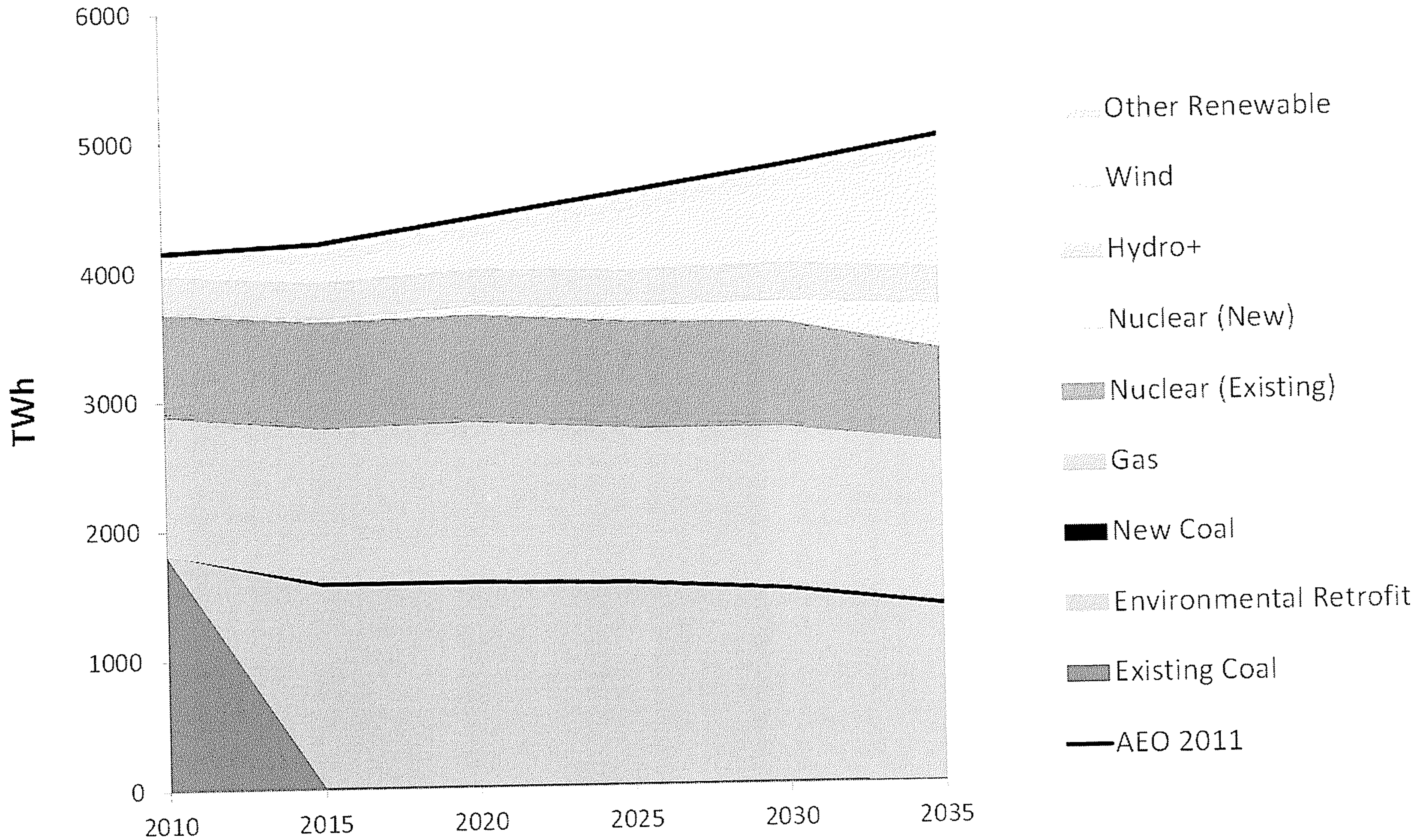
U.S. Electric Generation in Controls (Ref)



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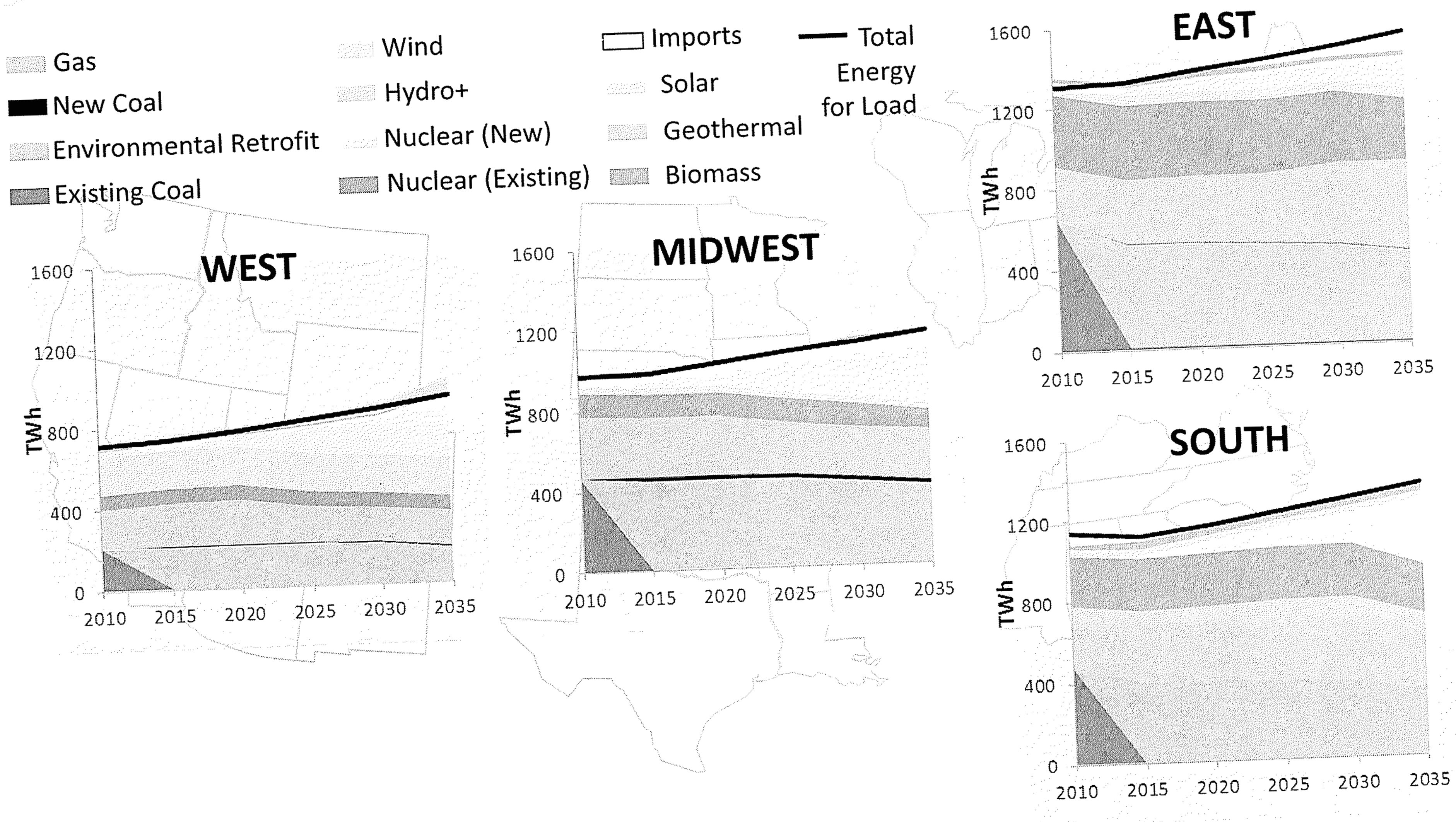
Regional Generation in Controls (Ref)



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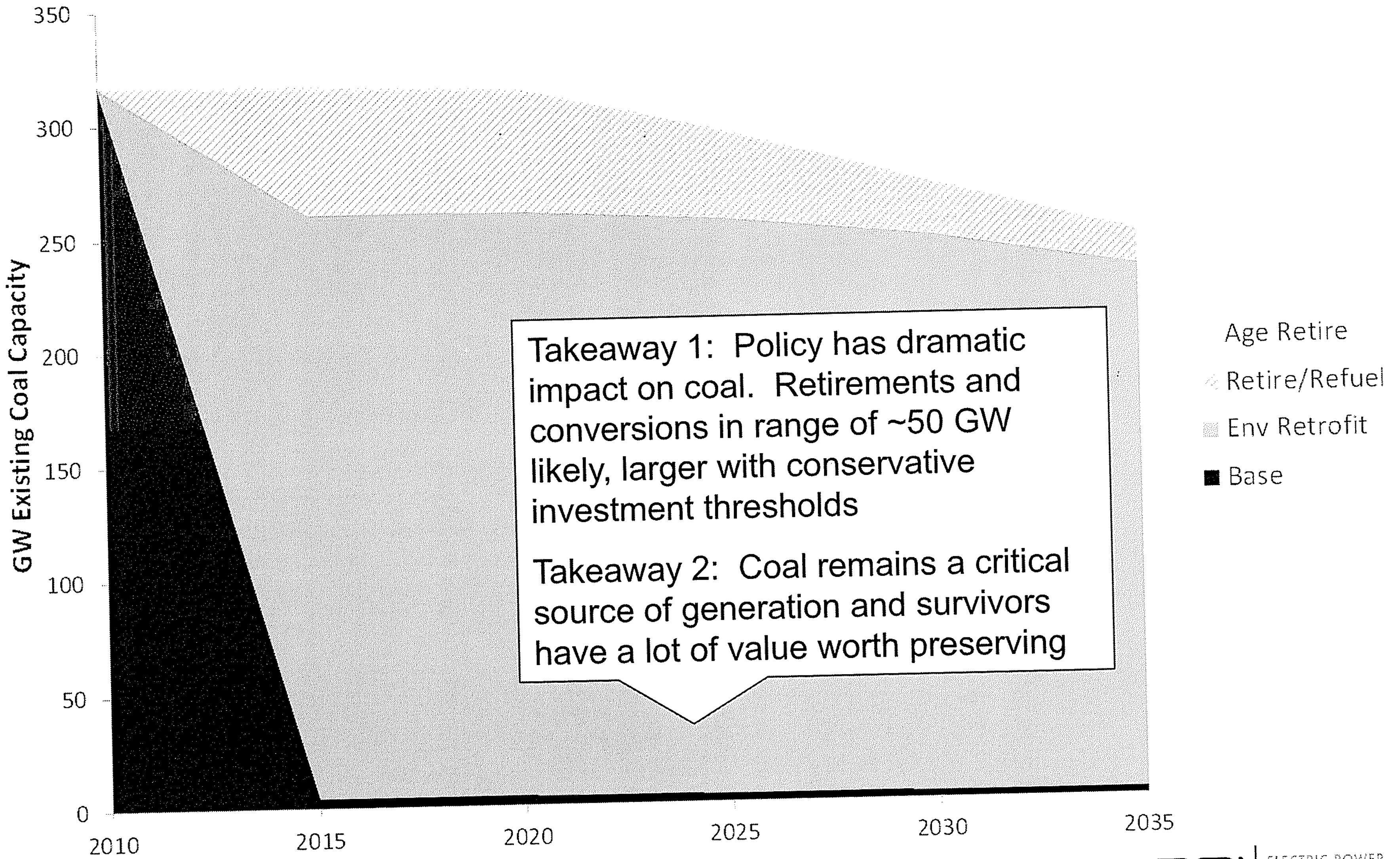
Coal Units May Cease to Operate Coal Due to Retirements as Well as Conversions to Gas

- Economics to retire or convert to gas or biomass can be very close
- Conversions can buy cheap capacity
- Capacity value depends on regional capacity needs and operating limitations of converted capacity
- Cost of conversion to gas can vary widely with distance to gas lines
- Many economically viable gas conversions may prove infeasible (e.g., siting, access to gas)
- As consequence we group units that cease to operate as coal into a Retire/Refuel category

Existing Coal Disposition in Controls (Ref)



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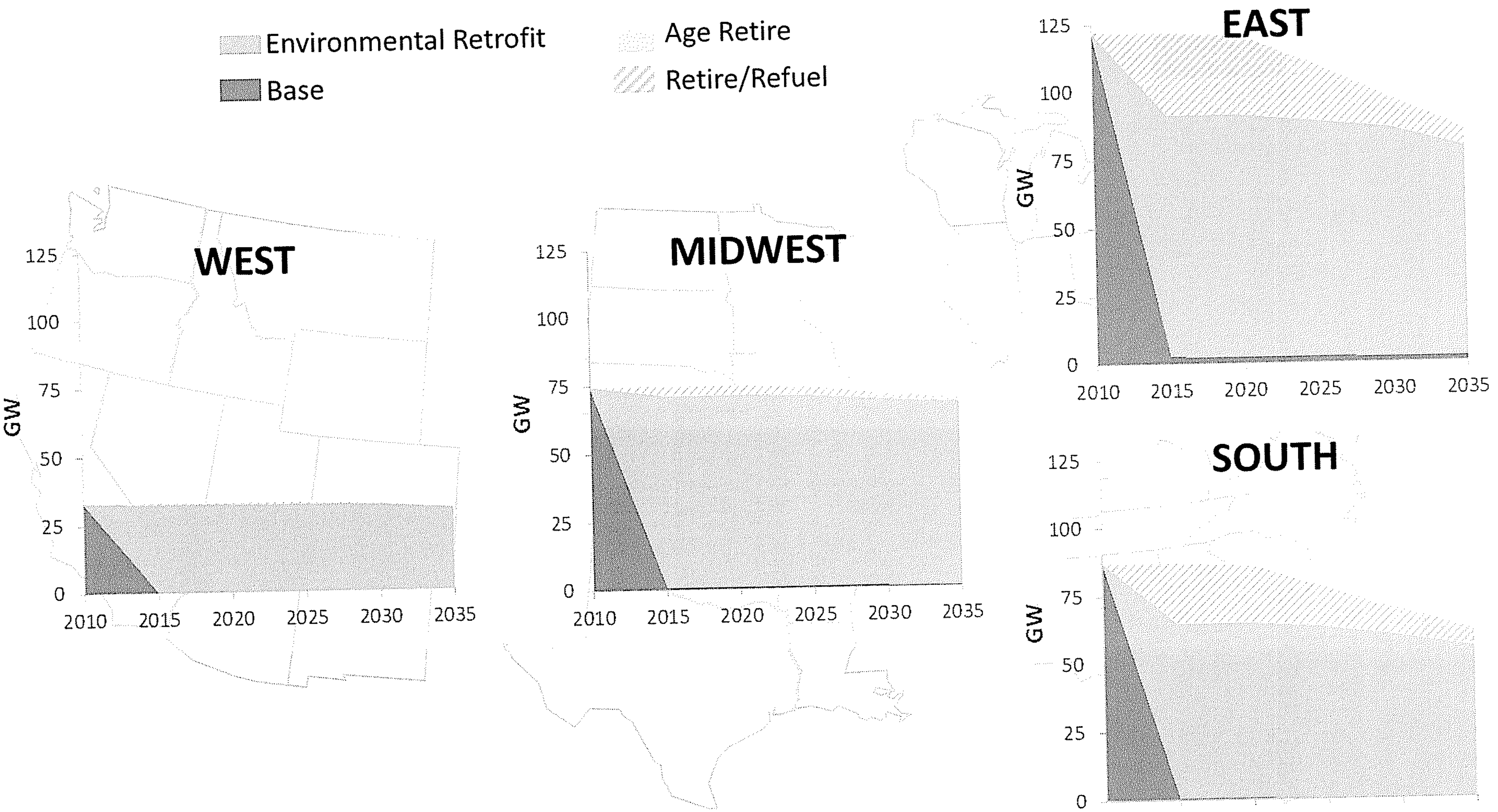
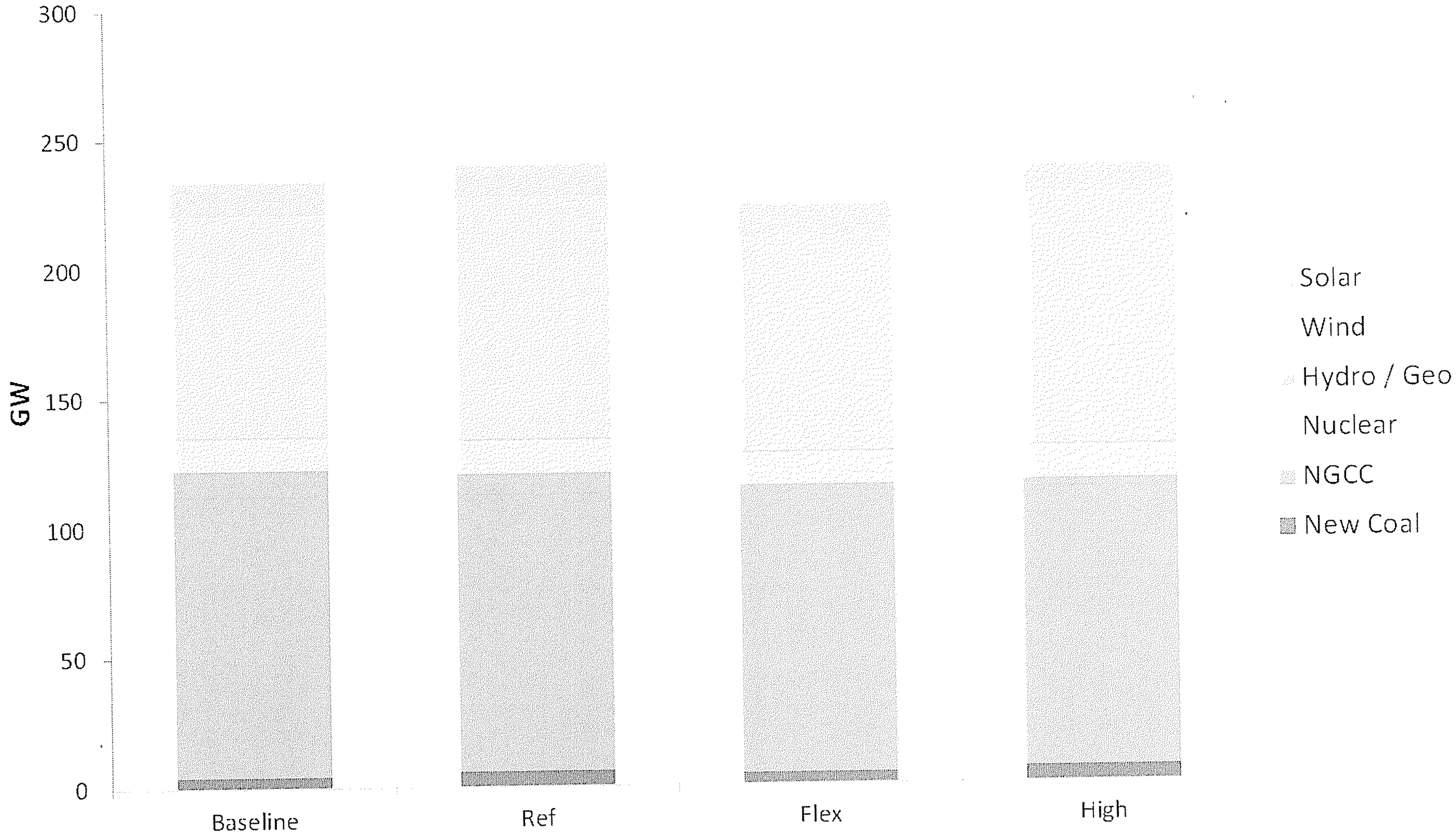
Regional Coal Disposition in Controls (Ref)



New Capacity Additions Through 2025



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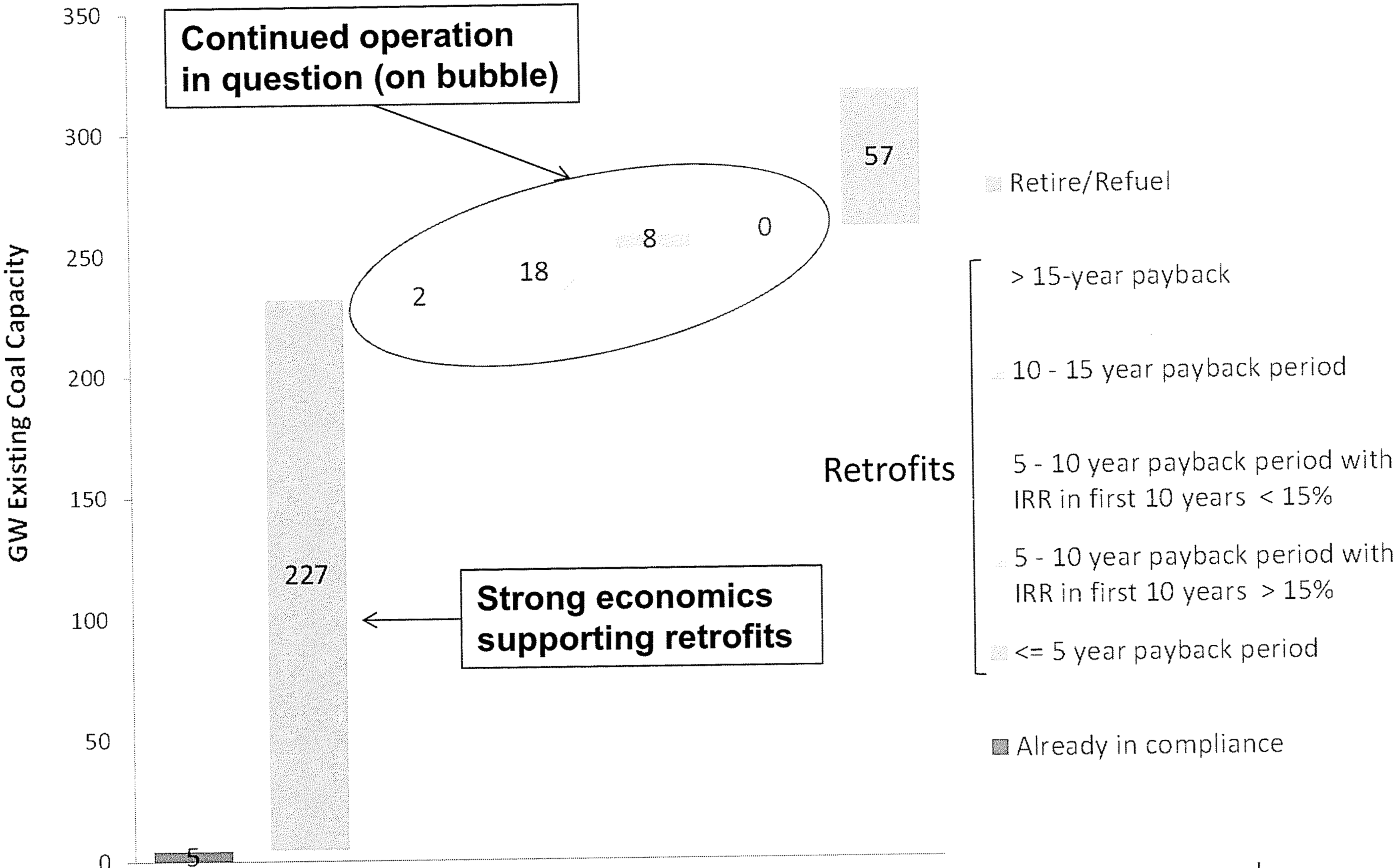
Broad Distribution of Pay-offs for Retrofits of Existing Coal (Ref)



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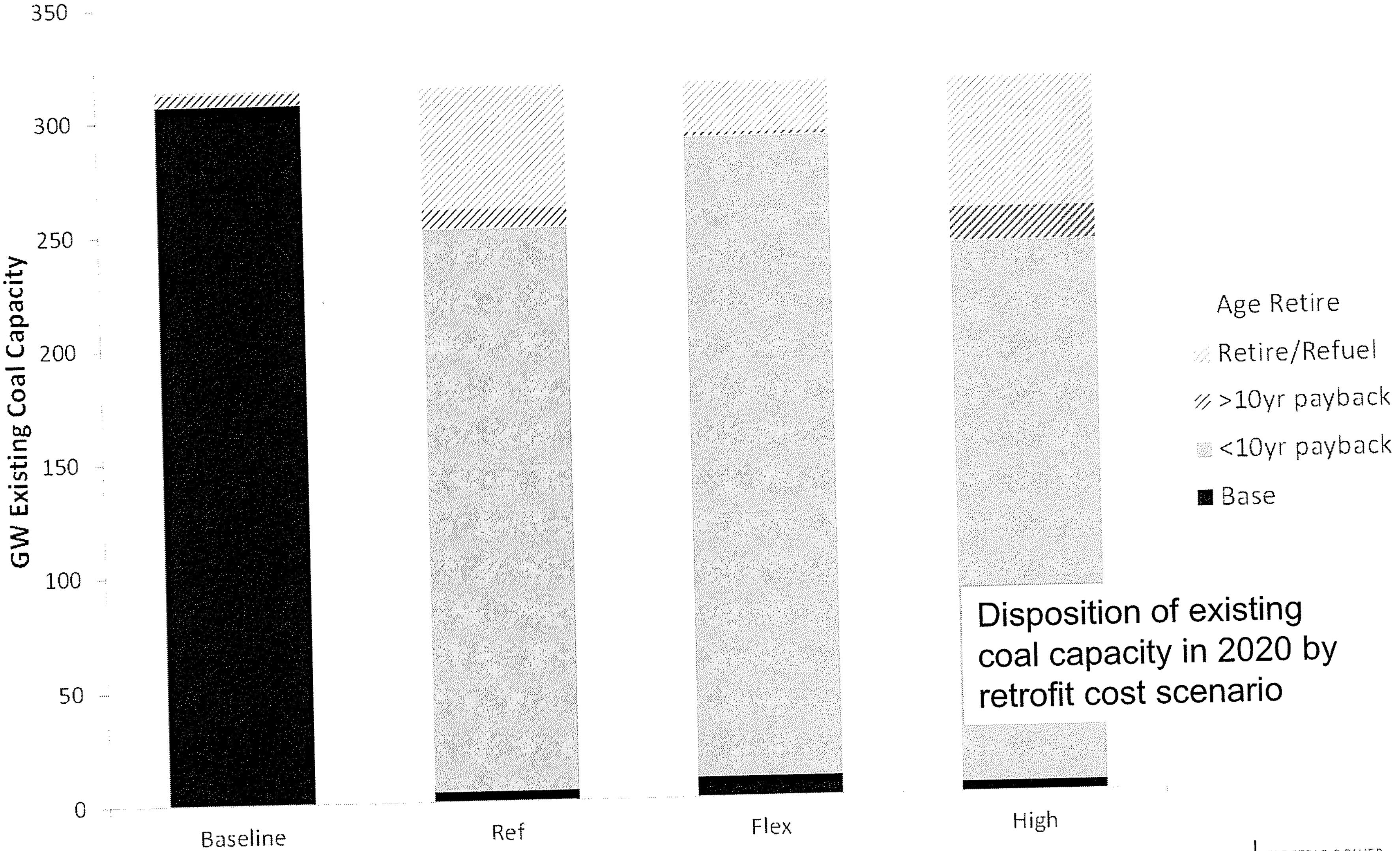
Potentially Large Fraction of Existing Coal Fleet May Retire or Refuel with Bio Energy or Gas



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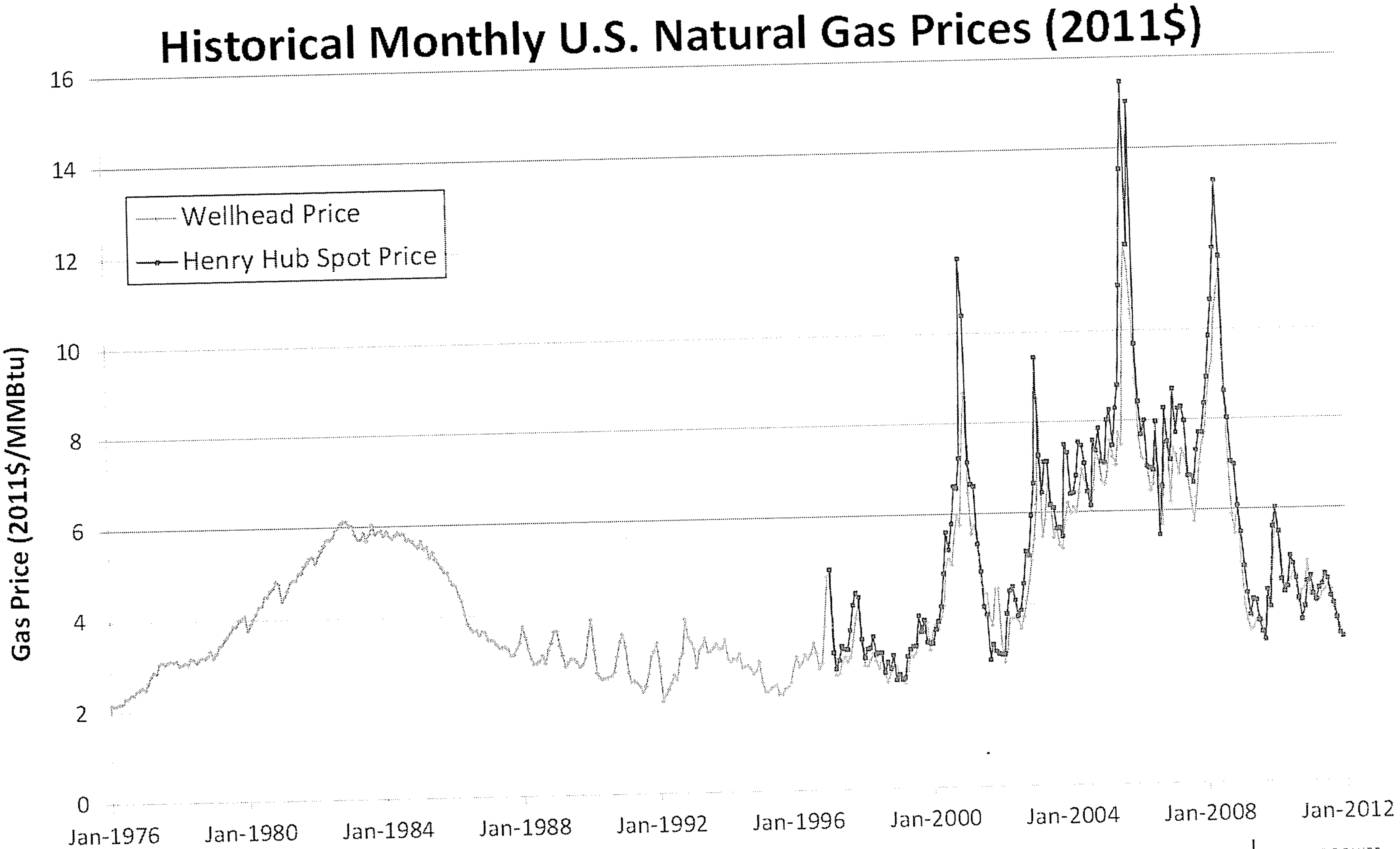
Long-term History of Natural Gas Prices Shows High Level of Variability



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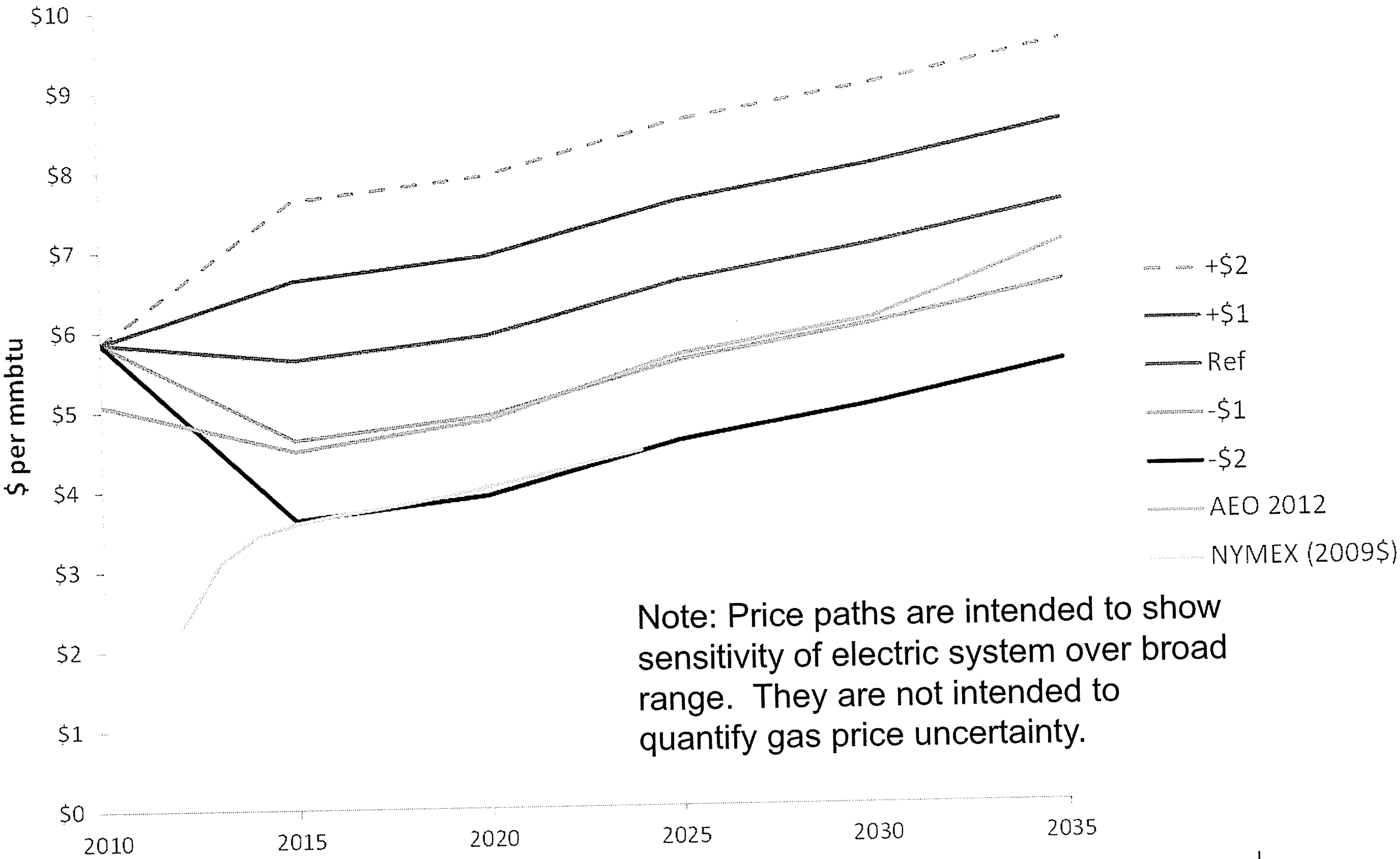
Sensitivity Analysis on Natural Gas Prices



Note: Price paths are intended to show sensitivity of electric system over broad range. They are not intended to quantify gas price uncertainty.

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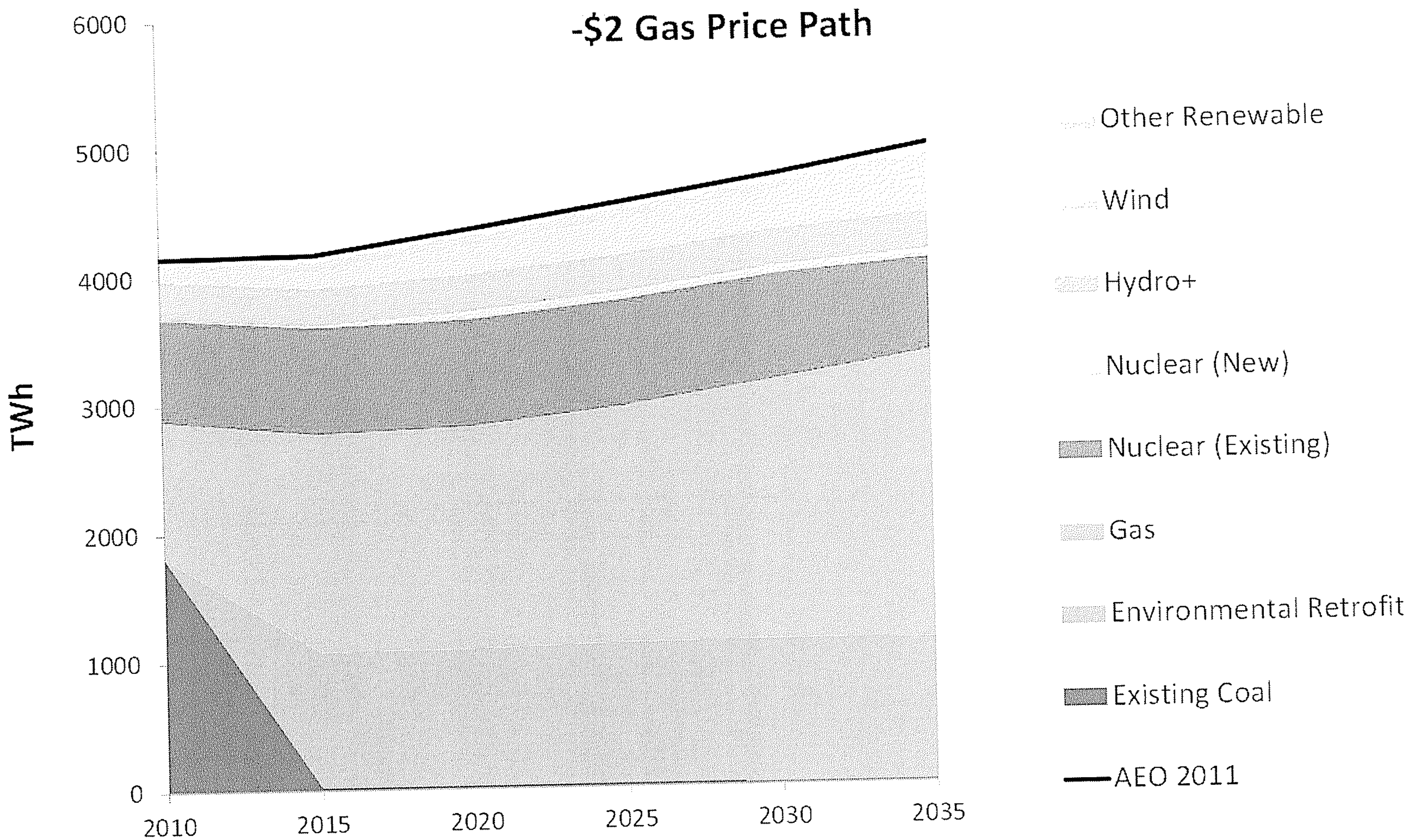
Generation with low gas prices



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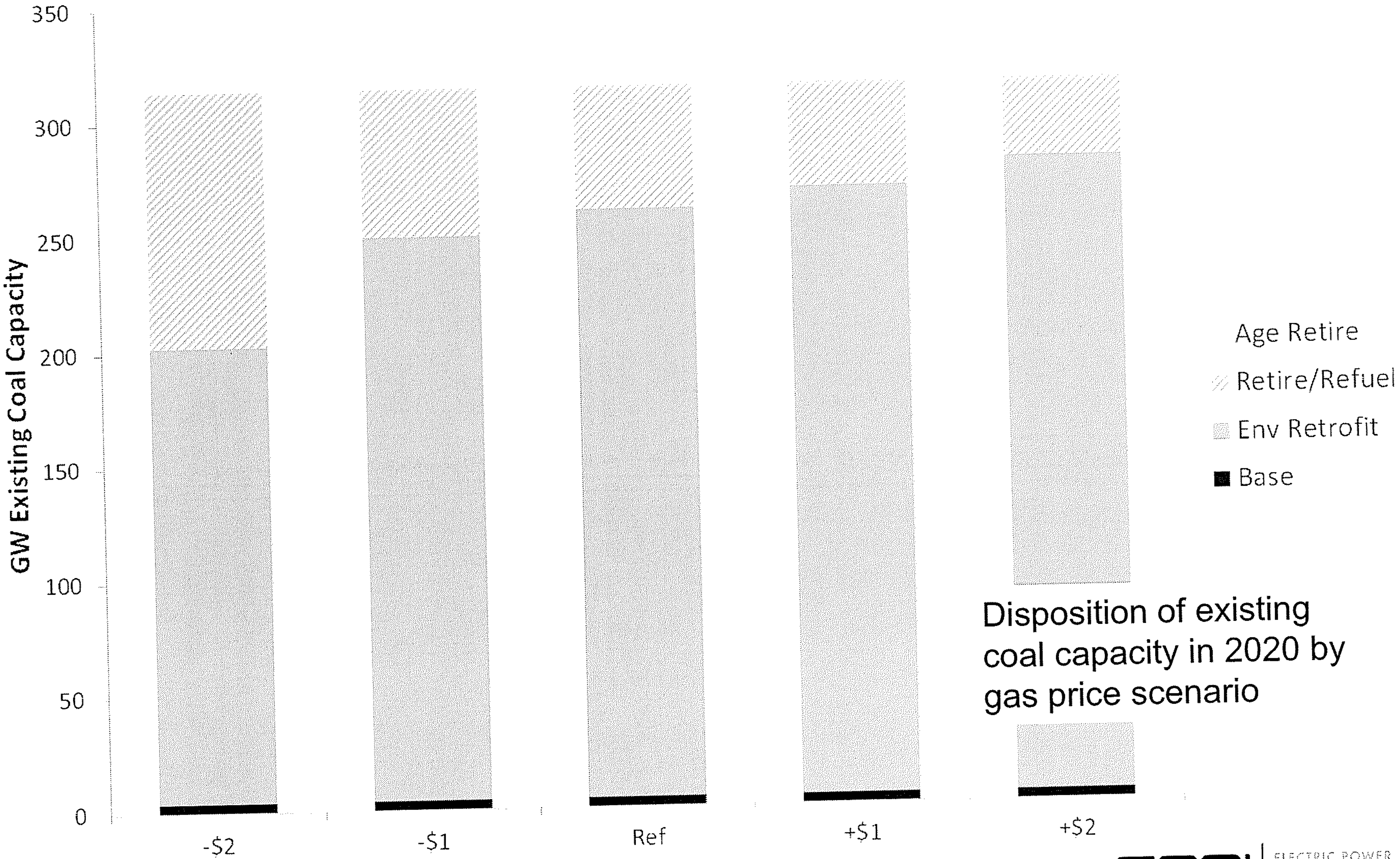
Gas Price Scenarios Show Critical Role of Gas Price Expectations for How Much Coal Survives



Disposition of existing coal capacity in 2020 by gas price scenario

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Natural Gas Price is the Dominant Uncertainty

Uncertainty level is very high

- Price range over last decade shows over 5 to 1 ratio
- Are NYMEX futures and AEO 2012 projections going to continue to decline?

Dramatic consequences

- Average power prices show ~$6/MWh swing for each $1 change in gas prices
- Low price paths have particularly large impact on retrofit vs. retire/refuel decisions

Implications for decisions

- Flexible compliance strategies with lower fixed costs (despite higher operating costs) reduce risk or regrets

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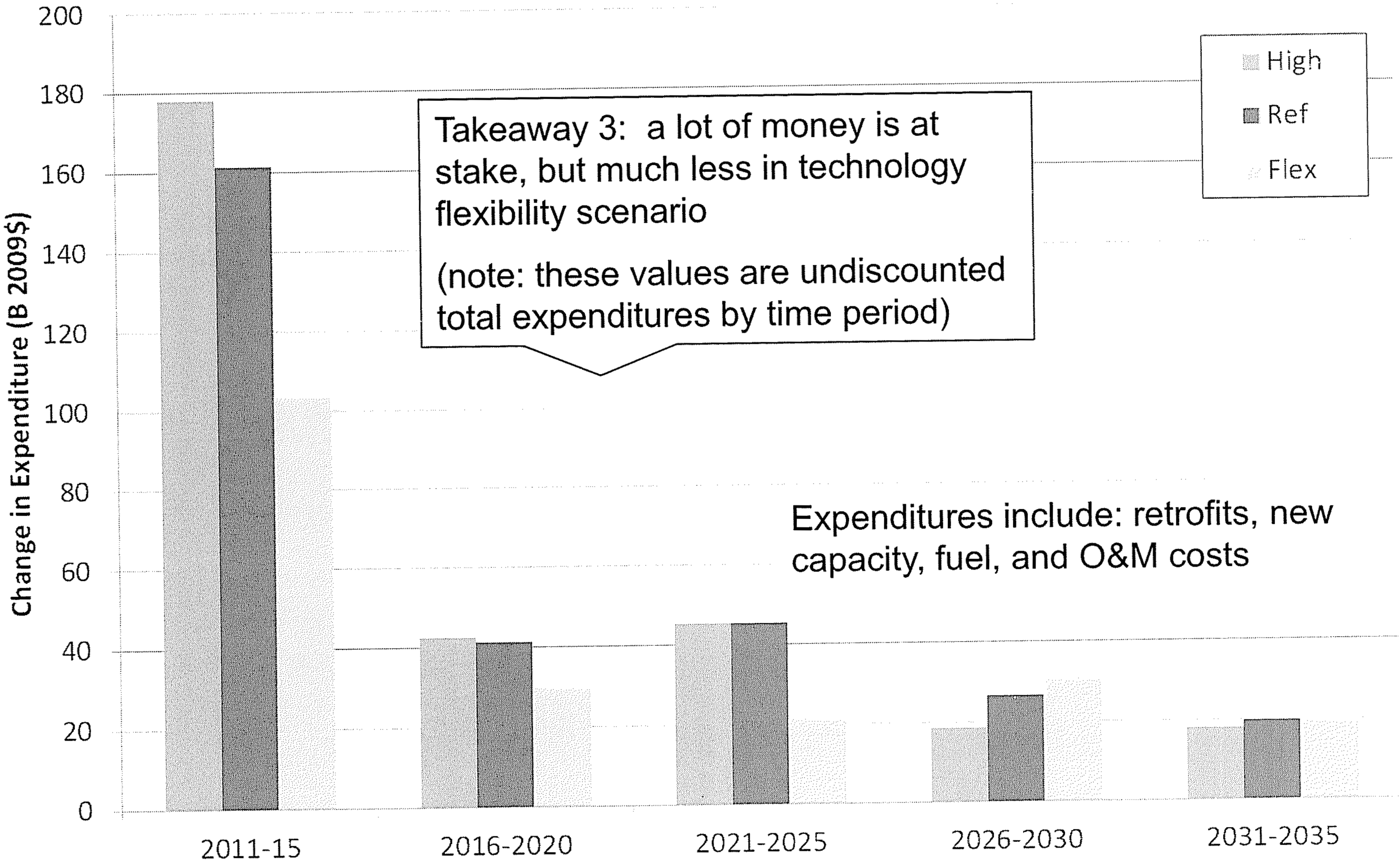
100's of Billions of Dollars in Possible Electric Sector Expenditures



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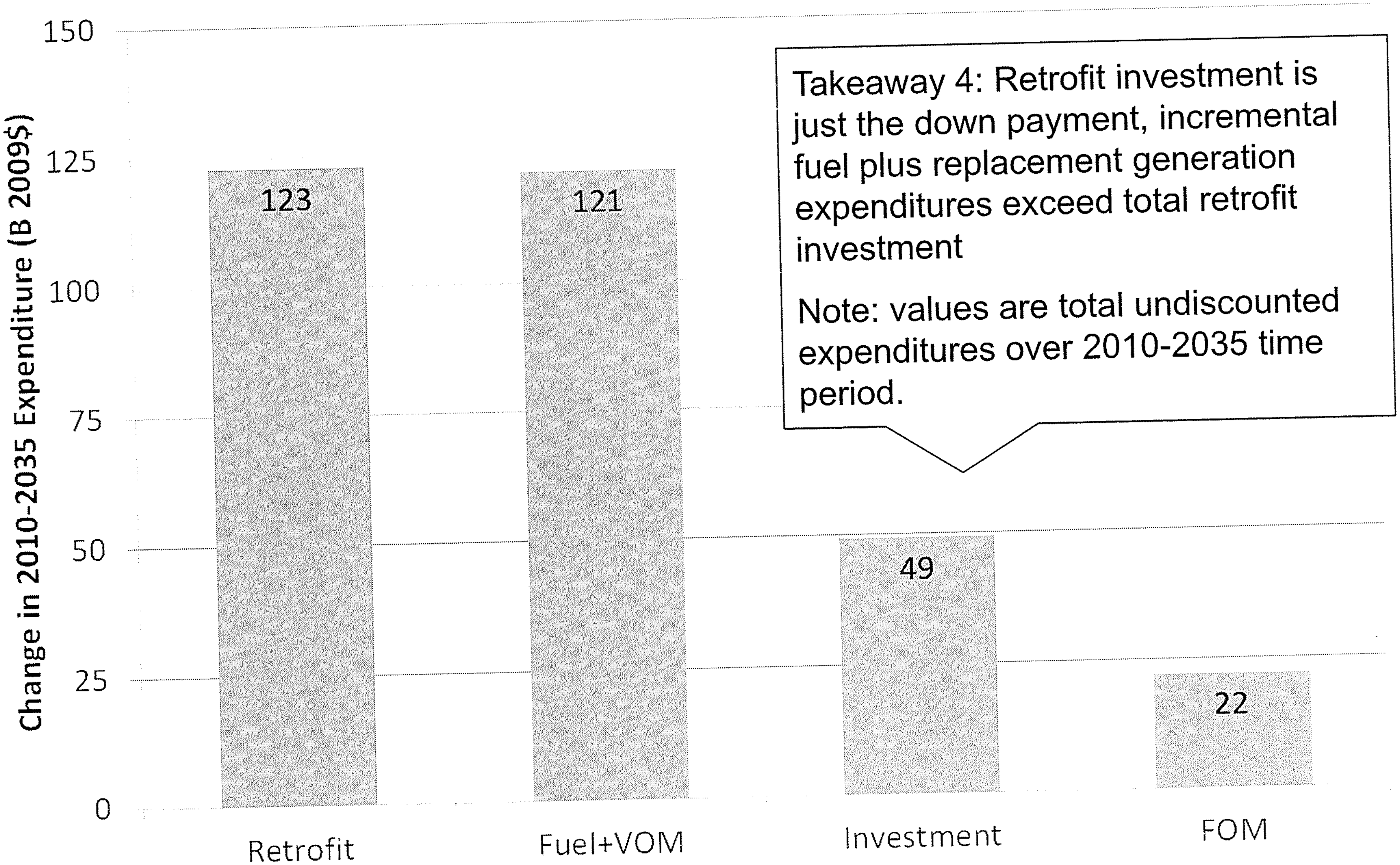
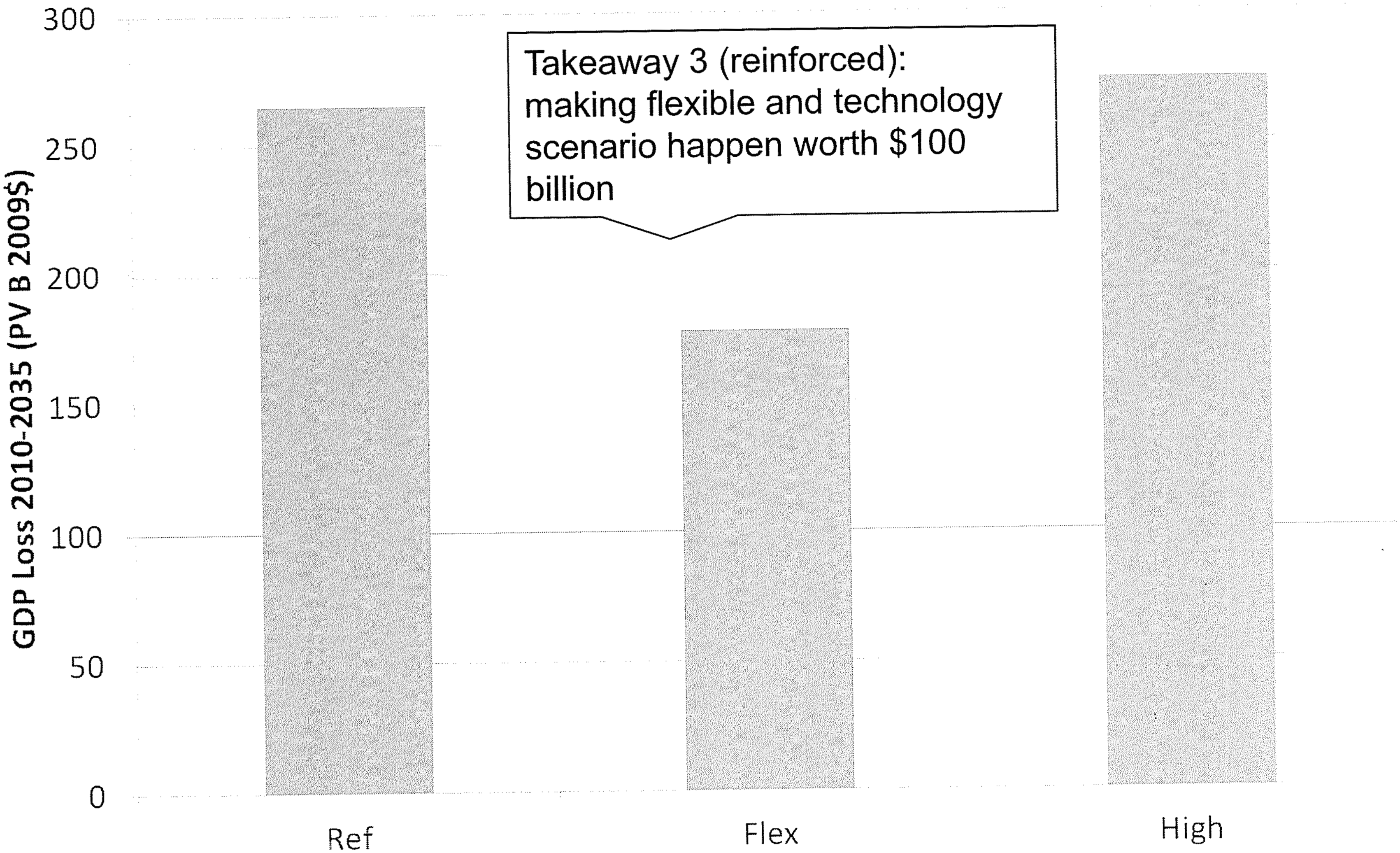
Retrofit Investment is Only Part of Policy Expenditure Costs (Ref)



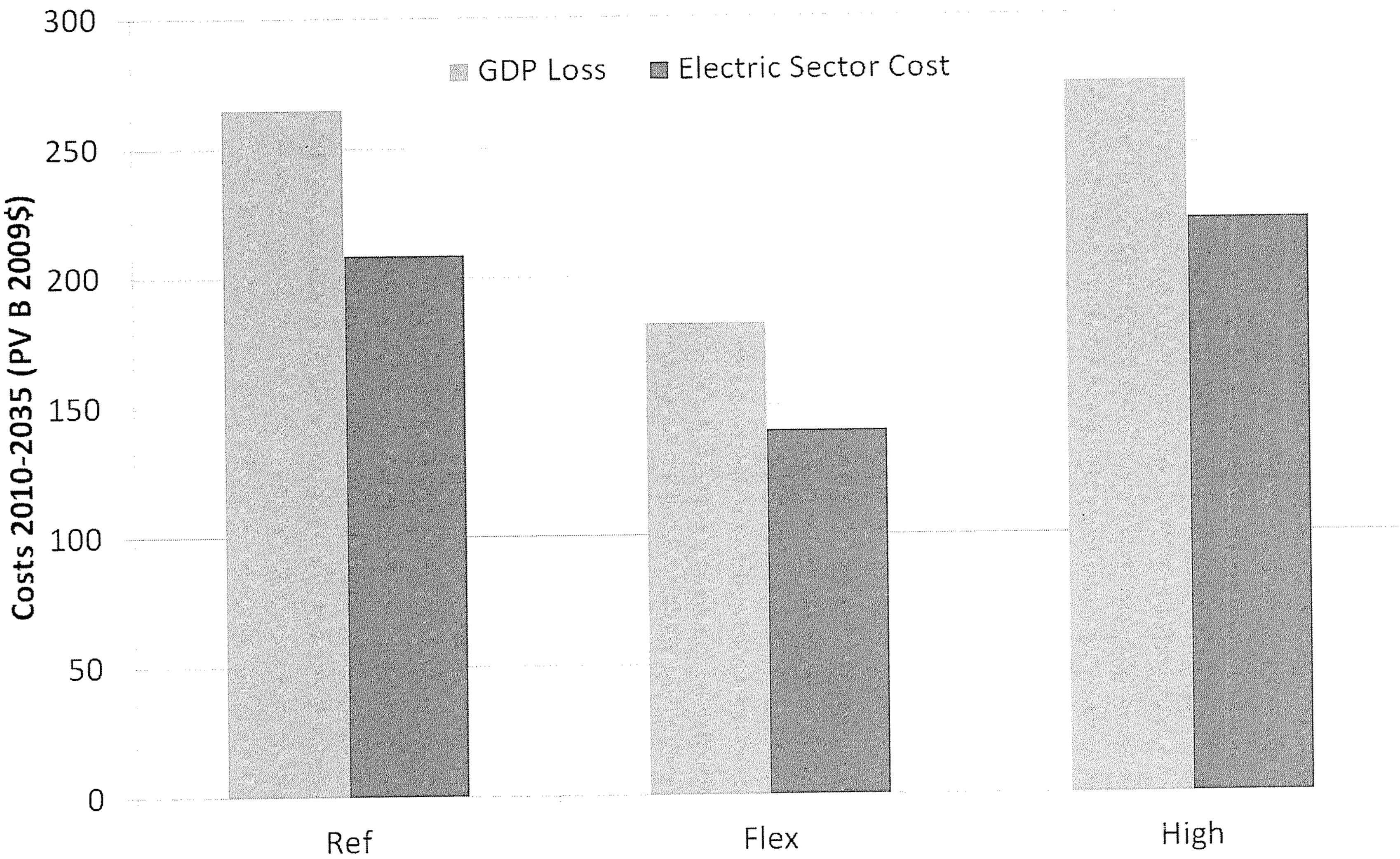
Takeaway 4: Retrofit investment is just the down payment, incremental fuel plus replacement generation expenditures exceed total retrofit investment

Note: values are total undiscounted expenditures over 2010-2035 time period.

GDP Impacts Show Magnitude of Costs and Opportunity in Flexibility



Note That Total GDP Impacts ~25% Greater Than Increased Cost to Electric Sector



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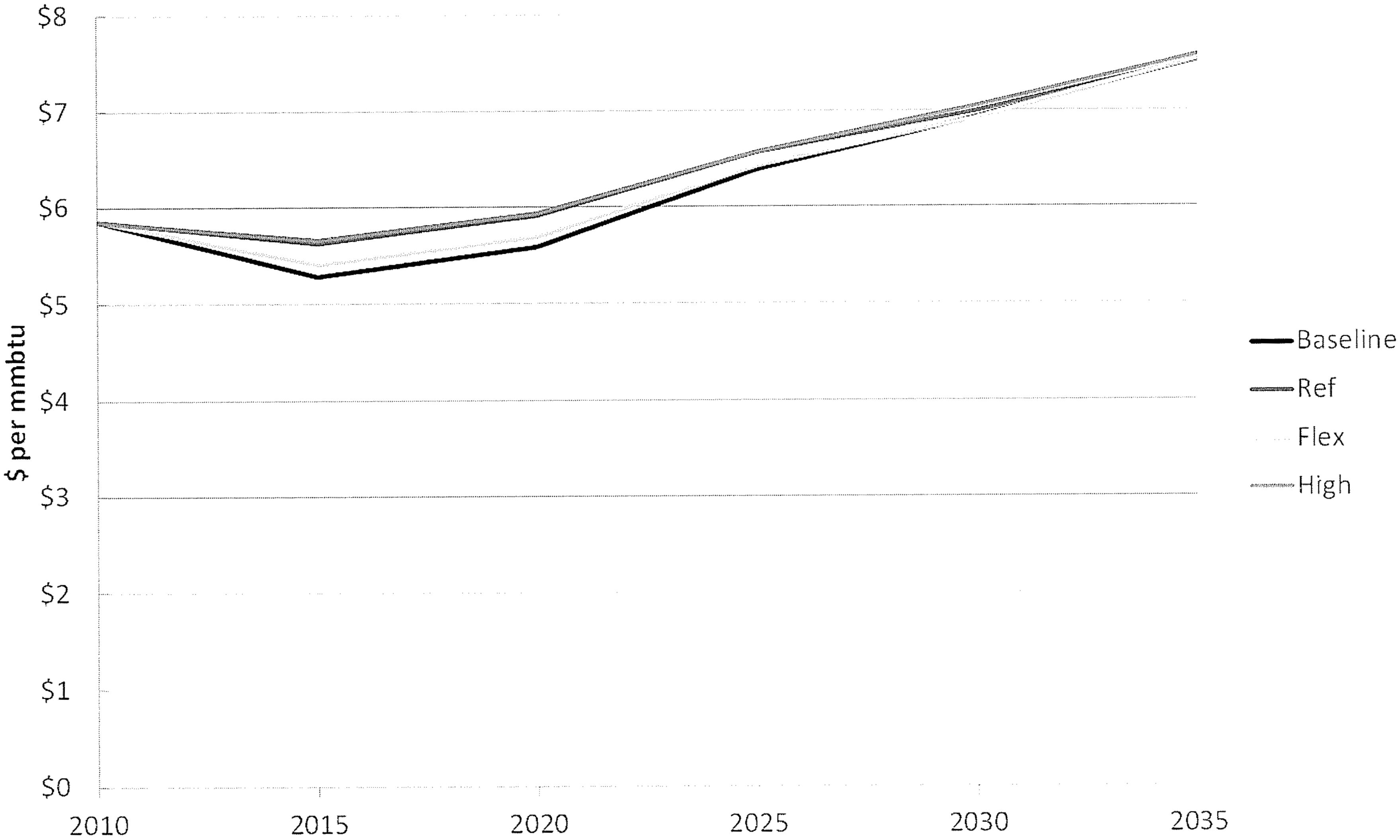
U.S. Average Power Producers' Gas Price



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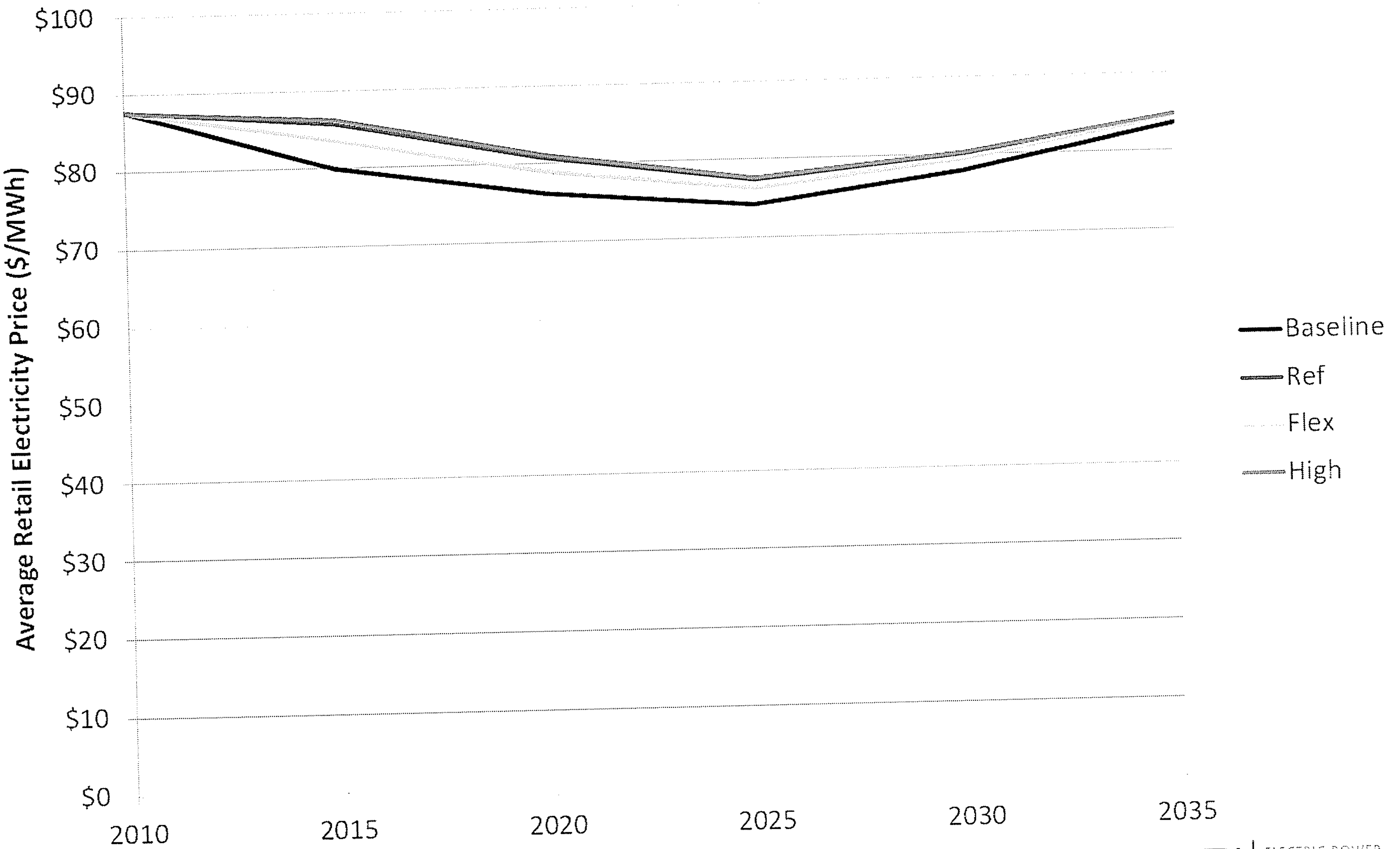
U.S. Average Retail Electricity Price



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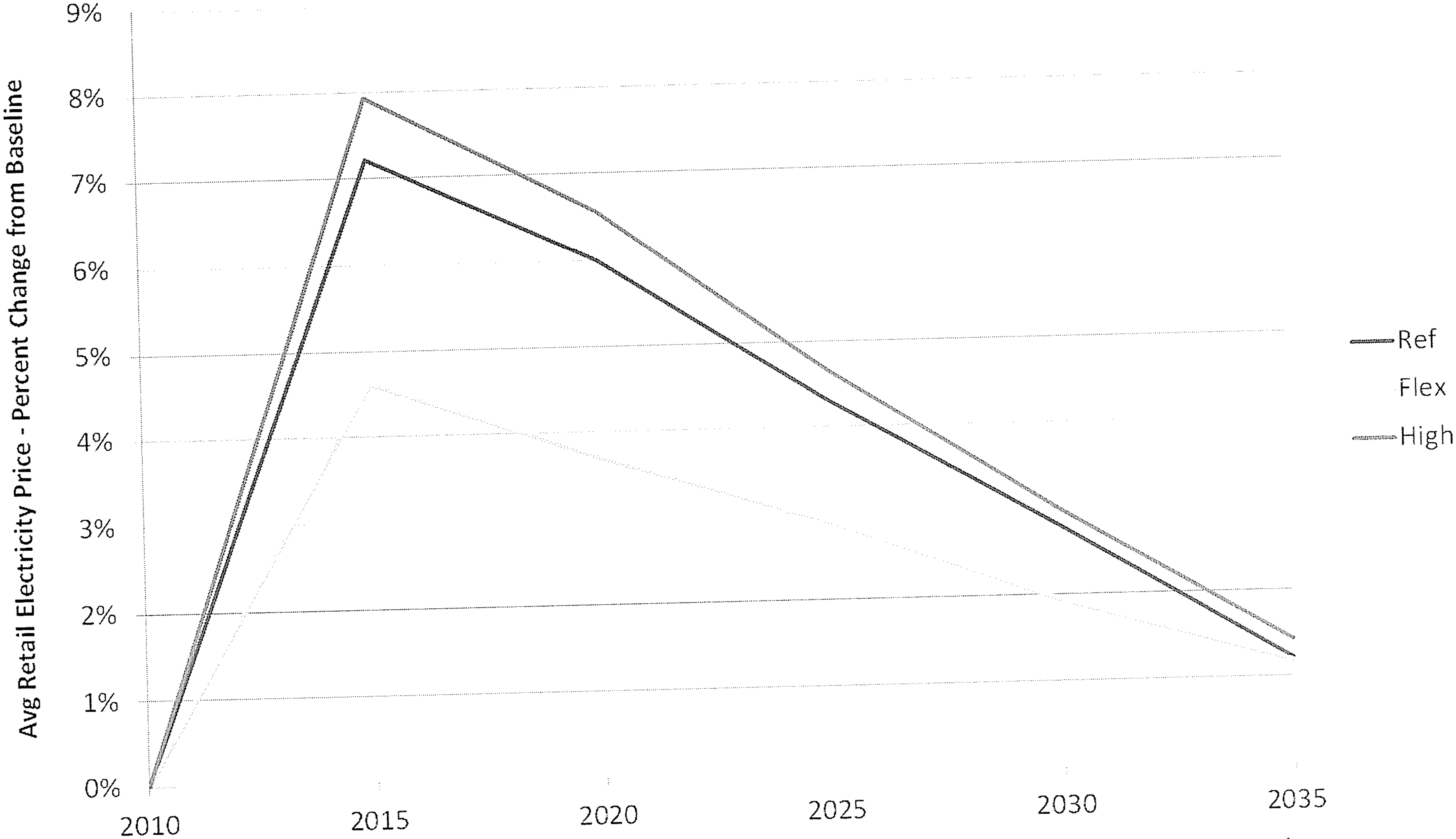
U.S. Average Retail Electricity Price - Percent Change from Baseline



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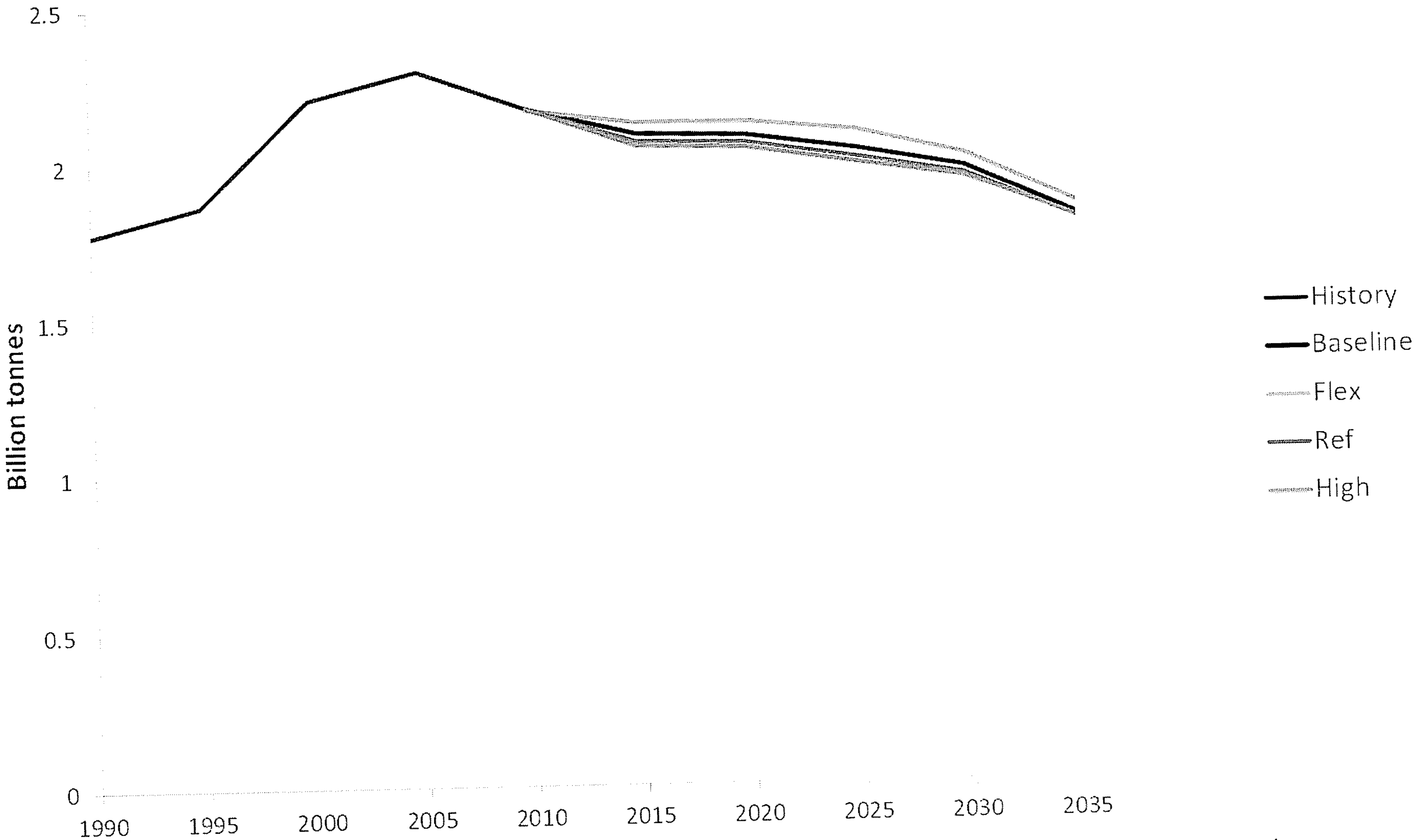
U.S. Electric Sector CO_2 Emissions



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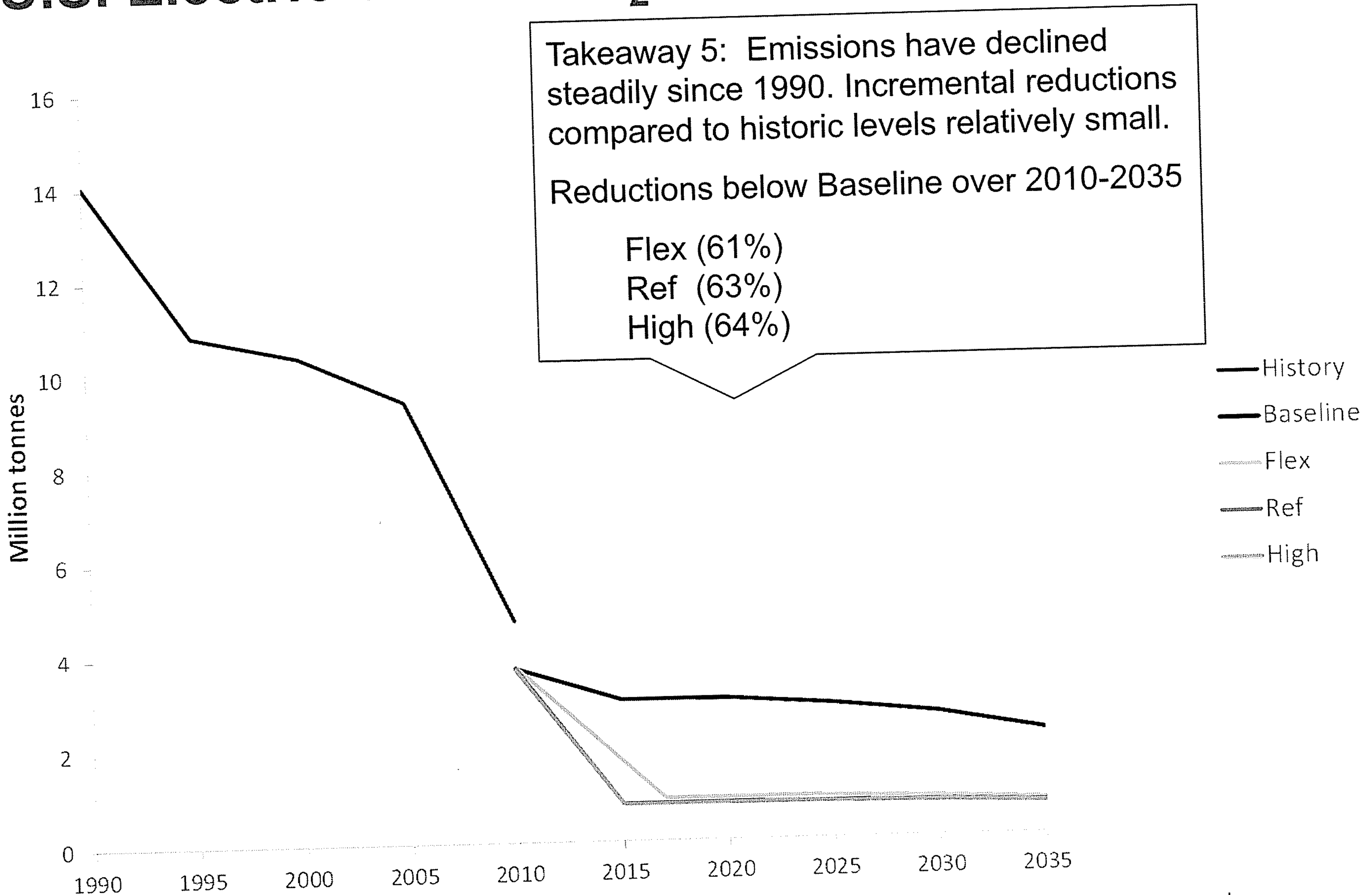
U.S. Electric Sector SO_2 Emissions

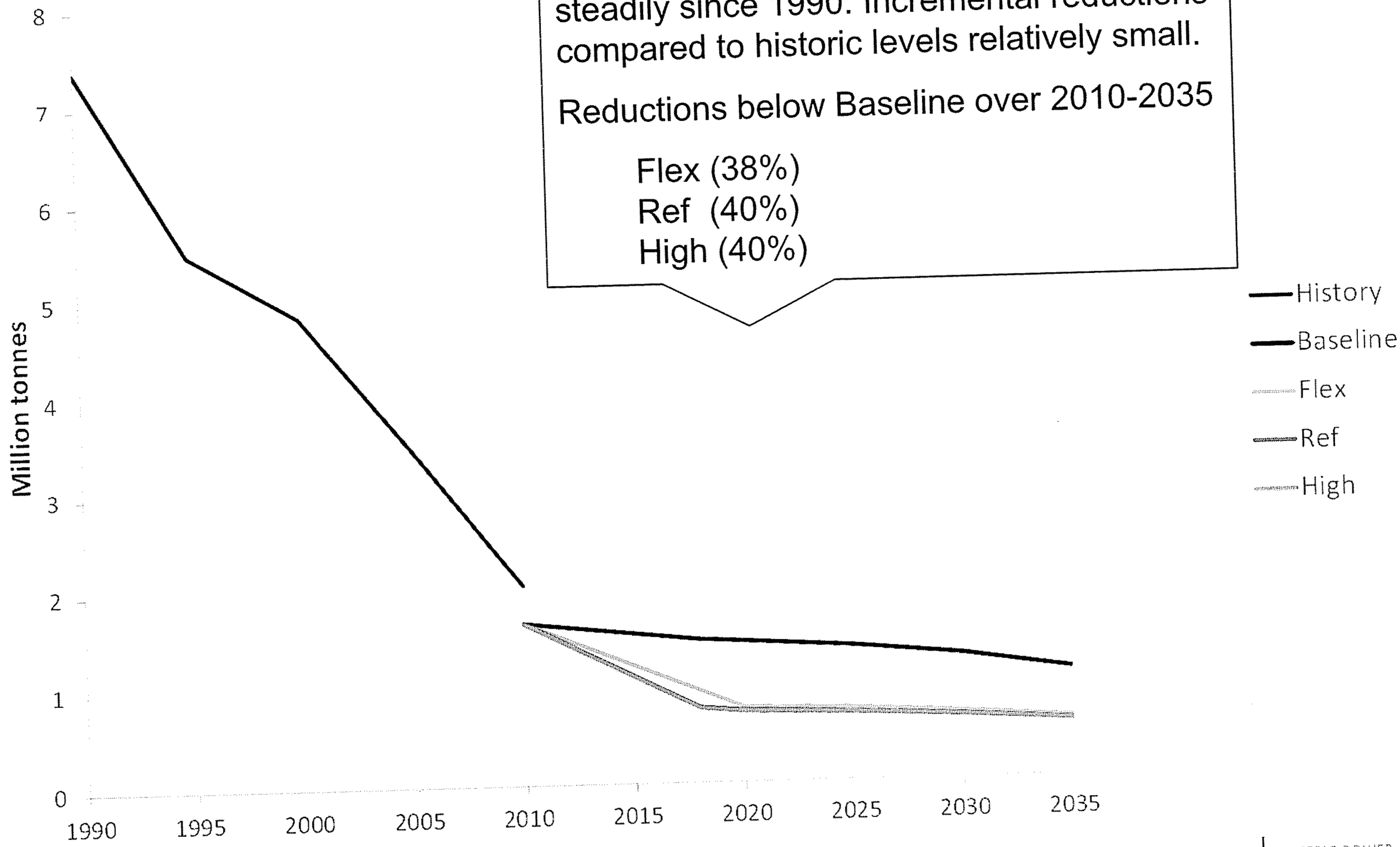


U.S. Electric Sector NO_x Emissions

Takeaway 5: Emissions have declined steadily since 1990. Incremental reductions compared to historic levels relatively small.

Reductions below Baseline over 2010-2035

Flex (38%)
Ref (40%)
High (40%)



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Concluding Observations

- Economic cost of full control policy is $175B to $275B (PV 2010-2035)
- Cost range driven by ability to deploy low-cost technologies, which may require policy flexibility and extra time to assess
- Cost impacts greatest in high-coal regions
- Compliance decisions dependent on gas price expectations
- 50 to 100+ GW of coal may retire or convert fuels
- Most of existing coal continues to play key role
- SO_2/NOx emissions drop to less than 30% of 2010 levels
- If emission reductions phased in over an extra two years the relative impact on cumulative emissions is modest

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INTERNATIONAL

EEI Preliminary Reference Case and Scenario Results

May 21st, 2010

Updated Reference Case

- Nuclear build limits – from NEI
  - Hard-wired units (5,500 MW)
  - Candidate units (4,300 MW) – allowed to be built on or after specified date, but only if deemed economic
  - Economic units – including 8 units above, up to 45 units by 2030 on national basis, regional limits based on existing brownfield sites
- Run year mapping
- Capacity credit update (10%) for wind
- Calibrated coal prices to AEO 2010
  - Minemouth prices calibrated to AEO 2010
  - Transportation prices based on EPA

EEI Master Assumptions Matrix – Reference Case

	EPA ARRA Analysis	EEI Base Case
Electric Demand – National Annual Average	EPA/AEO2009	EPA/AEO2009
Electric Demand -Regional	EPA/AEO2009	EPA/AEO2009
Electric Demand Elasticity	na	na
Natural Gas Supply Curves (Henry Hub)	EPA	EPA
Natural Gas Basis Differentials	EPA	EPA
Coal Price Supply Curves and Coal Transportation Costs	EPA	AEO2010/EPA
Biomass Supply Curves	EPA/AEO2009	EPA/AEO2009
New Build Capital Costs	EPA	EIA AEO/2010
Retrofit Capital Costs	EPA	EVA/NERC
Mercury and HAP Retrofit Structure	EPA	EVA/NERC
Technology Limits	EPA	EPA/NEI
Financing Assumptions – New Builds	EPA	EPA
Financing Assumptions – Retrofits	EPA	EPA for regulated EIA for merchant
3P Policy	CAIR w/ 1.6 million ton bank carryover into 2012	CAIR plus state mercury limits
Carbon	None	None

EEI Reference Case Regulations

	SO_2 Program	NO_x Program		Mercury Program	CO_2 Program
		Annual	Ozone Season		
CAIR Phase I (2010 -2014)	25 States + DC 2010 retirement ratio: 2:1 Existing Title IV for unaffected states	25 States + DC 1.522 million tons	25 States + DC 0.568 million tons	State Level Regulations CT, CO, DE, GA, IL, MA, MD, ME, MI, MN, MT, NC, NH, NJ, NM, NY, OR, WA, WI	None
CAIR Phase II (2015+)	25 States + DC Retirement ratio: 2.86:1 Existing Title IV for unaffected states	25 States + DC 1.268 million tons	25 States + DC 0.485 million tons		

- BART is included for all BART effected units not included in CAIR for SO_2 and NO_x and WRAP for SO_2.
- WRAP SO_2 is included.
- All existing state regulations for NO_x, SO_2, Hg and CO_2 are included.

EEI Scenario Descriptions

Scenario	Description
HAPS *(Scenario 1)*	All coal units required to have SCR, scrubber, ACI and fabric filter by 2015
HAPS+Ash+Water *(Scenario 2)*	**Ash (2015):** All units with wet fly ash disposal and/or wet bottom ash disposal are required to convert to dry handling and install a landfill and wastewater treatment facility. Cost components are as follows: •Conversion to dry fly ash handling - $15 million per unit •Conversion to dry bottom ash handling - $20 million per unit •New Landfill - $30 million per facility •New wastewater treatment facility - $120 million per facility Costs applied to units with ponds for fly ash and/or bottom ash based on EIA-923 Schedule 8A, 2008.[1] **Water (2015):** All fossil and nuclear facilities that have at least one once-through cooling unit and would have been classified as a Phase II Facility under the remanded Phase II rule are required to install cooling towers. This does not apply to facilities that are completely closed-cycle cooling even if they use more than 50 million gallons per day. However, it does include some facilities that use helper towers to cool the thermal discharge during portions of the year. The costs are as follows: •Nuclear - $454/gpm (avg. $220/kW) •Fossil - $330/gpm (avg. $215/kW) Costs are applied to units described above based on EPRI's database of electric generating facilities.[2]
HAPS+Ash+Water+CO2 *(Scenario 3)*	CO_2 price consistent with EIA's August 2009 analysis of HR 2454 (Waxman-Markey). Prices start in 2012 at $17/ton and increase to $60/ton in 2030 (2008$).

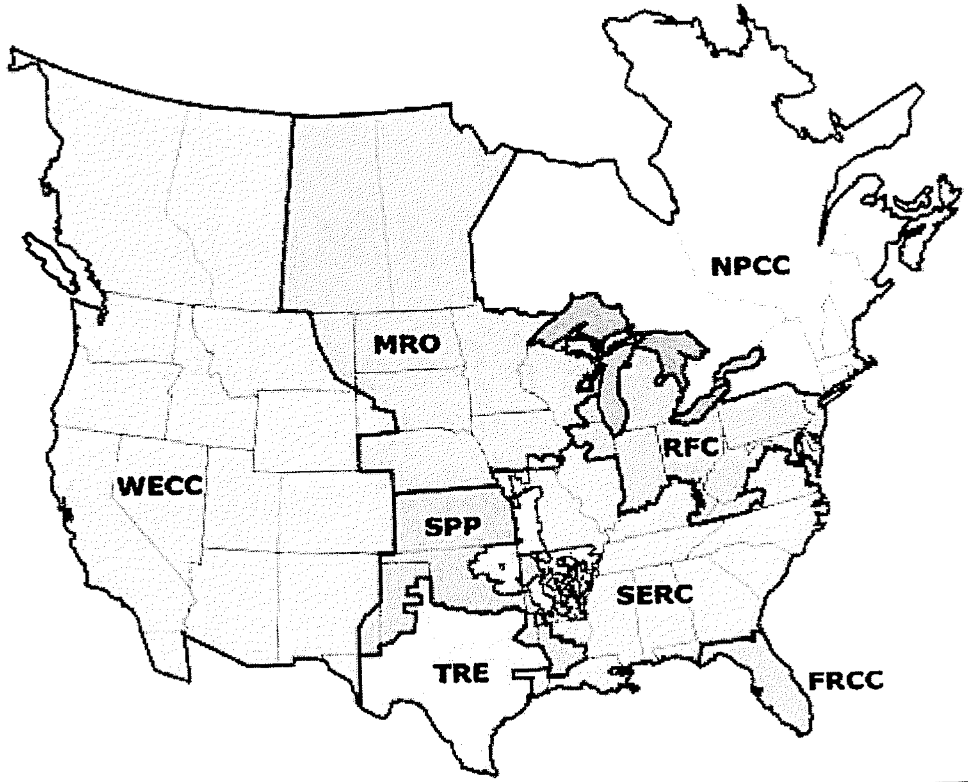
1 "20100507_Fly Ash and Bottom Ash Summary_Roewer.xls" received on May 7th, 2010
2 "Master List 4-29-10 Working Draft to EEI_calcv1.xls" received on May 5th 2010.

Run Year Structure

EPA Run Year	EPA Mapped Years
2012	2012-2013
2015	2014-2017
2020	2018-2022
2025	2023-2027
2032	2028-2035

EEI Run Year	EEI Mapped Years
2010	2010
2011	2011
2012	2012
2013	2013
2014	2014
2015	2015
2016	2016
2017	2017
2018	2018
2019	2019
2020	2020-2022
2025	2023-2027
2032	2028-2035

NERC Region Map



FRCC – Florida Reliability Coordinating Council	**SERC** –SERC Reliability Corporation
MRO – Midwest Reliability Organization	**SPP** – Southwest Power Pool, RE
NPCC – Northeast Power Coordinating Council	**TRE** – Texas Regional Entity
RFC – Reliability First Corporation	**WECC** – Western Electricity Coordinating Council
Note: NERC regional results shown in this presentation include the US only	

Source: http://www.nerc.com

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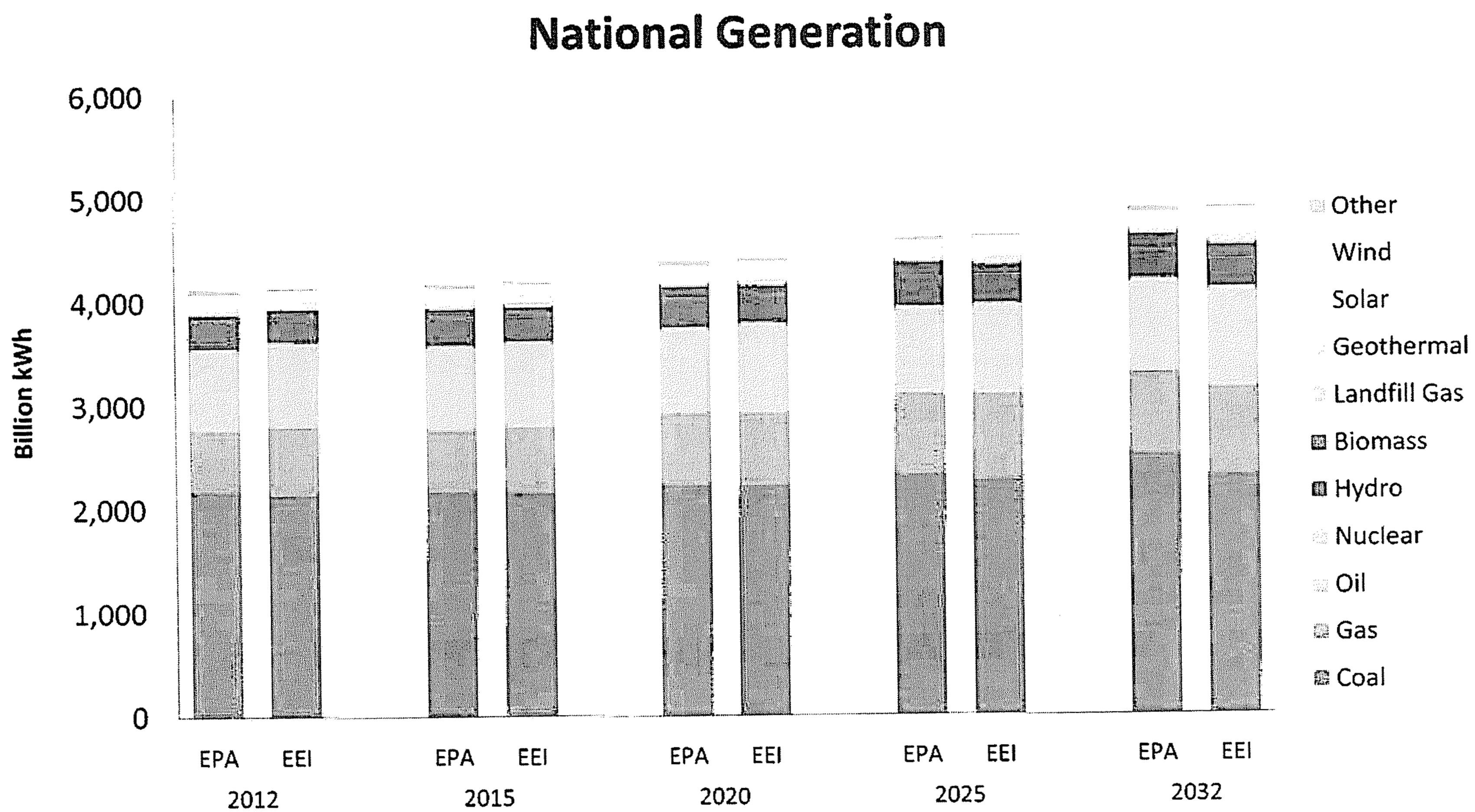
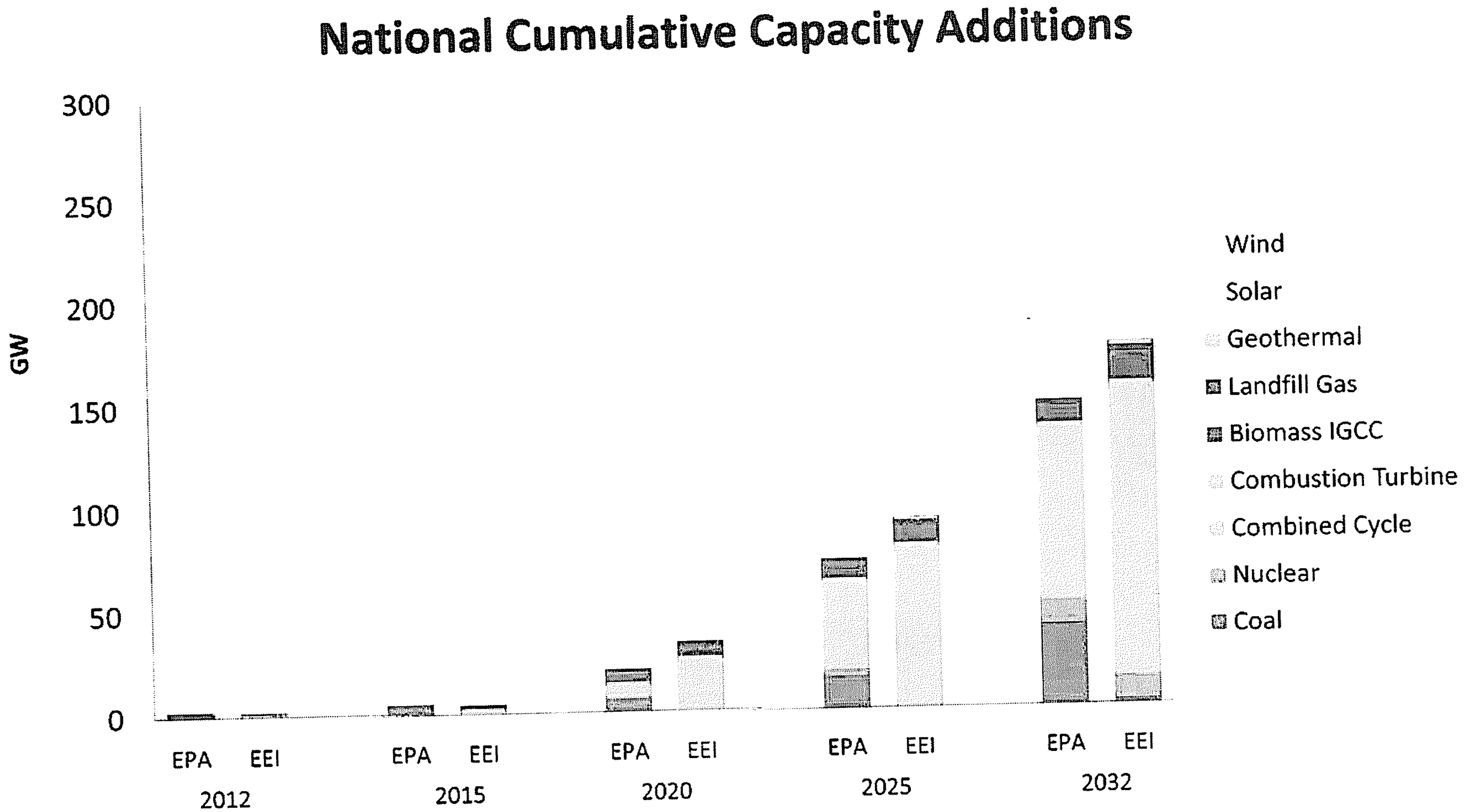
EEI Reference Case - National Level Results Compared to EPA ARRA 2009 Reference Case

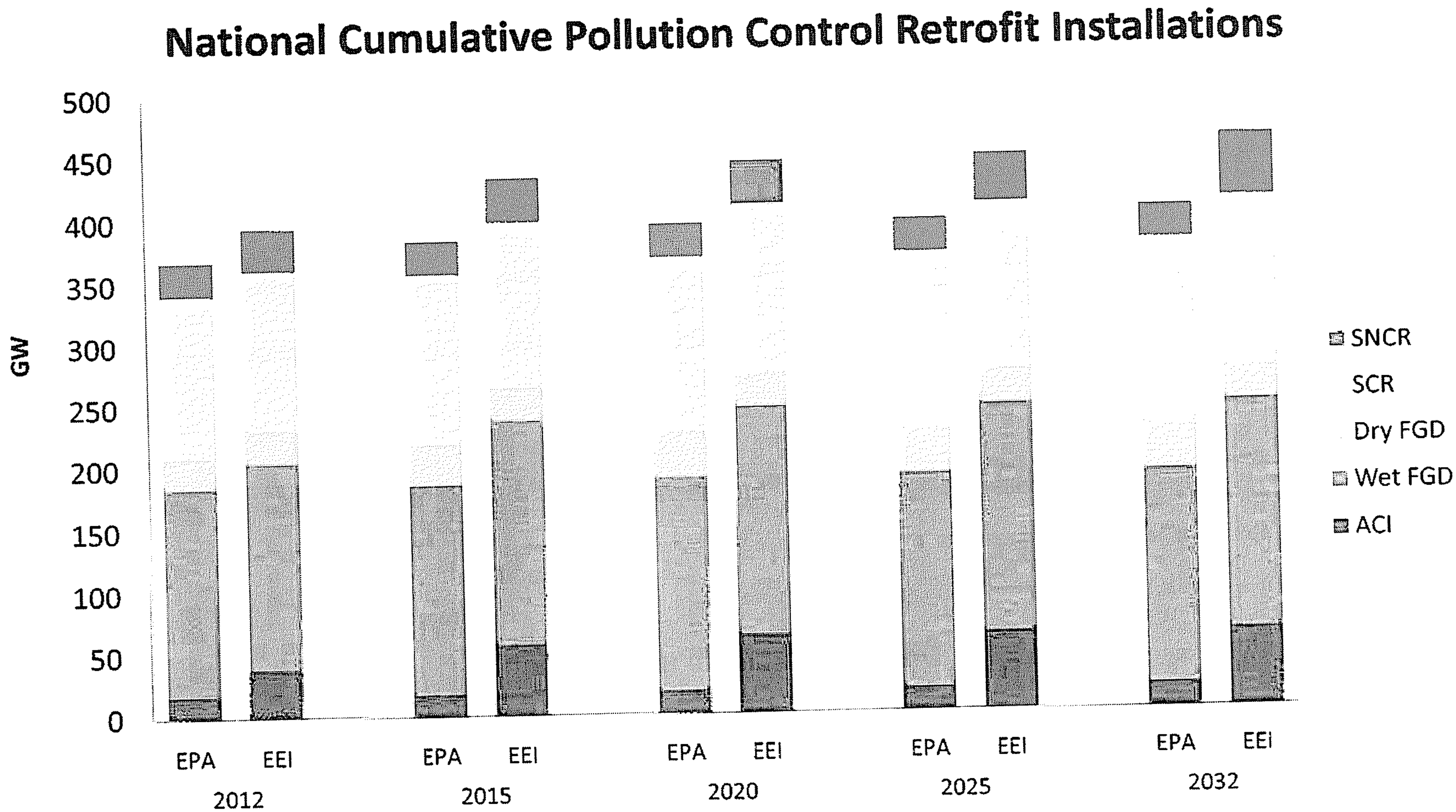
National Generation By Type



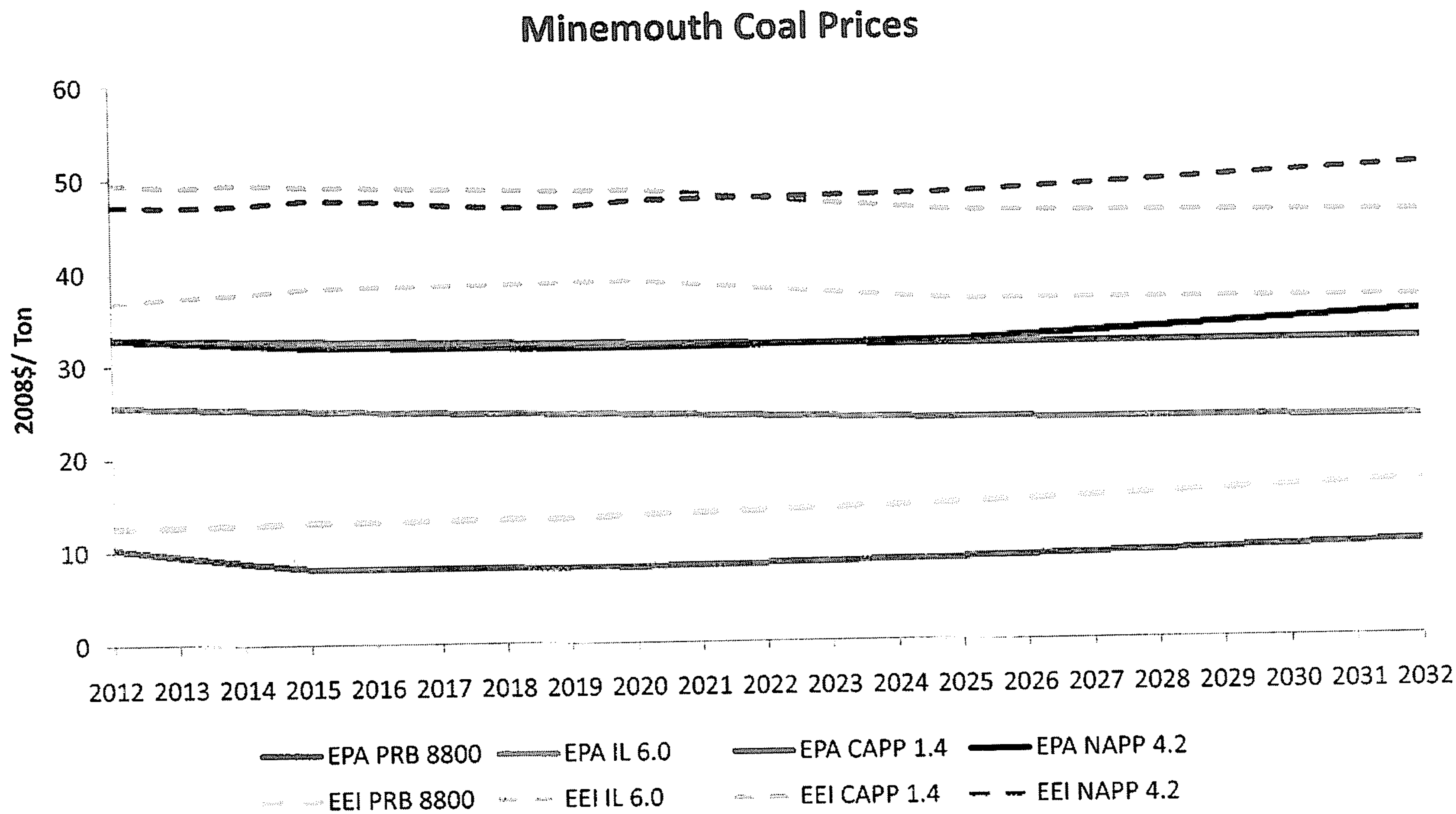
National Cumulative Capacity Additions



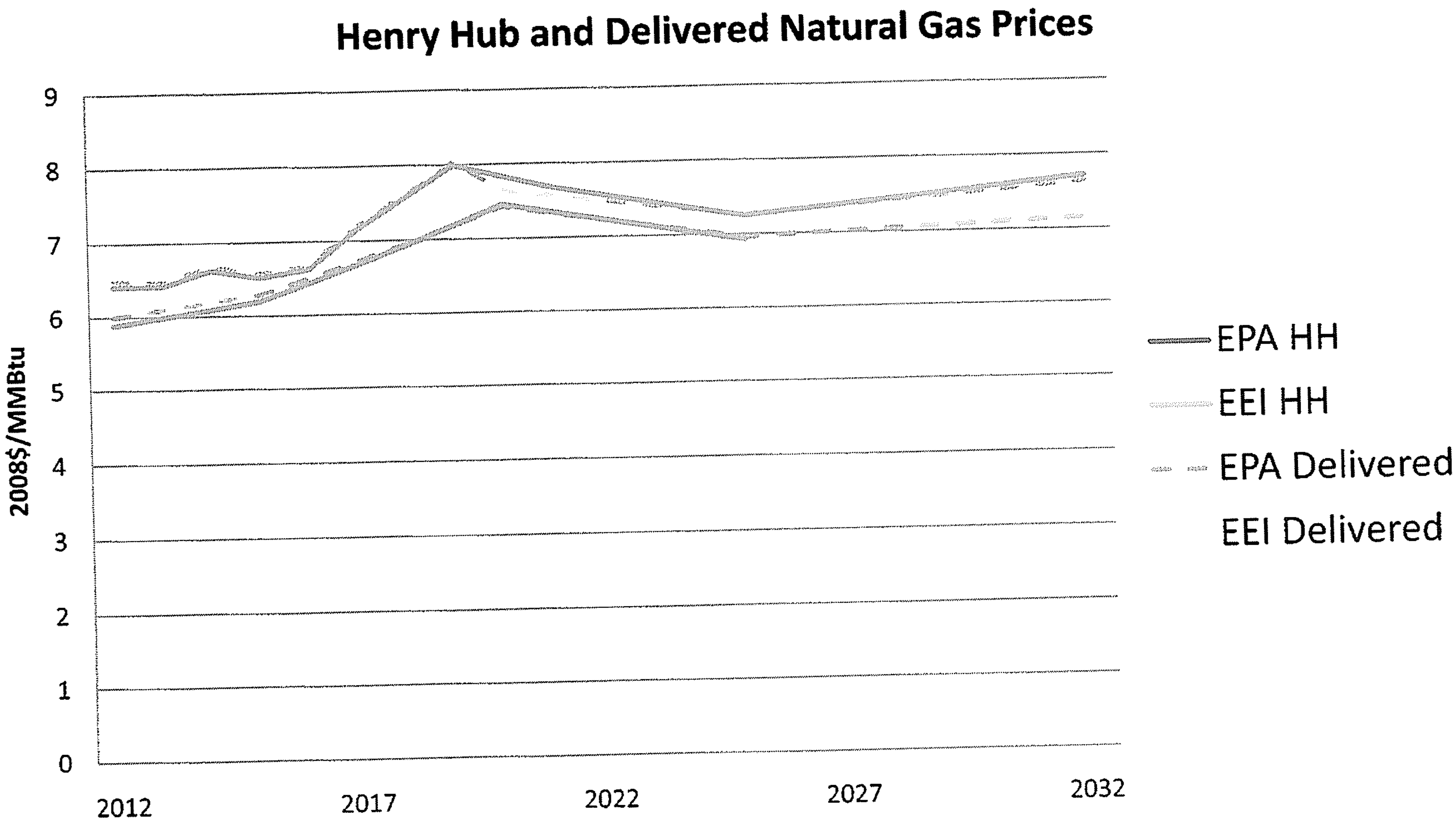
National Cumulative Pollution Control Installations (Existing + Firm + Economic)



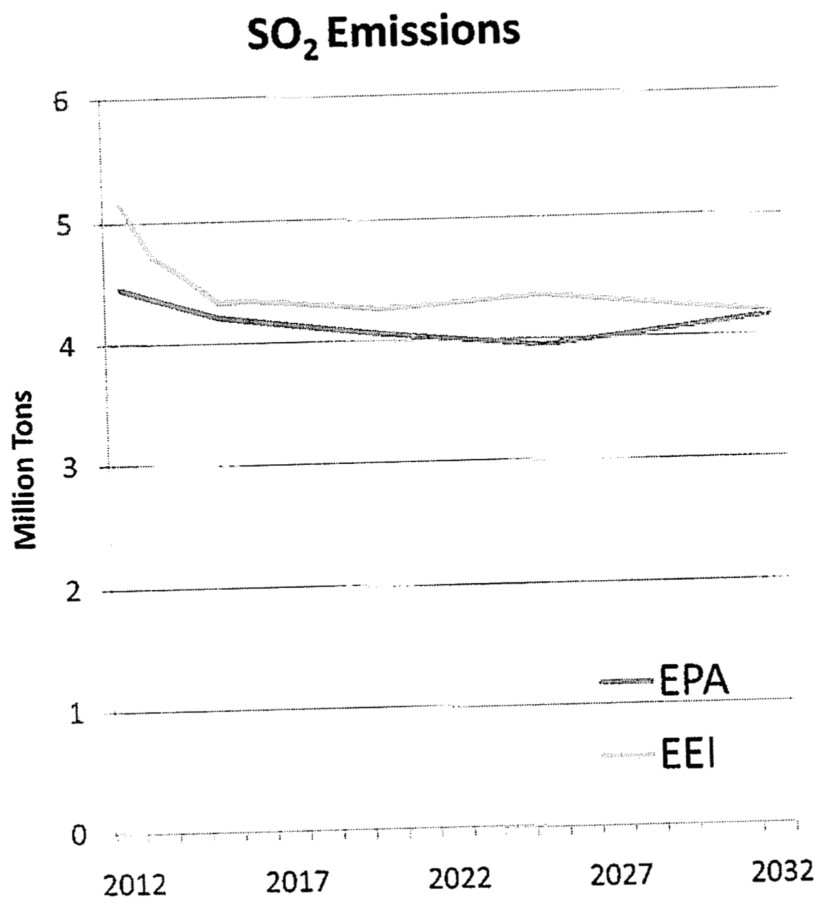
Minemouth Coal Prices

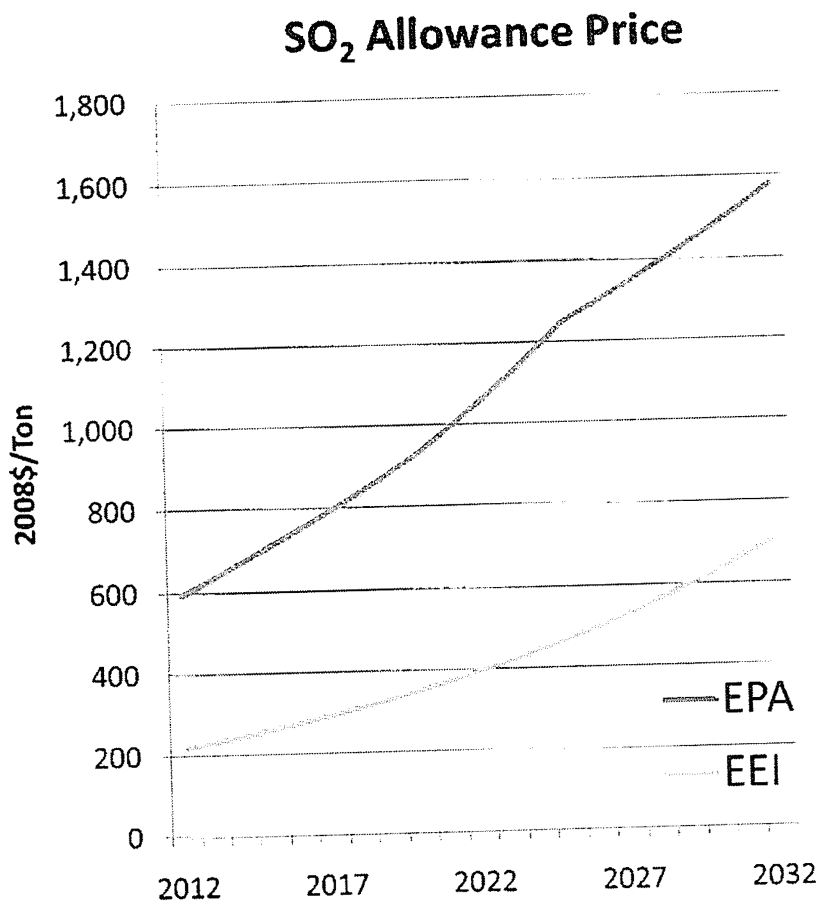


Henry Hub and Delivered Natural Gas Prices



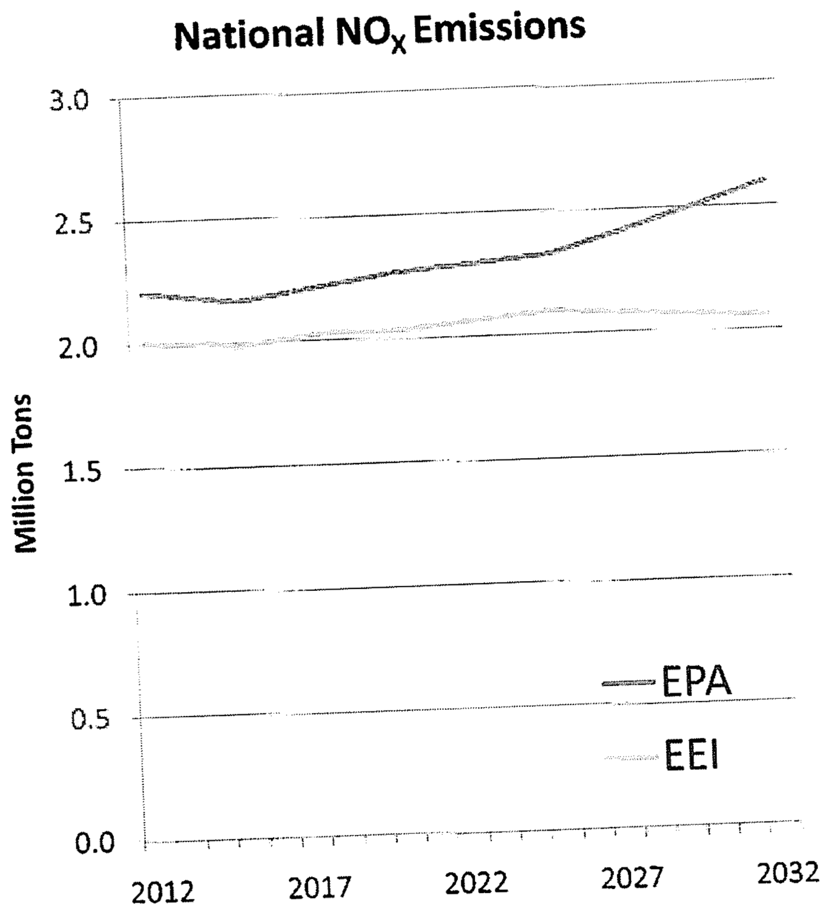
SO_2 Allowance Prices and Emissions

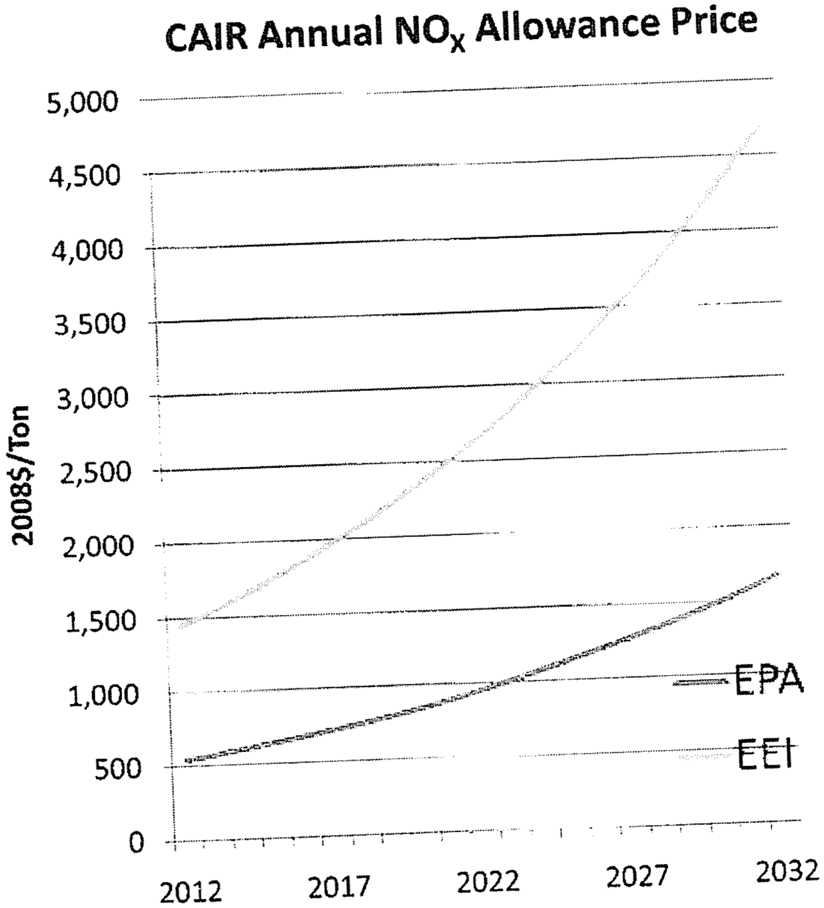




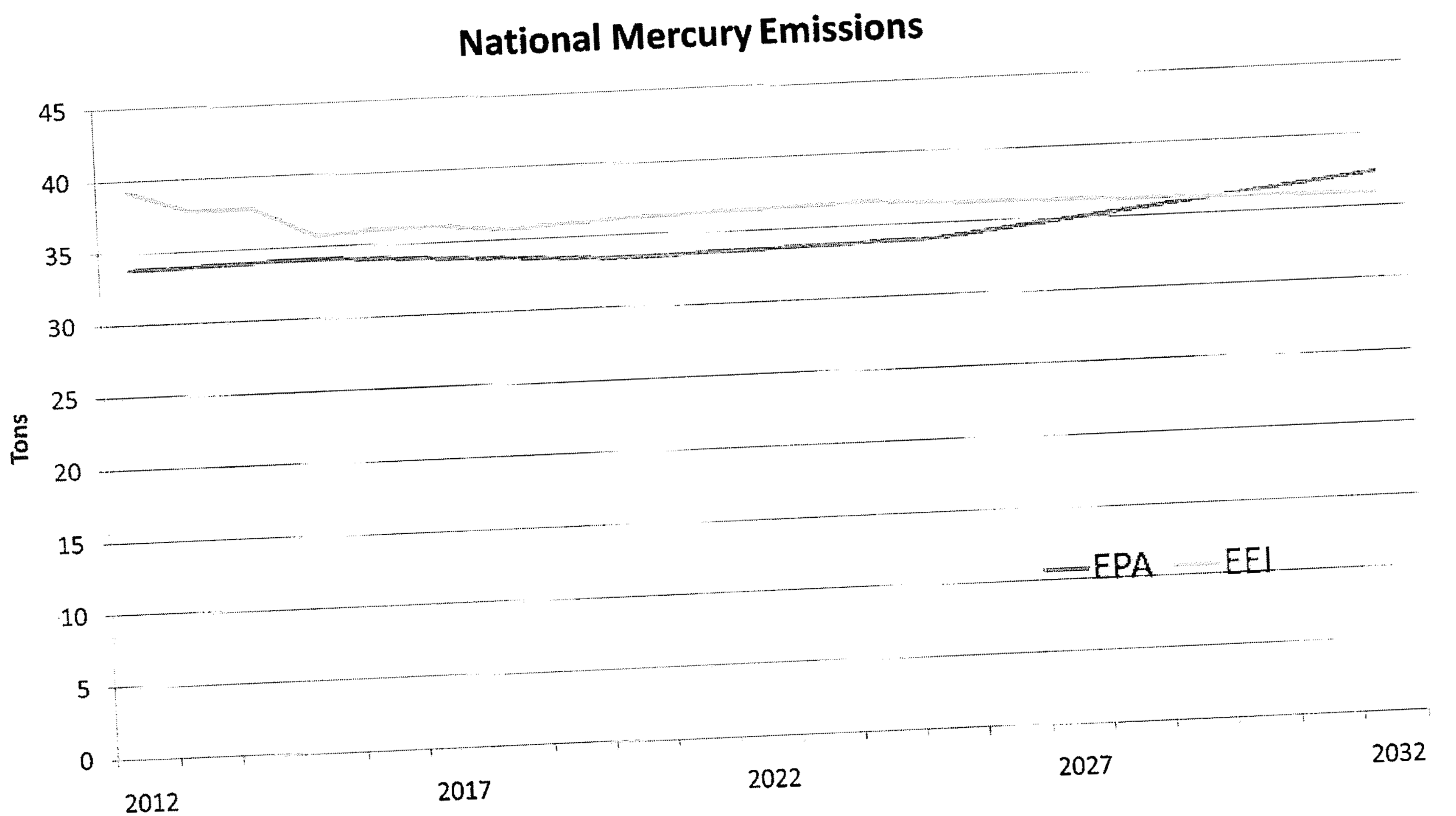
Note: The SO2 price is the $/ton price for units in a CAIR affected state. The $/allowance prices can be derived by dividing by 2 in 2010-2014 and 2.86 in 2015 and beyond.

NO_X Allowance Prices and Emissions

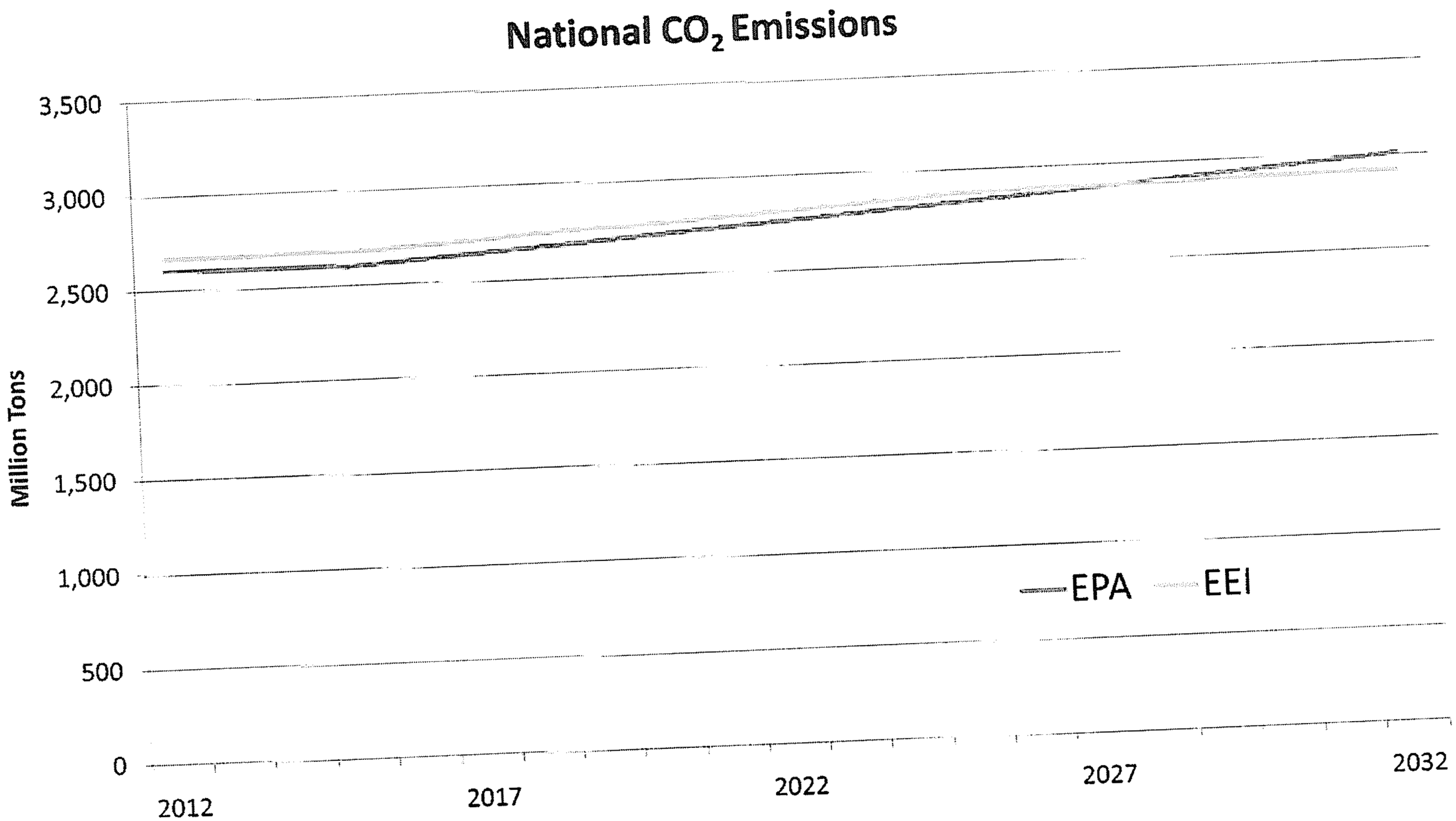




National Mercury Emissions



National CO_2 Emissions



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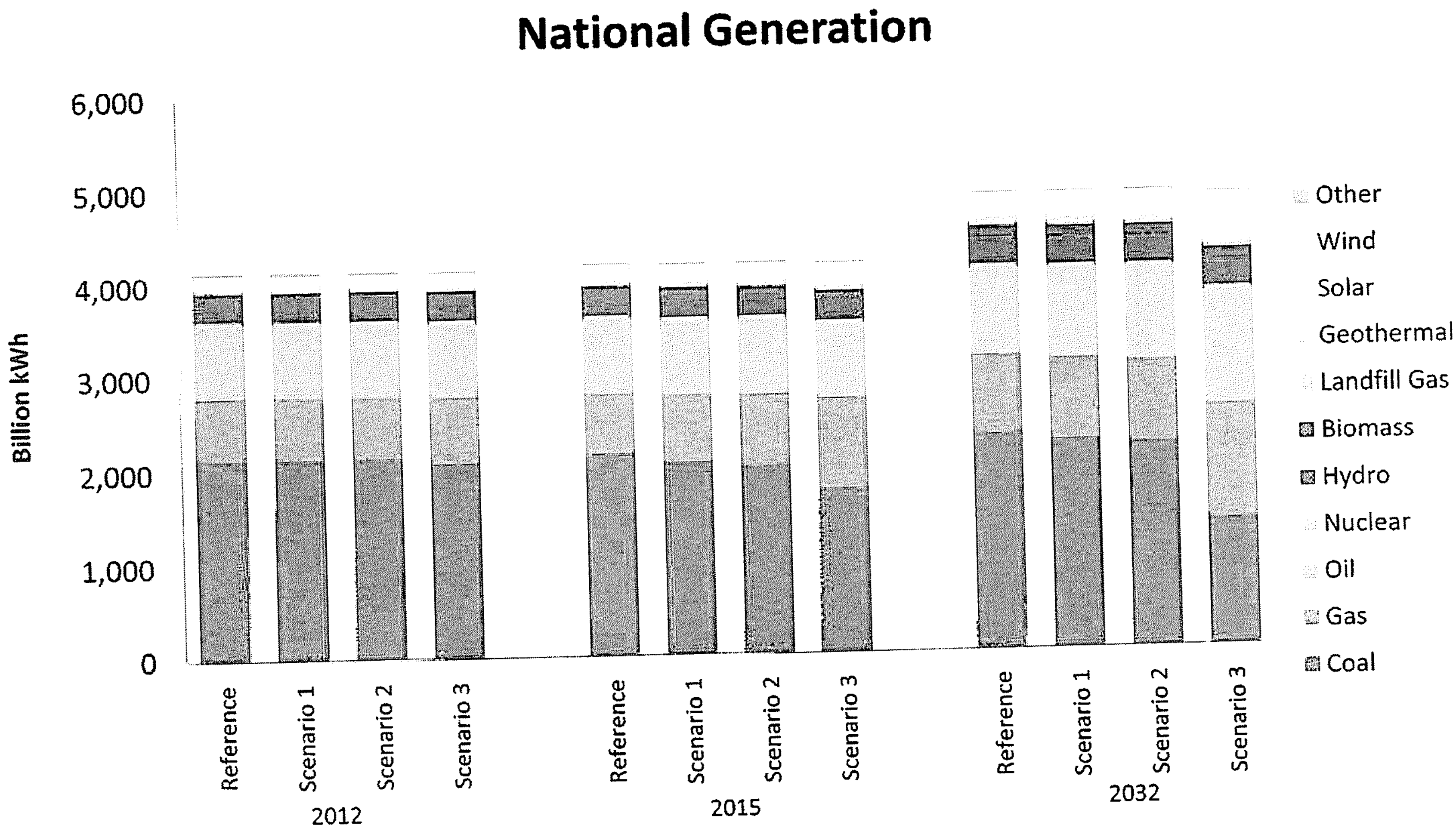
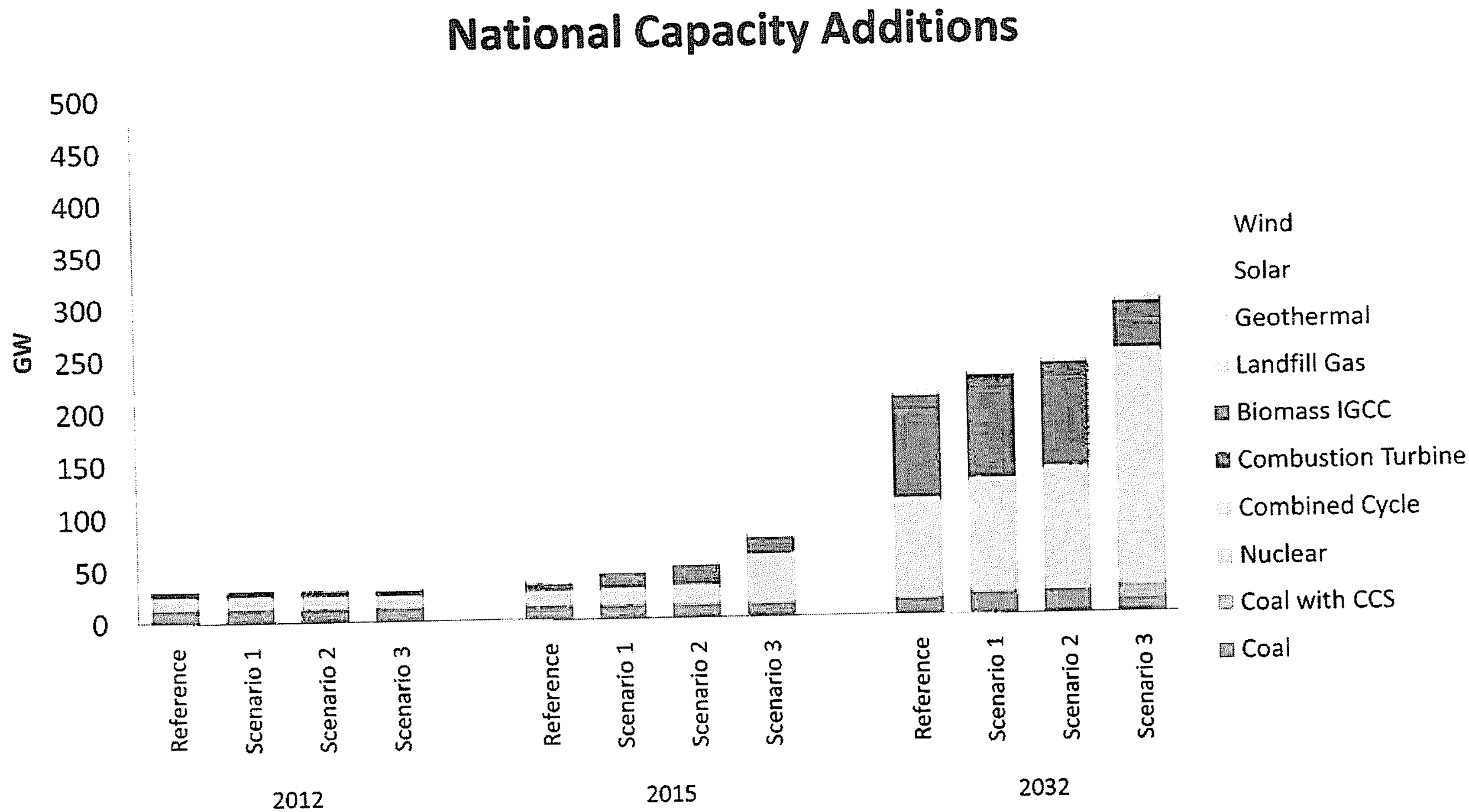
EEI Scenario Results

EEI CONFIDENTIAL BUSINESS INFORMATION: Do Not Cite, Quote or Distribute

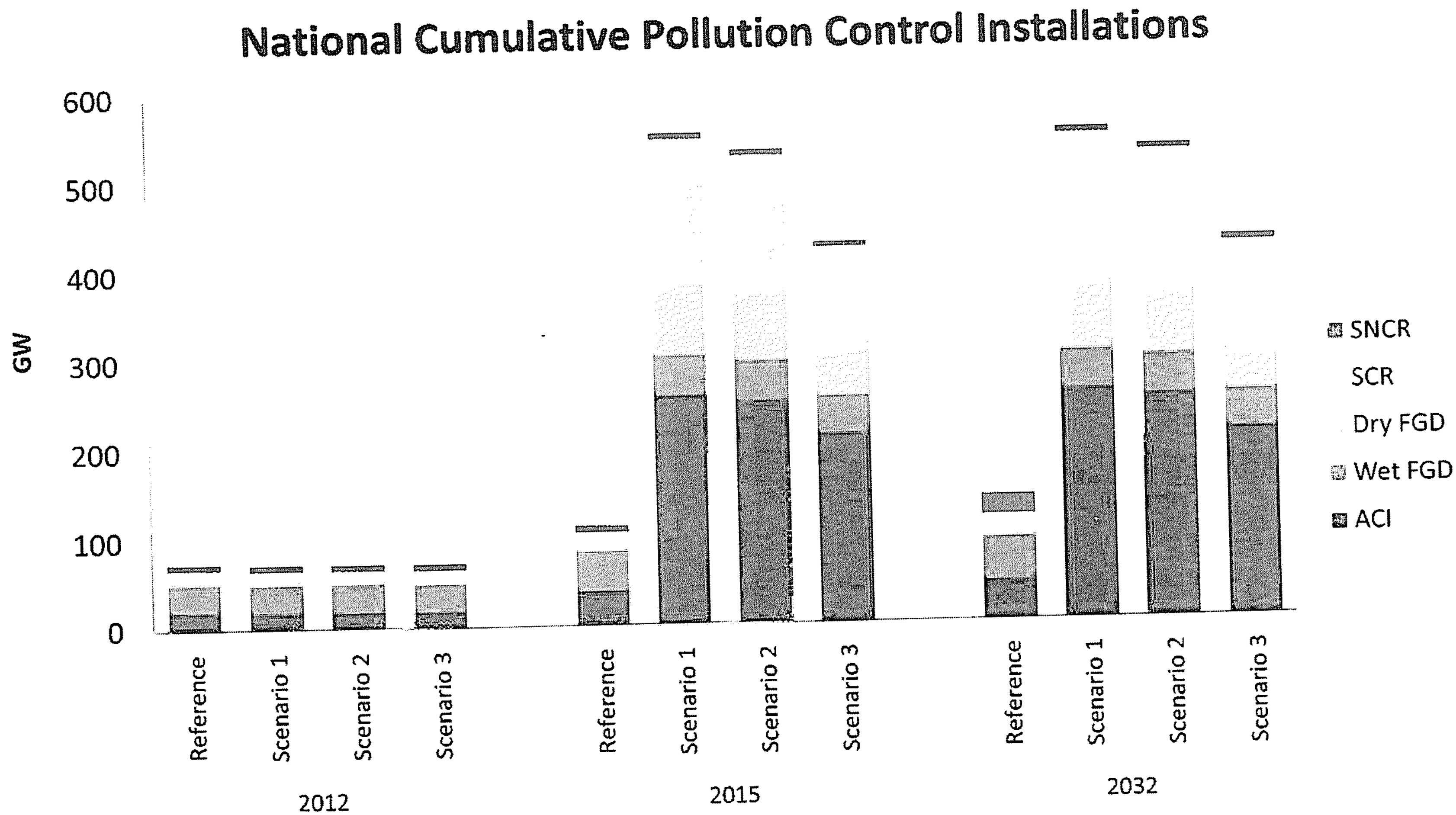
National Generation By Type



National Cumulative Capacity Additions by Scenario (Firm + Economic)

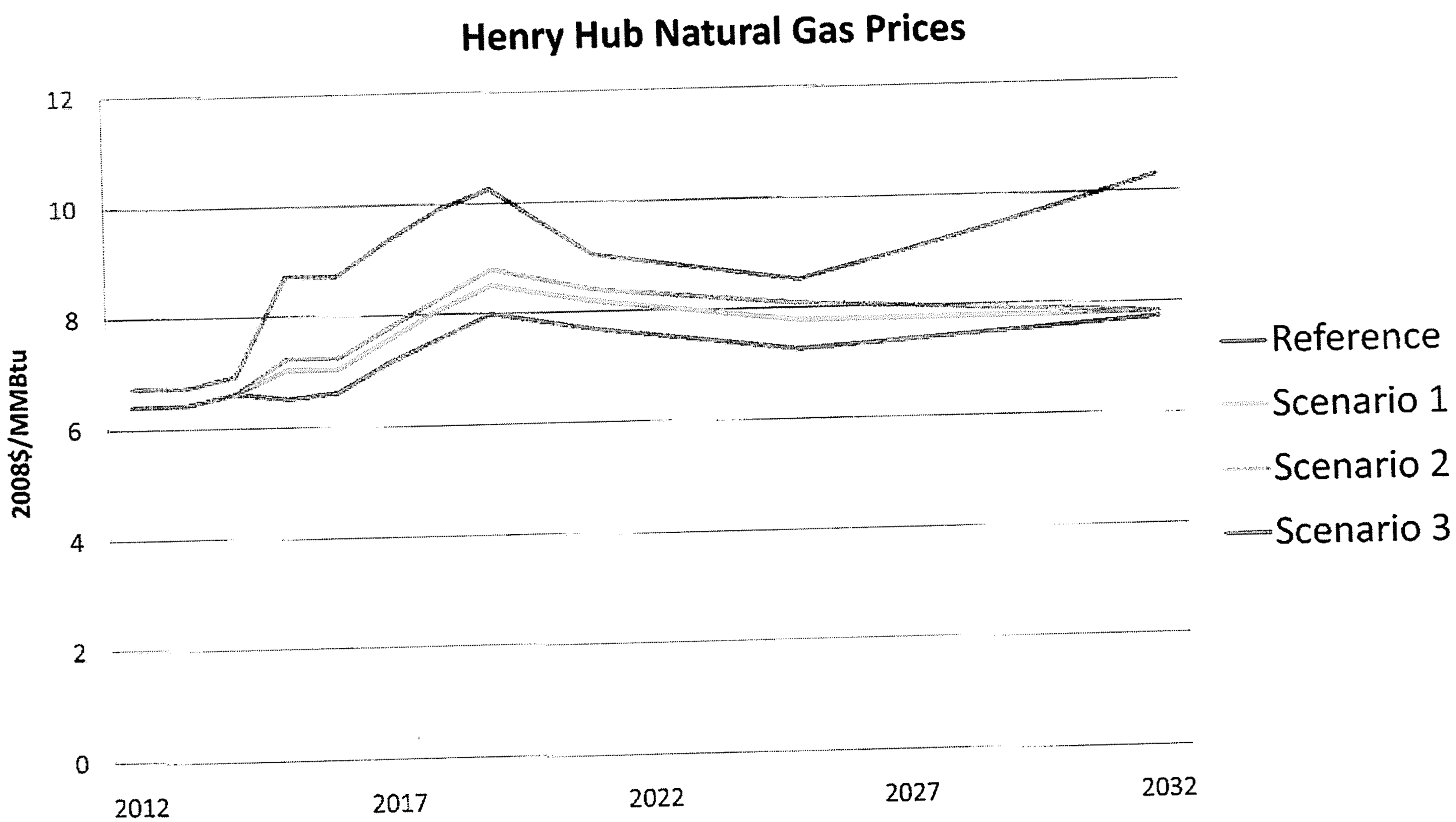


National Cumulative Pollution Control Installations by Scenario (Firm + Economic)

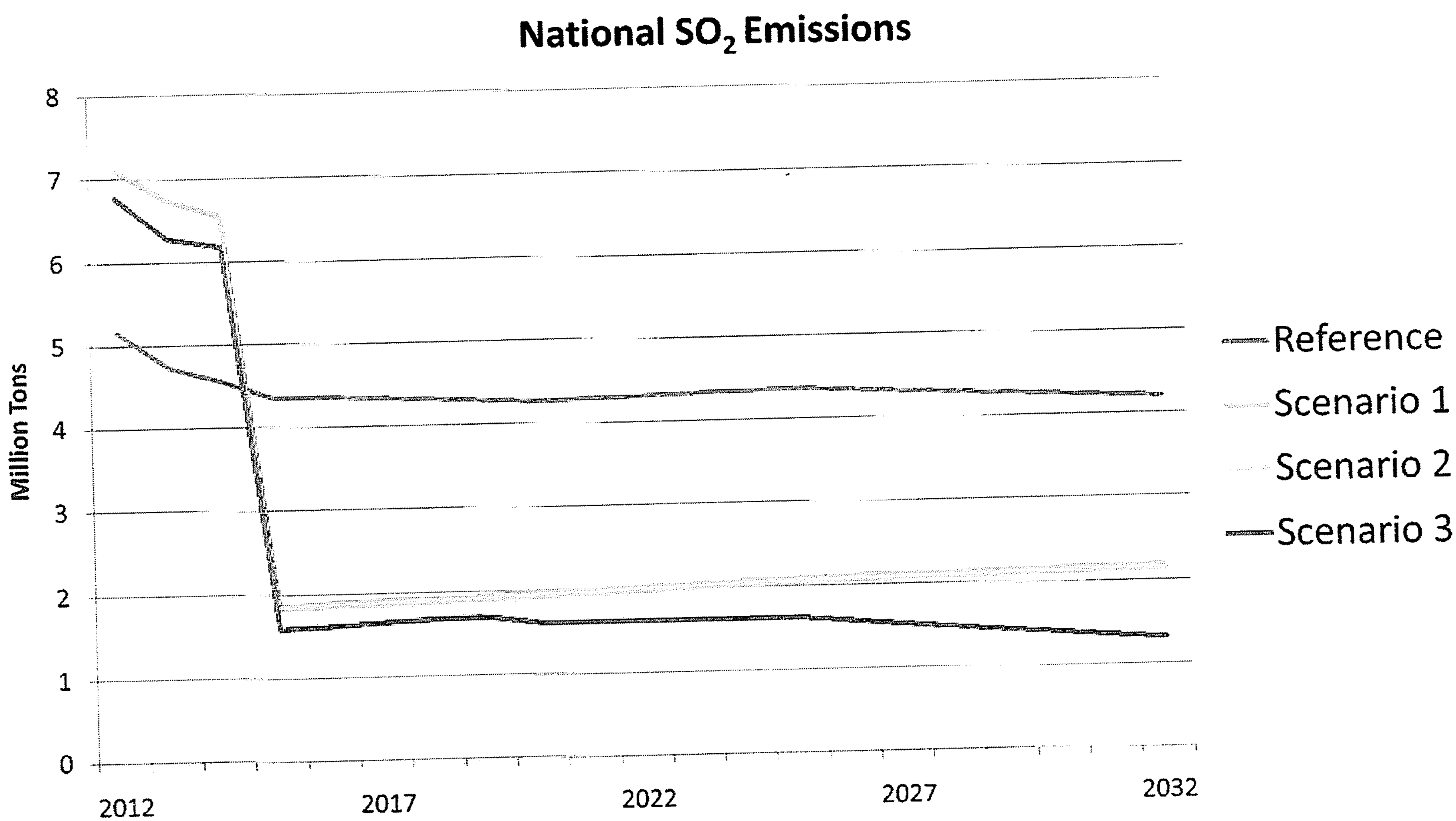


Note: Units may install more than one control and their capacity will be reported separately for each control.

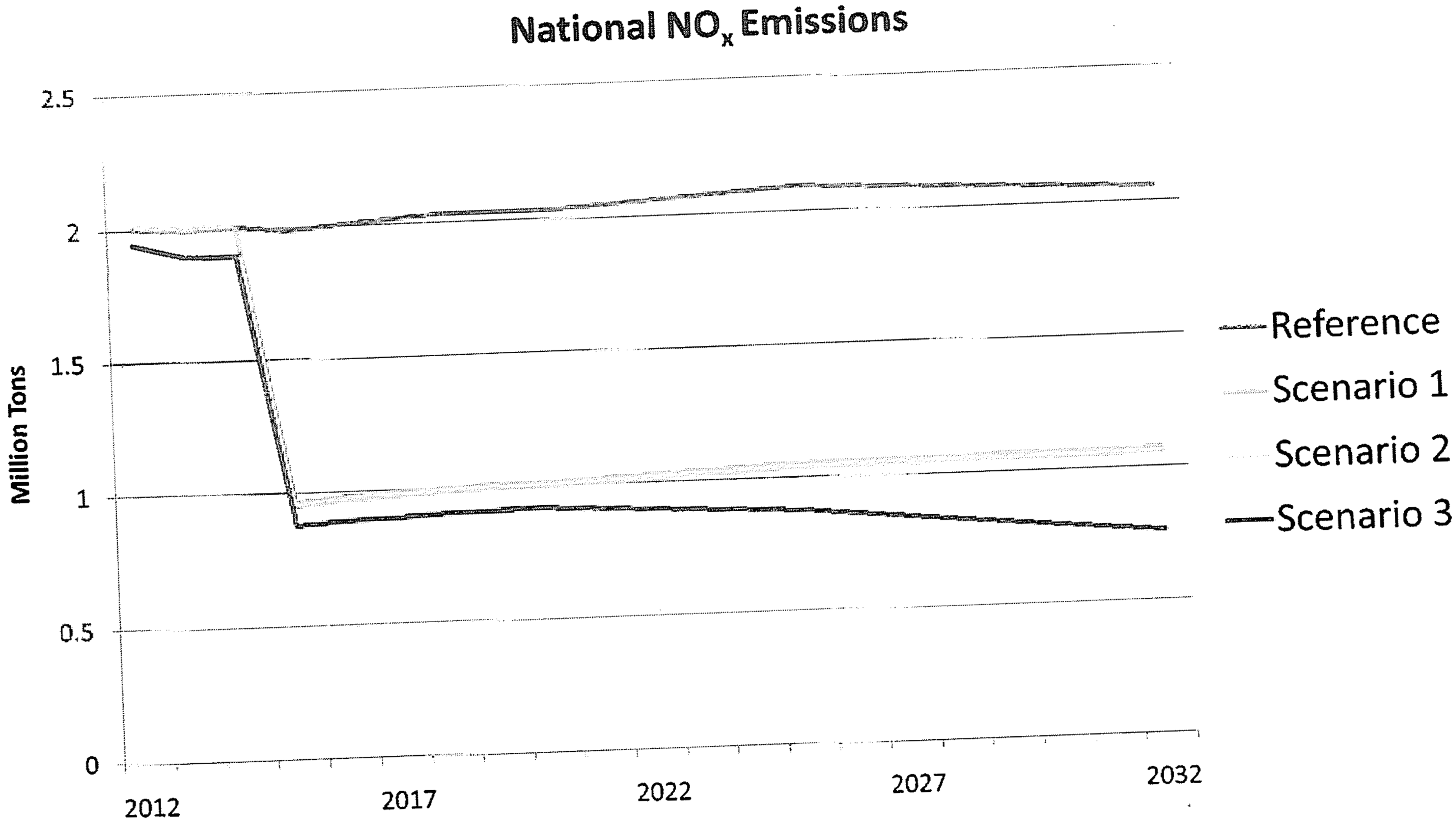
Henry Hub Natural Gas Prices



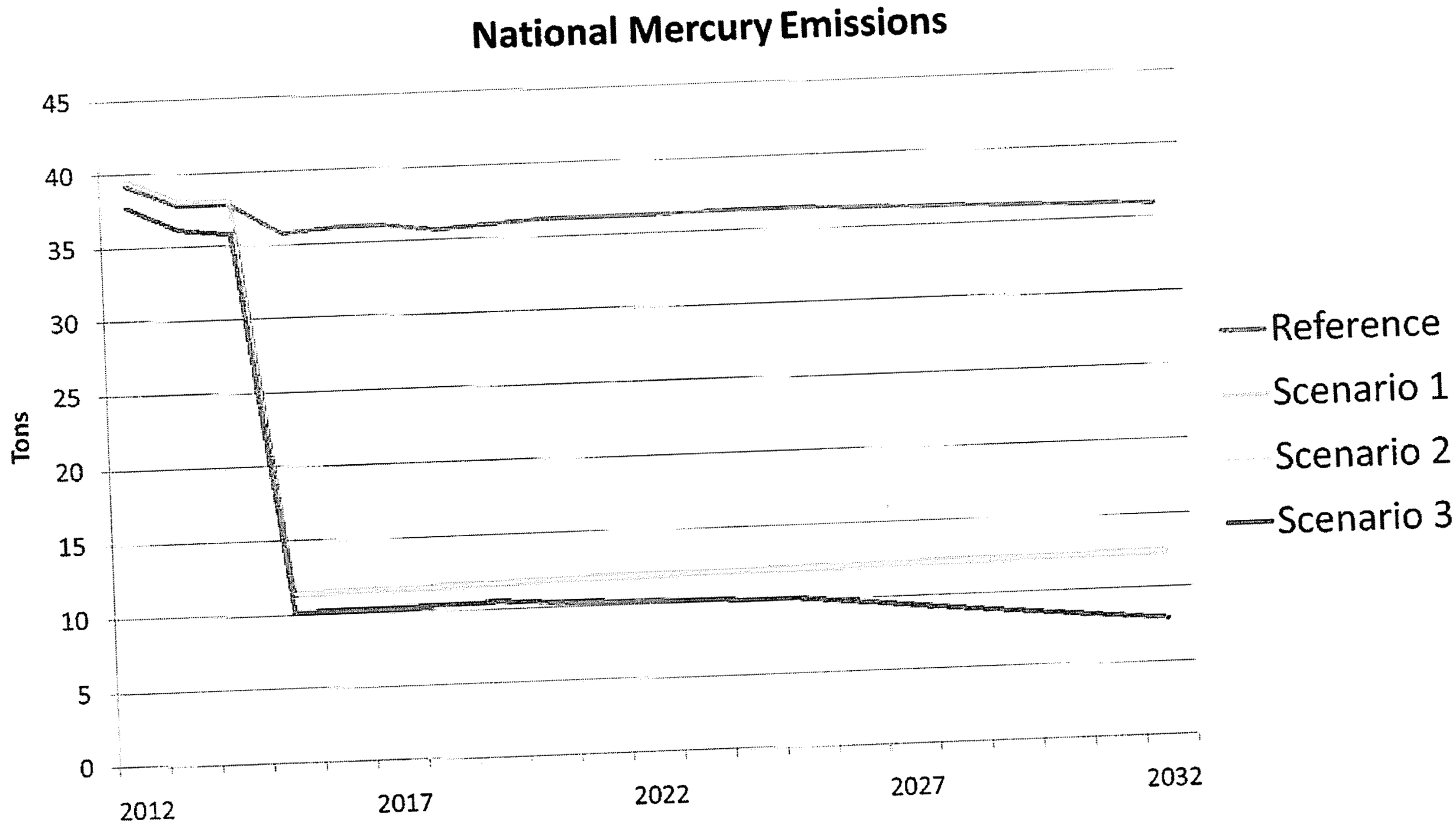
SO_2 Emissions



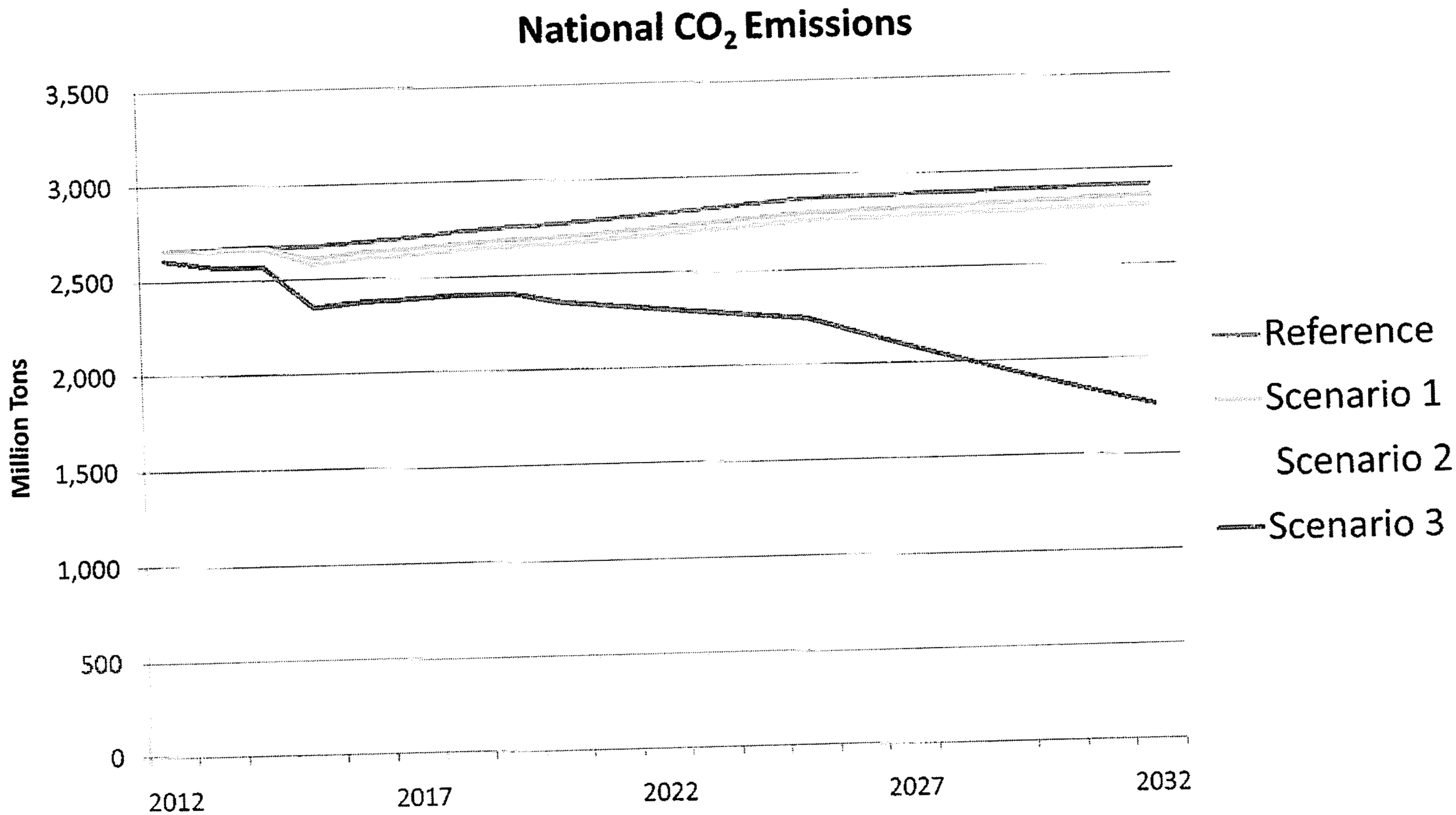
NO_X Emissions



National Mercury Emissions



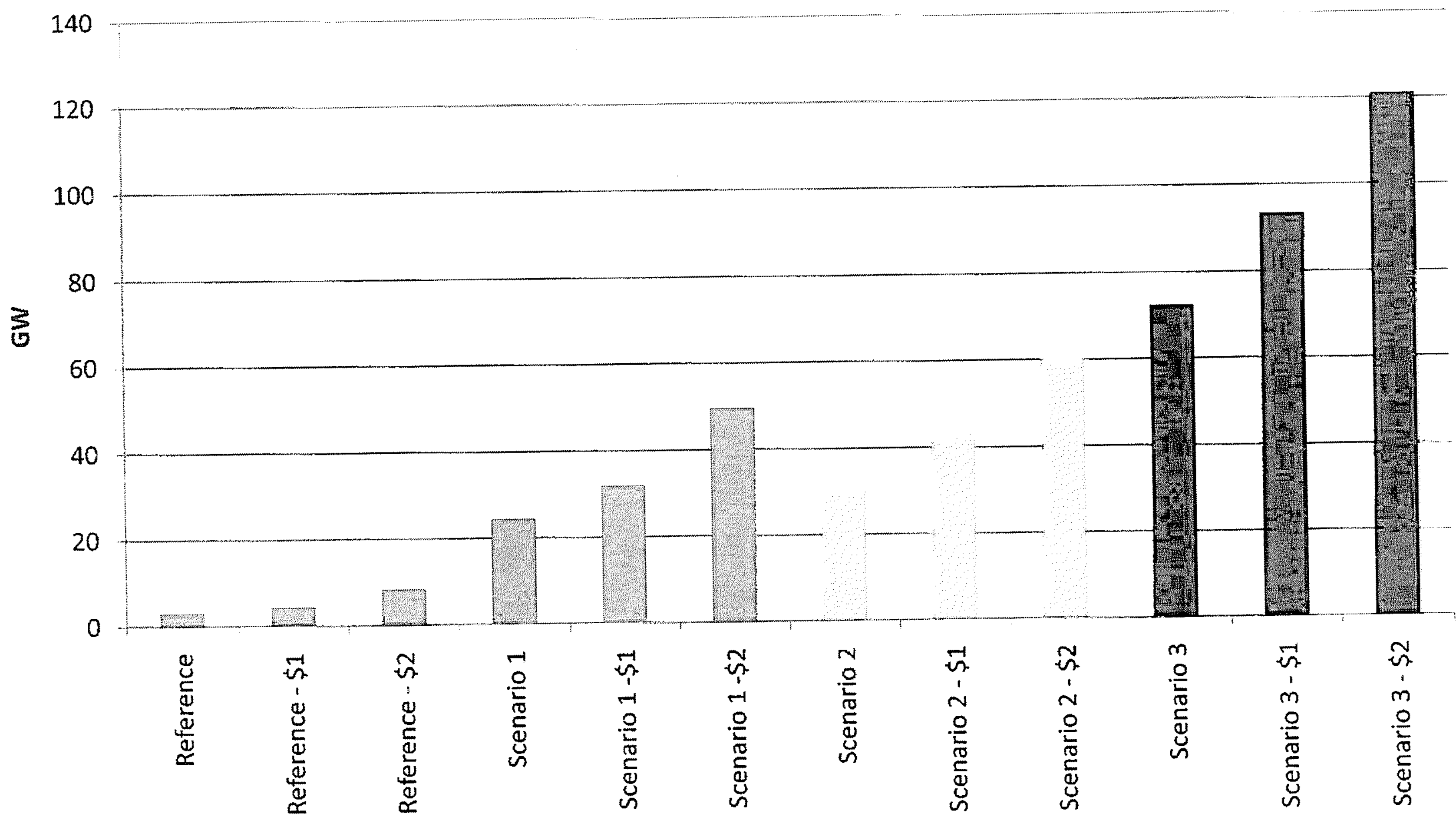
National CO_2 Emissions



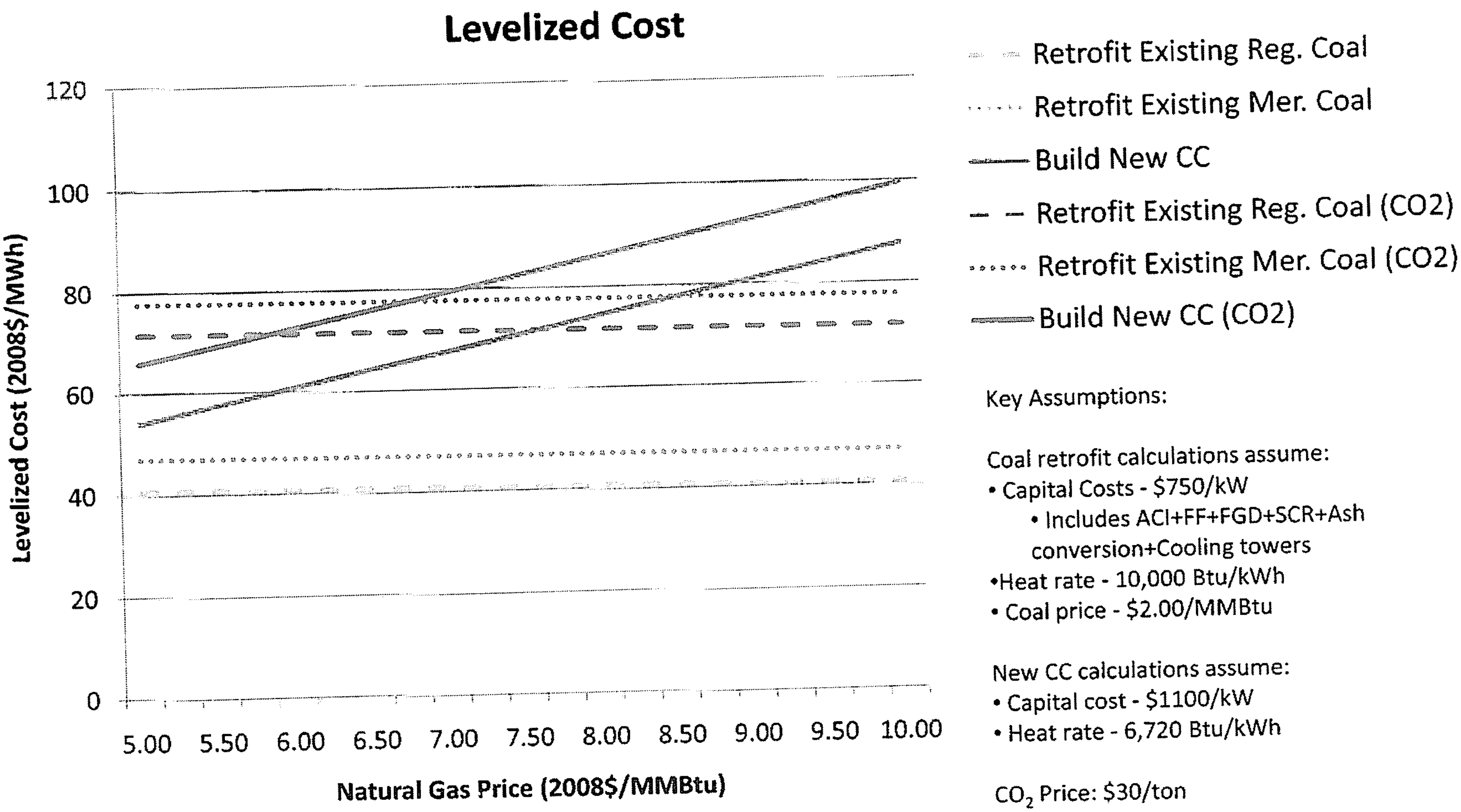
INTERNATIONAL

Retirements

Gas Price Sensitivities - Cumulative Coal Retirements through 2015



Natural Gas Prices Impact the Economics of Retrofitting Existing Coal vs. Building New – Avg. Compliance Cost



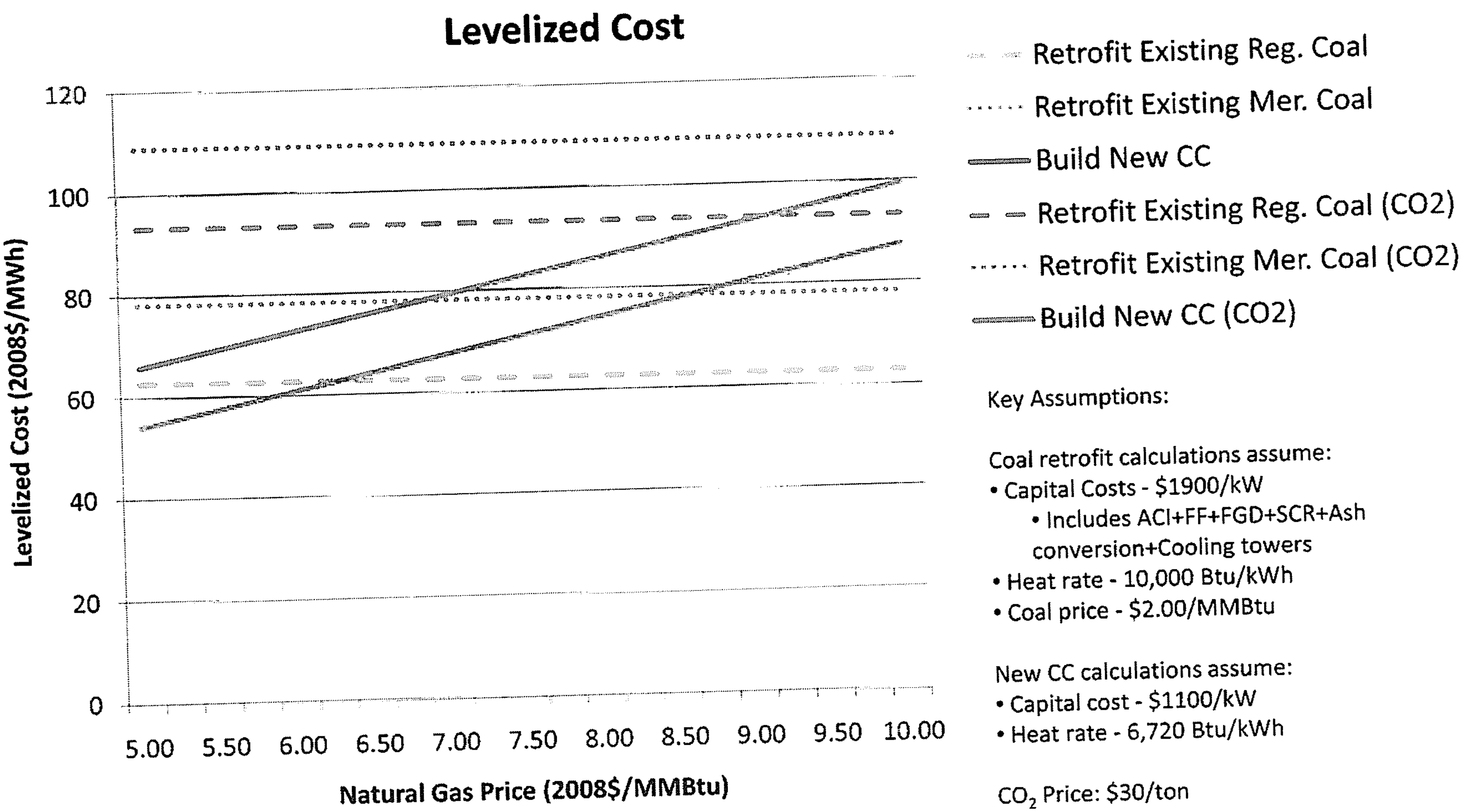
Key Assumptions:

Coal retrofit calculations assume:
- Capital Costs - $750/kW
  - Includes ACI+FF+FGD+SCR+Ash conversion+Cooling towers
- Heat rate - 10,000 Btu/kWh
- Coal price - $2.00/MMBtu

New CC calculations assume:
- Capital cost - $1100/kW
- Heat rate - 6,720 Btu/kWh

CO_2 Price: $30/ton

Natural Gas Prices Impact the Economics of Retrofitting Existing Coal vs. Building New – High Compliance Cost



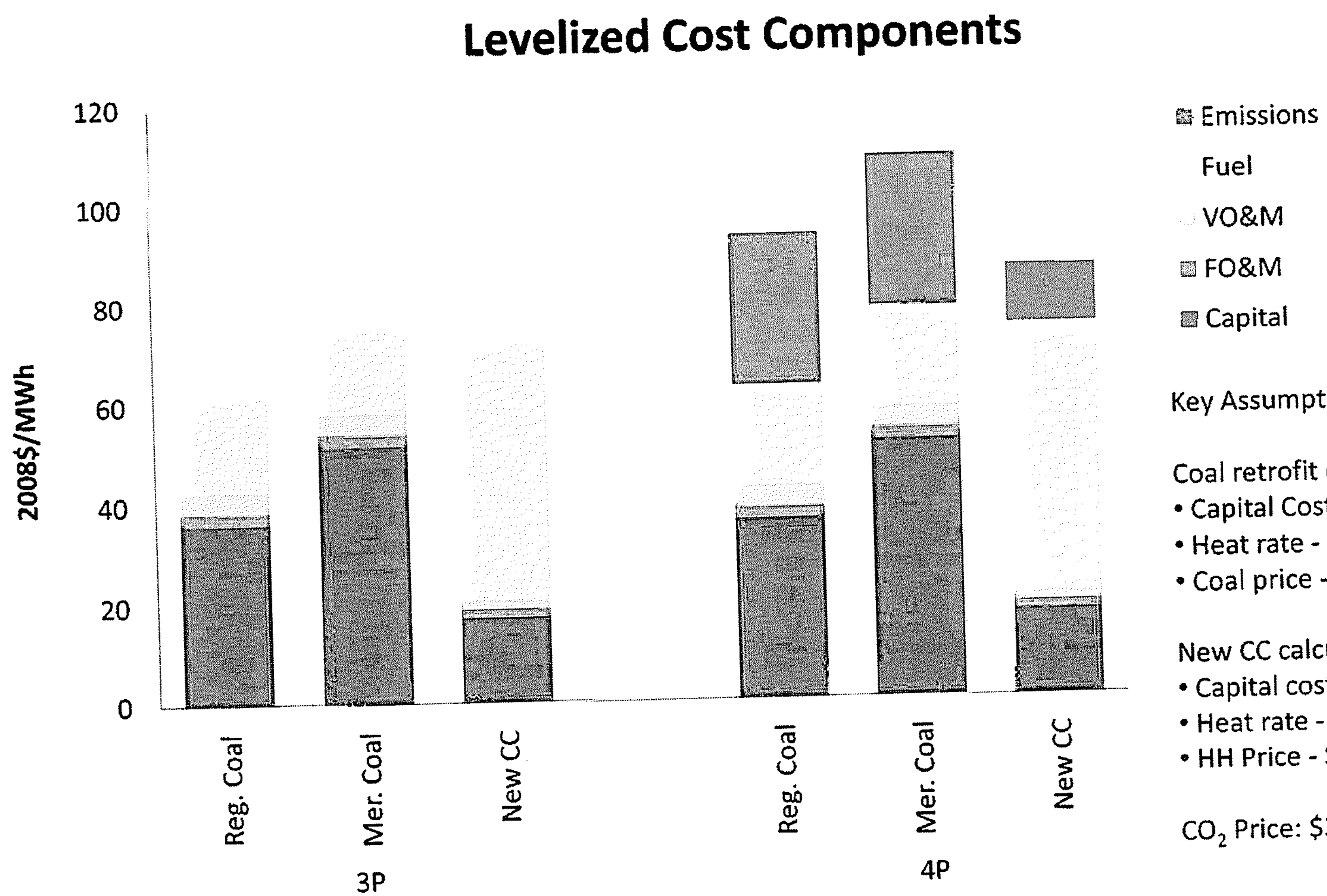
Key Assumptions:

Coal retrofit calculations assume:
- Capital Costs - $1900/kW
  - Includes ACI+FF+FGD+SCR+Ash conversion+Cooling towers
- Heat rate - 10,000 Btu/kWh
- Coal price - $2.00/MMBtu

New CC calculations assume:
- Capital cost - $1100/kW
- Heat rate - 6,720 Btu/kWh

CO_2 Price: $30/ton

Coal vs. CC Levelized Cost Components



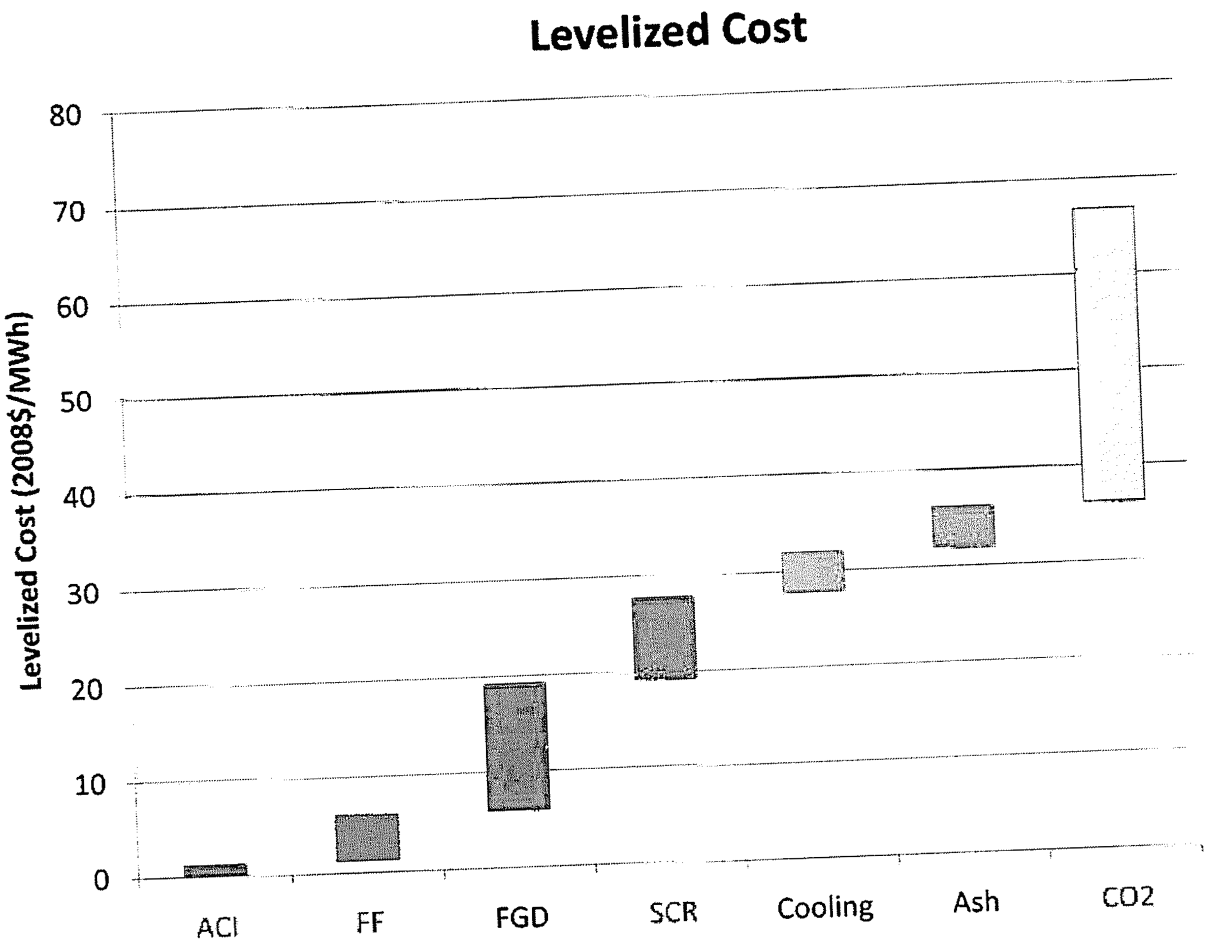
Key Assumptions:

Coal retrofit calculations assume:
- Capital Costs - $1900/kW
- Heat rate - 10,000 Btu/kWh
- Coal price - $2.00/MMBtu

New CC calculations assume:
- Capital cost - $1100/kW
- Heat rate - 6,720 Btu/kWh
- HH Price - $8.00/MMBtu

CO_2 Price: $30/ton

Levelized Regulated Coal Unit Compliance Costs



Key Assumptions:
- Capacity – 500 MW
- Heat Rate – 10,000 Btu/kWh
- CO_2 Price - $30/ton
- Regulated Unit

Levelized Merchant Coal Unit Compliance Costs

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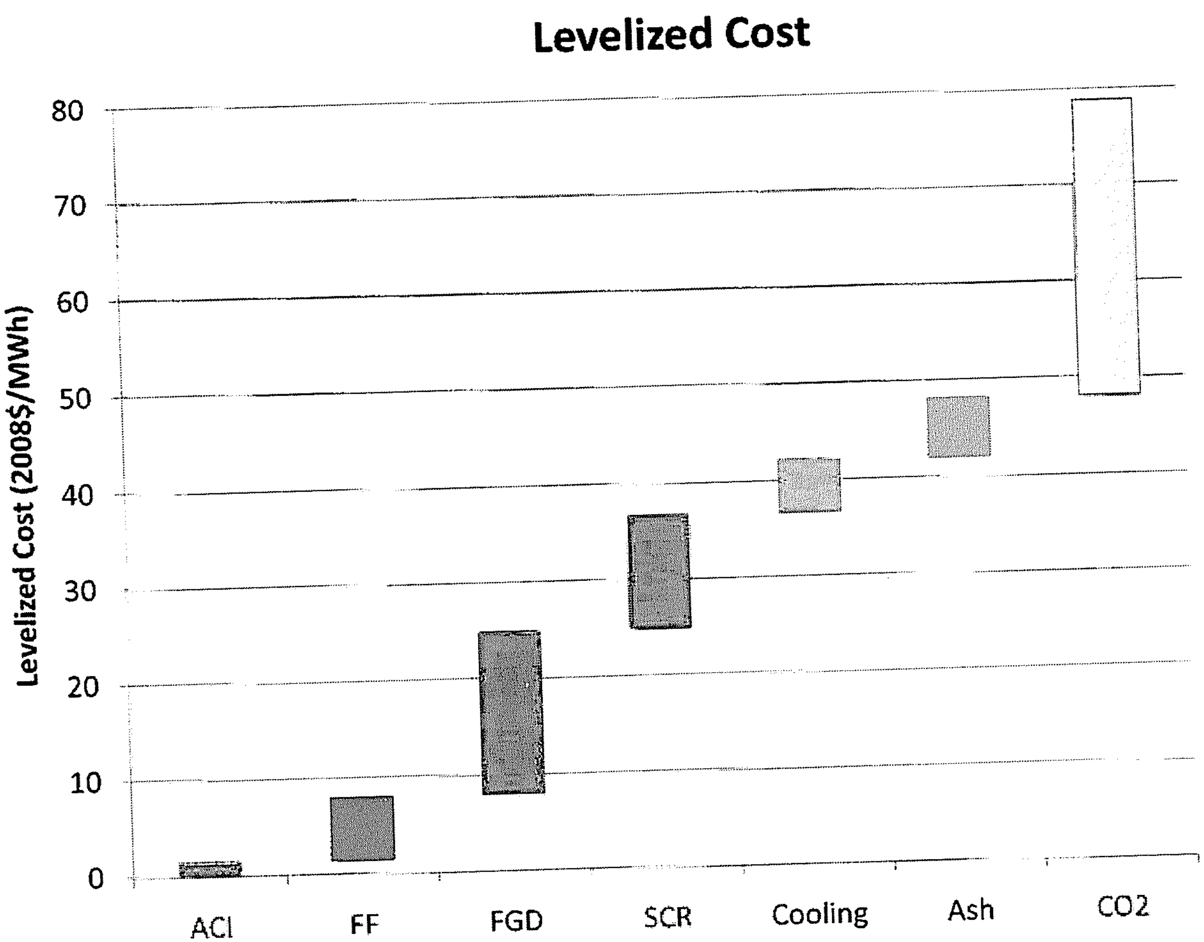

Key Assumptions:
- Capacity – 500 MW
- Heat Rate – 10,000 Btu/kWh
- CO_2 Price - $30/ton
- Merchant Unit

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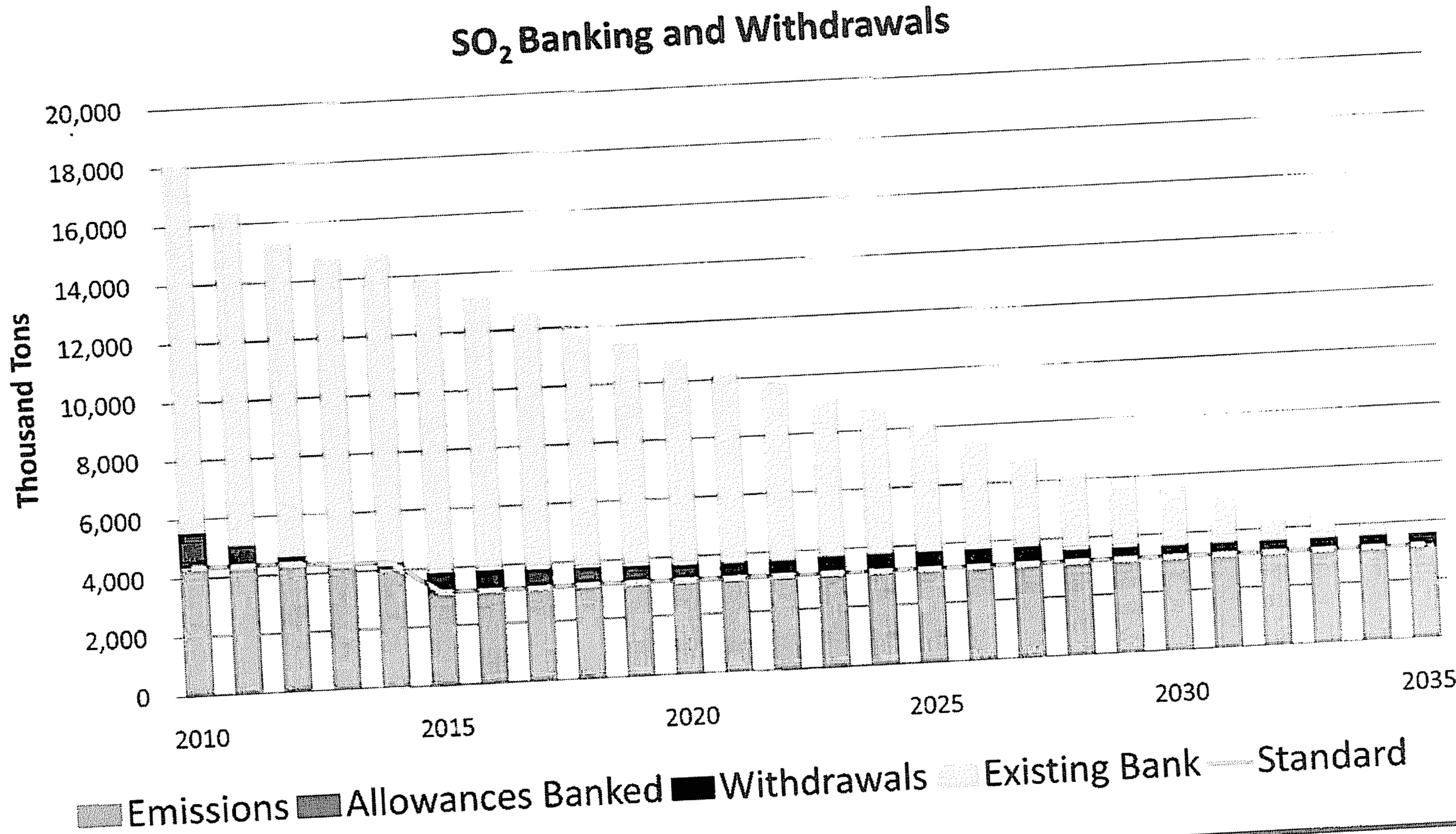
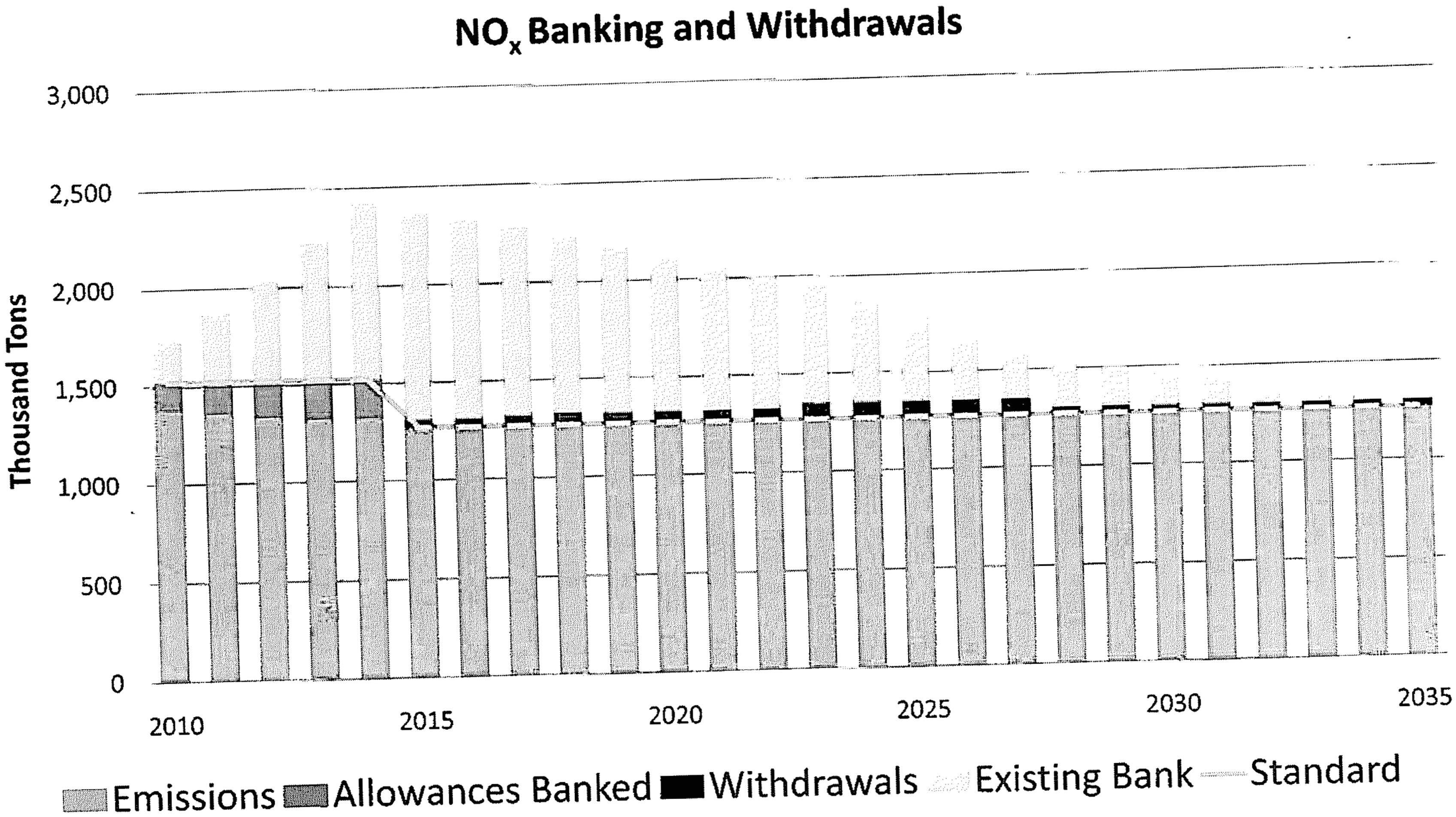
Appendix

Reference Case SO_2 Banking and Withdrawals



Reference Case NO_x Banking and Withdrawals

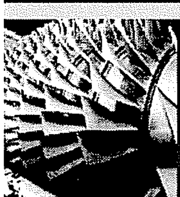


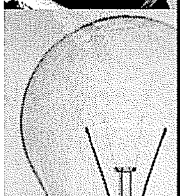
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2010 Special Reliability Scenario Assessment:

Resource Adequacy Impacts of Potential U.S. Environmental Regulations





October 2010

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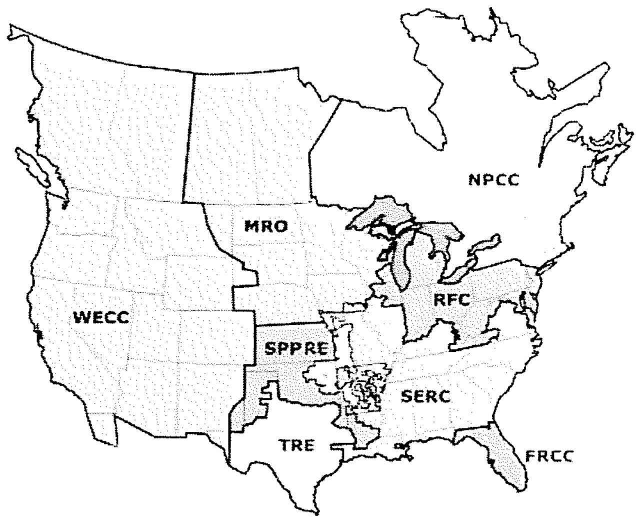
609.452.8060 | 609.452.9550 fax
www.nerc.com

NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas, as shown on the map below and listed in Table A. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: *The highlighted area between SPP and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.*

Table A: NERC Regional Entities

FRCC Florida Reliability Coordinating Council	SERC SERC Reliability Corporation
MRO Midwest Reliability Organization	SPP RE Southwest Power Pool Regional Entity
NPCC Northeast Power Coordinating Council	TRE Texas Reliability Entity
RFC Reliability*First* Corporation	WECC Western Electricity Coordinating Council

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the BPS, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the *Régie de l'énergie* of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have frameworks in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

Table of Contents

Executive Summary

In the United States, several regulations are in the process of being proposed by the U.S. Environmental Protection Agency (EPA) that directly affect the electric industry. Depending on the outcome of any or all of these potential regulations, the results could accelerate the retirement of a significant number of fossil fuel-fired power plants. EPA is currently developing rules that would mandate existing power suppliers to either invest in retrofitted environmental controls at existing generating plants or retire them. The most significant proposed EPA rules have been in development for over ten years and are currently undergoing court-ordered revisions that must be implemented within mandatory timeframes.

The results of this assessment show a significant potential impact to reliability should the four EPA rules be implemented as proposed. The reliability impact will be dependent on whether sufficient replacement capacity can be added in a timely manner to replace the generation capacity that is retired or lost because of the implementation of these rules. Implementation of the rules must allow sufficient time to construct new capacity or retrofit existing capacity. Planning Reserve Margins appear to be significantly impacted, deteriorating resource adequacy in a majority of the NERC Regions/subregions. In this scenario, reduced Planning Reserve Margins are a result of a loss of up to 19 percent of fossil fuel-fired steam capacity in the United States by 2018.[2] Additionally, considerable operational challenges will exist in managing, coordinating, and scheduling an industry-wide environmental control retrofit effort.

This assessment examines four potential EPA rulemaking proceedings that could result in unit retirements or forced retrofits between 2013 and 2018. Specifically, the rules under development include:

1. Clean Water Act – Section 316(b), Cooling Water Intake Structures
2. Title I of the Clean Air Act – National Emission Standards for Hazardous Air Pollutants (NESHAP) for the electric power industry (referred to herein as Maximum Achievable Control Technology (MACT) Standard)
3. Clean Air Transport Rule (CATR)
4. Coal Combustion Residuals (CCR) Disposal Regulations

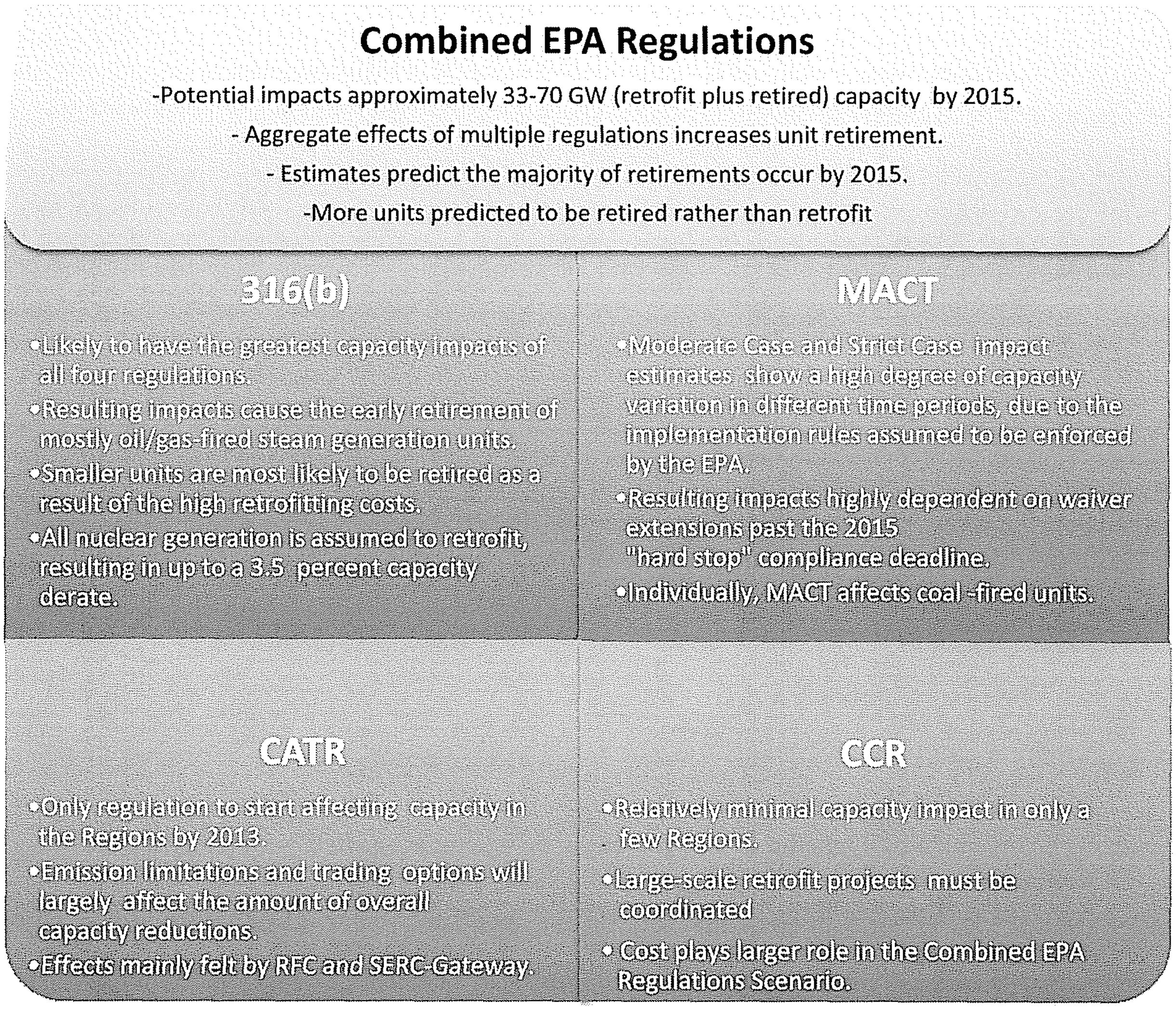
This assessment is designed to evaluate the potential impacts on Planning Reserve Margins, assuming that there would be no industry actions in the near term to address compliance issues or market response, and identify the need for additional resources that may arise in light of industry responses to each of these environmental regulations individually and in aggregate. Additionally, this assessment considers the number of generating units requiring retrofitting by NERC Region and subregion to demonstrate the magnitude of construction planning necessary for compliance in a timely fashion. The assessment relies on two separate scenario cases for each proposed rule, calculating the amount of capacity reductions due to accelerating unit retirements and increased station loads needed to power the additional environmental controls. For each

[2] A 19 percent reduction represents the results of the total capacity loss in the Strict Case for 2018 as a percentage of the total coal, gas, and oil steam units included in the 2009 Long-Term Reliability Assessment Reference Case. Refer to Appendix III and IV for details values.

proposed EPA rule and in aggregate, units were retired for this assessment based on an agreed upon cost calculation.[3]

Two scenario cases (Moderate Case and Strict Case) provide a range of sensitivities, with the Strict Case incorporating more stringent rule assumptions and higher compliance costs. The potential impacts of greenhouse gas (GHG) legislation are not considered in this assessment, but have been discussed separately in a recent NERC report.[4] Overall, the impact on reliability is a function of the timeline for finalizing the rules and ensuring compliance with the potential EPA regulations. The reliability impact of these rules will be dependent on whether sufficient replacement capacity can be added in a timely manner to replace the generation capacity that is retired or lost because of the implementation of these rules. This assessment does not account for industry's ability to acquire, construct, or finance replacement resources; however, implementation of the rules must allow sufficient time to construct new capacity or retrofit existing capacity.

Figure A: Summary and Highlights of the Four EPA Regulations Assessed[5]

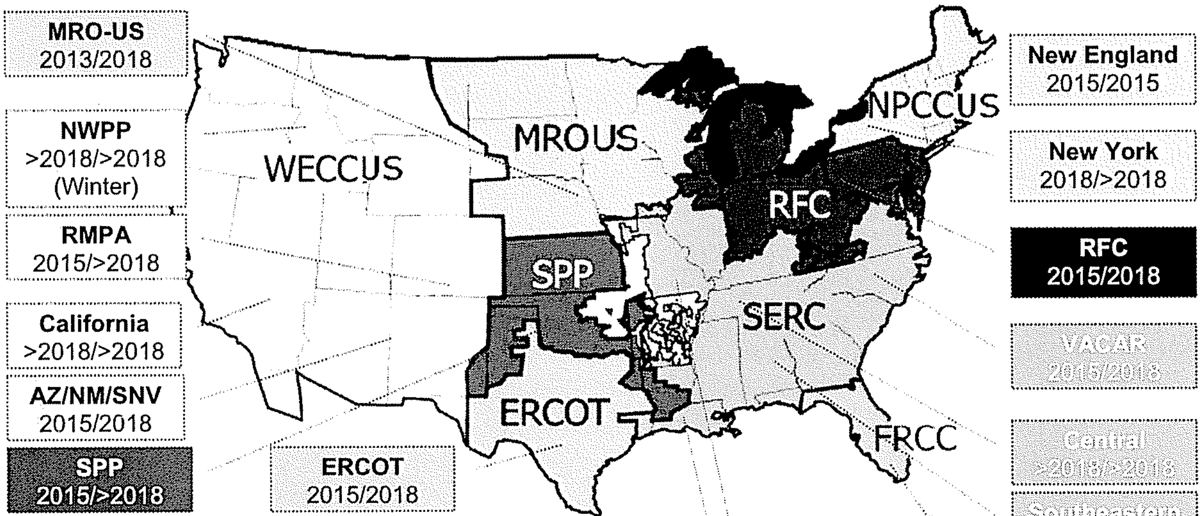


[3] Unit is retired if (CC+FC+VC) / (1-DR) > RC, where: CC = required compliance cost in \$/MWH, FC = current fixed O&M in \$/MWH, VC = variable O&M including fuel cost in \$/MWH, RC = replacement cost in \$/MWH and DR = derate factor that accounts for the incremental energy loss due to any new environmental controls. See *Appendix I, Assessment Methods*.

[4] http://www.nerc.com/files/RICCI_2010.pdf

[5] Individual EPA Regulations are listed in order of greatest potential impact to least top to bottom, left to right.

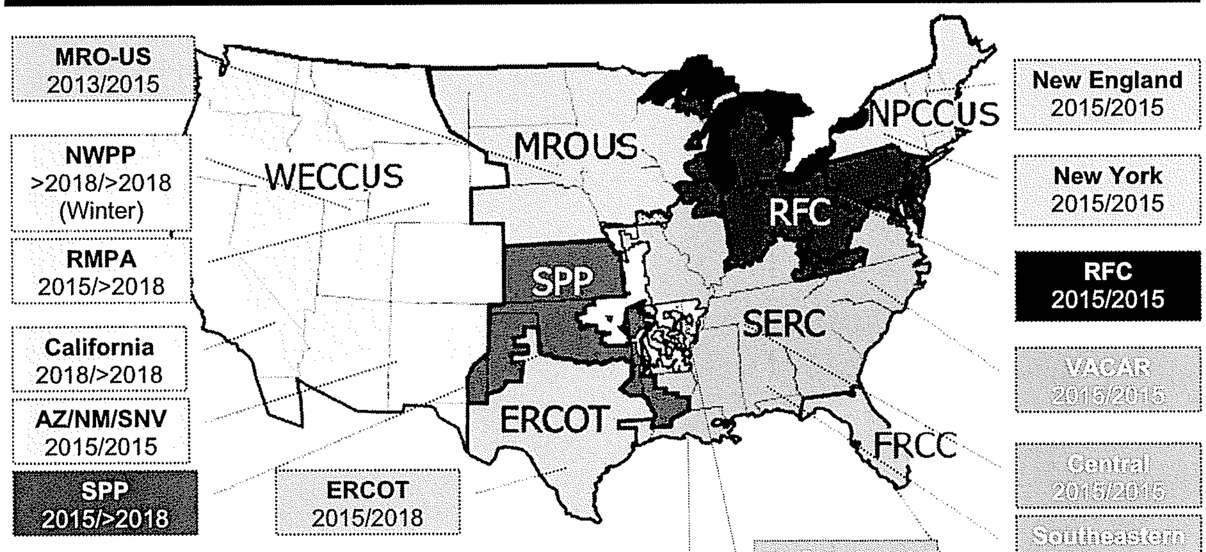
Figure B: Moderate Case Deliverable and Adjusted Potential Resources Reserve Margins Compared to NERC's Reference Margin Level



Years listed above represent the first modeled year when deliverable/adjusted potential capacity reserve margins fall below NERC reference margins. >2018 means that Planning Reserve Margins fall below the NERC Reference Margin Level at a time beyond 2018.

Deliverable Reserve Margin – Existing and Future-Planned Resources
Adjusted Potential Reserve Margin – Existing, Future-Planned, and Adjusted Potential Resources (Conceptual resources adjusted by a confidence factor)

Figure C: Strict Case Deliverable and Adjusted Potential Resources Reserve Margins Compared to NERC's Reference Margin Level



Years listed above represent the first modeled year when deliverable/adjusted potential capacity reserve margins fall below NERC reference margins. >2018 means that Planning Reserve Margins fall below the NERC Reference Margin Level at a time beyond 2018.

Proposed EPA Regulations May Have Significant Impacts on Forecast Planning Reserve Margins

Without additional power production or demand-side resources beyond those in current regional plans, the combined effects of the four EPA rules (Combined EPA Regulation Scenario) are shown to significantly affect Planning Reserve Margins and, in most Regions/subregions, more resources would be required to maintain NERC Reference Margin Levels. Up to a 78 GW reduction of coal, oil, and gas-fired generating capacity is identified for retirement during the ten-year period of this scenario. For the Moderate Case, this occurs in 2018; however, in the Strict Case a similar reduction occurs in 2015. The reduction in capacity significantly affects projected Planning Reserve Margins for a majority of the NERC Regions and subregions. Potentially significant reductions in capacity within a five-year period may require the addition of resources. For the United States as a whole, the Planning Reserve Margin is significantly reduced by nearly 9.3 percentage points in the Strict Case, significantly deteriorating future bulk power system reliability.

Rule Implementation Timeline Should Consider Reliability Impacts

Overall, impacts on Planning Reserve Margins and the need for more resources is a function of the compliance timeline associated with the potential EPA regulations. The Combined EPA Regulation Scenario affects a large amount of units, affecting some Regions more significantly than others. Based on the assessment's assumptions, the greatest risk to Planning Reserve Margins occurs by 2015 in the Combined EPA Regulation Scenario. The majority of the impacts will be seen within the next five years, requiring additional resources in a short timeframe. This situation is compounded by the large number of electric generation units that are likely to retrofit with environmental controls, as well as the convergence of overlapping replacement/retrofit generation capacity projects and heavy U.S. infrastructure projects in other sectors. Potential constraints of skilled construction labor, material shortages, financing, and escalation of compliance costs coupled with coordination of overlapping outages resulting in congestion expenses could present challenges in meeting the compressed time schedule.

Individually, the Section 316(b) Cooling Water Intake Structures Rule Has the Greatest Potential Impact on Planning Reserve Margins

Implementation of this rule will apply to 252 GW (1,201 units) of coal, oil steam, and gas steam generating units across the United States, as well as approximately 60 GW of nuclear capacity (approximately a third of all resources in the U.S.). Of this capacity, 33-36 GW (see Figure D) may be economically vulnerable to retirement if the proposed EPA rule requires power suppliers to convert to recirculating cooling water systems in order to continue operations. The remaining capacity may also be converted assuming it is unaffected by other proposed rules, resulting in a 5 GW derating across the United States. Therefore, the total capacity vulnerable to retirement increases to 37-41 GW. Planning Reserve Margins in almost half of NERC Regions/subregions are below the NERC Reference Margin Level by 2015. For example, in this scenario, Planning Reserve Margins are decreased by 18 percentage points in the SERC-Delta subregion, where the margin falls below zero. Other Regions/subregions significantly affected subregions include NPCC-New England and New York.

The MACT, CATR, and CCR Rules Also Contribute to Reductions in Capacity

Ranked in descending order of impact severity, the regulatory impacts of MACT, CATR and finally CCR on retirements, individually also accelerate retirements and will mostly affect existing coal-fired capacity:

- The **MACT Rule** considered alone could drive Planning Reserve Margins of 8 regions/subregions below the NERC Reference Margin Levels standards and trigger the retirement of 2-15 GW (Moderate to Strict Cases) of existing coal capacity by 2015. To comply, owners of the remaining capacity need to retrofit from 277 to 753 units with added environmental controls. The "hard stop" 2015 compliance deadline proposed by the MACT Rule makes retrofit timing a significant issue and potentially problematic.

- The **CATR** could have significant impacts as soon as 2015 should EPA require emission limits with no offset trading, resulting in potentially 3-7 GW of potential retirements and derated capacity, requiring retrofitting of 28-576 plants with environmental controls by 2015 (Moderate to Strict Cases). Planning Reserve Margins are affected most in the SERC-Gateway subregion with reductions starting in 2013.

- The **CCR Rule** alone is projected to have the least impact, triggering the retirement of up to 12 coal units (388 MW). Cost sensitivity assessment for CCR reveals that retirements could reach capacity of 2 GW (53 units) should costs exceed the assessment's Strict Case expenditure estimate by a factor of ten. While the resulting impacts of the CCR scenario may not have significant impacts to capacity by themselves, the associated compliance costs of CCR contribute to the Combined EPA Regulation Scenario.

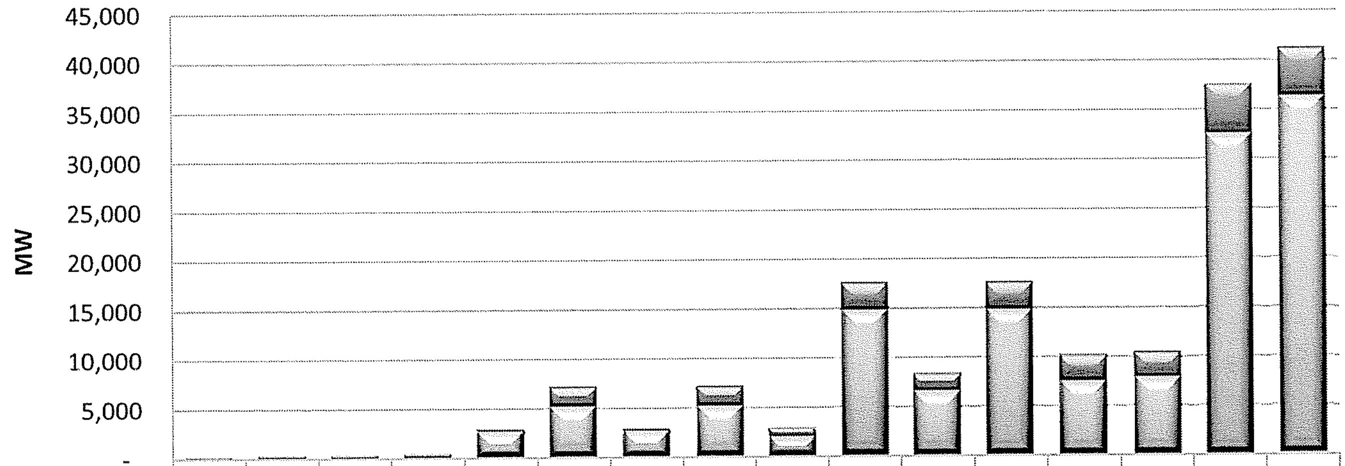
EPA Regulations Create a Need for Prompt Industry Response and Action

This report also identifies a number of tools the industry has for mitigating potential reliability impacts from the implementation of EPA regulations. For example, advancing Future or Conceptual resource in-service dates or the addition of new resources not yet proposed could help partially alleviate projected capacity losses in severely affected regions. Price signaling for the need of new resources will be important.

Industry coordination will be vital to ensure retrofits are completed in a way that does not diminish reliability. In addition, statutory and regulatory safeguards also allow the EPA, the President of the United States, and the Department of Energy to extend or waive compliance under certain circumstances. Implementing these industry and regulatory tools may be critical to maintain the reliability of the bulk power system.

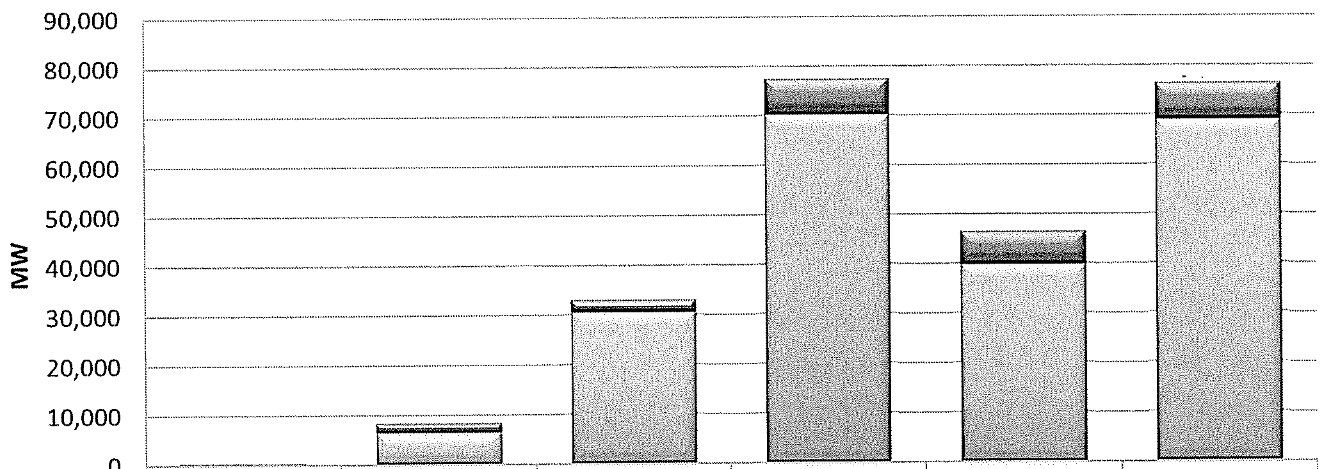
Second tier effects, including generation deliverability or stability impacts, must also be considered. For example, transmission system construction, enhancements, reconfiguration and development of new operating procedures may be necessary in some areas, all of which can create additional timing considerations.

Figure D: Potential Capacity Reduction Impacts Due to Each Potential EPA Regulation



	CCR				CATR				MACT				316(b)			
	2015		2018		2015		2018		2015		2018		2015		2018	
	M Case	S Case	M Case	S Case	M Case	S Case	M Case	S Case	M Case	S Case	M Case	S Case	M Case	S Case	M Case	S Case
Derate (MW)	0	0	0	0	142	1,952	142	1,952	806	2,746	1,750	2,746	2,575	2,551	4,954	4,848
Retired (MW)	130	287	287	388	2,740	5,221	2,740	5,221	2,061	14,879	6,617	14,879	7,597	7,880	32,522	36,366

Figure E: Potential Capacity Reduction Due to the Combined EPA Regulation Scenario



	2013		2015		2018	
	Moderate Case	Strict Case	Moderate Case	Strict Case	Moderate Case	Strict Case
Derate (MW)	17	1,934	2,394	7,289	6,479	7,348
Retired (MW)	538	6,457	30,563	70,059	39,867	68,979

Recommendations

Regulators

In the future, a variety of demands on existing infrastructure will be made to support the evolution from the current fuel mix, to one that includes generation that can meet proposed EPA regulations. The pace and aggressiveness of these environmental regulations should be adjusted to reflect and consider the overall risk to the bulk power system. EPA, FERC, DOE and state utility regulators, both together and separately, should employ the array of tools at their disposal to moderate reliability impacts, including, among other things, granting required extensions to install emission controls.

Industry

Regulators, system operators, and industry participants should employ available tools to ensure Planning Reserve Margins are maintained while forthcoming EPA regulations are implemented. For example, regional wholesale competitive markets should ensure forward capacity markets are functioning effectively to support the development of new replacement capacity where needed. Similarly, stakeholders in regulated markets should work to ensure that investments are made to retrofit or replace capacity that will be affected by forthcoming EPA regulations.

NERC

NERC should further assess the implications of the EPA regulations as greater certainty or finalization emerges around industry obligations, technologies, timelines, and targets. Strategies should be communicated throughout the industry to maintain the reliability of the bulk power system. This assessment should include impacts to operating reliability and second tier impacts (e.g., deliverability, stability, localized issues, outage scheduling, operating procedures, and industry coordination) of forthcoming EPA regulations.

Note: *The results in this report are based on assumptions of potential EPA regulations. The regulations discussed in this report are not yet final and all compliance deadlines, emission limitations, and retrofit costs may differ once the rules are finalized. This is a scenario of potential bulk power system impacts based on what is known today about the potential implementation of these rules. The resulting resource loss from these potential rules represent the loss of capacity should no more resources be added beyond the reference case.*

Executive Summary

Introduction

In the United States (U.S.), the electric power industry has made significant capital investment in air pollution control technologies to remove sulfur dioxide (SO_2), particulate matter and nitrogen oxide (NO_x) emissions at fossil-fired power plants. The bulk of these capital investments were made to existing coal plants in order to comply with evolving environmental regulations.

Several regulations are in the process of being proposed by the U.S. Environmental Protection Agency (EPA) requiring additional retrofits. Depending on the final determinations, the cost to comply with the final regulations may result in retirements of generation. This assessment is designed to consider four potential EPA regulations and their potential impacts on Planning Reserve Margins individually and in aggregate.[6] The four regulations assessed are:

1. Clean Water Act – Section 316(b), Cooling Water Intake Structures;
2. Title I of the Clean Air Act – National Emission Standards for Hazardous Air Pollutants (NESHAP), or Maximum Achievable Control Technology (MACT) Standards;
3. Clean Air Transport Rule (CATR); and
4. Coal Combustion Residuals (CCR)

Assumptions (described in detail later in this section) have been made in this assessment to measure the potential impacts on Planning Reserve Margins from these potential regulations before knowing how companies will actually respond to these requirements and market conditions. The goal is to provide industry and regulators additional information regarding the scope of generating units financially affected by the potential EPA Regulations and about the necessity for replacement capacity to maintain reliability during the implementation process—it is a hypothetical set of scenarios employing agreed upon assumptions.[7] Ultimately, plant owners will determine the costs of compliance and make decisions about investment versus unit retirement. For this assessment, a unit is assumed to retire if (CC+FC+VC) / (1-DR) > RC, where: CC = required compliance cost, FC = current fixed O&M, VC = variable O&M including fuel cost, RC = replacement cost all in $/MWH, and DR = derate factor that accounts for the incremental energy loss due to any new environmental controls. See *Appendix I: Assessment Methods* for more details.[8]

Below is a summary of the aforementioned regulations, listed in order of magnitude:

1. **Clean Water Act – Section 316(b), Cooling Water Intake Structures**
   A significant number of thermal (coal, nuclear, oil and gas steam) generation plants use cooling water to support the process of generating electricity and therefore, they are located on large water bodies or high flow-rate rivers. Many of these facilities use once-through cooling systems that draw large volumes of water from the ocean, lake, or river used to condense steam, returning the warmer water back into the body of water immediately after use. Section 316(b) of the Federal Water Pollution Control Act (FWPCA), more commonly known as the Clean Water Act, regulates intake structures for surface waters in the U.S. and calls for Best Technology Available (BTA) to

[6] Analysis performed by Energy Ventures Analysis, Inc. (http://www.evainc.com) for NERC in February-July 2010 serves as the basis for this report. Detailed status of the assessed regulations can be found in *Appendix II, Environmental Regulations*
[7] NERC vetted assumptions used in this assessment with the Reliability Assessment Subcommittee and multiple industry groups.
[8] The potential effects of pending CO_2 regulations were not included.

minimize adverse environmental impact (AEI). EPA has interpreted that to mean impingement mortality of fish and shellfish and entrainment of their eggs and larvae. EPA's rulemaking is expected to set significant new national technology-based performance standards to minimize AEI. EPA is revising its rules for cooling water intake structures at "existing" facilities – including electric power generating stations. EPA has moved to combine the Phase II (large existing generators) and Phase III (small existing generators, offshore oil & gas facilities and other manufacturing facilities) rules into one proceeding and plans to propose a revised rulemaking by February 2011 and a final rule is to be promulgated by July 2012.

In 2004, EPA originally adopted Phase II regulations to minimize impingement and entrainment of aquatic life in the water intake structures that applied to large existing power plants withdrawing 50 million or more gallons per day and using at least 25 percent of the water withdrawn for cooling purposes. Sources could comply using several alternatives.

However, a January 2007 ruling by the Second U.S. Circuit Court of Appeals remanded several provisions of the Phase II rule and EPA subsequently suspended its Phase II implementation[9] and is in process of developing a new rule to address the court concerns. Steam generating units employing once-through cooling systems could be required to replace their cooling water systems with closed-loop cooling systems.

This can affect Planning Reserve margins in two ways: 1) the cost of such retrofits may result in accelerated unit retirements and 2) closed-loop cooling retrofitting results in derating a unit's net output capacity, due to additional ancillary or station load requirements to serve generator equipment. This resource assessment and its implications for responses in the power generation market should inform and affect power plant owner's choices about plant retirements, plant additions, and unit retrofits.

2. **Title I of Clean Air Act – National Emission Standards for Hazardous Air Pollutants for the electric power industry, or Maximum Achievable Control Technology (MACT) Standards**
NESHAP or MACT requires coal-fired plants to reduce their emissions of air toxics, including mercury. In December 2000, the U.S. EPA issued a "regulatory determination" under the 1990 Clean Air Act Amendments that regulation of mercury is "appropriate and necessary" for coal- and oil-fired power plants. Title I of the Amendments required EPA to adopt MACT standard for air toxic control. In March 2005, EPA issued its final Clean Air Mercury Rule (CAMR) for coal-based power plants. The CAMR used a market-based cap-and-trade approach to require emissions reductions in two phases: 1) a cap of 38 tons in 2010 and 2) fifteen tons after 2018, for a total reduction of 70 percent from current levels. Facilities were to demonstrate compliance with the standard by holding one "allowance" for each ounce of mercury emitted in any given year. In the final rule, EPA stated the regulation of nickel emissions from oil-fired plants is not "appropriate and necessary." In February 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion in a case, which was initiated by 15 states and other groups, challenging the CAMR and EPA's decision to "de-list" mercury as a hazardous air pollutant (HAP). The Court held that EPA's reversal of the December 2000

[9] http://www.epa.gov/waterscience/316b/phase2/implementation-200703.pdf

regulatory finding was unlawful.[10] The Court vacated both the reversal and the CAMR. In February 2009, the acting Solicitor General, on behalf of EPA, filed a motion with the Supreme Court to dismiss the CAMR case. The motion states unequivocally that EPA will develop MACT standards for the utility industry under section 112 of the Clean Air Act. EPA is now obligated under a consent decree to propose a MACT rule by March 16, 2011 and to finalize the rule by November 16, 2011. In the interim, 19 states have already adopted their own mercury control requirements.

Section 112 in Title I of the Clean Air Act requires EPA to develop MACT standards for all the other listed air toxics emitted by coal- and oil-fired power plants. Based on an Information Collection Request (ICR), EPA is likely to set MACT standards for mercury, acid gases, heavy metals, and organics for coal- and oil-fired power plants. This could require significant additional emissions control equipment beyond what is necessary for compliance with mercury-only regulations. Under the Clean Air Act, EPA is obligated to implement the stricter standards within three years after the regulation becomes final.

3. **Clean Air Transport Rule (CATR)**
On July 6, 2010, EPA proposed a CATR program to reduce long-range transport of pollutants significantly contributing to downwind state ground-level ozone and fine particle non-attainment problems. This program would replace EPA's earlier Clean Air Interstate Rule that was overturned by the U.S. Court of Appeals in 2008 and temporarily reinstated until a replacement program was developed. As drafted, CATR would sharply reduce emissions of sulfur dioxide and nitrogen oxide from power plants in 31 states and the District of Columbia. EPA proposed three program options for public comment:
    1) the EPA preferred option which sets state emission budget caps and allows intrastate trading and limited interstate trading among power plants;
    2) the EPA Alternative 1 option which sets state emission budget caps and allows intrastate trading among power plants within a state; and
    3) the EPA Alternative 2 option which sets a pollution limit for each state and specifies the allowable unit-specific emission limit

Each of these options poses different reliability impacts. EPA will revise future state emission budgets as new stricter ozone and fine particulate ambient air quality standards are implemented. Depending on the outcome of the final regulation, power plant owners will likely need to retrofit additional emissions controls and, in some cases, retire units.[11]

4. **Regulations on Coal Combustion Residuals (CCR)**
Coal-fired power plants currently dispose of more than 130 million tons per year of coal-ash and solid byproducts. The failure of an ash disposal cell in December 2008 highlighted the concerns of coal-ash disposal and triggered calls for tighter regulation.[12] In May 2010, EPA proposed two options to regulate coal combustion residual disposal.[13]

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[10] http://pacer.cadc.uscourts.gov/docs/common/opinions/200802/05-1097a.pdf

[11] A follow-on rule "Transport Rule 2" is also being developed for proposal by the EPA that would require more environmental controls not covered by CATR, regulating NOx in particular. This would apply to a majority of the states in the Eastern Interconnection plus Texas. This rule is not assessed in this report, but may contribute to more investments in required control technologies needed.

[12] Disposal cells are used for settling and storing the coal fly ash. This accident occurred at TVA's Kingston Fossil Plant East Tennessee. http://www.tva.gov/kingston/index.htm

[13] http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ccr-rule/ccr-rule-prop.pdf

1) Regulate the coal fly ash as a special waste under subtitle C (hazardous waste) of the Resource Conservation and Recovery Act (RCRA). Under this option, facilities would need to close their surface ash impoundments within five years and dispose of the ash (past and future) in a regulated landfill with groundwater monitoring.

2) Regulate ash disposal as a non-hazardous waste under subtitle D of RCRA. This alternative would require the facility to remove the solids and retrofit the impoundment pond with a liner to protect against groundwater contamination. Any landfill CCR disposal would require liners for new landfills and groundwater monitoring of existing landfills.

Beyond regulating coal-ash and residuals being landfilled or placed into a surface impoundment, the EPA regulation may also affect the use of the remaining coal-ash and reused or recycled residuals in products such as cement, concrete, roadbed material, drywall, etc. The EPA has indicated it will not prevent beneficial uses of the coal fly ash; however, there would be a higher cost for added ash disposal volume and a potential stigma created by regulating ash as a hazardous material, potentially resulting in lost revenue from the recycling market.

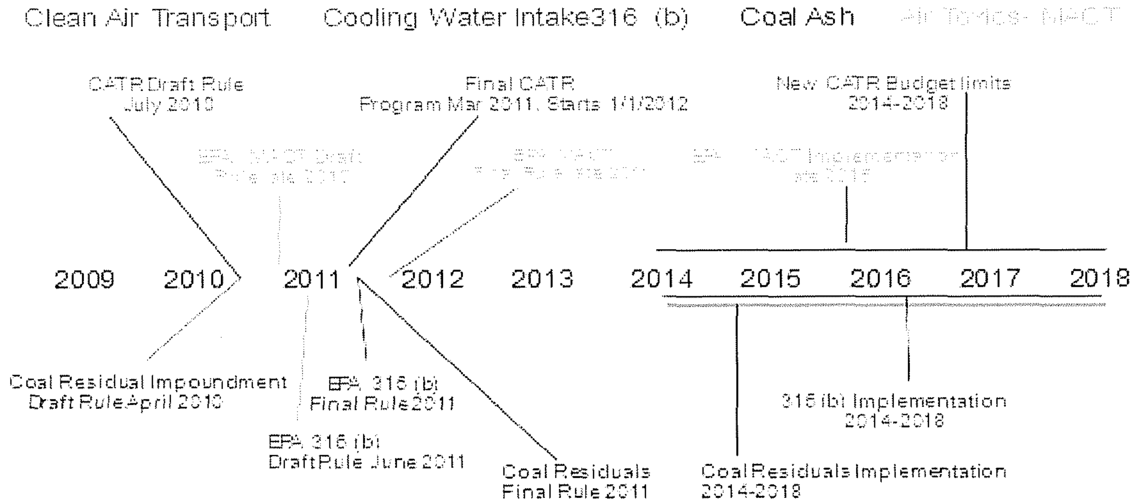
Furthermore, EPA is also considering a potential modification to the subtitle D option, called "D prime." Under the "D prime" option, existing surface impoundments would not have to close or install composite liners but could continue to operate for their useful life. Also in the "D prime" option, the other elements of the subtitle D option would remain the same. However, because no proposal has been made, this option is not included.

Timeline for Potential EPA Regulations

EPA has some flexibility in setting its compliance schedule for all potential rules except MACT (see Figure 1). Based upon current EPA schedules and historic implementation deadlines, EPA's air and solid waste regulations will likely be finalized by the end of 2011 with full compliance being anticipated by 2015–2016. The 316(b) water regulations are expected to be finalized in July 2012. It is anticipated that at least five years will be provided for compliance.

The overlapping compliance schedules for the air and solid waste regulations, along with required compliance for rule 316(b) following shortly thereafter, may trigger a large influx of environmental construction projects at the same time as new replacement generating capacity is needed. Such a large construction increase could cause potential bottlenecks and delays in engineering, permitting and construction. The risk of project delay increases if EPA decides on a compressed compliance schedule. The timing for scheduling unit outages to tie-in the environmental equipment becomes critical. Further, demand for critical equipment and supplies could potentially exceed production capacity and result in shortages and price escalations. However, surveys of labor or manufacturing were not conducted beyond the 25 percent cost increase in the Strict Case in this assessment.

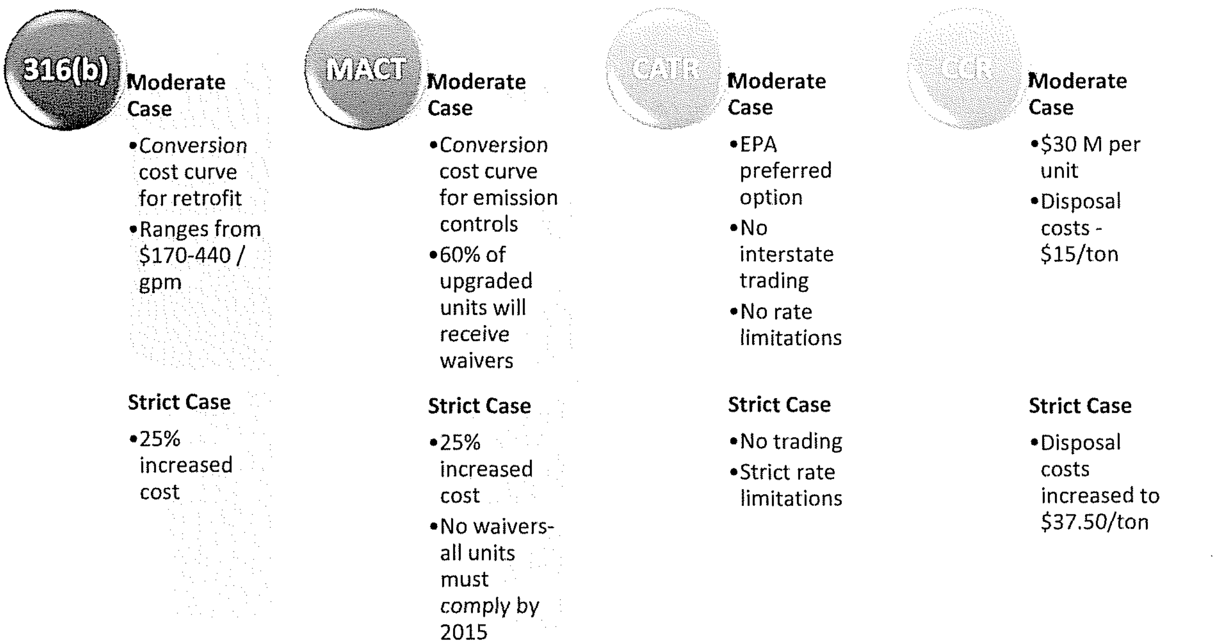
Figure 1: Timeline for Potential U.S. EPA Regulations Impacting the Electric Industry



Reliability Assessment Design

This reliability assessment used a plant-by-plant assessment. The cost factors for each unit were generic, based on its size and location and did not include engineering-level cost factors. Potential retirements and Planning Reserve Margin impacts are assessed for two cases (Moderate Case and Strict Case), for three different years (2013, 2015 and 2018), and for each regulation individually. The Combined EPA Regulation Scenario reflects the effects of the outcomes from the individual regulation cases working in aggregate. The Moderate Case assumes the costs as identified in *Appendix I: Assessment Methods and Appendix II: Environmental Regulations*. The Strict Case scenarios reflect the coupled effects of a higher increase in costs with more stringent requirements for the proposed rules. As the EPA proposed rules are not yet final, the Moderate Case and the Strict Case require expert judgment and sound assumptions on potential outcomes of the potential EPA rules.

Figure 2: Differences in Scenario Cases



In this reliability assessment, "economically vulnerable" generation capacity identifies units that would retire because of a specific potential environmental regulation. Unit retirement is assumed when the generic required cost of compliance with the proposed environmental regulation exceeds the cost of replacement power. In some cases, the costs imposed by the potential EPA regulations may cause "accelerated" or "early" retirement of unit generation capacity for an unknown time period. For the purpose of this assessment, replacement power costs were based on new natural gas generation capacity.[14] If the unit's retrofit costs are less than the cost of replacement power, then the unit is marked to be upgraded and retrofitted to meet the requirements of the potential environmental regulation, *i.e.*, it is not considered "economically vulnerable" for retirement. More discussion of the approach can be found in *Appendix I, Assessment Methods*.[15]

The assessment does not examine the possibility that the industry may be unable to meet its tight compliance deadlines. The Strict Case for 316(b) and MACT imposes a 25 percent cost increase to account for potential impacts if industry is unable to engineer, permit, build, or finance required retrofit environmental controls within the tight EPA compliance periods. Should multiple regulations phase-in simultaneously, replacement generation projects may encounter scheduling difficulties and scheduled retrofits may not be completed before deadlines. Where timing issues exist, waivers and extensions may be needed in order to complete a retrofit project instead of retiring the plant.

The assessment develops compliance costs based upon current average retrofit costs with existing technology market conditions. It does not assess the compliance cost risk from a run-up in labor and/or material costs caused by a construction boom from environmental control and replacement power projects. By applying average retrofit control costs by size in lieu of a detail engineering study, capital retrofit costs may be underestimated for sites with design, tight physical footprint and/or poor geologic considerations.[16]

This reliability assessment focused on measuring the potential resource implications through impacts on Planning Reserve Margins and identification of Regions/subregions where additional Regional resources may be required. The reference case for this study is based on resource projections contained in NERC's 2009 *Long-Term Reliability Assessment.*[17]

The impacts of potential EPA regulations may also have second tier effects on reliability, beyond resource adequacy. Resource deliverability, outage scheduling/construction constraints, local pockets of retirements, and transmission needs may also affect bulk power system reliability. While these issues were not studied in this assessment, the industry will need to resolve these concerns.

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[14] The model does not consider potential natural gas price fluctuations.

[15] Using a different retirement method may produce different results. For instance, assessing generation on future asset performance may potentially increase the amount of capacity 'vulnerable' to retirement when economics are unprofitable, depending on the model input assumptions.

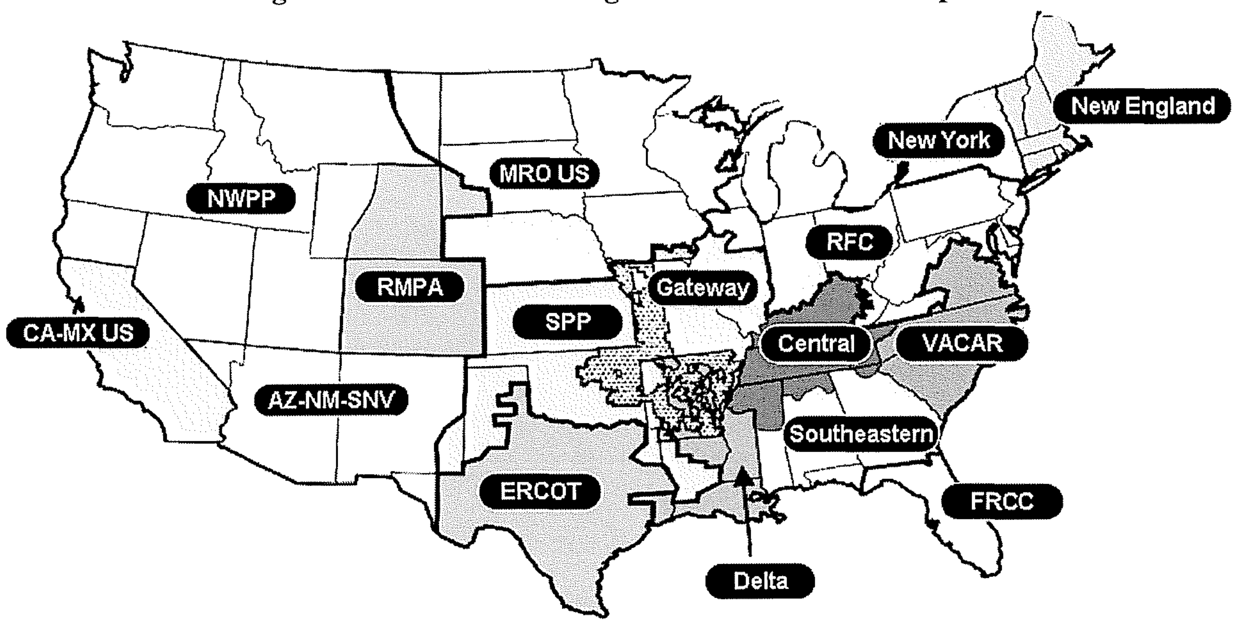
[16] This assessment did not include implementation. Because the compliance deadlines are short, generation owners may be challenged to engineer, permit, finance and build all required retrofit environmental controls within the proposed compliance periods. This may be especially challenging due to the phase-in of multiple regulations simultaneously. Further, some generation replacement projects also face similar risk of scheduling difficulties and may shutdown awaiting control completion, unless EPA grants waivers.

[17] http://www.nerc.com/files/2009_LTRA.pdf

The assessment objectives were:

1. identify potential future outcomes of EPA's active rulemaking for each of the Clean Water Act Section 316(b),[18,19] CCR, CATR, MACT and other air toxics individually and in aggregate (Combined EPA Regulation Scenario);
2. quantify and project impacts on Planning Reserve Margins for two sensitivity cases (Moderate Case and Strict Case) for each regulation (Clean Water Act Section 316(b), CCR, CATR, MACT and other air toxics), as well as their combined projected impacts for the years 2013, 2015, and 2018;
3. examine the impacts of potential unit retirement on future Regional reliability. Specifically, assess the impacts on Planning Reserve Margins to measure the relative impacts to resource adequacy across NERC Regions and Subregions (see Figure 3); and
4. provide the results to NERC's stakeholders, industry leaders, policymakers, regulators, and the public.

Figure 3: NERC US Subregions Assessed in this Report



Cost factors affect generating units as a "snapshot" in time, requiring unit operators to make the decision to finance retrofits for existing units or retire the units, replacing them with natural gas generation. Units "retire" if there are more economical replacement power alternatives available for compliance. Therefore, modeled years illustrate the scope of the U.S. bulk power industry that may be affected and the magnitude of attention required for nationwide compliance.

[18] http://www.nerc.com/files/NERC_SRA-Retrofit_of_Once-Through_Generation_090908.pdf

[19] DOE provided NERC a listing of vulnerable units (totaling approximately 240 GW). This information was supplemented by identifying those units that were expected to retire during the study timeframe, along with permitting dates. NERC reviewed the impact of either retrofitting units with existing once-through-cooling systems to closed-loop cooling systems (4 percent reduction in nameplate capacity) or unit retirements (capacity factors less than 35 percent) on NERC-U.S. and Regional capacity margins for 2012-2015.

Summary of Assumptions Used in This Report

The approach used in this assessment assumes that there are only two basic choices to consider when complying with the potential EPA regulations. The two choices are:

1. retrofit the generation unit and continue operations; or
2. retire the generation unit and replace it with a natural gas unit,

It was beyond the scope of this assessment to complete in-depth, individual plant assessment using site-specific cost factors to comply with each of the proposed EPA regulations. NERC contracted Energy Ventures Analysis Inc. (EVA)[20] to model potential reliability impacts. This model does not consider Planning Reserve Margin commitments, reliability-must-run conditions or transmission constraints. Instead, the model applied generic cost factors related to unit size and location to each unit as it was assessed. An economic approach is used that identifies which units may retire if the generic required cost of compliance with the proposed environmental regulation exceeds the cost of replacement power. As mentioned before, replacement power was considered to be gas-fired capacity. A more detailed discussion of the approach can be found in *Appendix I: Assessment Methods of This Report*.[21]

This assessment does not examine the additional impacts of adopting future greenhouse gas (GHG) control legislation, or other Clean Air Act requirements, including NAAQS, Regional haze/visibility, and GHG regulation,[22] national renewable portfolio standards, or other future EPA environmental rules that may lead to carbon reduction requirements. In practice, however, power suppliers are likely to consider the additional risk from uncertain future actions/rules in the U.S., such as future CO_2 legislation, when making plant investment decisions. Depending on how power suppliers quantify these risks, unit retirements may be higher than those projected in this assessment. Additionally, the report did not address any other climate change legislation.

Other assumptions affecting this reliability assessment include the following:

- Excludes plant retirements already committed or announced (13 GW) and excludes generation units not included in the NERC *2009 Long Term Reliability Assessment*[23] published in October 2009 (15 GW). Together these are equal to nearly 28 GW of capacity. These units were not included in this assessment because these units are not relied on to meet resource adequacy requirements nor do they have capacity

[20] EVA is contracted by domestic and international power producers, transportation companies, energy marketing companies and traders, industry organizations, etc.
http://evainc.com/

[21] Ibid. 11

[22] The analysis also did not address National Ambient Air Quality Standards (NAAQS) [June 2010 1-hour sulfur dioxide standard, February 2010 1-hour nitrogen dioxide standard, October 2010 revised 8-hour ozone standards (primary and possibly secondary), November 2011 revised particulate matter standards (primary and possibly secondary), the mid-2012 Transport Rule II following the October 2010 revised ozone standards, and the 2013 Transport Rule III following the November 2011 revised particulate matter standards], which could all force compliance actions by approximately 2015. The analysis also did not address regional haze. The Best Available Retrofit Technology (BART) controls in regional haze State Implementation Plans may be implemented could be required around 2015-16. The analysis did not address GHG regulation under the Clean Air Act, which will proceed in 2011 for new sources and modified sources. In step 1, starting on January 2, 2011, for sources subject to permitting for pollutants other than GHGs, new and modified sources emitting 75,000 tons per year (tpy) will be subject to Best Available Control Technology (BACT) requirements. In step 2, from July 2011 through June 2013, all sources above these thresholds – 100,000 tpy for new and 75,000 tpy for modified sources for CO2 - emissions – will be subject to Best Available Control Technology (BACT) requirements.

[23] http://www.nerc.com/files/2009_LTRA.pdf

commitments based on the *2009 Long Term Reliability Assessment.* Therefore, any capacity reduction from these units has already been considered in the *2009 Long Term Reliability Assessment* (reference case). The base generation capacity for each NERC Region/subregion is located in *Appendix III, Capacity Assessed by NERC Subregion.*

- Excludes a detailed assessment of the ability of generation owners to permit, engineer, finance, and build the required environmental controls within the short compliance timeframe. However, implementation will pose a large challenge to the equipment and construction sectors since multiple EPA programs are phased-in over the same timeframe. Compliance costs could escalate beyond the 25 percent increase of the high case (Strict Case), should the EPA require compliance within three years of the final rulemaking dates for some of the proposed rules (*i.e.*, 2014 or 2015). This situation is compounded by the large number of electric generation units that are likely to retrofit environmental controls, as well as from the competition created by replacement generation capacity projects and other heavy U.S. infrastructure projects in other sectors. A potential shortage of skilled construction labor, material shortages, and escalation of compliance costs could present challenges to meet the compressed time schedule.

- Compliance costs (capital, O&M and performance changes) are based upon current average retrofit costs with existing technology. The assessment does not evaluate the compliance cost increases resulting from a run-up in labor and material costs caused by demand increase for environmental control and replacement power projects. By applying average retrofit control costs by size in lieu of a detailed engineering study, capital retrofit costs may also underestimate the cost for sites with design, tight layout and/or poor geologic considerations. The assessment also assumes that each unit must make a decision on whether or not to retrofit with environmental controls. For example, if a plant has two units, the cost of two SCRs are used, not just one, as this is the most reliable option.

- Increased CCR disposal costs can vary widely based upon land availability, geology, and state disposal permit requirements. In this assessment, an EPA assumption of onsite disposal is adopted, and the EPA calculated disposal costs are similar to those employed. However, if onsite disposal were prohibited, the plant would incur additional costs to transport the ash and residuals to a properly permitted landfill. These costs could be significant, but cannot be estimated without a site-specific assessment. For these reasons, sensitivity comparisons were completed for CCR disposal costs.

- Power suppliers will need to bring their units offline to interconnect their new or retrofitted environmental controls. During these periods, suppliers will lose potential revenues and require use of replacement power. While the capital and O&M costs are incorporated into the compliance decision criteria, the replacement purchased power costs during these integration shutdowns have not been included and are unlikely to change or accelerate unit retirement decisions. However, these impacts would have the greatest effect on the nuclear plants that would incur the largest replacement power costs due to the duration of the retrofit outage.

- For retrofit of once-through-water cooling units, all nuclear plants are assumed to become exempted,[24] be subjected to alternative requirements as in the case of California's two operating nuclear plants,[25] or will be able to make the required investments due to the characteristics[26] of nuclear generation versus traditional fossil-fired generation.[27] Therefore, this assessment does not include any derate effects for nuclear capacity from Section 316(b). However, the maximum loss of capacity due to derate is estimated to be about 1.8 GW due to retrofit. Should 316(b) cause nuclear unit retirement, additional generation capacity loss may result.

- Generating units identified in this assessment may choose to wait until immediately prior to the compliance deadline before retiring the generation unit. This ability to delay retirement may act as a binary option causing many units to retire on December 31 prior to a January 1 deadline, and in some cases, may wait until January 1, 2018. The assumptions used for decision-making timing in this study are described in the *Some Unit Retirements Spread Through Time* section.

- All combined-cycle plants are assumed to make required investments to avoid being forced into early retirement. This may not be the case. For MACT, oil-fired units are assumed to meet emission limits through availability of suitable quality specifications of refined oil products.

- The assessment excludes any fossil-fuel market price or supply risks that are created by a large shift in the power generation mix from environmental compliance measures (*e.g.*, a shift from coal to natural gas fuel). Delivered natural gas and coal prices are fixed and do not change based on the level of retirements or the level of new replacement capacity that may be required.

- If a coal plant is retired under this method, there is nothing to prevent a secondary, after-the-fact decision. For instance, a coal unit may convert into a biomass-based unit, or convert to natural gas burners and continue operating as a steam plant. In addition, plant owners may decide to invest in construction at existing construction sites after retirement. Such decisions are beyond the scope of this assessment.

- The assessment did not examine or model the use of other sorbent injection technologies (*e.g.,* trona) as an alternative. For trona, capital costs would be lower, but higher operating costs would result. Limestone scrubbers are the norm in the United States, although, this technology has been used at older plants where owners did not want to make the larger capital investment. Further, while some future plants may opt for trona vs. a limestone scrubber, a majority of plants (greater than 97 percent) will use limestone.

- Delivered natural gas, coal and oil prices were based on the forecasts of EVA as of May 2010. Ten-year forward averages are applied for 2013, 2015 and 2018. Varying these price assumptions may produce different results. The base wholesale fuel price forecasts are depicted in Figure 4 on an undelivered basis.

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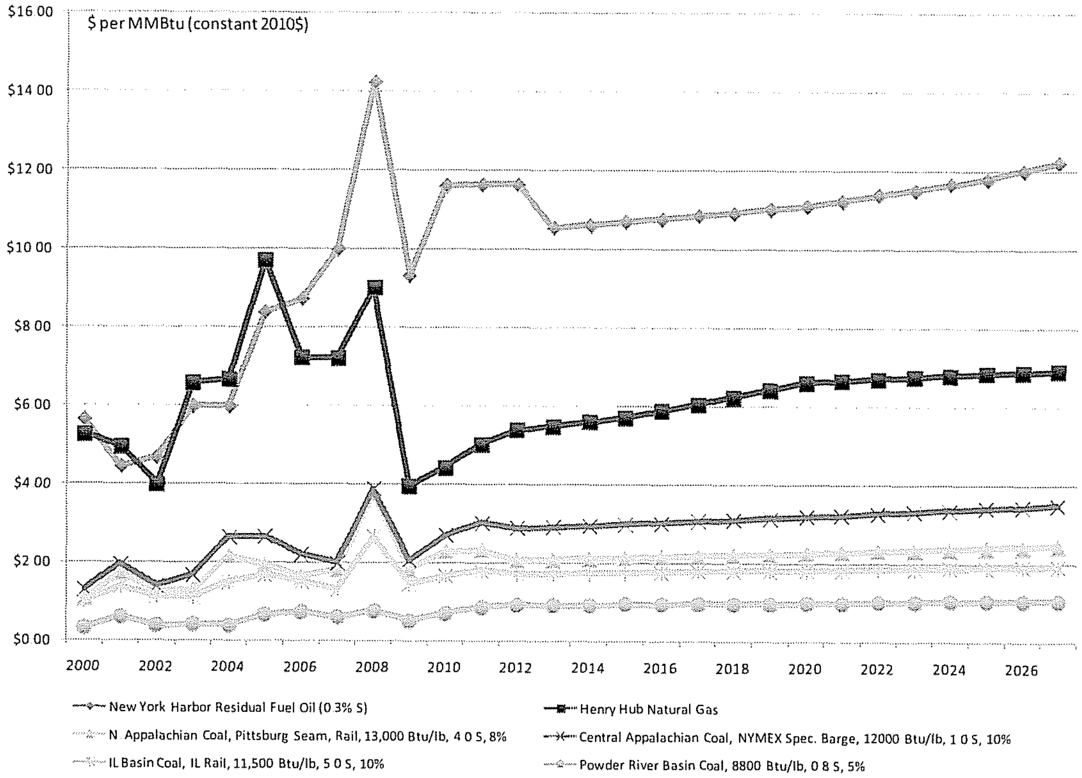
[24] http://www.snl.com/InteractiveX/article.aspx?CDID=A-10616386-10806&KPLT=2
[25] http://www.swrcb.ca.gov/water_issues/programs/npdes/docs/cwa316may2010/otcpolicy_final050410.pdf
[26] *e.g.*, Lower GHG emissions, longer in-service operations, higher availability, baseload resource
[27] DOE, 2008 http://www.oe.energy.gov/DocumentsandMedia/Cooling_Tower_Report.pdf

Figure 4: Wholesale Fuel Price Assumptions Used for This Assessment



S=Sulfur Content

Some Unit Retirements Spread Through Time

Because the implementation of multiple EPA regulations is tightly stacked through time, a large number of retirements may occur in the same year, requiring new resources to offset the capacity reductions. To simulate a more realistic and expected outcome, in certain instances, some of the retirement and waivers were simulated earlier in time, rather than reflecting all retirements in one year, such as in 2015 or 2018, depending on the regulation. These results are included in the scenario of the four potential regulations. In addition:

- **Section 316(b) and Coal Combustion Residuals:** As the EPA implementation deadlines are expected to be January 1, 2018, no units theoretically would need to be retired until 2018. However, this assessment assumes that 20 percent of designated units are retired in each year from 2013 through 2017 for the Moderate Case and the Strict Case. To select which individual units are simulated to retire, each designated plant's economics are ranked from the most expensive to least expensive production costs. The units with the most expensive plant costs were retired first for Section 316(b) and CCR. Conversely, the units with the lowest cost plant economics were upgraded first.

- **MACT:** For the Moderate Case only, 60 percent of units that are designated to upgrade environmental controls by 2015 receive waivers as of January 1, 2015. The most expensive 20 percent of units are retired by 2014 (no effects as of January 1, 2013), and then the next most expensive 20 percent of units are retired by 2015. Also conversely, the units with the lowest cost plant economics are upgraded first when the highest cost plants are retired.

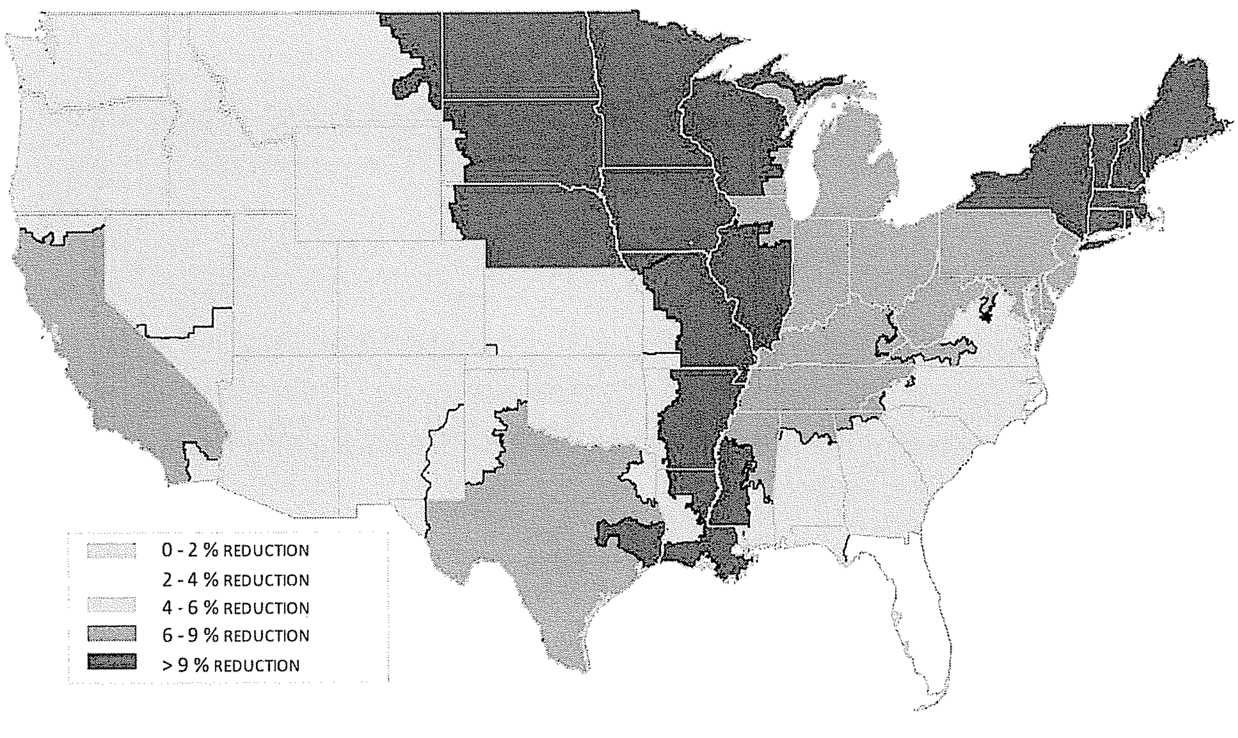
- **CATR:** The Strict Case simulated the highest 40 percent of units were retired by 2013 and the 40 lowest cost units were retrofitted by 2013.

Scenario Results

U.S. power suppliers will assess the impact of all future environmental requirements when making their environmental compliance decisions. Even in the absence of future GHG legislation, the combination of the four potential EPA rules may have significant economic impacts on generating units, potentially affecting the reliability of bulk power system as measured by significant declines in Planning Reserve Margins. Based on the design of this assessment, the overall total compliance cost impact would place between 40 and 69 GW of existing capacity (441-761 units) as "economically vulnerable" for accelerated retirement due to more cost efficient compliance alternatives by 2018. On-site stations loads for equipment operation derate the net generating capacity of the retrofitted units by 6.7-7.4 GW. The overall affect would be a total of 46-76 GW of capacity reductions significantly affecting Planning Reserve Margins if no additional resources are built beyond what is included in the *2009 NERC Long-Term Reliability Assessment* plans (see Figure 5). In many Regions/subregions, Planning Reserve Margins fall below the NERC Reference Margin Level, indicating the need for more resources.

The potential retirement and deratings affect resource portfolios in all eight NERC Regions, but especially in the ERCOT, MRO, NPCC, SERC, and NPCC Regions. The most significant individual impacts are due to the Section 316(b) regulation, then MACT, CATR and finally CCR. However, the Combined EPA Regulation Scenario has the greatest impact to reliability.

Figure 5: 2018 Reduction in Adjusted Potential Capacity Resources due to the Combined EPA Regulation Scenario



Scenario Results

Section 316(b) Cooling Water Intake Structures

In the Moderate Case scenario, the Section 316(b) rule alone could potentially increase the unit production costs above replacement power costs at 347 stations, retiring 33 GW of current generating capacity. This retired generating capacity was spread across the rule implementation period (2014-2018). The majority of the "economically vulnerable" units are older oil/gas steam units (253 units with 30 GW of capacity). An additional 94 coal steam units (capacity of 2.5 GW) are also "economically vulnerable". The remaining 688 would also incur a five GW capacity derating to support increases in station loads. Table 1 shows how these retirements and capacity derating penalties affect the NERC subregions for the year 2015 while 2018 impacts are shown in Table 2. For this assessment, no units were affected in 2013. As shown, SERC-Delta, RFC, WECC-CA, and ERCOT account for 65 percent of the unit retirements.

Table 1: 316(b) Impacts - 2015

	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	187	556	743	187	752	939
FRCC	69	68	137	69	68	137
MRO	340	450	789	338	479	817
NPCC-NE	0	1,061	1,061	0	1,061	1,061
NPCC-NY	22	958	980	22	958	980
RFC	988	763	1,751	954	763	1,717
SERC-Central	275	0	275	275	0	275
SERC-Delta	82	1,774	1,856	82	1,774	1,856
SERC-Gateway	288	266	555	288	266	555
SERC-Southeastern	60	224	284	52	224	276
SERC-VACAR	101	92	193	120	92	212
SPP	113	501	614	113	531	644
WECC-CA	0	786	786	0	786	786
WECC-AZ-NM-SNV	0	24	24	0	25	25
WECC-NWPP	36	39	75	36	39	75
WECC-RMPA	13	36	49	13	64	77
TOTAL	2,575	7,597	10,172	2,551	7,881	10,432

Should the cooling tower conversion costs be 25 percent higher than prior engineering studies indicated ($300/gpm versus $240/gpm), an additional 17 units (four GW) could retire resulting in a total of 37 GW.

Section 316(b) marginally affects coal units in comparison to its effects on oil/gas steam units (*i.e.*, 92–93 percent of capacity). In the Strict Case, most of the incremental retirements are older oil/gas steam units located in WECC-CA, NPCC, SERC-Delta, ERCOT, and RFC, ranked from highest to lowest. For the coal units, most "economically vulnerable" capacity is in RFC. The "economically vulnerable" capacity in the Strict Case is 12 percent greater than in the Moderate Case.

Table 2: 316(b) Impacts - 2018

	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	322	5,055	5,377	316	5,295	5,611
FRCC	177	862	1,039	164	1,367	1,531
MRO	400	1,259	1,659	400	1,264	1,664
NPCC-NE	194	2,504	2,698	180	2,904	3,084
NPCC-NY	347	3,011	3,357	327	3,618	3,946
RFC	1,532	5,503	7,035	1,526	5,661	7,187
SERC-Central	388	71	459	388	71	459
SERC-Delta	282	5,524	5,806	282	5,524	5,806
SERC-Gateway	296	526	822	295	543	838
SERC-Southeastern	209	469	678	209	469	678
SERC-VACAR	378	664	1,042	377	689	1,066
SPP	143	933	1,076	141	994	1,135
WECC-CA	227	5,055	5,283	182	6,881	7,063
WECC-AZ-NM-SNV	5	773	778	5	773	778
WECC-NWPP	40	129	169	40	129	169
WECC-RMPA	16	184	200	16	184	200
TOTAL	4,954	32,522	37,476	4,848	36,366	41,214

These estimates are slightly less, but comparable, to the October 2008 DOE study, *Electricity Reliability Impacts of a Mandatory Cooling Tower Rule for Existing Steam Generating Units* that resulted in approximately 40 GW of potential retirements. Some differences may be attributable to this study excluding more already announced generating unit retirements (more than 28 GW) and incorporating a more comprehensive retirement replacement cost method (versus applying a capacity factor criterion).

National Emissions Standards for Hazardous Pollutants (NESHAP) or Maximum Achievable Control Technology (MACT)

National Emissions Standards for Hazardous Pollutants (NESHAP) or Maximum Achievable Control Technology (MACT) will apply to all existing and future coal and oil fired steam capacity. The Moderate Case scenario rulemaking varies for MACT emission rate limitations by coal type. This assessment assumes that the EPA deadline is January 1, 2015. However, in the Moderate Case, only 40 percent of units that will eventually retire do so by January 1, 2015. As EPA has no authority under the Clean Air Act to grant waivers for a MACT standard, one of these two[28] conditions must occur:

- the EPA Administrator (or state with program approval) grants an extension of one additional year, finding more time is "necessary for the installation of controls"–§112(i)(3)(B). This may occur on a case-by-case basis; or

- a Presidential exemption for a period of not more than two years is granted, assuming the President finds (1) the technology to implement such standard is not available and (2) it is in the national security interests to do so. Additional one year extensions are also available –§112(i)(4).

The Moderate Case outcome is that there are no forced retirements as of January 1, 2013. Twenty percent of units retire by January 1, 2014, reaching 40 percent of units retired by January 1, 2015 followed by an additional 20 percent in each subsequent year, such that all designated units are retired by January 1, 2018. In 2015, the impact of the Moderate Case is roughly 2.1 GW of existing coal-fired capacity (59 units) "economically vulnerable" for retirement; another 0.8 GW may be derated. The figure triples by 2018 to 6.6 GW of coal capacity that may be retired and 1.8 GW derated for a total impact of 8.4 GW.

The Strict Case assumes that no waivers are granted and all electric generation units must be in compliance by January 1, 2015. Obtaining these waivers appears difficult; the EPA granted a sector-wide extension of one year only once, in a marine MACT rule. The Strict Case also assumes that all retirements occur in the two years leading up to the deadline, *i.e.*, during 2013 and 2014, with none as of January 1, 2013. The Strict Case also increases compliance costs by 25 percent. These two assumptions significantly change the assessment results, such that by 2015 there is 14.9 GW of existing coal-fired capacity (228 units) "economically vulnerable" for early retirement and 2.8 GW derated for a total of 17.6 GW. The 2015 result carries over into 2018.

MACT depicts the greatest variation between the two cases of all the EPA regulations. There is a 12 GW difference in capacity loss between the Moderate Case and the Strict Case by 2015. There is a nine GW difference by 2018. Distribution of this capacity by Region/subregion for 2015 and 2018 are shown in Table 3 and Table 4.

[28] Under section 202(c) of the Federal Power Act, the Secretary of Energy has authority when an emergency exists "by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes," to order such temporary interconnection of facilities or generation, delivery, interchange, or transmission of electric energy as in his/her judgment "will best meet the emergency and serve the public interest." However, section 202(c) does not specifically mention EPA or the Clean Air Act.

Table 3: MACT Impacts - 2015	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	73	0	73	73	0	73
FRCC	0	0	0	78	121	199
MRO	125	202	327	144	764	908
NPCC-NE	0	0	0	32	616	647
NPCC-NY	0	0	0	16	694	710
RFC	103	1,061	1,164	1,060	5,493	6,553
SERC-Central	61	71	132	305	1,000	1,305
SERC-Delta	69	18	87	69	95	164
SERC-Gateway	84	35	119	110	365	475
SERC-Southeastern	33	140	173	337	1,208	1,545
SERC-VACAR	0	465	465	255	2,649	2,905
SPP	127	0	127	130	52	181
WECC-CA	0	0	0	3	0	3
WECC-AZ-NM-SNV	49	0	49	49	1,580	1,629
WECC-NWPP	72	39	111	73	129	202
WECC-RMPA	10	0	10	10	100	110
TOTAL	806	2,032	2,838	2,746	14,865	17,611

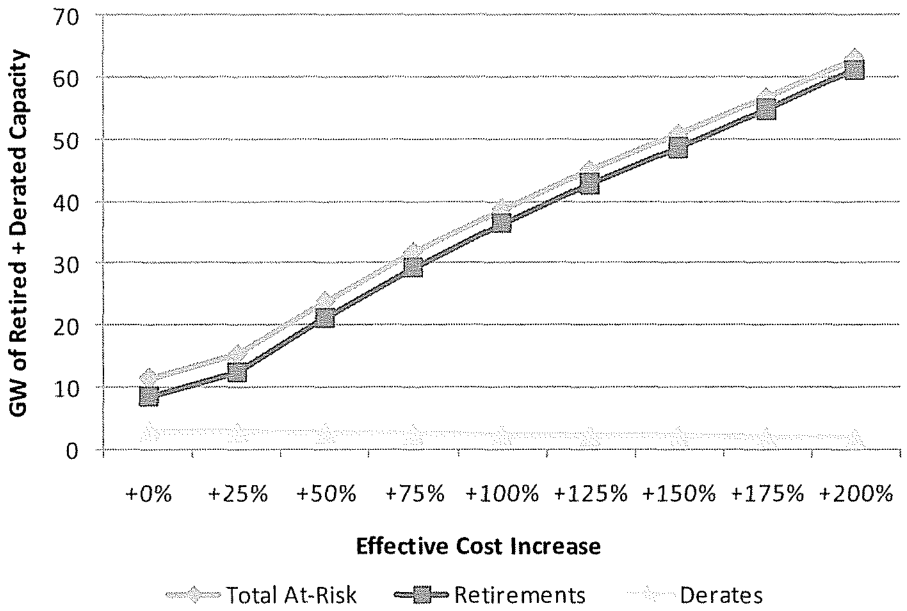
Table 4: MACT Impacts - 2018	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	73	0	73	73	0	73
FRCC	16	0	16	78	121	199
MRO	144	708	853	144	764	908
NPCC-NE	25	0	25	32	616	647
NPCC-NY	16	58	74	16	694	710
RFC	514	2,540	3,055	1,060	5,493	6,553
SERC-Central	167	184	351	305	1,000	1,305
SERC-Delta	70	46	116	69	95	164
SERC-Gateway	100	96	196	110	365	475
SERC-Southeastern	227	140	367	337	1,208	1,545
SERC-VACAR	132	970	1,102	255	2,649	2,905
SPP	130	52	181	130	52	181
WECC-CA	3	0	3	3	0	3
WECC-AZ-NM-SNV	49	1,580	1,629	49	1,580	1,629
WECC-NWPP	73	129	202	73	129	202
WECC-RMPA	10	100	110	10	100	110
TOTAL	1,750	6,602	8,352	2,746	14,865	17,611

Scenario Results

The impacts could be more severe if costs escalate due to tighter implementation timelines of three years and the large number of plants (840 units) that may need to upgrade their environmental controls at the same time. This could require additional new generation and expanded use of existing lower emission generation like natural gas. In circumstances in which power plant retirements trigger localized reliability concerns, EPA can follow established precedent, including use of consent decrees, to permit continued operation for reliability purposes only, pending necessary upgrades or generation additions.

A sensitivity comparison was completed for the 2015 Strict Case for MACT accounting for the compressed implementation timeline (see Figure 6). The risk that generation units will retire simply due to insufficiently available third party engineering services is not modeled in the sensitivity test. Because the 2015 Strict Case already includes a 25 percent cost premium, the sensitivity comparisons were completed at cost increase intervals of 25 percent from 0 percent up to 200 percent. As a result, retirements increased at an approximate linear rate from a low of 11.4 GW (retirements of 8.5 GW and derated capacity of 2.9 GW) at no cost increase up to 63 GW (retirements of 61.2 GW and derated capacity of 1.8 GW) at a 200 percent cost increase.

Figure 6: Sensitivity of Retirements Plus Derated Capacity as a Function of Higher Assumed Costs due to the MACT Regulation



Clean Air Transport Rule (CATR)

Starting in 2012, the CATR will apply to fossil fuel units with greater than 25 MW capacity that are located in 31 states. Although EPA provided three different options in July 2010, the EPA preferred option was selected for the Moderate Case. An analysis of this option found that the rule would have the greatest impact in the state utilities that relied heavily upon purchased allowances for compliance with their Acid Rain program and CAIR program obligations. By significantly limiting the use of out-of-state utility purchases and/or banked allowances after 2013, some utilities would be forced to retrofit FGD and SCR emission controls on their larger units or retire to comply. The oil and gas steam units would remain largely untouched because of their limited emissions. As described earlier in this report, these reductions would be concentrated to a few states.

The extent of retirements triggered by CATR is heavily linked to:

1. the flexibility provided to affected sources to avoid reductions in smaller emitting stations by retrofitting controls in larger emitting units (through allowance trading); and
2. the final budget state cap (the July 2010 draft emission caps are interim limits that will be reduced further as stricter future ambient fine particulate and ozone standards are adopted). The EPA preferred option (Moderate Case) would result in the retirement of five coal-fired units (538 MW) by 2013 and 18 coal-fired units (2,740 MW) by 2015 (see Tables 5 and 6).[29]

Table 5: CATR Impacts - 2013

	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	0	0	0	64	0	64
FRCC	0	0	0	4	0	4
MRO	0	0	0	162	155	318
NPCC-NE	0	162	162	1	0	1
NPCC-NY	0	0	0	0	0	0
RFC	1	376	377	191	781	972
SERC-Central	11	0	11	87	71	158
SERC-Delta	0	0	0	99	29	128
SERC-Gateway	0	0	0	94	35	129
SERC-Southeastern	5	0	5	145	130	275
SERC-VACAR	0	0	0	47	548	594
SPP	0	0	0	110	26	136
WECC-CA	0	0	0	0	0	0
WECC-AZ-NM-SNV	0	0	0	0	0	0
WECC-NWPP	0	0	0	0	0	0
WECC-RMPA	0	0	0	0	0	0
TOTAL	17	538	555	1,004	1,775	2,779

[29] Impacts from CATR would begin in 2014. For this report, only 2013, 2015, and 2018 were assessed.

Alternatively, EPA could elect to pursue emission rate limitations on the coal-fired units. This approach would provide no ability to trade at all and units would be forced to retrofit the needed controls or retire. With the impending changes in NAAQS unknown, the Strict Case assumes that EPA will adopt much stricter rate limits on all coal-fired capacity that only can be met through post combustion controls. Given the large demand created for emission controls, the capital cost will likely increase by 25 percent or more from current levels. Overall, 86 coal units (5,221 MW) would have their operating costs pushed above new replacement capacity and force their retirement. Although tied to the changing of the NAAQS, these retirements would likely occur in or before 2015. Further impacts, past 2015, are not expected to materialize.

Table 6: CATR Impacts - 2015

	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	0	0	0	91	0	91
FRCC	0	0	0	16	0	16
MRO	0	33	33	216	1,007	1,223
NPCC-NE	0	162	162	14	370	384
NPCC-NY	0	0	0	22	50	73
RFC	67	1,667	1,734	552	2,192	2,744
SERC-Central	15	0	15	154	136	290
SERC-Delta	0	0	0	127	29	155
SERC-Gateway	0	878	878	171	35	206
SERC-Southeastern	60	0	60	258	230	488
SERC-VACAR	0	0	0	130	1,056	1,186
SPP	0	0	0	202	115	317
WECC-CA	0	0	0	0	0	0
WECC-AZ-NM-SNV	0	0	0	0	0	0
WECC-NWPP	0	0	0	0	0	0
WECC-RMPA	0	0	0	0	0	0
TOTAL	142	2,740	2,882	1,952	5,221	7,173

The analysis affects coal units only and the most significant impact of the Strict Case occurs in RFC, SERC and MRO, which have the most remaining coal plants that require upgrading in the 31 states and the District of Columbia affected by CATR

Coal Combustion Residuals (CCR) Disposal Regulations

A distribution of the coal units "economically vulnerable" from the potential coal combustion byproducts rule is shown in Table 7 for both the Moderate Case and the Strict Case scenarios in 2018. As shown, the additional capital and annual operating cost increases under both scenarios would trigger the retirement of only four coal units with capacity of 287 MW in the Moderate Case and 12 units with capacity of 388 MW in the Strict Case. This "economically vulnerable" coal-fired capacity is located in three to four SERC subregions and MRO. Under the estimated compliance timeline, these coal unit retirements would likely not occur until the 2015—2018 period. A larger number of coal units are affected in the Strict Case, since the Moderate Case affects only those plants using ponds for ash disposal, whereas the Strict Case assumes that all coal plants will need to store coal combustion byproducts in a lined landfill.

Table 7: CCR Impacts - 2018

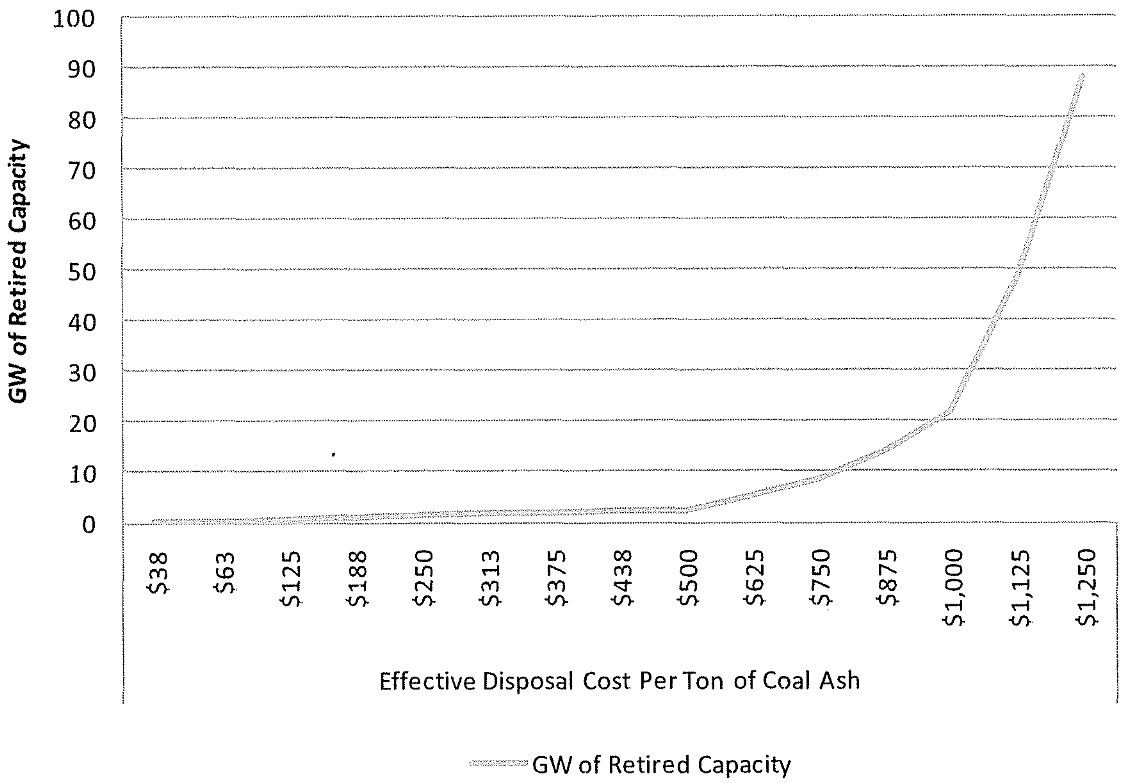
	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	0	0	0	0	0	0
FRCC	0	0	0	0	0	0
MRO	0	0	0	0	83	83
NPCC-NE	0	0	0	0	0	0
NPCC-NY	0	0	0	0	0	0
RFC	0	0	0	0	0	0
SERC-Central	0	71	71	0	71	71
SERC-Delta	0	0	0	0	18	18
SERC-Gateway	0	86	86	0	86	86
SERC-Southeastern	0	130	130	0	130	130
SERC-VACAR	0	0	0	0	0	0
SPP	0	0	0	0	0	0
WECC-CA	0	0	0	0	0	0
WECC-AZ-NM-SNV	0	0	0	0	0	0
WECC-NWPP	0	0	0	0	0	0
WECC-RMPA	0	0	0	0	0	0
TOTAL	0	287	287	0	388	388

These estimates are substantially less than the EOP Group Study titled *Cost Estimates for the Mandatory Closure of Surface Impoundments Used for the Management of Coal Combustion Byproducts at Coal Fired Utilities* that resulted in 35 GW of "economically vulnerable" coal-fired capacity. Some differences are likely to be attributable to this assessment excluding already announced generating unit retirements (more than 28 GW) and incorporating a more comprehensive retirement replacement cost method (versus applying a unit size criterion).

Because of the large difference in results, sensitivity comparisons were conducted to determine how the number of "economically vulnerable" units would vary under higher disposal cost assumptions. Disposal costs can vary significantly based upon suitable land availability and state landfill requirements. Like EPA, this assessment assumed that suitable landfill sites could be found, permitted and operated near to existing coal plants. If no suitable sites can be permitted, power suppliers may be forced to transport their residuals to appropriately permitted offsite landfills and pay tipping fees that could increase disposal costs.

In lieu of conducting site-specific assessment, a sensitivity comparison was completed across a wide range of ash disposal costs from $37.50 up to $1,250 per ton (see Figure 7). The economic retirements slope gradually upward from 0.3 to 2.1 GW as costs increase from $37.50 to $500 per ton, then retirements begin to jump significantly with amounts reaching 22 GW at $1,000 per ton, and exponentially increase to 49 GW at $1,125 and nearly 88 GW at $1,250 per ton. However, the costs are believed to be well contained within the flat slope portion of the line on the far left side. However, the additional costs that may become associated with distance removal of the hazardous substance to existing certified landfills could drive costs upward.

Figure 7: Sensitivity of Retirements as a Function of Higher Assumed Coal-Ash Disposal Costs due to Coal Combustion Residuals regulations



Combined EPA Environmental Rulemaking

The reliability impact of each rule outlined above reflects the cost and retirement decisions for each individually. However, power suppliers will likely make their retirement decisions based upon compliance costs for the combination of all future environmental requirements. Although some environmental control overlap exists between the CATR and MACT (*i.e.*, for FGD and SCR retrofits), most compliance costs are expected to be additive between the different EPA rules.

The cumulative effect of the four potential EPA rules is provided in Tables 8, 9, and 10 for each of the three years assessed. In 2015, anywhere from 31–70 GW of existing fossil fuel capacity (351–678 generation units; beyond the 28 GW of retirements already announced and not included in NERC's Long Term Reliability Assessment) are "economically vulnerable" for retirement from these four potential EPA rules. Additionally the 273–700 units of continuing operation will be derated by a total of 2.4-7.3 GW from the increased parasitic loads from the control operation. The projected retirements are significantly lower in 2013 and significantly higher for the Moderate Case in 2018.

Table 8: Combined EPA Regulations Impacts - 2013

	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	0	0	0	91	0	91
FRCC	0	0	0	16	0	16
MRO	0	0	0	216	1,007	1,223
NPCC-NE	0	162	162	12	532	545
NPCC-NY	0	0	0	19	258	278
RFC	1	376	377	541	2,876	3,418
SERC-Central	11	0	11	153	211	364
SERC-Delta	0	0	0	127	29	155
SERC-Gateway	0	0	0	171	35	206
SERC-Southeastern	5	0	5	258	230	488
SERC-VACAR	0	0	0	128	1,163	1,291
SPP	0	0	0	58	89	147
WECC-CA	0	0	0	144	26	170
WECC-AZ-NM-SNV	0	0	0	0	0	0
WECC-NWPP	0	0	0	0	0	0
WECC-RMPA	0	0	0	0	0	0
TOTAL	17	538	555	1,934	6,457	8,391

For the combined potential EPA rulemaking, the retirement and derating penalties are concentrated in five NERC Regions/subregions for the 2015 Moderate Case -- SERC, NPCC, RFC, ERCOT, and WECC, ranked in order of highest to lowest. For the 2015 Strict Case, the rank order is SERC, RFC, WECC, NPCC, and finally ERCOT.

Scenario Results

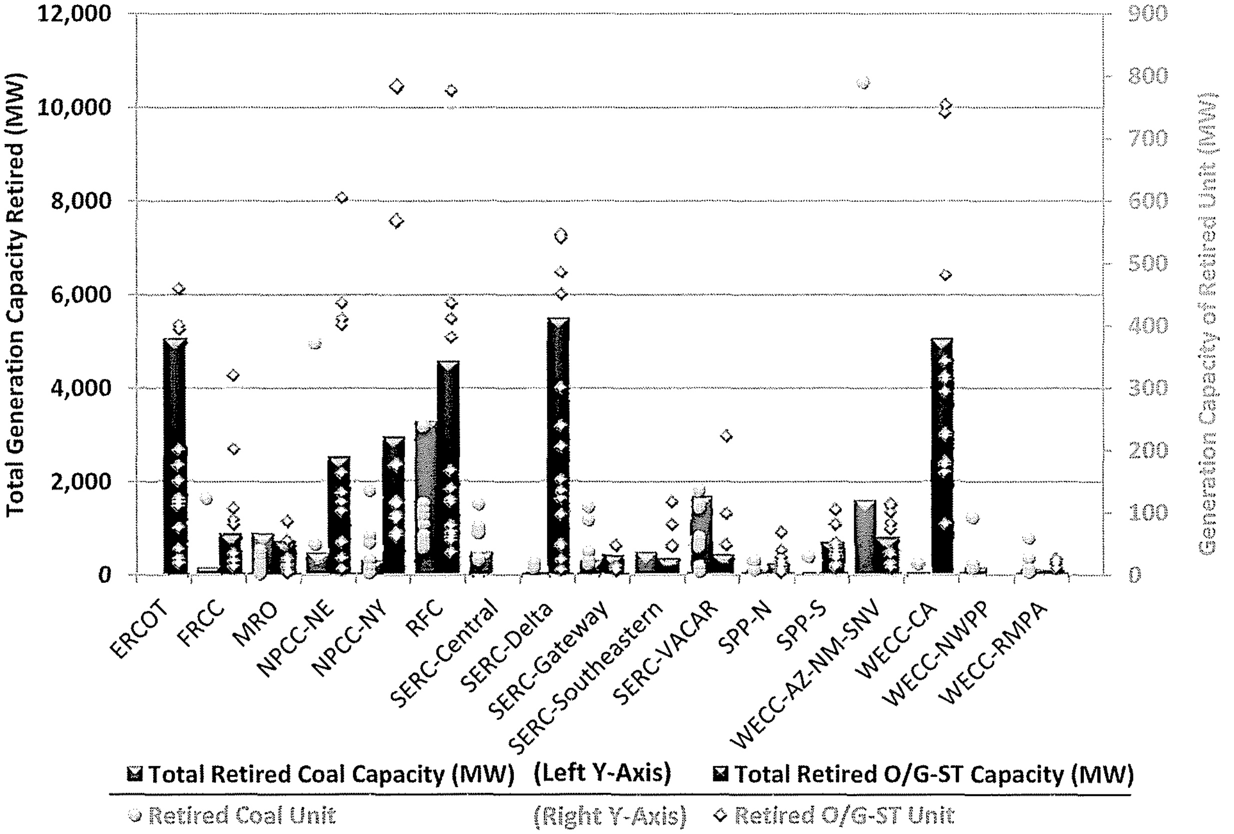
Table 9: Combined EPA Regulations Impacts - 2015						
	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	246	5,055	5,301	480	5,295	5,775
FRCC	71	862	933	239	1,488	1,727
MRO	319	1,259	1,578	612	4,424	5,036
NPCC-NE	0	2,504	2,504	169	3,938	4,107
NPCC-NY	35	3,011	3,046	309	4,759	5,068
RFC	607	4,890	5,497	2,224	16,423	18,648
SERC-Central	237	71	308	509	4,546	5,055
SERC-Delta	113	5,524	5,636	465	5,803	6,268
SERC-Gateway	113	526	639	413	3,902	4,315
SERC-Southeastern	140	469	609	537	3,132	3,669
SERC-VACAR	132	915	1,047	515	5,042	5,557
SPP	198	831	1,029	428	2,149	2,577
WECC-CA	0	3,560	3,560	195	6,452	6,647
WECC-AZ-NM-SNV	49	773	822	54	2,353	2,407
WECC-NWPP	108	129	237	113	129	242
WECC-RMPA	25	184	208	25	225	251
TOTAL	2,394	30,563	32,957	7,289	70,059	77,349

Table 10: Combined EPA Regulations Impacts - 2018						
	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	366	5,055	5,421	480	5,295	5,775
FRCC	188	983	1,171	239	1,488	1,727
MRO	534	1,553	2,087	612	4,424	5,036
NPCC-NE	196	2,970	3,166	169	3,938	4,107
NPCC-NY	353	3,239	3,592	309	4,759	5,068
RFC	1,965	7,848	9,813	2,266	15,451	17,717
SERC-Central	541	445	986	509	4,546	5,055
SERC-Delta	352	5,541	5,892	465	5,803	6,268
SERC-Gateway	390	694	1,084	442	3,299	3,741
SERC-Southeastern	423	781	1,204	537	3,132	3,669
SERC-VACAR	476	2,066	2,542	515	5,042	5,557
SPP	271	972	1,243	428	2,149	2,577
WECC-CA	230	5,055	5,285	182	6,947	7,130
WECC-AZ-NM-SNV	54	2,353	2,407	54	2,353	2,407
WECC-NWPP	113	129	242	113	129	242
WECC-RMPA	27	184	210	25	225	251
TOTAL	6,479	39,867	46,346	7,348	68,979	76,327

This assessment models both coal and oil/gas-steam unit capacity retirement. Figures 8 and 9 depict total capacity loss for both unit types, as well as the size of individual retired units by Region for the 2018 Moderate and Strict Case assessments.

In Figures 8 and 9, each retired unit is plotted on the scatter chart based on unit size (Right Y-Axis). In some cases, data points for units with the same unit size (MW) may overlap and be hidden. The blue and red bars (Left Y-Axis) show the total retired capacity by subregion. Overall, a majority of the retired units are less than 200 MW.

Figure 8: 2018 Moderate Case
Units Retired for Combined Scenario



The Strict Case (see Figure 9) has a significant impact on coal units in the MRO, RFC, SERC-Central, SERC-Gateway, SERC-Southern, and SERC-VACAR Regions/subregions.

Figure 9: 2018 Strict Case
Units Retired for Combined Scenario

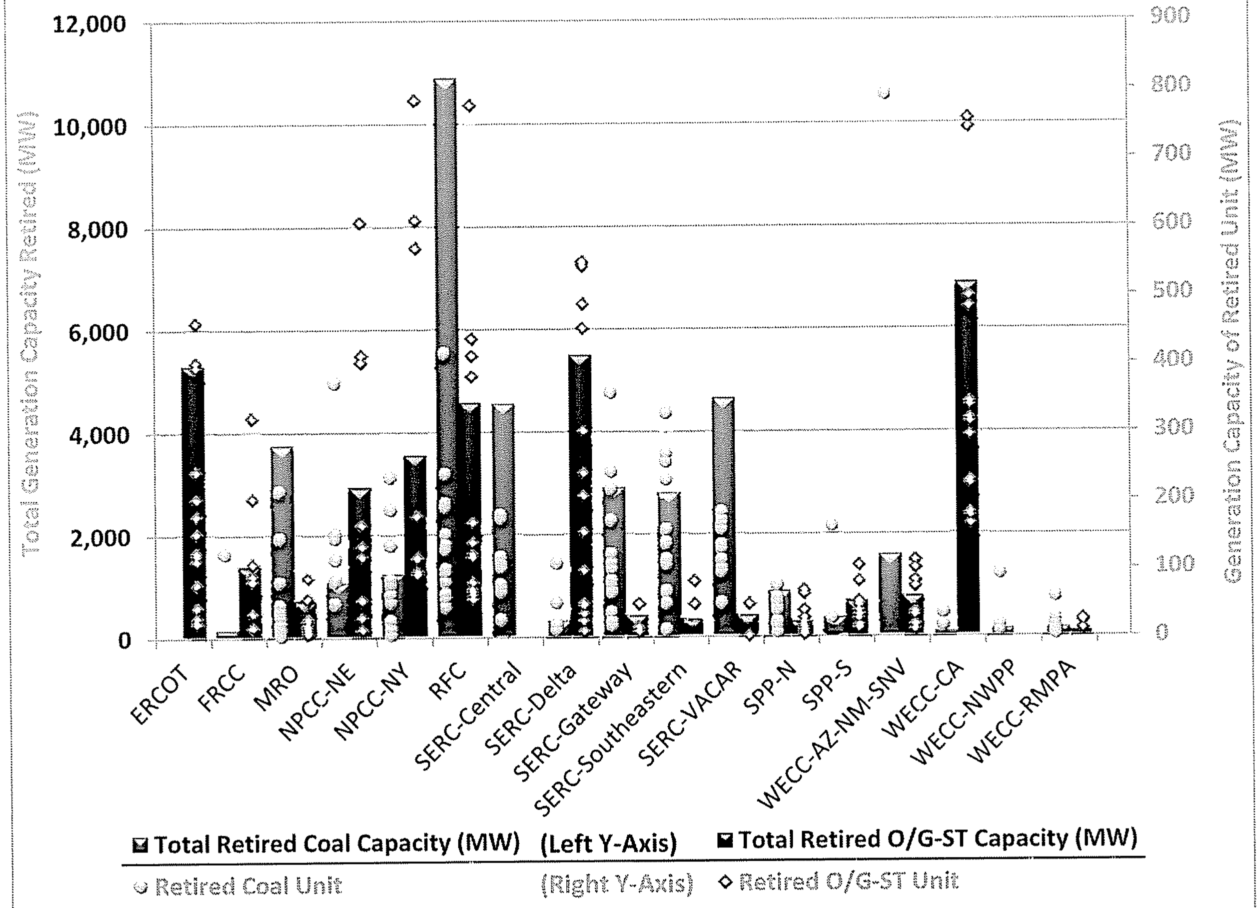
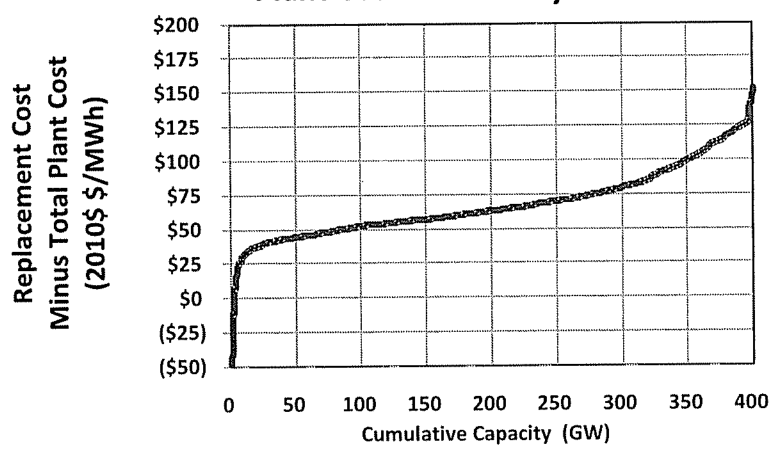


Figure 10 illustrates the model's representation of the differential between two items: the cost of a new gas plant and today's operating/ongoing costs for any new investment that has incremental costs, regardless of its source or mandate.

Figure 10: Replacement Cost Minus
Plant Cost Before Any Retrofits



Reliability Assessment

Impacts on Bulk Power System Adequacy

Early retirement of multiple units in the short-run can stress the bulk power system if plans are not in place to add resources. This can affect both short- and long-term planning strategies and reduce Planning Reserve Margins.[30] Sufficient Planning Reserve Margins must be maintained to provide reliable electric service. With fewer resources, flexibility is reduced and the risk of a capacity shortage may increase, unless additional resources are available. Where Planning Reserve Margins fall below zero, there is a basic inability to serve load with available resources.

For this assessment, NERC studied the effects on Planning Reserve Margins from both unit retirement (assuming retired capacity is not replaced) and retrofits, which cause capacity reductions due to increased station loads to support emission controls or new intake structures. Planning Reserve Margins are presented using Deliverable Capacity Resources and Adjusted Potential Capacity Resources.[31] The assessment of effects to Planning Reserve Margins does not consider the ability of the electric power industry to replace retired capacity. Each modeled year portrays a "snapshot" of potential effects caused by the potential EPA regulations, rather than an ongoing timeline of retrofits and retirements. Models do not account for units coming out of retirement due to future conditions. The demand and resource projections from the *2009 Long-Term Reliability Assessment* are used as the reference case and can be found in *Appendix III, Data Tables*.

Models for each year in all cases show identical Planning Reserve Margin reductions for Deliverable and Adjusted Potential Capacity Resources, indicating that the potential EPA regulations have little to no effect on Existing-Other, Future Other, and Conceptual Resources. Therefore, comparative analysis of Deliverable Capacity Resources and Adjusted Potential Capacity figures indicates the magnitude of future resource additions required to maintain future reserve requirements.

Resources from these ten-year projections are reduced to form the scenario cases (Moderate Case and Strict Case—previously described in the report) and calculate the resulting Planning Reserve Margins. This reliability assessment includes a comparison of the impacts on Planning Reserve Margin for the years 2013, 2015, and 2018 based on the 2009 reference case. The resulting Planning Reserve Margin was compared to the NERC Reference Margin Level to determine if

[30] Planning Reserve Margin is designed to measure the amount of generation capacity available to meet expected demand in the planning horizon. Coupled with probabilistic analysis, calculated planning reserve margins have been an industry standard used by planners for decades as a relative indication of resource adequacy. Planning Reserve Margin is the difference between available capacity and peak demand, normalized by peak demand (as a percentage) needed to maintain reliable operation while meeting unforeseen increases in demand (*e.g.* extreme weather) and/or unexpected outages of existing capacity. From a planning perspective, Planning Reserve Margin trends identify whether capacity additions are keeping up with demand growth.

[31] Deliverable Capacity Resources (DCR)—defined as Existing-Certain and Net Firm Transactions plus Future-Planned capacity resources plus net transactions—and Adjusted Potential Capacity Resources (APCR)—defined as the sum of Deliverable Capacity Resources, Existing-Other Resources, Future-Other Resources (reduced by a confidence factor), Conceptual Resources (reduced by a confidence factor), and net transactions—account for future generation capacity planned for in the reference case.[31] DCR represents existing generation that has been identified as "Certain" plus future firm resources. APCR prevents this assessment from being overly conservative in two ways: 1) Conceptual resources measure industry's future response towards maintaining Planning Reserve Margins and 2) APCR represents the portion of the interconnection queue that is historically built. A range of resource projections is identified and evaluated from these two values in this assessment.

more resources are needed in the scenario case (see Table 11).[32] For the resource adequacy assessment, NERC chose a range of resource categories to evaluate Planning Reserve Margins for this scenario. The range includes Deliverable Capacity Resources on the low-end and Adjusted Potential Capacity Resources on the high-end. Refer to the *Terms Used in This Report* section for detailed definitions regarding supply/resource categories.

Table 11: NERC Reference Margin Levels	
ERCOT	12.5%
FRCC	15.0%
MRO	15.0%
NPCC	
New England	15.0%
New York	16.5%
RFC	15.0%
SERC	
Central	15.0%
Delta	15.0%
Gateway	12.7%
Southeastern	15.0%
VACAR	15.0%
SPP	13.6%
WECC	
AZ-NM-SNV	17.8%
CA-MX US	22.3%
NWPP	16.3%
RMPA	17.1%

Overall, impacts on Planning Reserve Margins and the need for more resources is a function of the compliance timeline associated with the potential EPA regulations. Up to a 78 GW reduction of coal, oil, and gas-fired generation capacity is identified for retirement during the ten-year period of this scenario. For the Moderate Case, this occurs in 2018; however, in the Strict Case similar reduction occurs in 2015. The reduction in capacity significantly affects projected Planning Reserve Margins for a majority of the NERC Regions and subregions. Potentially significant reductions in capacity within a five-year period may require heightened concentration towards the addition of resources. For the United States as a whole, the Planning Reserve Margin is significantly reduced up to 9.3 percentage points in the Strict Case.

Additionally, more transmission resources may be needed as the industry responds to resolve identified capacity deficiencies. As replacement generation is constructed, new transmission may be needed to interconnect new generation. Additionally, existing generation that may not be deliverable due to transmission limitations may need enhancements to the transmission system in order to allow firm and reliable transmission service.

While NERC did not model deliverability or stability impacts to the transmission system (second tier effects) in this assessment, constructing new transmission or refurbishing existing transmission may be required. Transmission system enhancements and reconfiguration may be necessary in some areas, which may create additional timing issues as transmission facilities will take relatively longer to construct than generation.

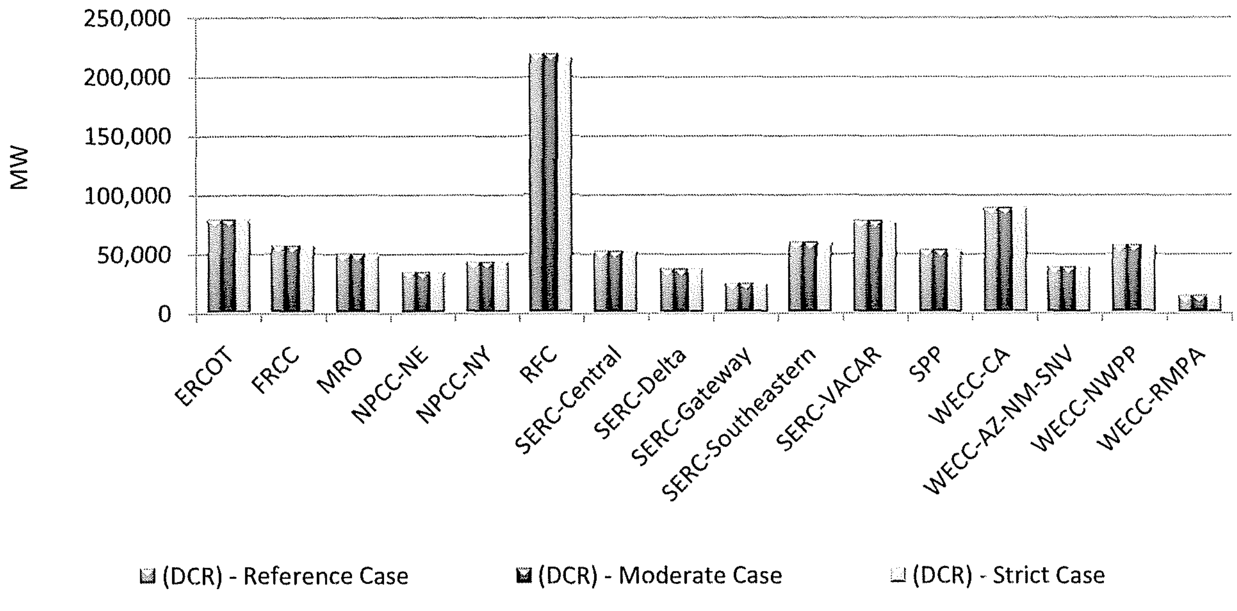
[32]NERC's Reference Reserve Margin Level is equivalent to the Target Reserve Margin Level provided by the Region/subregion's own specific margin based on load, generation, and transmission characteristics as well as regulatory requirements. If not provided, NERC assigned 15 percent Reserve Margin for thermal systems and 10 percent for predominately hydro systems.

Resource Adequacy Assessment Results: 2013

There are virtually no impacts to Planning Reserve Margins in the short term (2013). CATR is the only regulation that affects units in 2013. MRO, New England, RFC, SERC-Gateway, and SERC-Southeastern are the only Regions/subregions affected by CATR in the Moderate Case—ERCOT, FRCC, and all SERC subregions are affected in the Strict Case.

However, when CATR is modeled in the Combined EPA Regulation Scenario, the Strict Case results in a coal-fired capacity reduction of 8,391 MW by 2013 (see Figure 12). Overall, this amount does not appear to be significant and represents less than one percent of total capacity resources across the United States, but represents just fewer than 100 electric generation plants. The increased capacity reduction is a result of the increased costs being considered by generator owners, not only to comply with CATR, but with the 316(b), MACT, and CCR regulations. Because of these reductions, Planning Reserve Margins are reduced slightly in the affected Regions/subregions. The MRO Planning Reserve Margin decreases the most (about 2.7 percentage points when considering both the Deliverable and Adjusted Potential Planning Reserve Margins) to approximately 19 percent (see Figure 13 and 14). Other affected Regions/subregions include NPCC-New England and RFC, which result in a net Planning Reserve Margin reduction of less than two percentage points. There is no change to the Moderate Case when comparing the results of CATR modeled separately and the Combined EPA Regulation Scenario.

Figure 11: 2013 Summer Peak Deliverable Capacity Resources (DCR) Impacts of Combined EPA Regulation Scenario



Reliability Assessment

In MRO and the SERC-Southeastern subregion, Deliverable Planning Reserve Margin is below the NERC Reference Margin Level in both scenario cases. However, this is also true when considering the Reference Case. This indicates more resources may be needed regardless of impacts from potential EPA regulations. These two subregions must rely on Adjusted Potential Capacity Resources to meet the NERC Reference Margin Level in 2013.

Figure 12: 2013 Summer Peak Adjusted Potential Capacity Resources (APCR) Impacts of Combined EPA Regulation Scenario

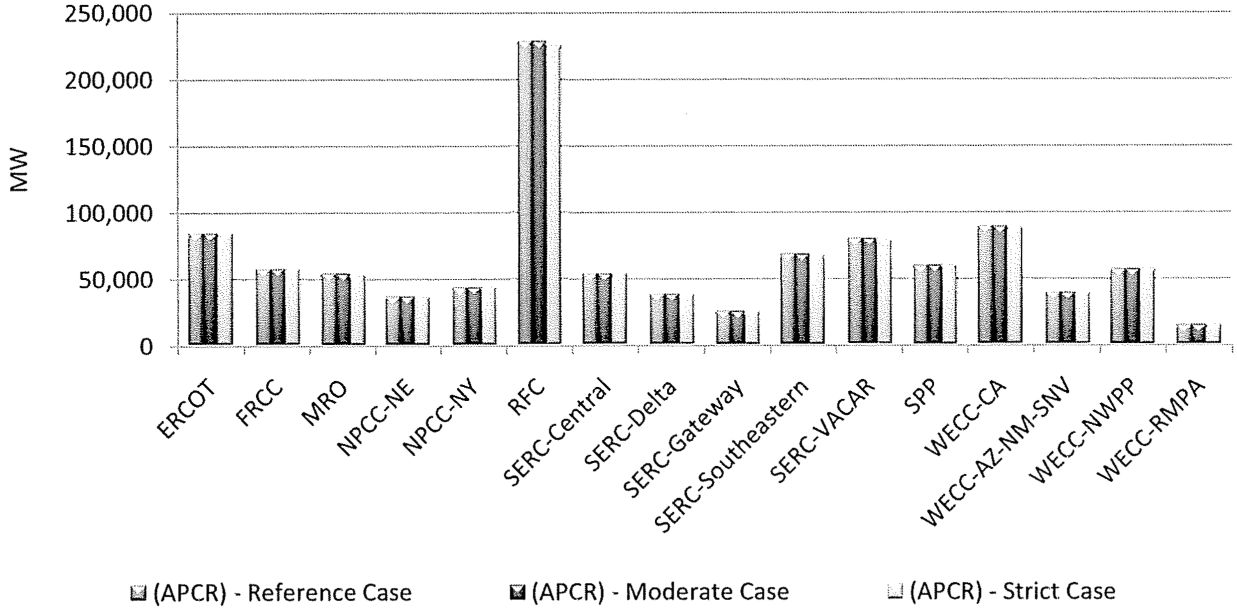


Figure 13: 2013 Summer Peak Deliverable Capacity Resources (DCR) Planning Reserve Margin Impacts of Combined EPA Regulation Scenario

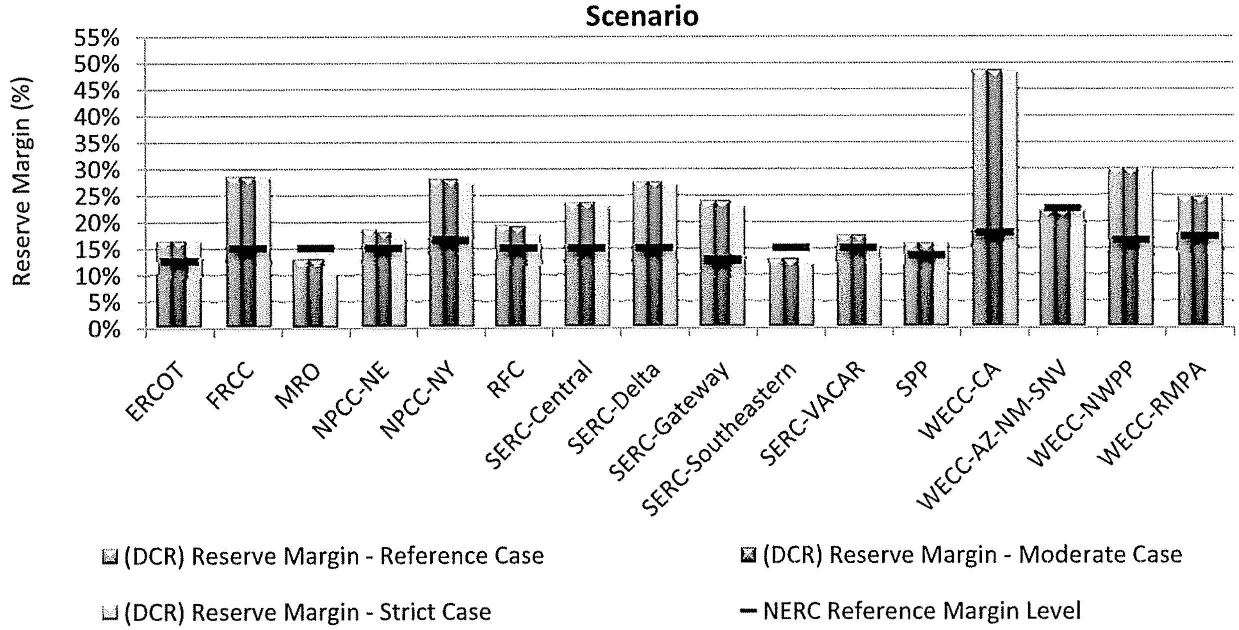


Figure 14: 2013 Summer Peak Adjusted Potential Capacity Resources (APCR) Planning Reserve Margin Impacts of Combined EPA Regulation Scenario

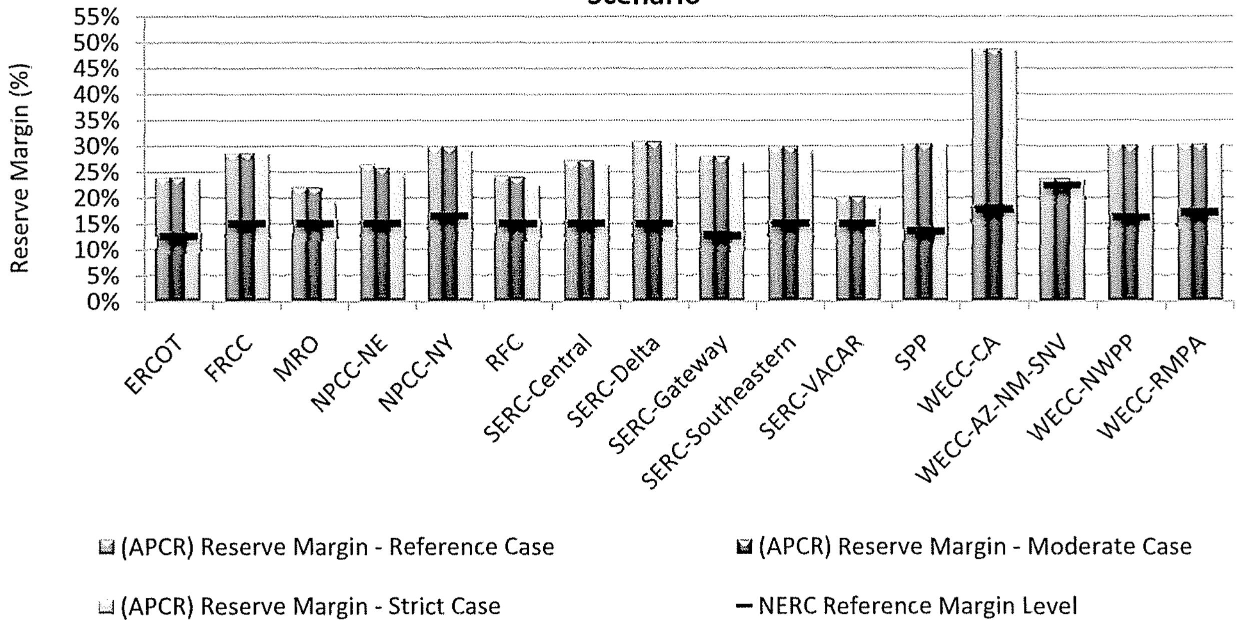


Table 12: Combined Impacts - 2013

	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	16.5% – 23.9%	0.0 – 0.0	16.3% – 23.8%	-0.1 – -0.1
FRCC	28.6% – 28.6%	0.0 – 0.0	28.5% – 28.5%	0.0 – 0.0
MRO	12.9% – 22.1%	0.0 – 0.0	10.1% – 19.3%	-2.7 – -2.7
NPCC-NE	18.0% – 25.9%	-0.6 – -0.6	16.7% – 24.6%	-1.9 – -1.9
NPCC-NY	28.1% – 29.8%	0.0 – 0.0	27.3% – 29.0%	-0.8 – -0.8
RFC	19.2% – 24.0%	-0.2 – -0.2	17.6% – 22.4%	-1.9 – -1.9
SERC-Central	23.6% – 27.2%	0.0 – 0.0	22.8% – 26.4%	-0.9 – -0.9
SERC-Delta	27.5% – 30.9%	0.0 – 0.0	27.0% – 30.4%	-0.5 – -0.5
SERC-Gateway	24.0% – 28.0%	0.0 – 0.0	22.9% – 27.0%	-1.0 – -1.0
SERC-Southeastern	13.0% – 29.8%	0.0 – 0.0	12.1% – 28.9%	-0.9 – -0.9
SERC-VACAR	17.5% – 20.3%	0.0 – 0.0	15.5% – 18.3%	-1.9 – -1.9
SPP	15.9% – 30.3%	0.0 – 0.0	15.9% – 30.3%	0.0 – 0.0
WECC-CA	48.6% – 48.6%	0.0 – 0.0	48.4% – 48.4%	-0.3 – -0.3
WECC-AZ-NM-SNV	22.1% – 23.7%	0.0 – 0.0	22.1% – 23.7%	0.0 – 0.0
WECC-NWPP	29.9% – 30.1%	0.0 – 0.0	29.9% – 30.1%	0.0 – 0.0
WECC-RMPA	24.7% – 30.3%	0.0 – 0.0	24.7% – 30.3%	0.0 – 0.0
TOTAL	22.3% – 27.7%	-0.1 – -0.1	21.4% – 26.7%	-1.0 – -1.0

Resource Adequacy Assessment Results: 2015

For the modeled year 2015, the assessment results have a greater impact on Planning Reserve Margin. Most notably, the Combined Proposed EPA Regulations Scenario shows considerable reductions, reducing Planning Reserve Margins across the United States during the next five years.

As previously discussed, the Moderate Case and the Strict Case differ in key assumptions. In 2015, capacity reductions range from 33 GW (Moderate Case) to 77 GW (Strict Case). For the Moderate Case, ERCOT, RFC, and the SERC-Delta Regions/subregions are the most affected, each with approximately a 5,500 MW reduction in capacity (Figure 16). For the Strict Case, RFC capacity is reduced by 16.4 GW.

Figure 15: 2015 Summer Peak Deliverable Capacity Resources (DCR) Impacts of Combined EPA Regulation Scenario

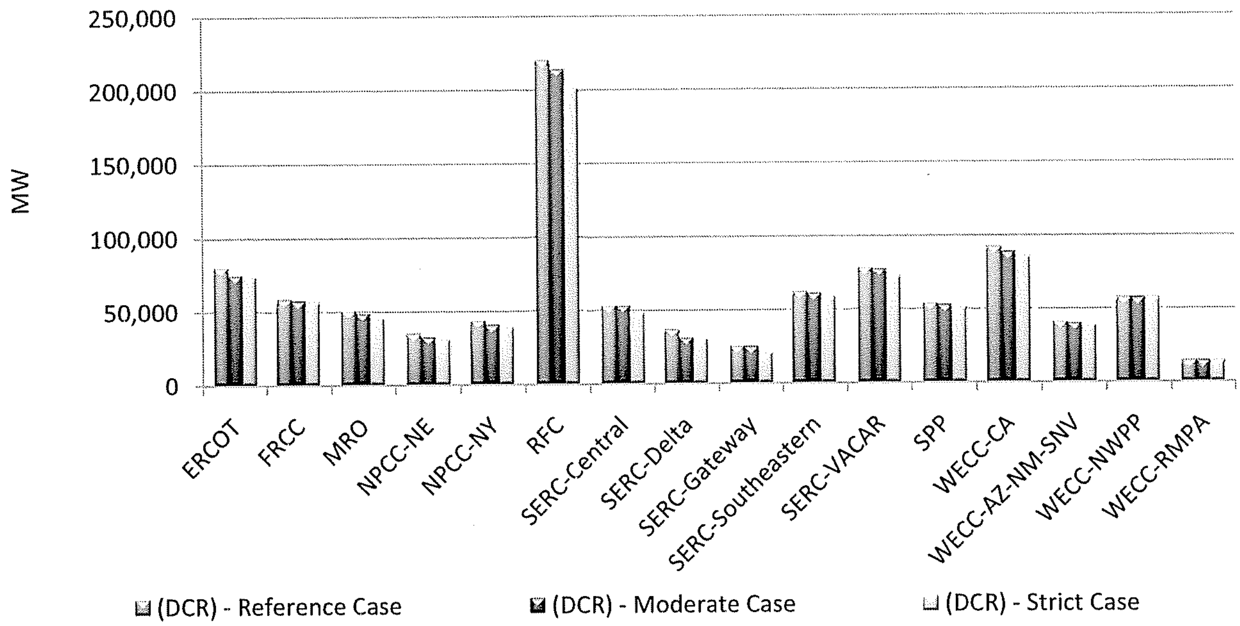
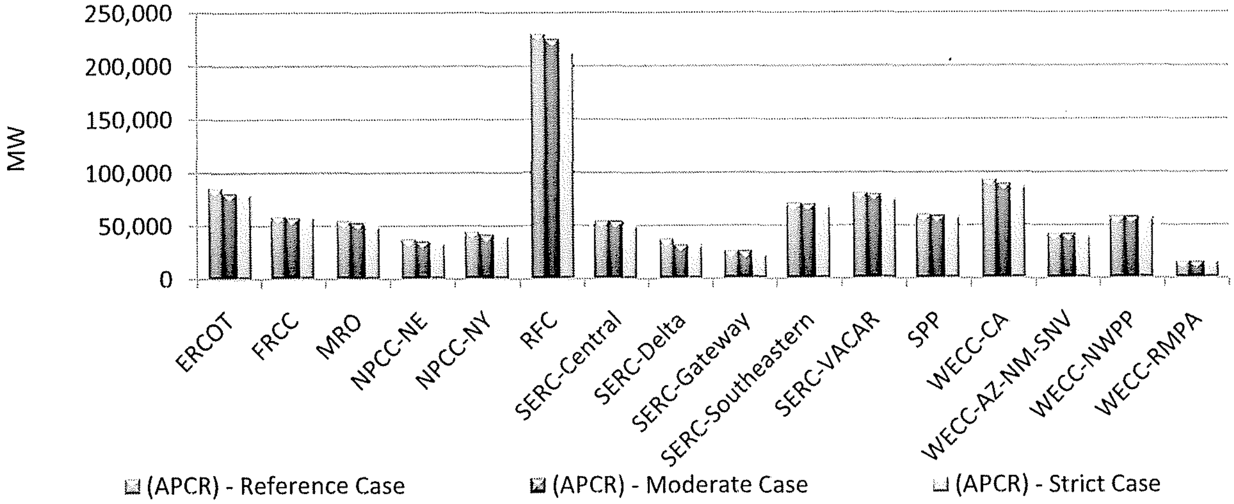


Figure 16: 2015 Summer Peak Adjusted Potential Capacity Resources (APCR) Impacts of Combined EPA Regulation Scenario



For the Moderate Case, a 3.2 percent reduction in overall capacity results in Planning Reserve Margin reductions for a majority of the NERC Regions/subregions. Accordingly, the SERC-Central, SERC-Southeastern, SERC-VACAR, WECC-NWPP, and WECC-RMPA subregions show less than a two percentage point reduction in Planning Reserve Margin. When considering the Deliverable Planning Reserve Margin a majority of the Regions/subregions fall below the NERC Reference Margin Level in 2015 for both cases. In MRO, Deliverable Planning Reserve Margins fall below zero in the Strict Case (Figure 17). Additionally, because of a 15 percent reduction in SERC-Delta capacity resources, the Planning Reserve Margin is reduced to 1.9 percent (Deliverable—see Figure 17) and 5.2 percent (Adjusted Potential—see Figure 18). In this scenario, more resources will be needed in the SERC-Delta subregion under the Moderate Case assumptions.

Figure 17: 2015 Summer Peak Deliverable Capacity Resources (DCR) Planning Reserve Margin Impacts of Combined EPA Regulation Scenario

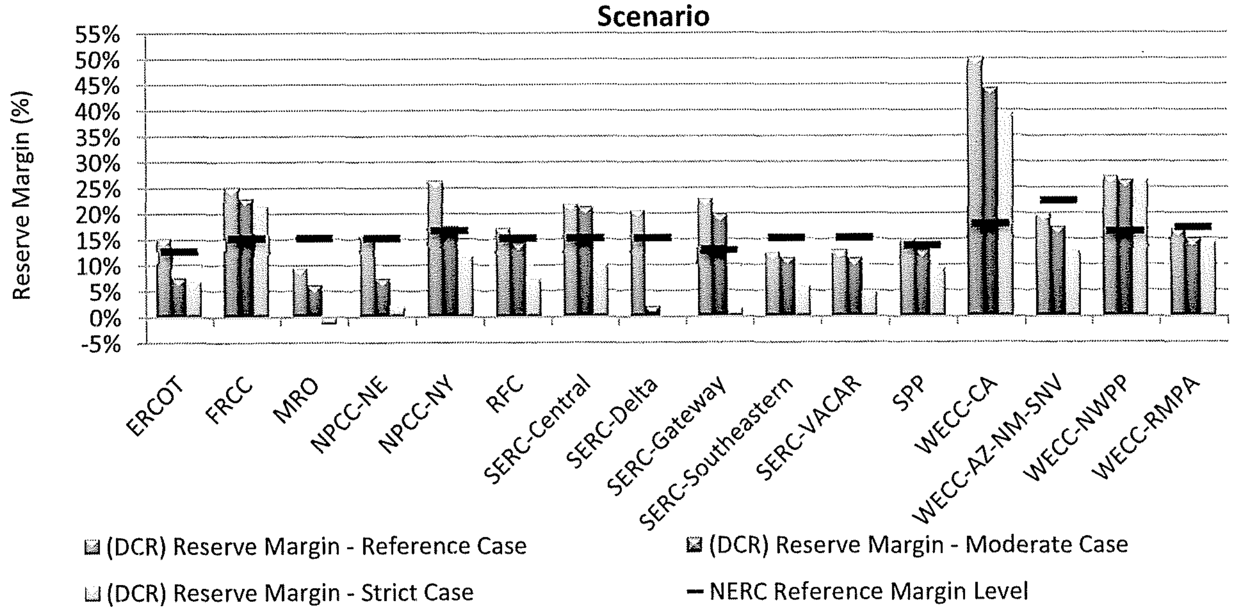
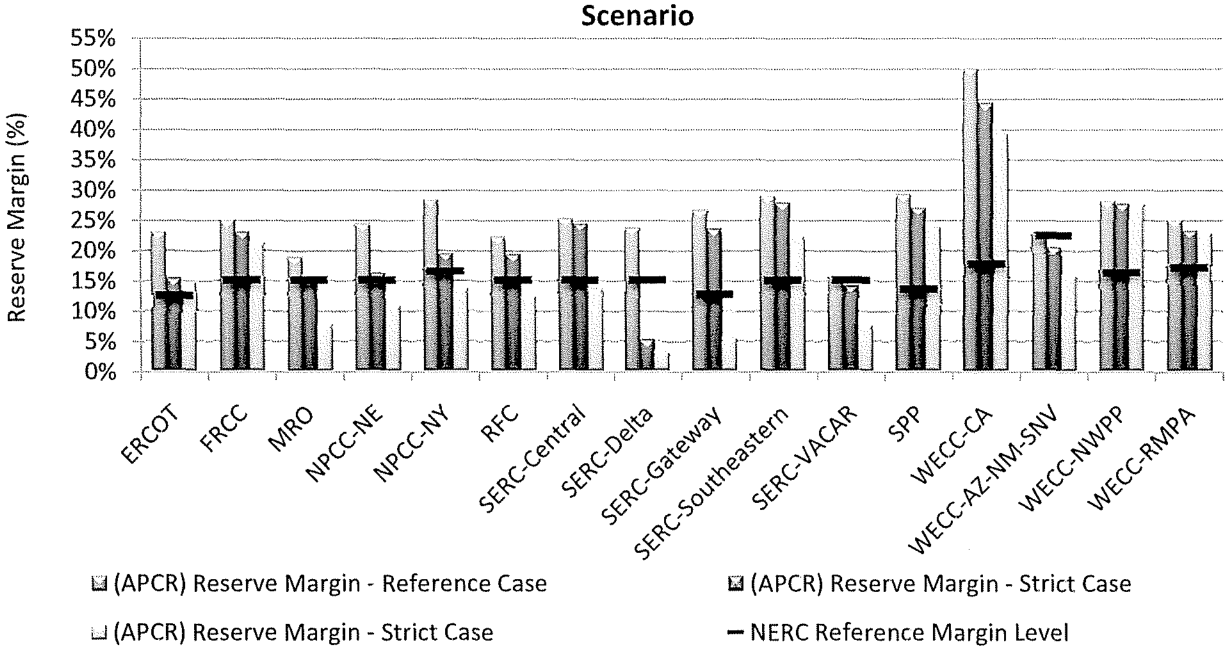


Figure 18: 2015 Summer Peak Adjusted Potential Capacity Resources (APCR) Planning Reserve Margin Impacts of Combined EPA Regulation Scenario



For the Strict Case, a 7.2 percent reduction in overall capacity results in significant Planning Reserve Margin reductions for all NERC Regions and subregions, except the WECC subregions of NWPP and RMPA. Planning Reserve Margins are significantly due to over a nine percent of capacity resources in MRO, NPCC-New England, NPCC-New York, SERC-Central, SERC-Delta, and SERC-Gateway. When considering Deliverable Planning Reserve Margins, nearly all Regions/subregions fall below the NERC Reference Margin Level (see Figure 17).Additionally, these Regions/subregions are below NERC's Reference Margin Levels under the Strict Case assumptions, indicating reductions in those Regions'/subregions' ability to maintain sufficient reserve levels. Most notably, SERC-Delta has a 3.1 percent Planning Reserve Margins in 2015. Additionally, capacity reductions in NPCC-New England, SERC-Gateway, and SERC-VACAR result in Planning Reserve Margins below 10 percent. In these Regions/subregions, more resources will be needed for this scenario.

The impacts to Planning Reserve Margins are highly dependent on which resources are projected to be in-serving in the Reference Case. As such, Adjusted Potential Capacity Resources Planning Reserve Margins are not as impacted as Deliverable Capacity Resources Planning Reserve Margin. Therefore, in order to help mitigate resource adequacy issues, Adjusted Potential Resources (which include Conceptual Resources), which carry a level of uncertainty, may be needed to meet the NERC Reference Margin Level. However, as indicated above, even these additional resources may not be sufficient.

Table 13: Combined Impacts - 2015				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	7.5% – 15.4%	-7.7 – -7.7	6.8% – 14.7%	-8.4 – -8.4
FRCC	23.0% – 23.0%	-2.0 – -2.0	21.3% – 21.3%	-3.7 – -3.7
MRO	5.9% – 15.5%	-3.5 – -3.5	-1.7% – 7.9%	-11.0 – -11.0
NPCC-NE	7.2% – 16.2%	-8.3 – -8.3	1.8% – 10.8%	-13.6 – -13.6
NPCC-NY	17.4% – 19.5%	-8.9 – -8.9	11.5% – 13.6%	-14.8 – -14.8
RFC	14.2% – 19.4%	-2.9 – -2.9	7.2% – 12.4%	-9.9 – -9.9
SERC-Central	21.0% – 24.5%	-0.7 – -0.7	10.1% – 13.6%	-11.6 – -11.6
SERC-Delta	1.9% – 5.2%	-18.6 – -18.6	-0.2% – 3.1%	-20.6 – -20.6
SERC-Gateway	19.6% – 23.6%	-3.1 – -3.1	1.5% – 5.5%	-21.3 – -21.3
SERC-Southeastern	11.3% – 27.9%	-1.1 – -1.1	5.7% – 22.4%	-6.6 – -6.6
SERC-VACAR	11.1% – 14.2%	-1.5 – -1.5	4.6% – 7.6%	-8.0 – -8.0
SPP	12.7% – 27.1%	-2.2 – -2.2	9.3% – 23.8%	-5.5 – -5.5
WECC-CA	44.3% – 44.3%	-5.8 – -5.8	39.3% – 39.3%	-10.8 – -10.8
WECC-AZ-NM-SNV	17.3% – 20.6%	-2.4 – -2.4	12.6% – 15.9%	-7.1 – -7.1
WECC-NWPP	26.5% – 27.6%	-0.5 – -0.5	26.5% – 27.6%	-0.5 – -0.5
WECC-RMPA	14.9% – 23.2%	-1.7 – -1.7	14.6% – 22.9%	-2.1 – -2.1
TOTAL	16.1% – 21.7%	-4.0 – -4.0	10.8% – 16.4%	-9.3 – -9.3

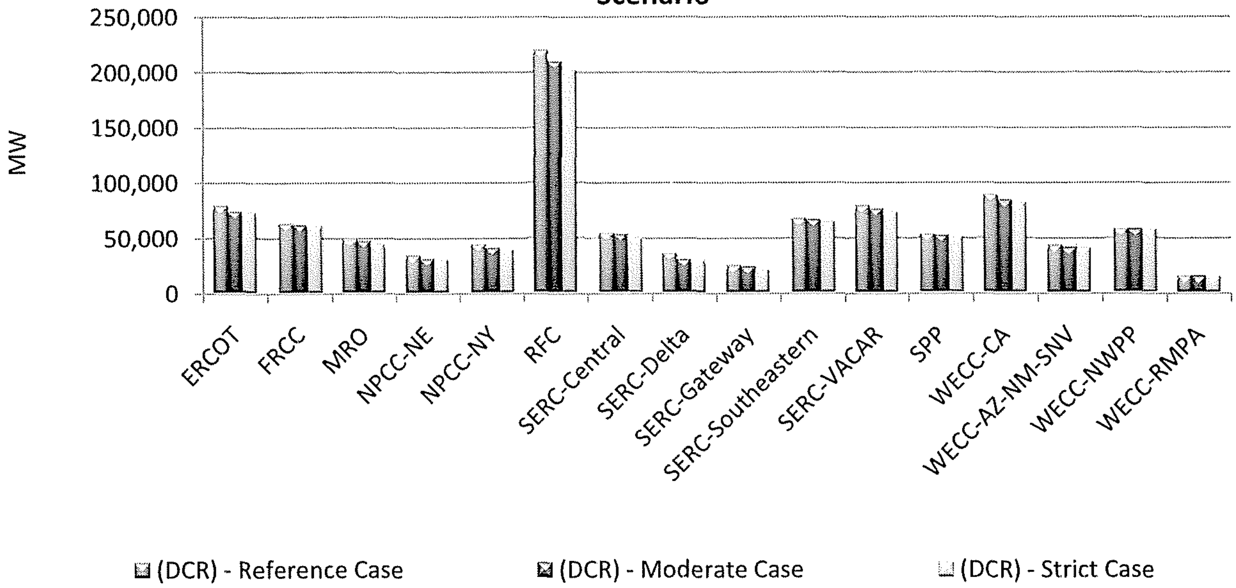
Resource Adequacy Assessment Results: 2018

Further reductions in capacity resources and Planning Reserve Margins are the results in 2018. Most notably, the Combined EPA Regulations Scenario shows considerable reductions, effectively reducing Planning Reserve Margins across the United States within the next eight years.

The Combined Regulation Scenario shows the most notable capacity resources reductions. As previously discussed, the Moderate Case and the Strict Case differ in key assumptions that have been made to the model. In 2018, capacity reductions range from 46 GW (Moderate Case) to 76 GW (Strict Case).[33] For the Moderate Case, RFC is the more affected Region with just under a 10 GW reduction in capacity resources, followed by ERCOT, SERC-Delta, and the WECC-CA Regions/subregions, each with approximately a 5.5 GW capacity reduction (Figure 15).

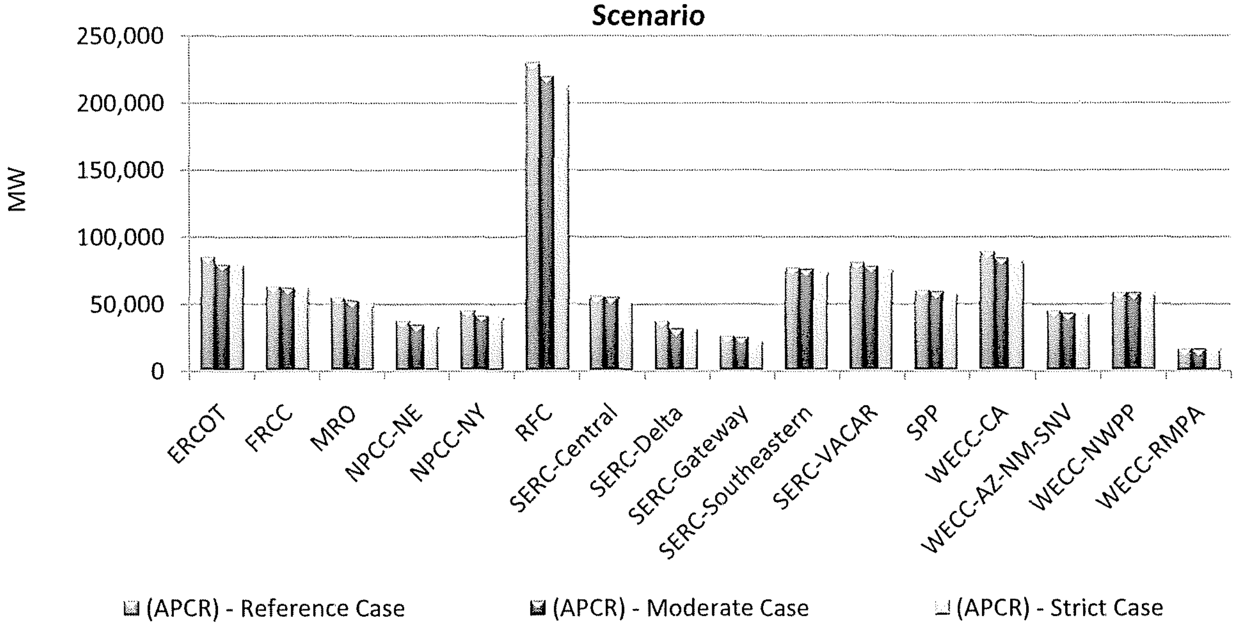
For the Strict Case, RFC capacity is reduced by 17.7 GW. With the exception of FRCC, WECC-NWPP, and WECC-RMPA, all Regions/subregions show at least a five percent reduction in capacity resources. MRO, NPCC-New England, NPCC-New York, SERC-Central, SERC-Delta, and SERC-Gateway all show at least a nine percent reduction in capacity resources; SERC-Delta shows a 17 percent reduction, suggesting more resources will be needed in these areas.

Figure 19: 2018 Summer Peak Deliverable Capacity Resources (DCR) Impacts of Combined EPA Regulation Scenario



[33] The total reductions for the 2018 Combined Regulation-Strict Case (76 GW) is less than the total reductions for the 2015 Combined Regulation-Strict Case (77 GW) due to slightly higher gas prices assumed for the year 2018. Therefore, plants may opt to retrofit rather than purchase replacement generation. Each modeled year portrays a "snapshot" of potential effects caused by the EPA regulations, rather than an ongoing timeline of retrofits and retirements.

Figure 20: 2018 Summer Peak Adjusted Potential Capacity Resources (APCR) Impacts of Combined EPA Regulation Scenario



The capacity reductions identified in this scenario significantly reduce Planning Reserve Margins. The Moderate Case depicts a 4.4 percent reduction in overall capacity resulting in sizeable Planning Reserve Margin reductions for a majority of the NERC Regions/subregions. The WECC-NWPP and WECC-RMPA subregions show less than a two percentage point reduction. When considering the Deliverable Planning Reserve Margin a majority of the Regions/subregions fall below the NERC Reference Margin Level in 2018 for both cases (Figure 21). Significant capacity reductions in ERCOT, MRO, NPCC-New England, and SERC-Delta result in Planning Reserve Margin below 10 percent (see Figure 22) when considering the Adjusted Potential Planning Reserve Margin.

When considering Deliverable Capacity Resources, ERCOT, MRO, NPCC-New England, and SERC-Delta fall below zero. With Adjusted Potential Capacity Resources, the SERC-Delta Planning Reserve Margin is reduced 18.7 percentage points to -0.5 percent because of a 16 percent reduction in SERC-Delta resources.

The Strict Case shows that a 7.2 percent reduction in overall capacity results in significant Planning Reserve Margin reductions for almost all NERC Regions and subregions, except the WECC subregions of NWPP and RMPA. Planning Reserve Margins are significantly reduced as a result of capacity resource reductions greater than 10 percent in MRO, NPCC-New England, NPCC-New York, SERC-Delta, and SERC-Gateway (see Figure 22). A majority of the NERC Regions/subregions are below NERC's Reference Margin Level under the Strict Case assumptions. Most notably, MRO and SERC-Delta Planning Reserve Margin in 2018 are 3.7 and -1.7 percent, respectively. Additionally, capacity reductions in ERCOT, NPCC-New England, RFC, SERC-Gateway, SERC-Southeastern, SERC-VACAR, and SPP result in Planning Reserve Margins below10 percent.

Figure 21: 2018 Summer Peak Deliverable Capaity Resources (DCR) Planning Reserve Margin Impacts of Combined EPA Regulation Scenario

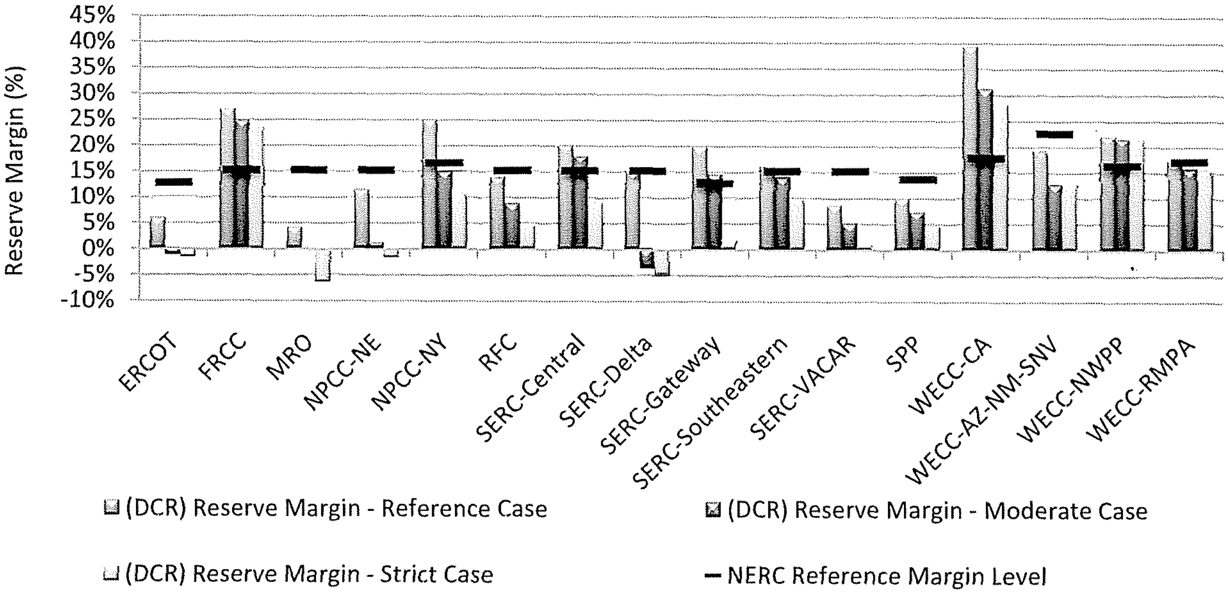


Figure 22: 2018 Summer Peak Adjusted Potential Capacity Resources (APCR) Planning Reserve Margin Impacts of Combined EPA Regulation Scenario

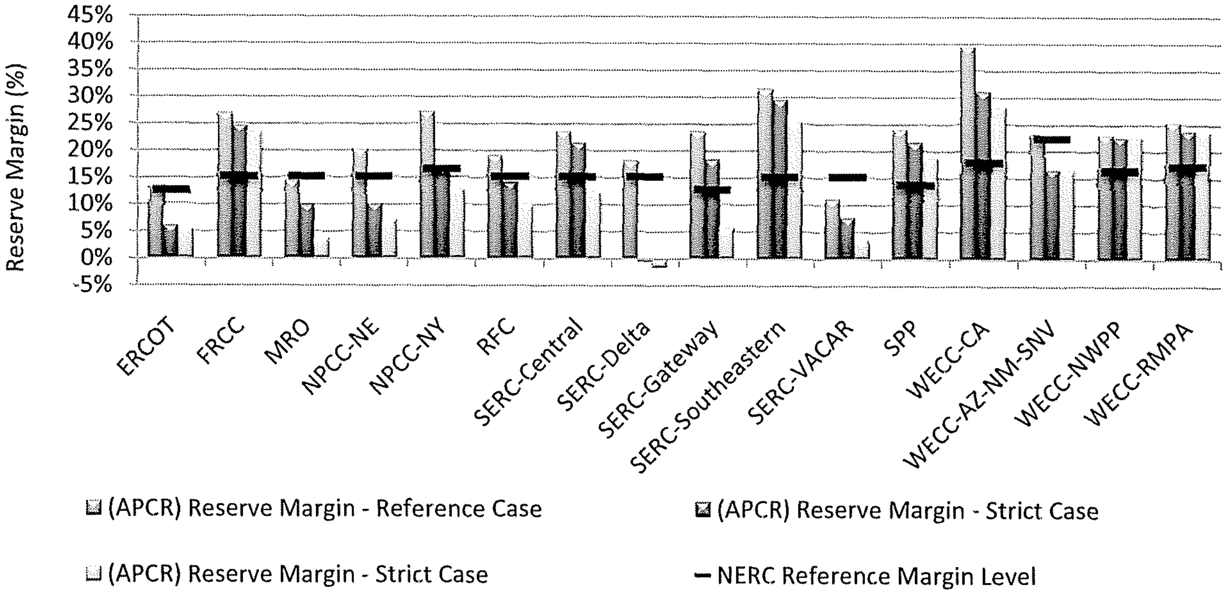


Table 14: Combined Impacts - 2018				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	-1.2% – 6.0%	-7.2 – -7.2	-1.7% – 5.6%	-7.7 – -7.7
FRCC	24.6% – 24.6%	-2.3 – -2.3	23.5% – 23.5%	-3.5 – -3.5
MRO	-0.3% – 9.9%	-4.4 – -4.4	-6.5% – 3.7%	-10.6 – -10.6
NPCC-NE	1.2% – 10.0%	-10.2 – -10.2	-1.8% – 6.9%	-13.3 – -13.3
NPCC-NY	14.9% – 16.9%	-10.2 – -10.2	10.7% – 12.7%	-14.4 – -14.4
RFC	8.7% – 14.1%	-5.1 – -5.1	4.7% – 10.0%	-9.2 – -9.2
SERC-Central	18.0% – 21.3%	-2.2 – -2.2	9.0% – 12.3%	-11.2 – -11.2
SERC-Delta	-3.7% – -0.5%	-18.7 – -18.7	-4.9% – -1.7%	-19.9 – -19.9
SERC-Gateway	14.5% – 18.4%	-5.2 – -5.2	1.7% – 5.6%	-18.0 – -18.0
SERC-Southeastern	13.9% – 29.6%	-2.1 – -2.1	9.7% – 25.4%	-6.3 – -6.3
SERC-VACAR	5.0% – 7.6%	-3.5 – -3.5	0.9% – 3.4%	-7.6 – -7.6
SPP	7.4% – 21.4%	-2.6 – -2.6	4.6% – 18.7%	-5.3 – -5.3
WECC-CA	31.1% – 31.1%	-8.3 – -8.3	28.2% – 28.2%	-11.2 – -11.2
WECC-AZ-NM-SNV	12.6% – 16.6%	-6.6 – -6.6	12.6% – 16.6%	-6.6 – -6.6
WECC-NWPP	21.5% – 22.6%	-0.5 – -0.5	21.5% – 22.6%	-0.5 – -0.5
WECC-RMPA	15.7% – 23.8%	-1.6 – -1.6	15.4% – 23.5%	-1.9 – -1.9
TOTAL	11.0% – 16.5%	-5.3 – -5.3	7.6% – 13.1%	-8.8 – -8.8

Industry Actions: Tools and Solutions for Mitigating Resource Adequacy Issue

In addition to the potential for waivers or extensions, a variety of tools and solutions can help mitigate significant reliability impacts resulting from resource adequacy concerns created by this scenario assessment. They include, but are not limited to:

Advancing In-service Dates of Future or Conceptual Resources

- Generation resources may be able to advance their in-service dates where sufficient lead time is given.
- Accelerated construction may be possible.
- Existing market tools, such as forward capacity markets and reserve sharing mechanisms, can assist in signaling resource needs. Price signalling will be important in developing new resources.

Addition of New Resources Not yet Proposed

- Smaller, combustion turbines or mobile generation units can be added to maintain local reliability where additional capacity is needed.
- Additional distributed generation may also mitigate local reliability issues.

Increased Demand-Side Management and Conservation

- Increased Energy Efficiency may offset future demand growth.
- Increasing available Demand Response resources can provide planning and operating flexibility by reducing peak demand.

Early Action to Mitigate Severe Losses

- Planning and constructing retrofits immediately will aid in preventing the potential for construction delays and overflows, mitigating the risk of additional unit loss.
- Managing retrofit timing on a unit basis will keep capacity supply by region stable..

Increase in Transfers

- Regions\subregions that have access to a larger pool of generation may be able to increase the amount of import capacity from areas with available capacity, transfer capability is sufficient. and deliverability is confirmed.
- Additional transmission or upgrades may enable additional transactions to provide additional resources across operating boundaries.

Developing or Exploring Newer Technologies

- Other technologies exist, such as trona injection, that will allow companies to comply with EPA air regulations without installing more scrubbers.

Use of More Gas-Fired Generation

- Existing gas units may have additional power production potential, which can be expanded during off peak periods. This capacity can assist in managing plant outages during the installation of emission control systems.

Repowering of Coal-Fired Generation

- Some coal-fired generation have the potential to repower their units with combined-cycle gas turbines and reducing emmisions.

The enhancements listed are all options for consideration to offset potential reliability concerns identified in this scenario assessment. The industry should closely monitor the EPA regulation process as well as continued generator participation/early-retirement announcements.

Conclusions & Recommendations

Conclusions

The results of this assessment show a significant impact to reliability should the four potential EPA rules be implemented as assumed in this assessment. Impacts to both bulk power system planning and operations may cause serious concerns unless prompt industry action is taken. Planning Reserve Margins appear to be significantly impacted, deteriorating resource adequacy in a majority of the NERC Regions/subregions. Additionally, considerable operational challenges will exist in managing, coordinating, and scheduling an industry-wide environmental control retrofit effort.

Of the four selected EPA rules, the Section 316(b) Cooling Water Intake Structures rule individually has the greatest potential impact on Planning Reserve Margins. Implementation of this rule will apply to 252 GW (1,201 units) of coal, oil steam, and gas steam generating units across the United States resulting in total "vulnerable" capacity of 37-41 GW by 2018. Additionally, approximately 60GW of nuclear capacity may be affected. Because of this scenario, Planning Reserve Margins are decreased as much as 18 percentage points in the SERC-Delta subregion where the margin falls below zero (available generation will be unable to serve load), unless additional resources are added. Other Regions/subregions affected include NPCC-New England and New York.

The remaining three selected EPA rules assessed will mostly affect existing coal-fired capacity, ranked in descending order:

MACT

- The EPA MACT Rule alone could trigger the retirement of 2-15 GW (Moderate Case and Strict Case) of existing coal capacity by 2015. The "hard stop" 2015 compliance deadline proposed by the EPA MACT Rule makes retrofit timing a significant issue and potentially problematic.

CATR

- The CATR also could have significant impacts as soon as 2015, should EPA require emission limits with no offset trading, resulting in potentially 3-7 GW of retired and derated capacity and require retrofitting of 28-576 plants with environmental controls by 2015.

CCR

- The CCR Rule alone is projected to have the least impact, triggering the retirement of up to 12 coal units (388 MW). While the resulting impacts of the CCR scenario may not have significant impacts to capacity by itself, the associated compliance costs of CCR contribute to the Combined EPA Regulation Scenario.

Based on the assessment's assumptions, the greatest risk to Planning Reserve Margins occurs in 2015 for the Combined EPA Regulation Scenario. The overall total impact could make 46-76 GW of existing capacity "economically vulnerable" for retirement or derating by 2015. Additionally, the scenario cases assessed in this report indicate capacity reductions evident as early as 2013, resulting from the retirements of coal-fired plants and derate effects associated with plant retrofits. Impacts to Planning Reserve Margins can occur during the next four to eight years that could reduce bulk power system reliability, unless additional resources are constructed or acquired. It is essential that projected Conceptual supply resources be developed as one source of capacity replacement.

Recommendations

Regulators

In the future, a variety of demands on existing infrastructure will be made to support the evolution from the current fuel mix, to one that includes generation that can meet proposed EPA regulations. The pace and aggressiveness of these environmental regulations should be adjusted to reflect and consider the overall risk to the bulk power system. EPA, FERC, DOE and state utility regulators, both together and separately, should employ the array of tools at their disposal to moderate reliability impacts, including, among other things, granting required extensions to install emission controls.

Industry

Industry participants should employ available tools to ensure Planning Reserve Margins are maintained while forthcoming EPA regulations are implemented. For example, regional wholesale competitive markets should ensure forward capacity markets are functioning effectively to support the development of new replacement capacity where needed. Similarly, stakeholders in regulated markets should work to ensure that investments are made to retrofit or replace capacity that will be affected by forthcoming EPA regulations.

NERC

NERC should further assess the implications of the EPA regulations as greater certainty or finalization emerges around industry obligations, technologies, timelines, and targets. Strategies should be communicated throughout the industry to maintain the reliability of the bulk power system. This assessment should include impacts to operating reliability and second tier impacts (e.g., deliverability, stability, localized issues, outage scheduling, operating procedures, and industry coordination) of forthcoming EPA regulations.

Appendix I: Assessment Methods

Method for This Assessment

Some studies completed by various organizations have made assumptions that environmental regulations will cause all units that meet a certain criteria to retire, for example, all units less than 230MW that have a capacity factor below 35 percent. This simplified approach does not consider other important factors:

1. Regulated versus deregulated plant (can affect the ability to finance capital improvements as well as the cost of capital)
2. Unit ownership that can affect the cost of capital
3. Regional reserve margin, *i.e.*, the need to build new capacity to replace retired capacity
4. Operating cost of the unit versus the operating cost of replacement capacity
5. Management's attitude toward fossil fuel generation
6. State specific implementation
7. Other local and unit specific issues

In developing this report, NERC used a contracted model from Energy Ventures Associates (EVA), which does not consider Reference Planning Reserve Margins commitments, reliability-must-run factors or transmission constraints. Instead, the model applied generic costs factors, related to unit size and unit location, to each unit. An economic approach is used to identify units to retire when the generic required cost of compliance with the proposed environmental regulation exceeds the cost of replacement power. For the purpose of this assessment, replacement power was considered to be gas-fired capacity. This assessment was completed in constant 2010 U.S. dollars.

EVA used its delivered natural gas and coal price forecasts. All gas prices were assessed at the point of delivery to the electric generation plant. In addition, coal supply costs were adjusted for any savings resulting from the ability to burn a different quality of coal, *e.g.*, higher BTU coal.

One deviation from this general method occurs specifically for the expected outcome of the CATR regulation, such that the model considers the surplus credits that have accumulated and allows them to be used as an offset in lieu of installing additional environmental controls.

A brief description of the method follows:

Retirement criteria: retire if (CC+FC+VC) / (1-DR) > RC, where:

CC = required compliance cost in $/MWH
FC = current fixed O&M in $/MWH
VC = variable O&M including fuel cost in $/MWH
RC = replacement cost in $/MWH
DR = derate factor that accounts for the incremental energy loss due to any new environmental controls

CC = function(incremental capital, incremental fixed O&M cost, incremental variable O&M, cost of capital, capacity factor, remaining life without new regulation)

(IC * CRF +IFOM) / (8.76*CF) + IVOM, where:

IC = Incremental capital cost ($/kW) that is plant specific for each regulation, *i.e.*, can range from zero if the plant is already in compliance to the cost of any additional capital to comply with the proposed regulation. This cost is a function of the size of the plant and its location.

CRF = Capital recovery factor = $i * (1 + i)^n / ((1 + i)^n - 1)$

i = Pre-tax cost of capital:
Deregulated IOU = 17.5%
Regulated IOU = 12.7%
Coop = 7%
Municipality = 6%

n = Remaining life in years, linear interpolation between [CF=0, n=3], and [CF=100%, n=30], *i.e.*, if CF=30% then
n = (1-30%)*3 + 30%*30 = 11.1 years

IFOM = Incremental increase in the fixed O&M cost ($/kW-yr)

CF = Capacity factor of the plant in 2008

IVOM = Incremental increase in the variable O&M cost ($/MWh)

FC = Current fixed O&M cost in $/kW-yr / (8.76*CF)[34]

	0 MW	100MW	>300 MW
Coal =	$30.00/kW-yr	$21.00/kW-yr	$18.00/kW-yr
O/G Steam =	$22.50/kW-yr	$15.75/kW-yr	$13.50/kW-yr

VC = Variable O&M cost in $/MWH

	0 MW	100MW	>300 MW
Coal =	$5.00/MWh	$4.00/MWh	$3.75/MWh
O/G Steam =	$3.33/MWh	$2.67/MWh	$2.50/MWh

Plus fuel cost
= Delivered fuel cost ($/MMBtu) * heat rate (1000 Btu/kWh)

[34] Fixed Brownfield construction costs may be lower than the Greenfield costs assumed in this assessment.

RC = Replacement cost is a function of the capacity factor, cost of new combined cycle plants, cost of new peaking capacity, and natural gas price

If CF between 10% and 90%,
RC = [(1 - (CF - 10%)/80%) * RC10 + (CF- 10%)/80% * RC90]
If CF <=10%, RC = RC10
If CF >=90%, RC = RC90

RC10 = Full capital and operating cost of a new GT unit in the NERC Region in $/MWh@ 10% CF with the capital and delivered natural gas cost varying by region

RC90 = Full capital and operating cost of a new CC unit in the NERC Region in $/MWh@ 90% CF with the capital and delivered natural gas cost varying by region

A capacity factor of 90 percent was selected for the combined cycle unit as a proxy for the practical, maximum, annual operating rate of a typical fossil fuel unit. A capacity factor of 10 percent was selected for peaking gas plants as the upper limit of what is typically observed under actual operating conditions.

New gas plant cost assumptions illustrated by Table I-1 are:

Table I-1: Model Assumptions - New Gas Plant

	Average Ten Year Outlook for NG Price				New Combined Cycle Plant			New Gas Turbine			Other Parameters	
	Combined Cycle Natural Gas Price in $/MMBtu		Gas Turbine Natural Gas Price in $/MMBtu									
	2013-2022	2018-2027	2013-202	2018-202	Capital $/kW	Fixed O&M $/kW-yr	Var O&M $/kWH	Capital $/kW	Fixed O&M $/kW-yr	Var O&M $/kWH	Pre-Tax WACC	CRF $30.00
ERCOT	$6.35	$6.94	$6.26	$6.84	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	19.1%	0.192
FRCC	$7.75	$8.36	$6.78	$7.36	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
MRO	$6.40	$6.98	$6.30	$6.88	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
NPSS-NE	$7.10	$7.69	$6.99	$7.57	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	19.1%	0.192
NPCC-NY	$6.79	$7.34	$6.68	$7.22	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	19.1%	0.192
RFC	$6.68	$7.25	$6.39	$6.94	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	19.1%	0.192
SERC-Central	$6.46	$7.02	$6.29	$6.85	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
SERC-Delta	$6.27	$6.85	$6.18	$6.75	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
SERC-Gateway	$6.34	$6.96	$6.11	$6.73	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
SERC-Southeastern	$6.65	$7.21	$6.48	$7.04	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
SERC-VACAR	$6.86	$7.42	$6.59	$7.14	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
SPP	$6.76	$7.32	$6.54	$7.09	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
WECC-AZ-NM-SNV	$6.23	$6.80	$6.08	$6.64	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	19.1%	0.192
WECC-CA	$6.46	$7.06	$6.31	$6.89	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	19.1%	0.192
WECC-NWPP	$6.35	$6.94	$6.20	$6.77	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	19.1%	0.192
WECC-RMPA	$5.99	$6.54	$5.84	$6.38	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130

*** Constant 2010 NG Price**

WACC = Weighted Average Cost of Capital

CRF = Capital Recovery Factor

Heat Rates: 7,000 for combined cycle and 10,000 for gas turbine

Appendix I: Assessment Methods

Appendix II: Potential Environmental Regulations

Appendix II: Potential Environmental Regulations

Section 316(b) Cooling Water Intake Structures

The typical power plant uses a fuel (coal, gas or nuclear) to heat water into steam, which then turns a turbine connected to a generator, which produces electricity. The steam then condenses back into water to continue the process again. This condensation requires cooling either by water, air, or both. In open-loop cooling, (see Figure II-1), large volumes of water withdrawn from a water source (reservoir, lake or river) pass through the heat exchanger to condense steam in a single pass before the majority returns to the source. Closed-loop cooling is an alternative to open-loop cooling (see Figure II-2). Closed-loop cooling systems circulate a similar total volume of water as open-loop systems for a given plant size, but only withdraw a limited amount of water to replace evaporative loss and blow-down. There is also "dry" or air-cooling which requires little to no water and is cooled directly or indirectly via conductive heat transfer using a high flow rate of ambient air blown by fans across the condenser.

Figure II-1: Open-Loop Cooling

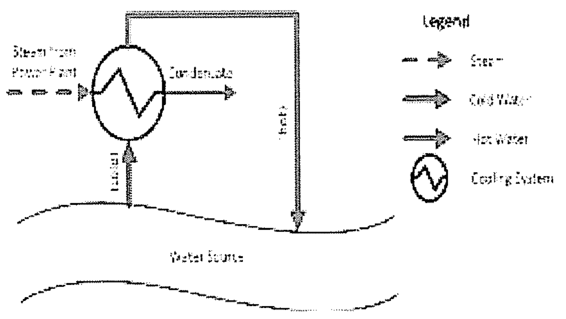
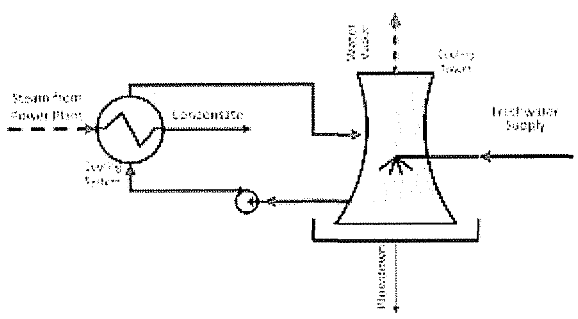


Figure II-2: Closed-Loop Cooling



Section 316(b) of the Clean Water Act regulates cooling water intake structures and requires that cooling water intake structures reflect the BTA for minimizing adverse environmental impacts. In defining BTA, EPA has, for more than 30 years, considered the cost and benefits of control alternatives. EPA originally developed the Section 316(b) rule for existing generation facilities using greater than 50 million gallons per day (mgd) in 2004-2007. However, parts of the rule were overturned in the U.S. Court of Appeals in 2007 and remanded to EPA for reconsideration. EPA is planning to issue a new draft rule for public comment by September 2010. Rule implementation is likely to start during 2014 and be fully implemented over a five-year compliance period.

This proposed water rule will likely apply to all existing and new nuclear and fossil steam generating units, which contributed over 93 percent of 2008 U.S. generation. Power sources such as combustion turbines, hydroelectric facilities, wind turbines, and solar PV panels use no cooling water and therefore will not be subject to the proposed rule. Major EPA proposed making policy issues directly affecting Planning Reserve Margins are:

- implementation period;
- applicability to existing structures and; and
- EPA BTA retrofit technology selection.

In its original 2004 existing facilities rule (overturned by the U.S. Court of Appeals in 2007), EPA set significant new national technology-based performance standards. The standards are intended to minimize adverse environmental impacts of cooling water intake structures by reducing the number of aquatic organisms lost. The performance standards prescribed ranges of reductions based on several factors and provided multiple compliance alternatives including the use of economic tests to properly implement site-specific regulatory BTA determinations.

However, EPA's expected draft replacement rule (Phase II) is expected to be substantially different due in part to the fact that the performance standards are expected to favor performance commensurate with cooling towers. In addition, despite a 2009 Supreme Court ruling that EPA has the discretion to use cost-benefit analyses when setting performance standards, EPA has signaled concerns associated with the use of cost-benefit analyses.

For example, if EPA defines BTA for cooling water systems such as recirculating cooling water systems with a reach-back provision to cover existing cooling water systems, up to 312 GW of existing steam electric power stations that use once-through cooling water systems may require additions to retrofit recirculating cooling water systems or acceleration of their retirement. For those units opting to retrofit, the stations would increase onsite electricity consumption (1-4 percent) from station loads because of increased power needs for cooling water pumping.

In its October 2008 report titled *Electricity Reliability Impacts of a Mandatory Cooling Tower Rule for Existing Steam Generating Units*, the U.S. Department of Energy (DOE) estimated that a tougher mandatory recirculating cooling water requirement, now being considered by EPA, would accelerate the retirement of 39.6 GW of existing fossil capacity and derate retrofitted control units by an additional 9.3 GW.[35] The DOE study made a simplifying assumption that existing steam units with once through cooling water systems operating at capacity factors less than 35 percent would be retired and retrofitted plant output capacity was reduced by four percent to represent increased station loads.

The 1,200 affected units with once through cooling water systems and their cooling water intake power suppliers identified rates through the U.S. Energy Information Administration (EIA) Form 923 and older Form 767 (Steam Electric Plant Operation and Design Report) data filings.[36] The affected units include 754 coal units, 405 oil/gas steam units and 42 units of nuclear capacity.

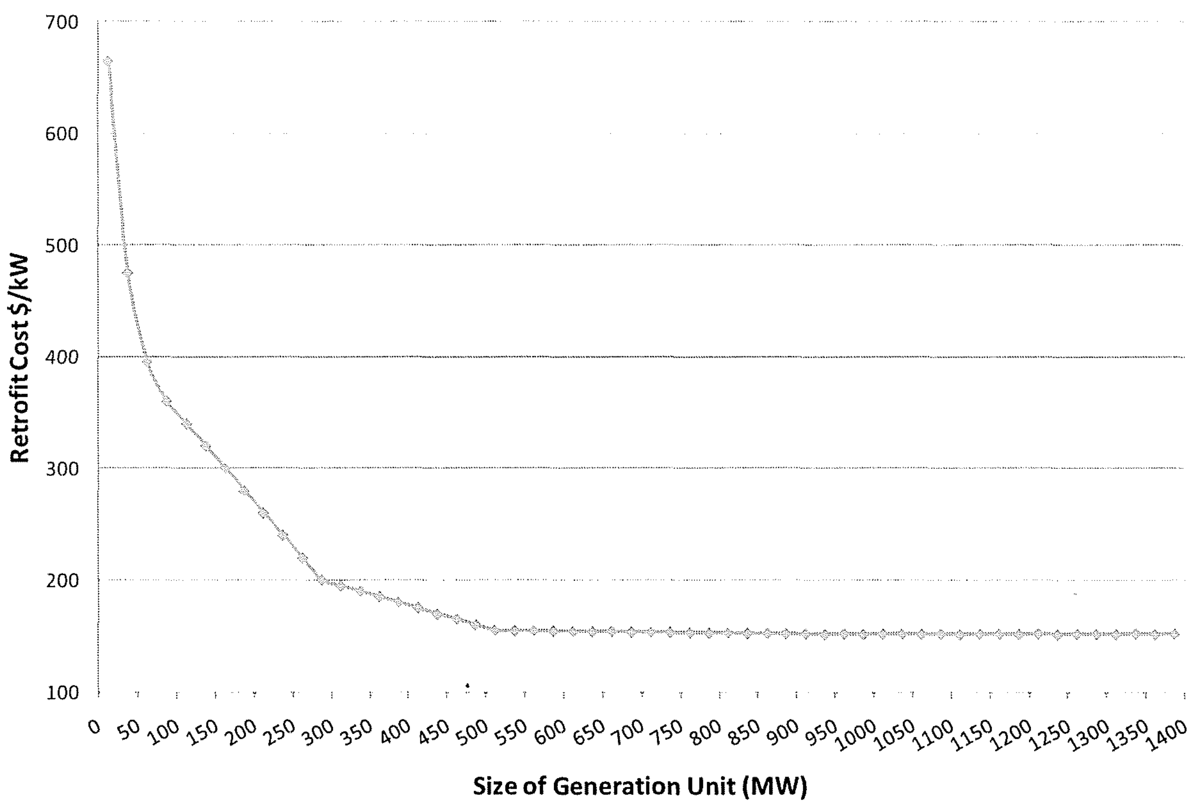
[35] http://www.oe.energy.gov/DocumentsandMedia/Cooling_Tower_Report.pdf
[36] http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html

For these units, capital cost estimates to convert from once through cooling water to recirculating cooling water systems are derived from three engineering studies and cost surveys:

- EPRI: _Issues Analysis of Retrofitting Once Through Cooled Plants with Closed Cycle Cooling_ (10/07);[37]
- Maulbetsch Consulting: EPRI Survey of 50 plant estimates (7/2002); and
- Stone & Webster: Study for Utility Water Assessment Group (7/2002).

These studies found that capital conversion costs are directly tied to the once-through cooling water pumping rate and heavily influenced by site layout and local conditions. Conversion costs ranged from $170-440 (2010 dollars) / gallons per minute (gpm) with an average capital conversion cost of $240/gpm. The average conversion costs were applied for most locations, except for known urban locations having constrained site conditions for which a 25 percent higher capital cost estimate of $300/gpm (2010 dollars) was applied. The base case costs applied in this reliability assessment are shown in Figure II-3.

Figure II-3: Base Case Retrofit Cost Curve for Section 316(b)($/kW)



In addition to the capital conversion costs, the station would lose both capacity and energy due to increased power consumption from the cooling water pump. The capacity and energy losses estimated in the 2008 DOE study and applied in this assessment are shown in Table II-1.

[37] EPRI is expected to issue a new revised report that will include detailed cost information not only for installing cooling towers, but also for retrofitting plants on sensitive water bodies, and operations and maintenance costs.

Table II-1: Capacity Derating/Energy Penalties Due to Cooling Tower Conversion

NERC Regions/ Subregions	Average Energy Loss %	Capacity Derating Penalty (%)
ERCOT	0.80%	2.50%
FRCC	0.90%	2.50%
MRO	1.40%	3.10%
NPCC	1.30%	3.40%
NYPP	1.20%	3.20%
RFC	1.60%	3.40%
Entergy	0.90%	2.60%
Gateway	1.20%	3.10%
Southeastern	0.80%	2.40%
TVA	0.90%	2.60%
VACAR	1.00%	2.80%
SPP	1.00%	2.80%
AZ-NM-SNV	1.40%	2.70%
CA	0.90%	2.50%
NWPP	1.40%	3.00%
RMPA	0.00%	2.50%
Total	1.20%	2.90%

Source: DOE *Electric Reliability Impacts of a Mandatory Cooling Tower Rule for Existing Steam Generating Units*(10/2008)

However, these referenced compliance costs and reliability impacts may be underestimated for the following reasons:

- First, the published studies used to develop the average capital cost estimates are based upon surveys done in 2002 and 2007. Such conversions are rare; no historic costing data have been published. Since these surveys, environmental project construction costs have escalated rapidly.
- Second, the site-specific conditions and plant layout can have significant impacts on conversion costs that are not reflected by applying industrial average estimates. Although an adjustment was made for known constrained urban sites, several more sites likely exist that may have similar (but unknown) site constraint problems.
- Finally, given the short potential rule implementation period and the large affected power plant population, demand for labor and construction materials for conversions could be in high demand and result in real cost escalation. Such capital cost run-ups have occurred in pollution control projects.

The Strict Case provides a 25 percent real price escalation in the average conversion cost to $300/gpm at most locations and $400/gpm at known constrained urban site locations to capture these potential risks. Alternatively, EPA could consider several policy options that could reduce the rule's impact. These options include (1) narrowing the rule scope to the largest cooling water consumers (*e.g.*, EPA's original rule applied only to water intakes greater than 50 million gallons per day), and (2) applying lower cost technology options for existing cooling systems (*e.g.* retrofitting fine mesh screens per the 2004 rule). Any narrowing of the regulation scope or cost would reduce the rule's reliability impacts. These alternative EPA regulatory options were not modeled for this assessment.

National Emissions Standards for Hazardous Pollutants (NESHAP) or Maximum Achievable Control Technology (MACT)

Under Title I of the 1990 Clean Air Act, EPA is obligated to develop an emission control program for listed air toxics for sources that emit at or above prescribed threshold values, including mercury. The Clean Air Act defines MACT for existing sources as "the average emission limitation achieved by the best performing 12 percent of the existing sources." EPA is obligated under a consent decree to propose a MACT rule by March 16, 2011 and to finalize the rule by November 16, 2011. The Clean Air Act mandates a three-year compliance timeframe: 2014 or 2015.

The potential EPA MACT rule will apply to all 1,732 existing and future coal and oil fired capacity (415.2 GW of existing plus another 26 GW of new planned coal units). The only flexibility for compliance is for EPA to grant a one-year extension, granted on a case-by-case basis, and a Presidential exemption of no more than 2 years based on availability of technology and national security interests.

This assessment uses environmental control costing curves to develop unit-specific compliance cost estimates, with the increased unit production costs of new pollution controls compared to unit production costs of replacement power. EPA is expected to adopt different MACT emission rate limitations, which implies that new investments required will vary by coal type.

The Moderate Case assumes that MACT is not fully implemented until 2018, as waivers are provided, largely for reliability reasons, to units that have committed and scheduled environmental upgrade projects but which may not be completed by the 2015 deadline. Further, investments are made when equipment is not present or planned, depending on the coal type, as shown in Table II-2. If wet or dry FGD are not present, then wet FGD is added for all coal types. SCR control retrofits are added for bituminous coal only. In addition, fabric filter systems with halide-treated activated carbon injection (HACI) systems are added for all coal types, if not already present. Oil stations (109.7 GW) are assumed to meet their air toxic limits through tighter oil specifications at the refinery.

By contrast, Strict Case assumes no waivers are granted and all upgrades must be complete by January 1, 2015, or units would retire. Investment costs are also projected to increase by 25 percent in Strict Case as shown by Table II-3.

Table II-2: Moderate Case Assumptions for MACT Air Toxics (includes CAMR and Acid Gases)

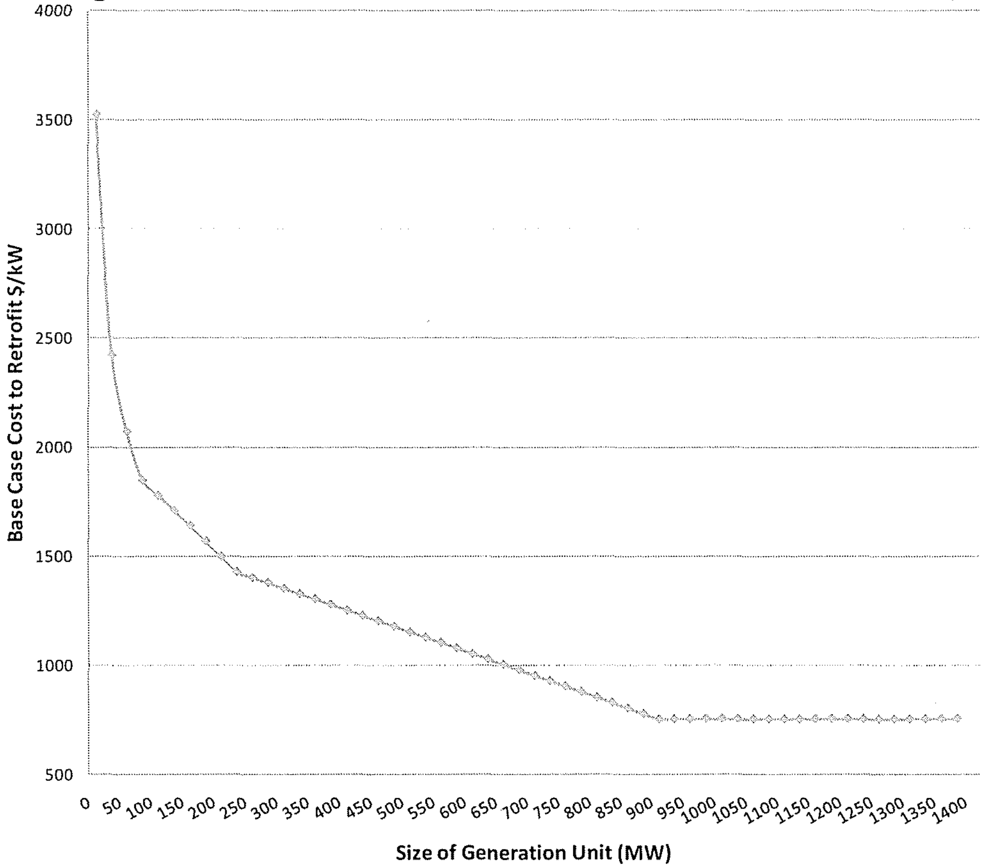
	Moderate Case		
	Bituminous	Sub-bituminous	Lignite
Wet FGD	If no wet or dry FGD, add wet FGD	If no wet or dry FGD, add wet FGD	If no wet or dry FGD, add wet FGD
Dry FGD			
SCR	Add		
Activated Carbon Injection		Add	Add
Baghouse (Fabric Filter)		Add	Add

Appendix II: Potential Environmental Regulations

Table II-3: Strict Case Assumptions for MACT Air Toxics (includes CAMR and Acid Gases)			
	Bituminous	Sub-bituminous	Lignite
Wet FGD	25%	25%	25%
Dry FGD	25%	25%	25%
SCR	25%		
Activated Carbon Injection	+25% Add	25%	25%
Baghouse (Fabric Filter)	+25% Add	25%	25%

Representative base case costs for bituminous coal are shown in Figure II-4.

Figure II-4: Bituminous Coal Base Case Cost Curves for MACT ($/kW)



Clean Air Transport Rule (CATR)

EPA developed its Clean Air Interstate Rule (CAIR) program to address the long-range emission transport contribution to fine particulate non-attainment and to take the first compliance step by reducing contributions from major fossil combustion stationary sources. Its *original* proposed program created a new annual NO_x cap-and-trade program and modified the existing Title IV SO_2 cap-and-trade program for 28 states for which upwind out-of-state contributions to non-attainment areas were considered significant. In 2008, the U.S. Court of Appeals overturned the EPA program due to concerns that NAAQS would not be met if sources complied through an unlimited amount of emission allowance purchases.

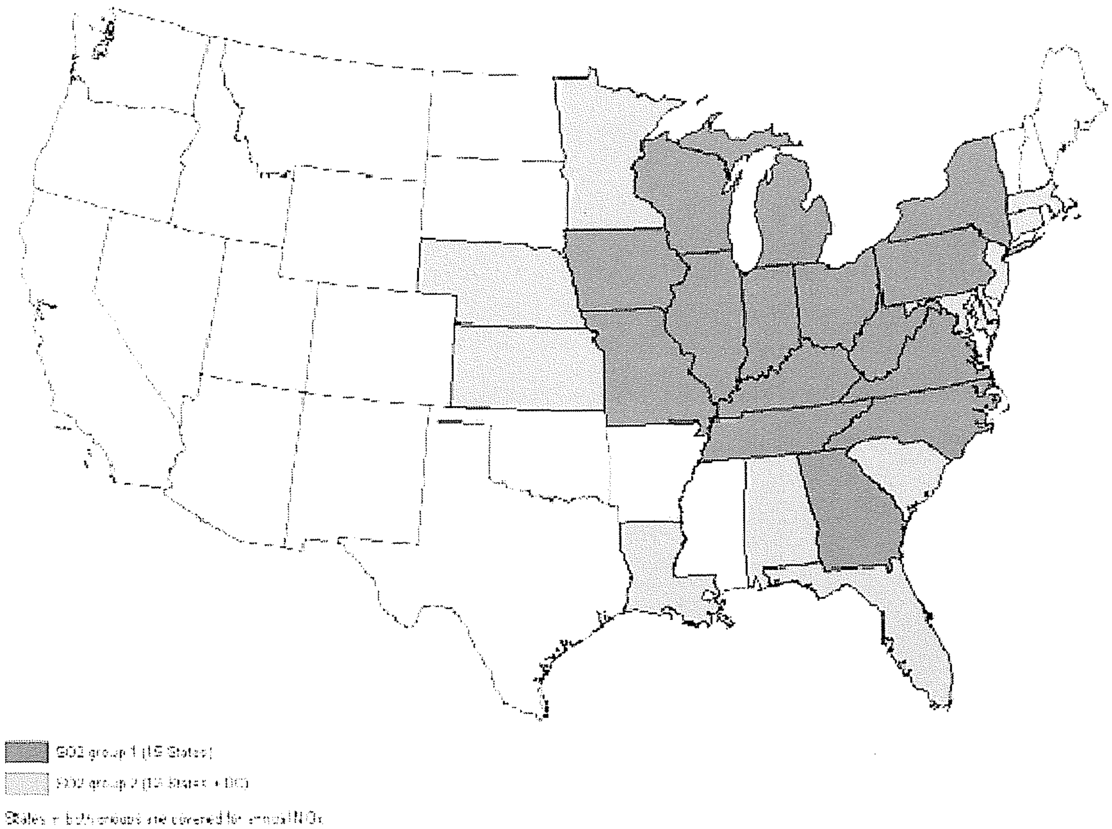
In July 2010, EPA proposed a draft CATR to control long-range transport of power plant SO_2/NO_x emissions that significantly contributed to non-attainment of fine particulate and ozone ambient air quality standards in downwind states—CATR will replace CAIR.[38] EPA anticipates issuing the final rule by March 2011. The draft program would apply only to fossil fuel electric generating units greater than 25 MW located in a designated state as shown in Figure II-5 .

Figure II-5: Clean Air Transport Rule Designated States

[38] EPA CATR Homepage: http://www.gpo.gov/fdsys/pkg/FR-2010-08-02/pdf/2010-17007.pdf#page=1 and proposed rule http://www.gpo.gov/fdsys/pkg/FR-2010-08-02/pdf/2010-17007.pdf#page=1

The potential EPA rule will regulate SO_2 and NO_x emissions under three new cap-and-trade programs (SO_2, annual NO_x and seasonal NO_x) starting January 1, 2012. EPA will set a state emissions budget cap for each pollutant, issue new allowances, and propose to significantly limit interstate allowance trading and banking after 2013. Previously banked surplus SO_2 and NO_x allowance credits and allocations created under the Acid Rain and CAIR programs cannot be used for compliance under the new program. For SO_2, affected states are organized into Group 1 or Group 2, as shown in Figure II-6.

Figure II-6: Clean Air Transport Rule Designated States



CATR applies to fossil power plant sources located within the 31 states and District of Colombia. The impact on the electric grid will vary depending on which of three EPA proposals becomes the final rule[39]:

- The EPA preferred option;
- Alternative 1 - the no interstate trading option; or
- Alternative 2 - the strict emission rate option.

EPA proposal is soliciting comments on its preferred option with limited interstate trading and intrastate trading, as well as the two alternative options. Further complicating compliance planning by electric generators, the agency recognizes that the proposed state emission budgets

[39] Described in the *Introduction* section of this report

caps are likely to change again in the near term when new fine particulate and ozone air quality standards are adopted, potentially later in 2010. These NAAQS will trigger new air quality modeling to determine the allowable pollutant loadings and allocations between contributing sources. Upon completion of this modeling, EPA will propose new state emission budget caps. The rule also gives the power industry a greater planning challenge than CAIR, since compliance must be on an aggregate state-by-state basis. In lieu of the current national emissions cap with unrestricted trading and banking, the new proposal also makes greater coordination essential between utilities within each state in order to optimize emission reductions. However, concerns over competition may limit coordination and result in less optimal compliance plans.

The new program is likely to require some electric generation units to retrofit additional FGD and selective catalytic reduction (SCR) controls by 2014, or retire. Strict emission limits that can only be met with post combustion FGD and SCR controls will directly affect 163 GW of coal-fired capacity that currently does not have FGD, or the 180 GW without post combustion NO_x controls. EPA's preferred option is summarized in Table II-4 below.

Table II-4: High Level Summary of Proposed CATR Regulation – EPA Preferred Option

SO_2 Cap & Trade Program				
	Group 1		Group 2	
	2012 Deadline	2014 Deadline	2012 Deadline	2014 Deadline
Number of States Affected	15	15	12 & DC	12 & DC
Emissions Cap (TPY)*	3,117,288	1,723,412	776,582	776,582
Emissions Credit Trading	EPA issues new allowances and surplus acid rain allowances become worthless. Trading allowed within Group 1.	Very strict annual state emission limitations on interstate trading and use of carryover allowances.	EPA issues new allowances and surplus acid rain allowances become worthless. Trading allowed within Group 2.	Very strict annual state emission limitations on interstate trading and use of carryover allowances.

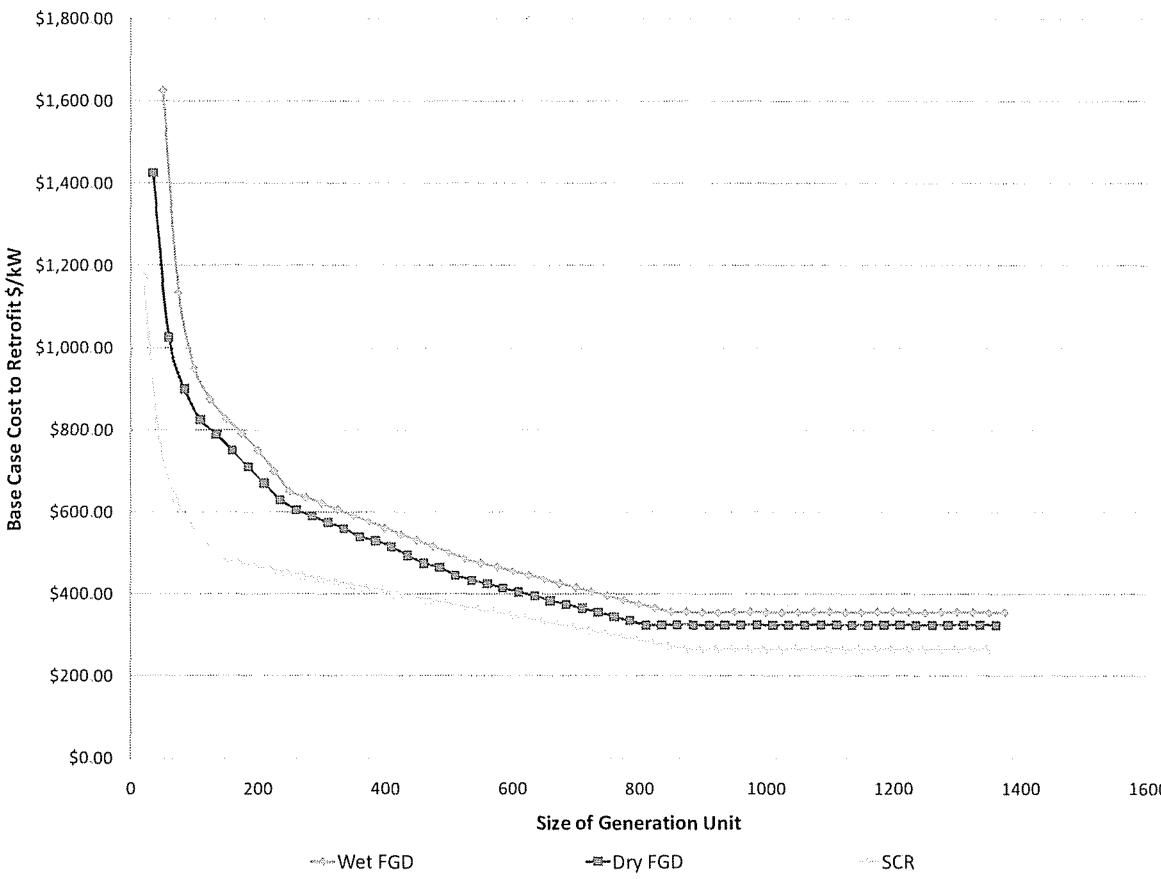
**EPA resets each state's budget at onset. State budget caps are likely to be revised once fine particulate NAAQS is implemented and modeling* is completed.

Annual NO_x Cap & Trade Program		
	27 States and District of Colombia	
	2012 Deadline	2014 Deadline
Number of States Affected	28	28
Emissions Cap (TPY)	1,317,312	1,317,312
Emissions Credit Trading	EPA issues new allowances and surplus CAIR ones become worthless. Trading allowed between all states.	Very strict annual state emission limitations on interstate trading and use of carryover allowances.

Appendix II: Potential Environmental Regulations

The costs for retrofitting post combustion controls are shown in Figure II-7. These capital costs are from utility project engineering estimates and recent projects. They are significantly higher than EPA study estimates that rely upon much older cost data and exclude owner and financing costs.

Figure II-7: Moderate Case Average Post Combustion Control Retrofit Costs for CATR ($/kW)



This assessment examines the impacts of the EPA's preferred option – limited cap-and-trade program -- as the Moderate Case. This option increases pressure to reduce emissions beyond current plans, particularly for sources in the six states of Indiana, Kentucky, Massachusetts, Missouri, Ohio and Pennsylvania. These six states must reduce their aggregated in-state SO_2 emissions by more than 250,000 tons per year by 2014. It may prove difficult to engineer, finance, permit and construct sufficient environmental controls in less than the three years required under the draft program. This assessment examines the economic decision at current control prices. The Strict Case assumes that EPA elects to adopt their future emission rate alternative that has no provisions for any trading between units and will force more coal units to have post combustion SO_2 and NO_x controls in the selected states. The assessment evaluates the available state credits to meet the state's limits and selects generating units for retirement in 2012 and 2014 that will be required to meet the emissions cap.

Coal Combustion Residuals (CCR)

Concerns raised by the December 2008 Kingston ash spill and its widespread environmental impact triggered EPA consideration of changing regulating coal-ash and waste byproduct (*e.g.*, scrubber sludge) disposal from its current special waste designation to Subtitle C Hazardous Waste under the Resource Conservation and Recovery Act. EPA developed a draft rule in September 2009 that was reviewed by the Office of Management and Budget and was issued in May 2010. A final rule is expected in 2011, with implementation expected to start in 2013–2015 and full compliance by 2018.

These EPA rules will regulate 136 million tons per year (tpy) of coal-ash and solid byproducts currently produced by the coal-fired stations. Policy issues that will impact decision making the most include:

- hazardous waste designation of coal-ash,
- impoundment design standards,
- groundwater protection standards, and
- rule implementation period.

EPA has proposed conversion of all coal-ash handling systems from utility-boilers to dry based systems, with two options proposed for disposal of all ash and coal byproducts in a landfill meeting either Subtitle C or D, which entails different types of waste disposal standards, and to close/cap existing ash ponds. Such a ruling requires the 359 coal units (128.5 GW) to convert their wet ash handling systems to dry based systems, incur greater ash disposal costs for the 136 million tons of ash disposal each year, and close and cap the existing 500 ash/sludge ponds in operation.

In addition, a hazardous waste designation under Subtitle C could eliminate the market for 20 million tons of ash that is currently resold into the market, although the EPA is considering a "special waste" designation, which would allow "beneficial" reuse of the substance to continue. Hazardous waste designation without exceptions would vastly expand the existing hazardous waste disposal market from its current size of 2 million tpy.

Prior public studies examining the ash disposal issue on power plant operation are limited. A 2009 EOP Group Study titled *Cost Estimates for the Mandatory Closure of Surface Impoundments Used for the Management of Coal Combustion Byproducts at Coal fired Utilities* was reviewed.[40],[41] This 2009 study concluded that EPA's draft rule could directly affect operations at 397 coal generating units (175 GW). The EOP Group study estimated bottom ash conversion costs of $30 million per unit, and this assumption is used in the Moderate Case of this assessment. In addition, at some stations, the ash ponds also dispose of fly ash (15 million tons per year or tpy) that would require an additional $3 billion investment to convert to dry handling systems. Outside of conversion costs, stations would have to build alternative wastewater treatment facilities at 155 facilities ranging, per facility, from $80 million without a flue gas desulfurization system (FGD) to $120 million with FGD per facility to provide storm water and/or FGD scrubber sludge treatment currently handled by the ash ponds. Ash pond closure

[40] http://www.whitehouse.gov//sites/default/files/omb/assets/oira_2050/2050_102809-2.pdf

[41] A revised EOP report is currently under review, reference report upon completion. Preliminary values indicate a 20 percent increase in cost.

Appendix II: Potential Environmental Regulations

costs were estimated to be $30 million per pond. The EOP Group study concluded, "*Units with below 230 MW of generating capacity have the greatest potential risk of ceasing operations if required to undertake mandatory closure of CCB surface impoundments*." These "economically vulnerable" coal units totaled 35 GW of existing capacity and represented 18 percent of 2005 U.S. coal generation.

However, the 2009 EOP Study contained some deficiencies that could underestimate compliance costs as follows:

- First, the study excluded any land acquisition costs for landfill or expanded wastewater treatment facilities.
- Second, the study excluded the increased disposal cost if ash was designated as hazardous waste.
- Third, it excluded costs for existing ash pond closures. These remediation costs will vary significantly based upon the extent of any groundwater contamination, site geology and aquifer use. However, any remediation might be considered as a sunk cost since it would be incurred independently of the future operating decision. If these costs were indeed considered sunk, they should not be incorporated into unit retirement decisions.

A total of 359 coal-fired units (128.5 GW) of coal-fired capacity reported using wet pond based systems for their ash and/or byproduct handling systems in their EIA Form 767 and 923 filings. For these units, the 2009 EOP study cost estimates for bottom ash conversion and wastewater treatment upgrades are applied on a unit basis. The additional EOP ash waste disposal costs of $15 per ton (2010 dollars) were added for handling in a regulated non-hazardous onsite landfill to the unit operating costs in the Moderate Case of this study. The pond closure and remediation costs are assumed to become sunk costs that would be incurred independently of the future power plant operations. Therefore, only incremental costs associated with ongoing operations are accounted for in the decision to invest or retire the unit. When these incremental power production costs exceeded new replacement capacity costs, the units became potential retirement candidates.

However, as outlined above, the EOP Group study may have underestimated compliance costs and thereby underestimated potential grid reliability impacts. Based on discussions with various subject-matter experts, the capital compliance cost uncertainty is likely to be plus/minus 25 percent. To account for potentially higher costs under stricter Subtitle C guidelines, landfill costs are assumed to be much higher at $37.50 per ton (2010 dollars) in the Strict Case, which is also similar to the EPA study's estimated disposal costs. In lieu of conducting site-specific assessments, sensitivity comparisons are completed across a wide range of ash disposal costs from $37.50 to $1,250 per ton.

Appendix III: Capacity Assessed by NERC Subregion

Figure III-1: Base Fossil-Fired Generation Capacity Assessed by NERC Region/Subregion

	No. Units	Capcity (MW)
Coal Units		
ERCOT	31	17,685
FRCC	22	9,444
MRO	157	25,231
NPCC-NE	13	2,634
NPCC-NY	21	2,812
RFC	309	97,302
SERC-Central	99	24,487
SERC-Delta	21	9,317
SERC-Gateway	51	13,998
SERC-Southeastern	65	24,223
SERC-VACAR	109	24,147
SPP	62	19,111
WECC-CA	10	2,182
WECC-AZ-NM-SNV	29	11,911
WECC-NWPP	39	12,097
WECC-RMPA	45	6,419
TOTAL	1080	302,998
O/G - ST Units		
ERCOT	55	14,418
FRCC	23	6,841
MRO	25	691
NPCC-NE	23	6,040
NPCC-NY	34	11,181
RFC	43	8,942
SERC-Central	0	0
SERC-Delta	88	16,519
SERC-Gateway	13	561
SERC-Southeastern	8	506
SERC-VACAR	6	2,012
SPP	92	10,955
WECC-CA	56	15,439
WECC-AZ-NM-SNV	28	2,142
WECC-NWPP	8	705
WECC-RMPA	7	175
TOTAL	509	97,124

Appendix III: Capacity Assessed by NERC Subregion

Appendix IV: Data Tables

For the resource adequacy assessment, NERC chose a range of resource categories to evaluate Planning Reserve Margins for this scenario. The range includes Deliverable Capacity Resources on the low-end and Adjusted Potential Capacity Resources on the high-end. Refer to the *Terms Used in this Report* section for detailed definitions regarding supply/resource categories.

Table IV-1: 2009 Long-Term Reliability Assessment Reference Case - 2009 Figures

	Net Internal Demand - Reference Case (MW)	Deliverable Capacity Resources - Reference Case (MW)	Adjusted Potential Capacity Resources - Reference Case (MW)	Deliverable Capacity Resources Reserve Margin - Reference Case	Adjusted Potential Capacity Resources Reserve Margin - Reference Case
ERCOT	62,376	72,204	72,204	15.8%	15.8%
FRCC	42,531	51,870	51,870	22.0%	22.0%
MRO	41,306	50,308	51,098	21.8%	23.7%
NPCC-NE	27,875	33,703	33,921	20.9%	21.7%
NPCC-NY	33,233	42,968	43,658	29.3%	31.4%
RFC	169,900	215,800	217,904	27.0%	28.3%
SERC-Central	40,874	50,828	51,196	24.4%	25.3%
SERC-Delta	27,178	38,466	38,602	41.5%	42.0%
SERC-Gateway	18,947	20,306	21,117	7.2%	11.5%
SERC-Southeastern	47,789	58,745	67,788	22.9%	41.8%
SERC-VACAR	62,083	75,663	77,426	21.9%	24.7%
SPP	43,696	50,127	56,648	14.7%	29.6%
WECC-CA	58,421	71,334	71,334	22.1%	22.1%
WECC-AZ-NM-SNV	29,843	35,076	35,076	17.5%	17.5%
WECC-NWPP	41,391	56,705	56,710	37.0%	37.0%
WECC-RMPA	10,939	13,517	13,517	23.6%	23.6%
TOTAL	758,382	937,619	960,070	23.1%	26.1%

Table IV-2: 2009 Long-Term Reliability Assessment Reference Case - 2013 Projections

	Net Internal Demand - Reference Case (MW)	Deliverable Resources - Reference Case (MW)	Adjusted Potential Resources - Reference Case (MW)	Deliverable Resources Reserve Margin - Reference Case	Adjusted Potential Capacity Resources Reserve Margin - Reference Case
ERCOT	68,284	79,521	84,617	16.50%	23.90%
FRCC	44,697	57,464	57,464	28.60%	28.60%
MRO	44,482	50,218	54,299	12.90%	22.10%
NPCC-NE	29,365	34,827	37,122	18.60%	26.40%
NPCC-NY	33,861	43,381	43,957	28.10%	29.80%
RFC	183,900	219,600	228,502	19.40%	24.30%
SERC-Central	42,437	52,473	53,990	23.60%	27.20%
SERC-Delta	29,406	37,499	38,505	27.50%	30.90%
SERC-Gateway	20,032	24,834	25,645	24.00%	28.00%
SERC-Southeastern	53,099	59,987	68,949	13.00%	29.80%
SERC-VACAR	66,926	78,611	80,494	17.50%	20.30%
SPP	46,153	53,477	60,149	15.90%	30.30%
WECC-CA	60,073	89,293	89,293	48.60%	48.60%
WECC-AZ-NM-SNV	32,060	39,157	39,663	22.10%	23.70%
WECC-NWPP	44,076	57,240	57,353	29.90%	30.10%
WECC-RMPA	11,616	14,483	15,131	24.70%	30.30%
TOTAL	810,467	992,063	1,035,134	22.40%	27.70%

Table IV-3: 2009 Long-Term Reliability Assessment Reference Case - 2015 Projections

	Net Internal Demand - Reference Case (MW)	Deliverable Resources - Reference Case (MW)	Adjusted Potential Capacity Resources - Reference Case (MW)	Deliverable Resources Reserve Margin - Reference Case	Adjusted Potential Capacity Resources Reserve Margin - Reference Case
ERCOT	69,057	79,523	84,967	15.20%	23.00%
FRCC	46,579	58,235	58,235	25.00%	25.00%
MRO	45,675	49,952	54,312	9.40%	18.90%
NPCC-NE	30,115	34,777	37,487	15.50%	24.50%
NPCC-NY	34,264	43,281	43,977	26.30%	28.30%
RFC	187,700	219,800	229,546	17.10%	22.30%
SERC-Central	43,432	52,882	54,399	21.80%	25.30%
SERC-Delta	30,369	36,582	37,588	20.50%	23.80%
SERC-Gateway	20,300	24,916	25,727	22.70%	26.70%
SERC-Southeastern	55,225	62,050	71,237	12.40%	29.00%
SERC-VACAR	69,198	77,941	80,046	12.60%	15.70%
SPP	46,554	53,480	60,210	14.90%	29.30%
WECC-CA	61,564	92,405	92,405	50.10%	50.10%
WECC-AZ-NM-SNV	33,836	40,519	41,622	19.80%	23.00%
WECC-NWPP	45,306	57,546	58,061	27.00%	28.20%
WECC-RMPA	12,097	14,110	15,116	16.60%	25.00%
TOTAL	831,271	997,997	1,044,936	20.10%	25.70%

Table IV-4: 2009 Long-Term Reliability Assessment Reference Case - 2018 Projections					
	Net Internal Demand - Reference Case (MW)	Deliverable Resources - Reference Case (MW)	Adjusted Potential Capacity Resources - Reference Case (MW)	Deliverable Resources Reserve Margin - Reference Case	Adjusted Potential Capacity Resources Reserve Margin - Reference Case
ERCOT	75,019	79,525	84,969	6.00%	13.30%
FRCC	49,885	63,336	63,336	27.00%	27.00%
MRO	47,534	49,469	54,317	4.10%	14.30%
NPCC-NE	30,960	34,499	37,209	11.40%	20.20%
NPCC-NY	35,231	44,081	44,777	25.10%	27.10%
RFC	193,100	219,800	230,054	13.80%	19.10%
SERC-Central	45,288	54,410	55,927	20.10%	23.50%
SERC-Delta	31,438	36,161	37,167	15.00%	18.20%
SERC-Gateway	20,817	24,916	25,727	19.70%	23.60%
SERC-Southeastern	58,505	67,860	77,047	16.00%	31.70%
SERC-VACAR	72,814	79,025	80,880	8.50%	11.10%
SPP	48,500	53,319	60,141	9.90%	24.00%
WECC-CA	63,916	89,054	89,054	39.30%	39.30%
WECC-AZ-NM-SNV	36,382	43,381	44,819	19.20%	23.20%
WECC-NWPP	47,292	57,687	58,200	22.00%	23.10%
WECC-RMPA	12,874	15,102	16,146	17.30%	25.40%
TOTAL	869,554	1,011,624	1,059,770	16.30%	21.90%

Appendix IV: Data Tables

Table IV-5: Combined Impacts - Number of Units Retired by Region and Size - 2018	Coal					Gas/Oil Steam				
	0-99 (MW)	100-199	200-399	>400 (MW)	Total	0-99 (MW)	100-199	200-399	>400 (MW)	Total
Moderate Case										
ERCOT	0	0	0	0	0	8	10	7	3	28
FRCC	0	1	0	0	1	5	1	2	0	8
MRO	57	0	0	0	57	24	1	0	0	25
NPCC-NE	2	0	1	0	3	5	4	0	4	13
NPCC-NY	6	1	0	0	7	5	3	0	3	11
RFC	36	10	1	0	47	19	8	3	3	33
SERC-Central	6	1	0	0	7	0	0	0	0	0
SERC-Delta	3	0	0	0	3	31	5	4	6	46
SERC-Gateway	5	1	0	0	6	12	0	0	0	12
SERC-Southeastern	5	2	0	0	7	4	1	0	0	5
SERC-VACAR	28	4	0	0	32	3	0	1	0	4
SPP-N	4	0	0	0	4	15	0	0	0	15
SPP-S	1	0	0	0	1	17	1	0	0	18
WECC-AZ-NM-SNV	0	0	0	2	2	9	3	0	0	12
WECC-CA	0	0	0	0	0	2	7	6	3	18
WECC-NWPP	4	0	0	0	4	0	0	0	0	0
WECC-RMPA	6	0	0	0	6	5	0	0	0	5
Total	163	20	2	2	187	164	44	23	22	253
Strict Case										
ERCOT	0	0	0	0	0	8	10	8	3	29
FRCC	0	1	0	0	1	5	1	2	1	9
MRO	88	7	1	0	96	24	1	0	0	25
NPCC-NE	4	3	1	0	8	5	4	0	5	14
NPCC-NY	10	3	1	0	14	5	3	0	4	12
RFC	56	44	4	1	105	19	8	3	3	33
SERC-Central	6	32	0	0	38	0	0	0	0	0
SERC-Delta	4	2	0	0	6	31	5	4	6	46
SERC-Gateway	13	9	3	0	25	12	0	0	0	12
SERC-Southeastern	5	10	5	0	20	4	1	0	0	5
SERC-VACAR	34	23	0	0	57	3	0	1	0	4
SPP-N	19	0	0	0	19	16	0	0	0	16
SPP-S	1	2	0	0	3	17	1	0	0	18
WECC-AZ-NM-SNV	0	0	0	2	2	9	3	0	0	12
WECC-CA	3	0	0	0	3	2	7	9	5	23
WECC-NWPP	4	0	0	0	4	0	0	0	0	0
WECC-RMPA	9	0	0	0	9	5	0	0	0	5
Total	256	136	15	3	410	165	44	27	27	263

Table IV-6: Combined Impacts - 2018						
	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
Coal Units						
ERCOT	231	0	231	351	0	351
FRCC	124	121	245	187	121	308
MRO	534	862	1,397	612	3,733	4,345
NPCC-NE	92	466	558	79	1,034	1,113
NPCC-NY	92	302	394	68	1,214	1,282
RFC	1,965	3,285	5,250	2,266	10,888	13,154
SERC-Central	541	445	986	509	4,546	5,055
SERC-Delta	151	46	197	265	308	573
SERC-Gateway	390	289	679	442	2,894	3,336
SERC-Southeastern	423	452	875	537	2,803	3,340
SERC-VACAR	453	1,658	2,111	492	4,634	5,126
SPP	252	91	342	411	1,207	1,618
WECC-CA	12	0	12	10	81	90
WECC-AZ-NM-SNV	49	1,580	1,629	49	1,580	1,629
WECC-NWPP	109	129	239	109	129	239
WECC-RMPA	27	100	126	25	141	167
TOTAL	5,445	9,825	15,270	6,414	35,312	41,726
O/G-ST Units						
ERCOT	135	5,055	5,190	129	5,295	5,424
FRCC	65	862	927	52	1,367	1,419
MRO	0	691	691	0	691	691
NPCC-NE	104	2,504	2,608	90	2,904	2,995
NPCC-NY	261	2,937	3,198	241	3,544	3,786
RFC	0	4,563	4,563	0	4,563	4,563
SERC-Central	0	0	0	0	0	0
SERC-Delta	200	5,495	5,695	200	5,495	5,695
SERC-Gateway	0	405	405	0	405	405
SERC-Southeastern	0	329	329	0	329	329
SERC-VACAR	23	408	431	23	408	431
SPP	19	881	901	17	942	960
WECC-CA	218	5,041	5,259	172	6,867	7,039
WECC-AZ-NM-SNV	5	773	778	5	773	778
WECC-NWPP	3	0	3	3	0	3
WECC-RMPA	0	84	84	0	84	84
TOTAL	1,033	30,027	31,061	934	33,667	34,601

Table IV-7: 316(b) Impacts - 2013				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	16.5% – 23.9%	0.0 – 0.0	16.5% – 23.9%	0.0 – 0.0
FRCC	28.6% – 28.6%	0.0 – 0.0	28.6% – 28.6%	0.0 – 0.0
MRO	12.9% – 22.1%	0.0 – 0.0	12.9% – 22.1%	0.0 – 0.0
NPCC-NE	18.6% – 26.4%	0.0 – 0.0	18.6% – 26.4%	0.0 – 0.0
NPCC-NY	28.1% – 29.8%	0.0 – 0.0	28.1% – 29.8%	0.0 – 0.0
RFC	19.4% – 24.3%	0.0 – 0.0	19.4% – 24.3%	0.0 – 0.0
SERC-Central	23.6% – 27.2%	0.0 – 0.0	23.6% – 27.2%	0.0 – 0.0
SERC-Delta	27.5% – 30.9%	0.0 – 0.0	27.5% – 30.9%	0.0 – 0.0
SERC-Gateway	24.0% – 28.0%	0.0 – 0.0	24.0% – 28.0%	0.0 – 0.0
SERC-Southeastern	13.0% – 29.8%	0.0 – 0.0	13.0% – 29.8%	0.0 – 0.0
SERC-VACAR	17.5% – 20.3%	0.0 – 0.0	17.5% – 20.3%	0.0 – 0.0
SPP	15.9% – 30.3%	0.0 – 0.0	15.9% – 30.3%	0.0 – 0.0
WECC-CA	48.6% – 48.6%	0.0 – 0.0	48.6% – 48.6%	0.0 – 0.0
WECC-AZ-NM-SNV	22.1% – 23.7%	0.0 – 0.0	22.1% – 23.7%	0.0 – 0.0
WECC-NWPP	29.9% – 30.1%	0.0 – 0.0	29.9% – 30.1%	0.0 – 0.0
WECC-RMPA	24.7% – 30.3%	0.0 – 0.0	24.7% – 30.3%	0.0 – 0.0
TOTAL	22.4% – 27.7%	0.0 – 0.0	22.4% – 27.7%	0.0 – 0.0

Table IV-8: MACT Impacts - 2013				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	16.5% – 23.9%	0.0 – 0.0	16.5% – 23.9%	0.0 – 0.0
FRCC	28.6% – 28.6%	0.0 – 0.0	28.6% – 28.6%	0.0 – 0.0
MRO	12.9% – 22.1%	0.0 – 0.0	12.9% – 22.1%	0.0 – 0.0
NPCC-NE	18.6% – 26.4%	0.0 – 0.0	18.6% – 26.4%	0.0 – 0.0
NPCC-NY	28.1% – 29.8%	0.0 – 0.0	28.1% – 29.8%	0.0 – 0.0
RFC	19.4% – 24.3%	0.0 – 0.0	19.4% – 24.3%	0.0 – 0.0
SERC-Central	23.6% – 27.2%	0.0 – 0.0	23.6% – 27.2%	0.0 – 0.0
SERC-Delta	27.5% – 30.9%	0.0 – 0.0	27.5% – 30.9%	0.0 – 0.0
SERC-Gateway	24.0% – 28.0%	0.0 – 0.0	24.0% – 28.0%	0.0 – 0.0
SERC-Southeastern	13.0% – 29.8%	0.0 – 0.0	13.0% – 29.8%	0.0 – 0.0
SERC-VACAR	17.5% – 20.3%	0.0 – 0.0	17.5% – 20.3%	0.0 – 0.0
SPP	15.9% – 30.3%	0.0 – 0.0	15.9% – 30.3%	0.0 – 0.0
WECC-CA	48.6% – 48.6%	0.0 – 0.0	48.6% – 48.6%	0.0 – 0.0
WECC-AZ-NM-SNV	22.1% – 23.7%	0.0 – 0.0	22.1% – 23.7%	0.0 – 0.0
WECC-NWPP	29.9% – 30.1%	0.0 – 0.0	29.9% – 30.1%	0.0 – 0.0
WECC-RMPA	24.7% – 30.3%	0.0 – 0.0	24.7% – 30.3%	0.0 – 0.0
TOTAL	22.4% – 27.7%	0.0 – 0.0	22.4% – 27.7%	0.0 – 0.0

Table IV-9: CATR Impacts - 2013				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	16.5% – 23.9%	0.0 – 0.0	16.4% – 23.8%	-0.1 – -0.1
FRCC	28.6% – 28.6%	0.0 – 0.0	28.6% – 28.6%	0.0 – 0.0
MRO	12.9% – 22.1%	0.0 – 0.0	12.2% – 21.4%	-0.7 – -0.7
NPCC-NE	18.0% – 26.4%	-0.6 – 0.0	18.6% – 26.4%	0.0 – 0.0
NPCC-NY	28.1% – 29.8%	0.0 – 0.0	28.1% – 29.8%	0.0 – 0.0
RFC	19.2% – 24.3%	-0.2 – 0.0	18.9% – 23.7%	-0.5 – -0.5
SERC-Central	23.6% – 27.2%	0.0 – 0.0	23.3% – 26.9%	-0.4 – -0.4
SERC-Delta	27.5% – 30.9%	0.0 – 0.0	27.1% – 30.5%	-0.4 – -0.4
SERC-Gateway	24.0% – 28.0%	0.0 – 0.0	23.3% – 27.4%	-0.6 – -0.6
SERC-Southeastern	13.0% – 29.8%	0.0 – 0.0	12.5% – 29.3%	-0.5 – -0.5
SERC-VACAR	17.5% – 20.3%	0.0 – 0.0	16.6% – 19.4%	-0.9 – -0.9
SPP	15.9% – 30.3%	0.0 – 0.0	15.6% – 30.0%	-0.3 – -0.3
WECC-CA	48.6% – 48.6%	0.0 – 0.0	48.6% – 48.6%	0.0 – 0.0
WECC-AZ-NM-SNV	22.1% – 23.7%	0.0 – 0.0	22.1% – 23.7%	0.0 – 0.0
WECC-NWPP	29.9% – 30.1%	0.0 – 0.0	29.9% – 30.1%	0.0 – 0.0
WECC-RMPA	24.7% – 30.3%	0.0 – 0.0	24.7% – 30.3%	0.0 – 0.0
TOTAL	22.3% – 27.7%	-0.1 – 0.0	22.1% – 27.4%	-0.3 – -0.3

Table IV-10: CCR Impacts - 2013				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	16.5% – 23.9%	0.0 – 0.0	16.5% – 23.9%	0.0 – 0.0
FRCC	28.6% – 28.6%	0.0 – 0.0	28.6% – 28.6%	0.0 – 0.0
MRO	12.9% – 22.1%	0.0 – 0.0	12.9% – 22.1%	0.0 – 0.0
NPCC-NE	18.6% – 26.4%	0.0 – 0.0	18.6% – 26.4%	0.0 – 0.0
NPCC-NY	28.1% – 29.8%	0.0 – 0.0	28.1% – 29.8%	0.0 – 0.0
RFC	19.4% – 24.3%	0.0 – 0.0	19.4% – 24.3%	0.0 – 0.0
SERC-Central	23.6% – 27.2%	0.0 – 0.0	23.6% – 27.2%	0.0 – 0.0
SERC-Delta	27.5% – 30.9%	0.0 – 0.0	27.5% – 30.9%	0.0 – 0.0
SERC-Gateway	24.0% – 28.0%	0.0 – 0.0	24.0% – 28.0%	0.0 – 0.0
SERC-Southeastern	13.0% – 29.8%	0.0 – 0.0	13.0% – 29.8%	0.0 – 0.0
SERC-VACAR	17.5% – 20.3%	0.0 – 0.0	17.5% – 20.3%	0.0 – 0.0
SPP	15.9% – 30.3%	0.0 – 0.0	15.9% – 30.3%	0.0 – 0.0
WECC-CA	48.6% – 48.6%	0.0 – 0.0	48.6% – 48.6%	0.0 – 0.0
WECC-AZ-NM-SNV	22.1% – 23.7%	0.0 – 0.0	22.1% – 23.7%	0.0 – 0.0
WECC-NWPP	29.9% – 30.1%	0.0 – 0.0	29.9% – 30.1%	0.0 – 0.0
WECC-RMPA	24.7% – 30.3%	0.0 – 0.0	24.7% – 30.3%	0.0 – 0.0
TOTAL	22.4% – 27.7%	0.0 – 0.0	22.4% – 27.7%	0.0 – 0.0

Table IV-11: Combined Impacts - 2013				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	16.5% – 23.9%	0.0 – 0.0	16.3% – 23.8%	-0.1 – -0.1
FRCC	28.6% – 28.6%	0.0 – 0.0	28.5% – 28.5%	0.0 – 0.0
MRO	12.9% – 22.1%	0.0 – 0.0	10.1% – 19.3%	-2.7 – -2.7
NPCC-NE	18.0% – 25.9%	-0.6 – -0.6	16.7% – 24.6%	-1.9 – -1.9
NPCC-NY	28.1% – 29.8%	0.0 – 0.0	27.3% – 29.0%	-0.8 – -0.8
RFC	19.2% – 24.0%	-0.2 – -0.2	17.6% – 22.4%	-1.9 – -1.9
SERC-Central	23.6% – 27.2%	0.0 – 0.0	22.8% – 26.4%	-0.9 – -0.9
SERC-Delta	27.5% – 30.9%	0.0 – 0.0	27.0% – 30.4%	-0.5 – -0.5
SERC-Gateway	24.0% – 28.0%	0.0 – 0.0	22.9% – 27.0%	-1.0 – -1.0
SERC-Southeastern	13.0% – 29.8%	0.0 – 0.0	12.1% – 28.9%	-0.9 – -0.9
SERC-VACAR	17.5% – 20.3%	0.0 – 0.0	15.5% – 18.3%	-1.9 – -1.9
SPP	15.9% – 30.3%	0.0 – 0.0	15.9% – 30.3%	0.0 – 0.0
WECC-CA	48.6% – 48.6%	0.0 – 0.0	48.4% – 48.4%	-0.3 – -0.3
WECC-AZ-NM-SNV	22.1% – 23.7%	0.0 – 0.0	22.1% – 23.7%	0.0 – 0.0
WECC-NWPP	29.9% – 30.1%	0.0 – 0.0	29.9% – 30.1%	0.0 – 0.0
WECC-RMPA	24.7% – 30.3%	0.0 – 0.0	24.7% – 30.3%	0.0 – 0.0
TOTAL	22.3% – 27.7%	-0.1 – -0.1	21.4% – 26.7%	-1.0 – -1.0

Table IV-12: 316(b) Impacts - 2015				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	14.1% – 22.0%	-1.1 – -1.1	13.8% – 21.7%	-1.4 – -1.4
FRCC	24.7% – 24.7%	-0.3 – -0.3	24.7% – 24.7%	-0.3 – -0.3
MRO	7.6% – 17.2%	-1.7 – -1.7	7.6% – 17.1%	-1.8 – -1.8
NPCC-NE	12.0% – 21.0%	-3.5 – -3.5	12.0% – 21.0%	-3.5 – -3.5
NPCC-NY	23.5% – 25.5%	-2.9 – -2.9	23.5% – 25.5%	-2.9 – -2.9
RFC	16.2% – 21.4%	-0.9 – -0.9	16.2% – 21.4%	-0.9 – -0.9
SERC-Central	21.1% – 24.6%	-0.6 – -0.6	21.1% – 24.6%	-0.6 – -0.6
SERC-Delta	14.3% – 17.7%	-6.1 – -6.1	14.3% – 17.7%	-6.1 – -6.1
SERC-Gateway	20.0% – 24.0%	-2.7 – -2.7	20.0% – 24.0%	-2.7 – -2.7
SERC-Southeastern	11.8% – 28.5%	-0.5 – -0.5	11.9% – 28.5%	-0.5 – -0.5
SERC-VACAR	12.4% – 15.4%	-0.3 – -0.3	12.3% – 15.4%	-0.3 – -0.3
SPP	13.6% – 28.0%	-1.3 – -1.3	13.5% – 28.0%	-1.4 – -1.4
WECC-CA	48.8% – 48.8%	-1.3 – -1.3	48.8% – 48.8%	-1.3 – -1.3
WECC-AZ-NM-SNV	19.7% – 22.9%	-0.1 – -0.1	19.7% – 22.9%	-0.1 – -0.1
WECC-NWPP	26.8% – 28.0%	-0.2 – -0.2	26.8% – 28.0%	-0.2 – -0.2
WECC-RMPA	16.2% – 24.6%	-0.4 – -0.4	16.0% – 24.3%	-0.6 – -0.6
TOTAL	18.8% – 24.5%	-1.2 – -1.2	18.8% – 24.4%	-1.3 – -1.3

Table IV-13: MACT Impacts - 2015				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	15.0% – 22.9%	-0.1 – -0.1	15.0% – 22.9%	-0.1 – -0.1
FRCC	25.0% – 25.0%	0.0 – 0.0	24.6% – 24.6%	-0.4 – -0.4
MRO	8.6% – 18.2%	-0.7 – -0.7	7.4% – 16.9%	-2.0 – -2.0
NPCC-NE	15.5% – 24.5%	0.0 – 0.0	13.3% – 22.3%	-2.2 – -2.2
NPCC-NY	26.3% – 28.3%	0.0 – 0.0	24.2% – 26.3%	-2.1 – -2.1
RFC	16.5% – 21.7%	-0.6 – -0.6	13.6% – 18.8%	-3.5 – -3.5
SERC-Central	21.5% – 24.9%	-0.3 – -0.3	18.8% – 22.2%	-3.0 – -3.0
SERC-Delta	20.2% – 23.5%	-0.3 – -0.3	19.9% – 23.2%	-0.5 – -0.5
SERC-Gateway	22.2% – 26.1%	-0.6 – -0.6	20.4% – 24.4%	-2.3 – -2.3
SERC-Southeastern	12.0% – 28.7%	-0.3 – -0.3	9.6% – 26.2%	-2.8 – -2.8
SERC-VACAR	12.0% – 15.0%	-0.7 – -0.7	8.4% – 11.5%	-4.2 – -4.2
SPP	14.6% – 29.1%	-0.3 – -0.3	14.5% – 28.9%	-0.4 – -0.4
WECC-CA	50.1% – 50.1%	0.0 – 0.0	50.1% – 50.1%	0.0 – 0.0
WECC-AZ-NM-SNV	19.6% – 22.9%	-0.1 – -0.1	14.9% – 18.2%	-4.8 – -4.8
WECC-NWPP	26.8% – 27.9%	-0.2 – -0.2	26.6% – 27.7%	-0.4 – -0.4
WECC-RMPA	16.5% – 24.8%	-0.1 – -0.1	15.7% – 24.0%	-0.9 – -0.9
TOTAL	19.7% – 25.4%	-0.3 – -0.3	17.9% – 23.6%	-2.1 – -2.1

Appendix IV: Data Tables

Appendix IV: Data Tables

Table IV-14: CATR Impacts - 2015

	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	15.2% – 23.0%	0.0 – 0.0	15.0% – 22.9%	-0.1 – -0.1
FRCC	25.0% – 25.0%	0.0 – 0.0	25.0% – 25.0%	0.0 – 0.0
MRO	9.3% – 18.8%	-0.1 – -0.1	6.7% – 16.2%	-2.7 – -2.7
NPCC-NE	14.9% – 23.9%	-0.5 – -0.5	14.2% – 23.2%	-1.3 – -1.3
NPCC-NY	26.3% – 28.3%	0.0 – 0.0	26.1% – 28.1%	-0.2 – -0.2
RFC	16.2% – 21.4%	-0.9 – -0.9	15.6% – 20.8%	-1.5 – -1.5
SERC-Central	21.7% – 25.2%	0.0 – 0.0	21.1% – 24.6%	-0.7 – -0.7
SERC-Delta	20.5% – 23.8%	0.0 – 0.0	19.9% – 23.3%	-0.5 – -0.5
SERC-Gateway	18.4% – 22.4%	-4.3 – -4.3	21.7% – 25.7%	-1.0 – -1.0
SERC-Southeastern	12.3% – 28.9%	-0.1 – -0.1	11.5% – 28.1%	-0.9 – -0.9
SERC-VACAR	12.6% – 15.7%	0.0 – 0.0	10.9% – 14.0%	-1.7 – -1.7
SPP	14.9% – 29.3%	0.0 – 0.0	14.2% – 28.7%	-0.7 – -0.7
WECC-CA	50.1% – 50.1%	0.0 – 0.0	50.1% – 50.1%	0.0 – 0.0
WECC-AZ-NM-SNV	19.8% – 23.0%	0.0 – 0.0	19.8% – 23.0%	0.0 – 0.0
WECC-NWPP	27.0% – 28.2%	0.0 – 0.0	27.0% – 28.2%	0.0 – 0.0
WECC-RMPA	16.6% – 25.0%	0.0 – 0.0	16.6% – 25.0%	0.0 – 0.0
TOTAL	19.7% – 25.4%	-0.3 – -0.3	19.2% – 24.8%	-0.9 – -0.9

Table IV-15: CCR Impacts - 2015

	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	15.2% – 23.0%	0.0 – 0.0	15.2% – 23.0%	0.0 - 0.0
FRCC	25.0% – 25.0%	0.0 – 0.0	25.0% – 25.0%	0.0 - 0.0
MRO	9.4% – 18.9%	0.0 – 0.0	9.4% – 18.9%	0.0 - 0.0
NPCC-NE	15.5% – 24.5%	0.0 – 0.0	15.5% – 24.5%	0.0 - 0.0
NPCC-NY	26.3% – 28.3%	0.0 – 0.0	26.3% – 28.3%	0.0 - 0.0
RFC	17.1% – 22.3%	0.0 – 0.0	17.1% – 22.3%	0.0 - 0.0
SERC-Central	21.8% – 25.3%	0.0 – 0.0	21.6% – 25.1%	-0.2 - -0.2
SERC-Delta	20.5% – 23.8%	0.0 – 0.0	20.5% – 23.8%	0.0 - 0.0
SERC-Gateway	22.7% – 26.7%	0.0 – 0.0	22.3% – 26.3%	-0.4 - -0.4
SERC-Southeastern	12.1% – 28.8%	-0.2 – -0.2	12.1% – 28.8%	-0.2 - -0.2
SERC-VACAR	12.6% – 15.7%	0.0 – 0.0	12.6% – 15.7%	0.0 - 0.0
SPP	14.9% – 29.3%	0.0 – 0.0	14.9% – 29.3%	0.0 - 0.0
WECC-CA	50.1% – 50.1%	0.0 – 0.0	50.1% – 50.1%	0.0 - 0.0
WECC-AZ-NM-SNV	19.8% – 23.0%	0.0 – 0.0	19.8% – 23.0%	0.0 - 0.0
WECC-NWPP	27.0% – 28.2%	0.0 – 0.0	27.0% – 28.2%	0.0 - 0.0
WECC-RMPA	16.6% – 25.0%	0.0 – 0.0	16.6% – 25.0%	0.0 - 0.0
TOTAL	20.0% – 25.7%	0.0 – 0.0	20.0% – 25.7%	0.0 - 0.0

Table IV-16: Combined Impacts - 2015				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	7.5% – 15.4%	-7.7 – -7.7	6.8% – 14.7%	-8.4 – -8.4
FRCC	23.0% – 23.0%	-2.0 – -2.0	21.3% – 21.3%	-3.7 – -3.7
MRO	5.9% – 15.5%	-3.5 – -3.5	-1.7% – 7.9%	-11.0 – -11.0
NPCC-NE	7.2% – 16.2%	-8.3 – -8.3	1.8% – 10.8%	-13.6 – -13.6
NPCC-NY	17.4% – 19.5%	-8.9 – -8.9	11.5% – 13.6%	-14.8 – -14.8
RFC	14.2% – 19.4%	-2.9 – -2.9	7.2% – 12.4%	-9.9 – -9.9
SERC-Central	21.0% – 24.5%	-0.7 – -0.7	10.1% – 13.6%	-11.6 – -11.6
SERC-Delta	1.9% – 5.2%	-18.6 – -18.6	-0.2% – 3.1%	-20.6 – -20.6
SERC-Gateway	19.6% – 23.6%	-3.1 – -3.1	1.5% – 5.5%	-21.3 – -21.3
SERC-Southeastern	11.3% – 27.9%	-1.1 – -1.1	5.7% – 22.4%	-6.6 – -6.6
SERC-VACAR	11.1% – 14.2%	-1.5 – -1.5	4.6% – 7.6%	-8.0 – -8.0
SPP	12.7% – 27.1%	-2.2 – -2.2	9.3% – 23.8%	-5.5 – -5.5
WECC-CA	44.3% – 44.3%	-5.8 – -5.8	39.3% – 39.3%	-10.8 – -10.8
WECC-AZ-NM-SNV	17.3% – 20.6%	-2.4 – -2.4	12.6% – 15.9%	-7.1 – -7.1
WECC-NWPP	26.5% – 27.6%	-0.5 – -0.5	26.5% – 27.6%	-0.5 – -0.5
WECC-RMPA	14.9% – 23.2%	-1.7 – -1.7	14.6% – 22.9%	-2.1 – -2.1
TOTAL	16.1% – 21.7%	-4.0 – -4.0	10.8% – 16.4%	-9.3 – -9.3

Table IV-17: 316(b) Impacts - 2018				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	-1.2% – 6.1%	-7.2 – -7.2	-1.5% – 5.8%	-7.5 – -7.5
FRCC	24.9% – 24.9%	-2.1 – -2.1	23.9% – 23.9%	-3.1 – -3.1
MRO	0.6% – 10.8%	-3.5 – -3.5	0.6% – 10.8%	-3.5 – -3.5
NPCC-NE	2.7% – 11.5%	-8.7 – -8.7	1.5% – 10.2%	-10.0 – -10.0
NPCC-NY	15.6% – 17.6%	-9.5 – -9.5	13.9% – 15.9%	-11.2 – -11.2
RFC	10.2% – 15.5%	-3.6 – -3.6	10.1% – 15.4%	-3.7 – -3.7
SERC-Central	19.1% – 22.5%	-1.0 – -1.0	19.1% – 22.5%	-1.0 – -1.0
SERC-Delta	-3.4% – -0.2%	-18.5 – -18.5	-3.4% – -0.2%	-18.5 – -18.5
SERC-Gateway	15.7% – 19.6%	-3.9 – -3.9	15.7% – 19.6%	-4.0 – -4.0
SERC-Southeastern	14.8% – 30.5%	-1.2 – -1.2	14.8% – 30.5%	-1.2 – -1.2
SERC-VACAR	7.1% – 9.6%	-1.4 – -1.4	7.1% – 9.6%	-1.5 – -1.5
SPP	7.7% – 21.8%	-2.2 – -2.2	7.6% – 21.7%	-2.3 – -2.3
WECC-CA	31.1% – 31.1%	-8.3 – -8.3	28.3% – 28.3%	-11.1 – -11.1
WECC-AZ-NM-SNV	17.1% – 21.1%	-2.1 – -2.1	17.1% – 21.1%	-2.1 – -2.1
WECC-NWPP	21.6% – 22.7%	-0.4 – -0.4	21.6% – 22.7%	-0.4 – -0.4
WECC-RMPA	15.8% – 23.9%	-1.6 – -1.6	15.8% – 23.9%	-1.6 – -1.6
TOTAL	12.0% – 17.6%	-4.3 – -4.3	11.6% – 17.1%	-4.7 – -4.7

Table IV-18: MACT Impacts - 2018				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	5.9% – 13.2%	-0.1 – -0.1	5.9% – 13.2%	-0.1 – -0.1
FRCC	26.9% – 26.9%	0.0 – 0.0	26.6% – 26.6%	-0.4 – -0.4
MRO	2.3% – 12.5%	-1.8 – -1.8	2.2% – 12.4%	-1.9 – -1.9
NPCC-NE	11.3% – 20.1%	-0.1 – -0.1	9.3% – 18.1%	-2.1 – -2.1
NPCC-NY	24.9% – 26.9%	-0.2 – -0.2	23.1% – 25.1%	-2.0 – -2.0
RFC	12.2% – 17.6%	-1.6 – -1.6	10.4% – 15.7%	-3.4 – -3.4
SERC-Central	19.4% – 22.7%	-0.8 – -0.8	17.3% – 20.6%	-2.9 – -2.9
SERC-Delta	14.7% – 17.9%	-0.4 – -0.4	14.5% – 17.7%	-0.5 – -0.5
SERC-Gateway	18.8% – 22.6%	-0.9 – -0.9	17.4% – 21.3%	-2.3 – -2.3
SERC-Southeastern	15.4% – 31.1%	-0.6 – -0.6	13.3% – 29.1%	-2.6 – -2.6
SERC-VACAR	7.0% – 9.6%	-1.5 – -1.5	4.5% – 7.1%	-4.0 – -4.0
SPP	9.6% – 23.6%	-0.4 – -0.4	9.6% – 23.6%	-0.4 – -0.4
WECC-CA	39.3% – 39.3%	0.0 – 0.0	39.3% – 39.3%	0.0 – 0.0
WECC-AZ-NM-SNV	14.8% – 18.7%	-4.5 – -4.5	14.8% – 18.7%	-4.5 – -4.5
WECC-NWPP	21.6% – 22.6%	-0.4 – -0.4	21.6% – 22.6%	-0.4 – -0.4
WECC-RMPA	16.5% – 24.6%	-0.9 – -0.9	16.5% – 24.6%	-0.9 – -0.9
TOTAL	15.4% – 20.9%	-1.0 – -1.0	14.3% – 19.8%	-2.0 – -2.0

Table IV-19: CATR Impacts - 2018				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	6.0% – 13.3%	0.0 - 0.0	5.9% - 13.1%	-0.1 - -0.1
FRCC	27.0% – 27.0%	0.0 - 0.0	26.9% - 26.9%	0.0 - 0.0
MRO	4.0% – 14.2%	-0.1 - -0.1	1.5% - 11.7%	-2.6 - -2.6
NPCC-NE	10.9% – 19.7%	-0.5 - -0.5	10.2% - 18.9%	-1.2 - -1.2
NPCC-NY	25.1% – 27.1%	0.0 - 0.0	24.9% - 26.9%	-0.2 - -0.2
RFC	12.9% – 18.2%	-0.9 - -0.9	12.4% - 17.7%	-1.4 - -1.4
SERC-Central	20.1% – 23.5%	0.0 - 0.0	19.5% - 22.9%	-0.6 - -0.6
SERC-Delta	15.0% – 18.2%	0.0 - 0.0	14.5% - 17.7%	-0.5 - -0.5
SERC-Gateway	15.5% – 19.4%	-4.2 - -4.2	18.7% - 22.6%	-1.0 - -1.0
SERC-Southeastern	15.9% – 31.6%	-0.1 - -0.1	15.2% - 30.9%	-0.8 - -0.8
SERC-VACAR	8.5% – 11.1%	0.0 - 0.0	6.9% - 9.4%	-1.6 - -1.6
SPP	9.9% – 24.0%	0.0 - 0.0	9.3% - 23.3%	-0.7 - -0.7
WECC-CA	39.3% – 39.3%	0.0 - 0.0	39.3% - 39.3%	0.0 - 0.0
WECC-AZ-NM-SNV	19.2% – 23.2%	0.0 - 0.0	19.2% - 23.2%	0.0 - 0.0
WECC-NWPP	22.0% – 23.1%	0.0 - 0.0	22.0% - 23.1%	0.0 - 0.0
WECC-RMPA	17.3% – 25.4%	0.0 - 0.0	17.3% - 25.4%	0.0 - 0.0
TOTAL	16.0% – 21.5%	-0.3 - -0.3	15.5% - 21.1%	-0.8 - -0.8

Table IV-20: CCR Impacts - 2018				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	6.0% – 13.3%	0.0 – 0.0	6.0% – 13.3%	0.0 – 0.0
FRCC	27.0% – 27.0%	0.0 – 0.0	27.0% – 27.0%	0.0 – 0.0
MRO	4.1% – 14.3%	0.0 – 0.0	3.9% – 14.1%	-0.2 – -0.2
NPCC-NE	11.4% – 20.2%	0.0 – 0.0	11.4% – 20.2%	0.0 – 0.0
NPCC-NY	25.1% – 27.1%	0.0 – 0.0	25.1% – 27.1%	0.0 – 0.0
RFC	13.8% – 19.1%	0.0 – 0.0	13.8% – 19.1%	0.0 – 0.0
SERC-Central	20.0% – 23.3%	-0.2 – -0.2	20.0% – 23.3%	-0.2 – -0.2
SERC-Delta	15.0% – 18.2%	0.0 – 0.0	15.0% – 18.2%	-0.1 – -0.1
SERC-Gateway	19.3% – 23.2%	-0.4 – -0.4	19.3% – 23.2%	-0.4 – -0.4
SERC-Southeastern	15.8% – 31.5%	-0.2 – -0.2	15.8% – 31.5%	-0.2 – -0.2
SERC-VACAR	8.5% – 11.1%	0.0 – 0.0	8.5% – 11.1%	0.0 – 0.0
SPP	9.9% – 24.0%	0.0 – 0.0	9.9% – 24.0%	0.0 – 0.0
WECC-CA	39.3% – 39.3%	0.0 – 0.0	39.3% – 39.3%	0.0 – 0.0
WECC-AZ-NM-SNV	19.2% – 23.2%	0.0 – 0.0	19.2% – 23.2%	0.0 – 0.0
WECC-NWPP	22.0% – 23.1%	0.0 – 0.0	22.0% – 23.1%	0.0 – 0.0
WECC-RMPA	17.3% – 25.4%	0.0 – 0.0	17.3% – 25.4%	0.0 – 0.0
TOTAL	16.3% – 21.8%	0.0 – 0.0	16.3% – 21.8%	0.0 – 0.0

Table IV-21: Combined Impacts - 2018				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	-1.2% – 6.0%	-7.2 – -7.2	-1.7% – 5.6%	-7.7 – -7.7
FRCC	24.6% – 24.6%	-2.3 – -2.3	23.5% – 23.5%	-3.5 – -3.5
MRO	-0.3% – 9.9%	-4.4 – -4.4	-6.5% – 3.7%	-10.6 – -10.6
NPCC-NE	1.2% – 10.0%	-10.2 – -10.2	-1.8% – 6.9%	-13.3 – -13.3
NPCC-NY	14.9% – 16.9%	-10.2 – -10.2	10.7% – 12.7%	-14.4 – -14.4
RFC	8.7% – 14.1%	-5.1 – -5.1	4.7% – 10.0%	-9.2 – -9.2
SERC-Central	18.0% – 21.3%	-2.2 – -2.2	9.0% – 12.3%	-11.2 – -11.2
SERC-Delta	-3.7% – -0.5%	-18.7 – -18.7	-4.9% – -1.7%	-19.9 – -19.9
SERC-Gateway	14.5% – 18.4%	-5.2 – -5.2	1.7% – 5.6%	-18.0 – -18.0
SERC-Southeastern	13.9% – 29.6%	-2.1 – -2.1	9.7% – 25.4%	-6.3 – -6.3
SERC-VACAR	5.0% – 7.6%	-3.5 – -3.5	0.9% – 3.4%	-7.6 – -7.6
SPP	7.4% – 21.4%	-2.6 – -2.6	4.6% – 18.7%	-5.3 – -5.3
WECC-CA	31.1% – 31.1%	-8.3 – -8.3	28.2% – 28.2%	-11.2 – -11.2
WECC-AZ-NM-SNV	12.6% – 16.6%	-6.6 – -6.6	12.6% – 16.6%	-6.6 – -6.6
WECC-NWPP	21.5% – 22.6%	-0.5 – -0.5	21.5% – 22.6%	-0.5 – -0.5
WECC-RMPA	15.7% – 23.8%	-1.6 – -1.6	15.4% – 23.5%	-1.9 – -1.9
TOTAL	11.0% – 16.5%	-5.3 – -5.3	7.6% – 13.1%	-8.8 – -8.8

Appendix V: Related Study Work and References

Related Study Work For 316(b)

The U.S. Senate Committee on Appropriations, Subcommittee on Energy and Water Development, requested the Office of Electricity Delivery and Energy Reliability of the Department of Energy (DOE or Department) to examine the impacts to electricity reliability of requiring generators with once-through cooling systems to be replaced with closed-cycle cooling towers.

DOE provided NERC with a list of steam generation units that would be required to retrofit to cooling towers. DOE requested NERC to model the reliability impacts of the cooling tower mandate using certain assumptions. NERC provided DOE with its results in a white paper, 2008-*2017 NERC Capacity Margins: Retrofit of Once-Through Cooling Systems at Existing Generating Facilities.*

In the white paper, NERC concluded that once the deadline for the cooling tower retrofits has passed, the generation losses resulting from the requirement would exacerbate a potential decline in electric Planning Reserve Margins needed to ensure reliable delivery of electricity. Generally, the goal for NERC Regions is to have the equivalent of between 10 and 15 percent of their peak generation demand available to meet contingencies. NERC projects overall capacity reserve margins to fall to 14.7 percent by 2015, assuming only planned generation is built. However, upon assessing the impact of a cooling tower mandate, NERC projects that, "U.S. resource margins will drop from 14.7 percent to 10.4 percent when both the retired units and auxiliary loads due to retrofitting were compared to the *Reference Case*."

The following assumptions were used for this assessment:

Assumptions specified by DOE:

- Close-loop cooling systems will be added to all nuclear units. Capacity factors can be used as a proxy for economic suitability for retrofit
- Unit Retirements/Retrofits were based on the following capacity factors from 2006:
  - Units with a capacity factor less than 35 percent are assumed to be retired.
  - Units with a capacity factor greater than or equal to 0.35 were derated by four percent of maximum rated (nameplate) capacity.
  - 60 percent of retirements/retrofits was projected to begin in 2013, 20 percent in 2014 and 20 percent in 2015.
- Plants deemed "difficult to retrofit" due to geographical limitations (e.g. land-locked, space and permitting constraints) could result in early retirement. This assessment does not assume their early retirement.
- No new plants are built to replace capacity lost to retired units or auxiliary loads.
- Retrofits are instantaneous, with no capacity shortfalls due to plant shutdowns.
- Plants with a zero capacity factor (inactive or not yet built) are not assessed. These plants are not included in the Region's *Reference Case*.

Appendix V: Related Study Work and References

Assumptions specified by NERC:

- The NERC Reference Margin Level adopted the Regional/subregional Target Capacity Margin. If not available, the NERC Reference Margin Level is based on supply-side fuel: 13 percent for thermal systems and 9 percent for hydro (Capacity Margin).
- Unit Retirement/Retrofit capacity reduction comparison is based against "Adjusted Potential Resources", calculated with all Existing Capacity and probable Planned Additions, Proposed Additions, and Net Transactions.
- Units already expected to retire between 2010 and 2015 were not considered part of the capacity reduction as they are already factored into the Region's projections.

NERC reviewed the impact of either retrofitting units with existing once-through-cooling systems to closed-loop cooling systems (resulting in four percent reduction in nameplate capacity) or unit retirements (capacity factor less than 35 percent) on NERC-US and Regional capacity margins for 2008–2017. Based on a worst-case view, NERC-US Adjusted Potential Resources may be impacted up to 49,000 MW, reducing the Adjusted Potential Resource Margin by 4.3 percent and some areas may require more resources to offset capacity reductions and maintain the reliability of the bulk power system. Some subregions, such as WECC-CA, NPCC-NE, ERCOT, SERC-Central and NPCC-NY, experience significant impacts.

Table V-1: 2015 US Summer Peak Potential Retrofit/Retirement Effects

	Adjusted Potential Resources (MW)	Reduction due to Retirement (MW)	Derate due to Retrofit (MW)	NERC Reference Margin Level	Adjusted Potential Resources Margin	Margin Reduction	Reduced Margin
United States							
WECC - CA-MX US	72,293	10,137	289	13.2%	12.7%	14.7%	-2.0%
NPCC - New England	31,673	2,827	428	13.0%	10.0%	10.3%	-0.3%
ERCOT	86,436	10,919	542	11.1%	15.9%	12.9%	3.0%
NPCC US	72,750	6,481	990	13.0%	13.3%	9.9%	3.4%
WECC US	176,944	10,177	314	12.3%	11.1%	5.6%	5.5%
NPCC - New York	41,077	3,654	561	13.0%	15.9%	9.6%	6.3%
SERC - VACAR	78,182	553	1,032	13.0%	11.0%	1.8%	9.2%
WECC - RMPA	15,609	40	0	10.5%	10.2%	0.2%	10.0%
SERC - Central	54,548	0	949	13.0%	12.6%	1.5%	11.0%
SERC - Delta	41,259	4,266	466	13.0%	21.5%	10.2%	11.4%
RFC	230,062	3,339	2,863	12.8%	14.5%	2.4%	12.1%
SERC	269,599	6,054	3,307	13.0%	15.6%	3.0%	12.5%
SERC - Southeastern	66,675	675	357	13.0%	13.9%	1.4%	12.6%
MRO US	55,582	529	612	13.0%	15.1%	1.8%	13.3%
FRCC	63,170	1,267	454	13.0%	18.7%	2.3%	16.4%
WECC - NWPP	51,861	0	25	11.9%	16.9%	0.0%	16.8%
SPP	63,700	817	257	12.0%	24.1%	1.3%	22.8%
SERC - Gateway	28,935	560	502	13.0%	28.8%	2.7%	26.1%
Total-NERC US	1,018,243	39,583	9,339	13.0%	14.7%	4.3%	10.4%

In comparing the results of the prior collaborative DOE/NERC assessment to the results in this report, impacts of similar magnitudes were found. Further, the areas (Regions/subregions) of concern highlighted in the prior assessment are aligned with those identified in this assessment.

EPRI Study Work For CCR:

EPRI conducted a screening assessment of the potential impact of EPA's expected proposals for management of CCR prior to publication of the draft rule.[42] This assessment indicated that 40 to 97 GW of coal-fired capacity could be "at risk" for retirement based on the increased costs associated with such a rule. The methods for estimating compliance costs at the generating unit level are similar to methods discussed in this report, with three significant differences:

- the sample of coal-fired generating units included in the assessment;
- the definition of the term "at risk" capacity; and
- some aspects of the cost assignment logic for Subtitle C (hazardous waste) management of CCRs.

Coal-Fired Capacity Assumptions

The total capacity represented by the units included in the EPRI analysis differed from the total capacity of the units included in the NERC assessment. Included in the EPRI analysis--but excluded from NERC's--are smaller units not in the bulk power system, planned coal-fired units not currently operating but scheduled to come online during the 20-year EPRI study horizon, and units that have recently announced early retirements. Since EPRI's analysis in 2009, several utilities have announced plans to retire older coal-fired generating units. Combined, the units included in EPRI's analysis, but excluded from the NERC assessment, represent 20 GW of capacity.

Definition of "at risk" Coal Capacity

The EPRI study was a screening-level economic analysis, intended to identify individual generating units that were predicted to be no longer profitable under a Subtitle C regulation. Any unit that would no longer be profitable was defined as "at risk." "At risk" in this context means that a decision would have to be made with respect to the generating unit: early retirement, repower, purchase power, or continue operation at a loss or at higher market prices. NERC, however, starts with the premise that reliability cannot be compromised and that for many units shutdown is not an option (particularly base-load units) without major disruption to the power grid. Thus, NERC's assessment compared the cost of compliance with Subtitle C requirements to the cost of natural gas-fired replacement power in order to determine which decision would be the most economical for a generating unit; only those units where compliance costs exceeded repowering costs were considered candidates for shutdown and thus deemed "at risk" for retirement.

Subtitle C Cost Assumptions

In assessing the cost of hazardous waste regulation on power plants, EPRI considered costs that NERC did not include in its assessment. One was the cost of off-site disposal at a commercial facility. NERC's assessment assumed all power plants would locate and construct Subtitle C landfills on or near the power plant property. While some states do not currently allow establishment of hazardous waste landfills within the state, NERC assumed that provisions

[42] EPRI, 2009, Testimony at the House Subcommittee on Energy and Environment Hearing on "Drinking Water and Public Health Impacts of Coal Combustion Waste Disposal," Washington DC, December 10, 2009. http://mydocs.epri.com/docs/CorporateDocuments/SectorPages/Portfolio/Environment/Ken%20Ladwig%20Written%20Testimony%20USHouse-E%26E%2010Dec2009%20FINAL.pdf

would be made to facilitate permitting of these Subtitle C facilities. Based on current disposal patterns, interviews with several utilities, and site-specific conditions such as land availability and watershed restrictions, EPRI assumed that a percentage of plants would be forced to dispose of CCRs in off-site commercial facilities, at higher costs for both transportation and disposal. The EPRI analysis also included special handling costs at the power plant to meet Subtitle C requirements. The NERC assessment did not include any special handling costs at the plant nor engineering retrofits that may be necessary for meeting Subtitle C standards. Finally, the NERC assessment assumed continued CCR utilization at current rates; EPRI ran simulations with both continued CCR use at the same rate and no CCR use.

Follow-on Steps

In their regulatory proposal, EPA requested additional information on both off-site disposal costs and "upstream" management and storage costs associated with Subtitle C regulation. In response to the EPA's request for additional cost data, EPRI is in the process of developing detailed engineering costs for Subtitle C regulation at the power plant as well as at CCR disposal sites. EPRI will share the engineering information and cost data with NERC when it is available. EPRI will prepare a technical report with the engineering and cost data in 4Q 2010 that will be publicly available.

Terms Used in This Report

Adjusted Potential Capacity Resources — The sum of Deliverable Capacity Resources, Existing Other Resources, Future Other Resources (reduced by a confidence factor), Conceptual Resources (reduced by a confidence factor), and net provisional transactions minus all derates. (MW)

Adjusted Potential Reserve Margin (%) — The sum of Deliverable Capacity Resources, Existing Other Resources, Future Other Resources (reduced by a confidence factor), Conceptual Resources (reduced by a confidence factor), and net provisional transactions minus all derates and Net Internal Demand shown as a percent of Net Internal Demand.

Capacity Categories — *See **Existing Generation Resources, Future Generation Resources,** and **Conceptual Generation Resources**.*

Conceptual Generation Resources — This category includes generation resources that are not included in *Existing Generation Resources* or *Future Generation Resources*, but have been identified and/or announced on a resource planning basis through one or more of the following sources:

1. Corporate announcement
2. Entered into or is in the early stages of an approval process
3. Is in a generator interconnection (or other) queue for study
4. "Place-holder" generation for use in modeling, such as generator modeling needed to support NERC Standard TPL analysis, as well as, integrated resource planning resource studies.

Resources included in this category may be adjusted using a confidence factor (%) to reflect uncertainties associated with siting, project development or queue position.

Deliverable Capacity Resources — Existing, Certain and Net Firm Transactions plus Future, Planned capacity resources plus Expected Imports, minus Expected Exports. (MW)

Deliverable Reserve Margin (%) — Deliverable Capacity Resources minus Net Internal Demand shown as a percent of Net Internal Demand.

Demand — *See **Net Internal Demand**,* and ***Total Internal Demand***

Demand Response — Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Derate (Capacity) — The amount of capacity that is expected to be unavailable on seasonal peak.

Existing, Certain (Existing Generation Resources) — Existing generation resources available to operate and deliver power within or into the Region during the period of analysis in the assessment. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes, but is not limited to the following:

1. contracted (or firm) or other similar resource confirmed able to serve load during the period of analysis in the assessment;
2. where organized markets exist, designated market resource[43] that is eligible to bid into a market or has been designated as a firm network resource;
3. a Network Resource[44], as that term is used for FERC *pro forma* or other regulatory approved tariffs;
4. energy-only resources[45] confirmed able to serve load during the period of analysis in the assessment and will not be curtailed;[46]
5. capacity resources that cannot be sold elsewhere; and
6. other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed[47] during the period of analysis in the assessment.

Existing, Certain & Net Firm Transactions — Existing, Certain capacity resources plus Firm Imports, minus Firm Exports. (MW)

Existing, Certain and Net Firm Transactions (%) (Margin Category) – Existing, Certain and Net Firm Transactions minus Net Internal Demand shown as a percent of Net Internal Demand.

Existing Generation Resources — *See **Existing, Certain**, **Existing, Other**,* and ***Existing, but Inoperable.***

Existing, Inoperable (Existing Generation Resources) — This category contains the existing portion of generation resources that are out-of-service and cannot be brought back into service to serve load during the period of analysis in the assessment. However, this category can include inoperable resources that could return to service at some point in the future. This value may vary for future seasons and can be reported as zero. This includes all existing generation not included in categories Existing, Certain or Existing, Other, but is not limited to, the following:

1. mothballed generation (that cannot be returned to service for the period of the assessment);
2. other existing but out-of-service generation (that cannot be returned to service for the period of the assessment);
3. does not include behind-the-meter generation or non-connected emergency generators that normally do not run; and
4. does not include partially dismantled units that are not forecasted to return to service.

Existing, Other (Existing Generation Resources) — Existing generation resources that may be available to operate and deliver power within or into the Region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in Existing, Certain. This category includes, but is not limited to the following:

1. a resource with non-firm or other similar transmission arrangements;

[43] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[44] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[45] Energy Only Resources are generally generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area (Source: 2008 EIA 411 document OMB No. 1905-0129)." Note: Other than wind and solar energy, WECC does not have energy-only resources that are counted towards capacity.

[46] Energy only resources with transmission service constraints are to be considered in category Existing, Other.

[47] Energy only resources with transmission service constraints are to be considered in category Existing, Other.

2. energy-only resources that have been confirmed able to serve load for any reason during the period of analysis in the assessment, but may be curtailed for any reason;
3. mothballed generation (that may be returned to service for the period of the assessment);
4. portions of variable generation not counted in the Existing, Certain category (*e.g.*, wind, solar, etc. that may not be available or derated during the assessment period);
5. hydro generation not counted as Existing, Certain or derated; and
6. generation resources constrained for other reasons.

Expected (Transaction Category) — A category of Purchases/Imports and Sales/Exports with the following clarification:

1. Expected implies that a contract has not been executed, but is in negotiation, projected or other. These Purchases or Sales are expected to be firm.
2. Expected Purchases and Sales should be considered in the reliability assessments.

Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports with the following clarification contract including:

1. Firm implies a contract has been signed and may be recallable.
2. Firm Purchases and Sales should be reported in the reliability assessments. The purchasing entity should count such capacity in margin calculations. Care should be taken by both entities to appropriately report the generating capacity that is subject to such Firm contract.

Future Generation Resources (*See also **Future, Planned** and **Future, Other***) — This category includes generation resources the reporting entity has a reasonable expectation of coming online during the period of the assessment. As such, to qualify in either of the Future categories, the resource must have achieved one or more of these milestones:

1. Construction has started.
2. Regulatory permits being approved, are any one of the following:
   a. site permit;
   b. construction permit; or
   c. Environmental permit.
3. Regulatory approval has been received to be in the rate base.
4. There is an approved power purchase agreement.
5. Resources is approved and/or designated as a resource by a market operator.

Future, Other (Future Generation Resources) — This category includes future generating resources that do not qualify in *Future, Planned* and are not included in the Conceptual category. This category includes, but is not limited to, generation resources during the period of analysis in the assessment that:

1. may be curtailed or interrupted at any time for any reason;
2. are energy-only resources that may not be able to serve load during the period of analysis in the assessment;
3. are variable generation not counted in the *Future, Planned* category or may not be available or is derated during the assessment period; or
4. is hydro generation not counted in category *Future, Planned* or derated.

Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position.

Future, Planned (Future Generation Resources) — Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of analysis in the assessment. This category includes, but is not limited to, the following:

1. Contracted (or firm) or other similar resource;
2. Where organized markets exist, a designated market resource[48] that is eligible to bid into a market or has been designated as a firm network resource.
3. A Network Resource[49], as that term is used for FERC pro forma or other regulatory approved tariffs.
4. Energy-only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed[50].
5. Where applicable, is included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve.

NERC Reference Reserve Margin Level (%) — Either the Target Reserve Margin provided by the Region/subregion or NERC assigned based on capacity mix (*e.g.*, thermal/hydro). Each Region/subregion may have their own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the Regional/subregional Target Reserve Margin level is adopted as the NERC Reference Reserve Margin Level. If not, NERC assigned a 15 percent Reserve Margin for predominately thermal systems and 10 percent for predominately hydro systems.

Net Internal Demand: Total Internal Demand reduced by the total Dispatchable, Controllable, Capacity Demand Response equaling the sum of Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resource.

On-Peak (Capacity) — The amount of capacity that is expected to be available on seasonal peak.

Potential Capacity Resources — The sum of Deliverable Capacity Resources, Existing Other Resources, Future Other Resources, Conceptual Resources, and net provisional transactions minus all derates. (MW)

Potential Reserve Margin (%) — The sum of Deliverable Capacity Resources, Existing Other Resources, Future Other Resources, Conceptual Resources, and net provisional transactions minus all derates and Net Internal Demand shown as a percentage of Net Internal Demand.

Prospective Capacity Reserve Margin (%) — Prospective Capacity Resources minus Net Internal Demand shown as a percentage of Net Internal Demand.

Prospective Capacity Resources — Deliverable Capacity Resources plus Existing, Other capacity resources, minus all Existing, Other deratings (including derates from variable resources, energy only resources, scheduled outages for maintenance, and transmission-limited resources), plus Future, Other capacity resources (adjusted by a confidence factor), minus all Future, Other deratings. (MW)

Provisional (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including Purchases and Sales that are expected to be provisionally firm. Provisional implies

[48] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[49] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[50] Energy only resources with transmission service constraints are to be considered in category Future, Other.

that the transactions are under study, but negotiations have not begun. Provisional Purchases and Sales should be considered in the reliability assessments.

Reference Reserve Margin Level — *See **NERC Reference Reserve Margin Level***

Reserve Margin (%) —Roughly, Capacity minus Demand, divided by Demand or (Capacity-Demand)/Demand. Replaced *Capacity Margin(s) (%)* for NERC Assessments in 2009.

Target Reserve Margin (%) — Established target for Reserve Margin by the Region or subregion. Not all Regions report a Target Reserve Margin. The NERC Reference Reserve Margin Level is used in those cases where a Target Reserve Margin is not provided.

Transfer/Transaction (*See also **Firm, Non-Firm, Expected** and **Provisional)*** — Contracts for Capacity are defined as an agreement between two or more parties for the Purchase and Sale of generating capacity. Purchase contracts refer to imported capacity that is transmitted from an outside Region or subregion to the reporting Region or subregion. Sales contracts refer to exported capacity that is transmitted from the reporting Region or subregion to an outside Region or subregion. For example, if a resource subject to a contract is located in one Region and sold to another Region, the Region in which the resource is located reports the capacity of the resource and reports the sale of such capacity that is being sold to the outside Region. The purchasing Region reports such capacity as a purchase, but does not report the capacity of such resource. Transmission must be available for all reported Purchases and Sales.

Abbreviations Used in This Report

316(b)	Clean Water Act – Section 316(b), Cooling Water Intake Structures
APCR	Adjusted Potential Capacity Resources
AZ-NM-SNV	Arizona-New Mexico-Southern Nevada (subregion of WECC)
BTA	Best Technology Available
CA	California (subregion of WECC)
CA-MX-US	California-México (subregion of WECC)
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CCB	Coal Combustion Byproducts
CCR	Coal Combustion Residuals
DOE	U.S. Department of Energy
EIA	Energy Information Agency (of DOE)
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EVA	Energy Venture Associates
FERC	U.S. Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FRCC	Florida Reliability Coordinating Council
GHG	Greenhouse Gas
gpm	Gallons per minute
GW	Gigawatt
GWh	Gigawatt hours
HACI	Halide-treated Activated Carbon Injection
HAP	Hazardous Air Pollutants
MACT	Maximum Achievable Control Technology
mgd	Million gallons per day
MRO	Midwest Reliability Organization
MW	Megawatts (millions of watts)
MWH	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NESHAP	National Emissions Standards of Hazardous Air Pollutants
NO_x	Nitrogen Oxide
NPCC	Northeast Power Coordinating Council
NWPP	Northwest Power Pool Area (subregion of WECC)
NYPP	New York Power Pool
PV	Photovoltaic
RCRA	Resource Conservation Recovery Act
RFC	Reliability*First* Corporation
RMPA	Rocky Mountain Power Area (subregion of WECC)
RMR	Reliability Must Run
RMRG	Rocky Mountain Reserve Group
RP	Reliability Planner
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool
tpy	Tons per year
TRE	Texas Regional Entity
TVA	Tennessee Valley Authority
VACAR	Virginia and Carolinas (subregion of SERC)
WECC	Western Electricity Coordinating Council

Abbreviations Used in This Report

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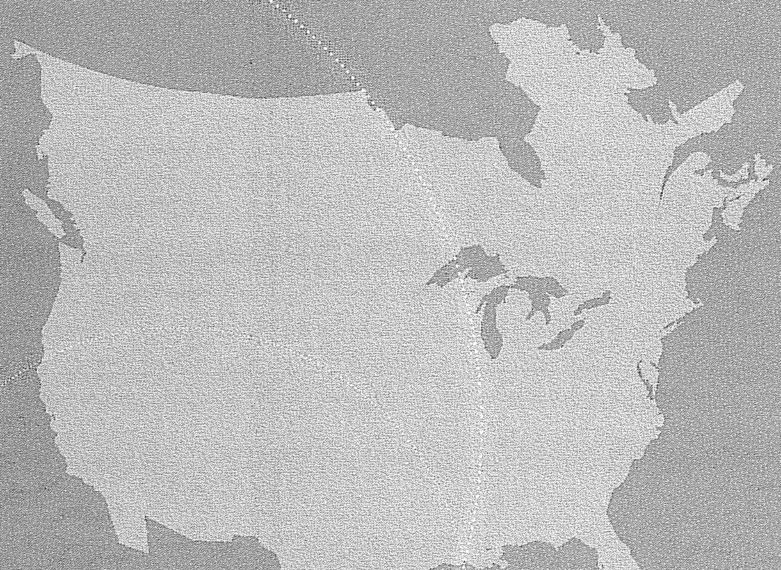
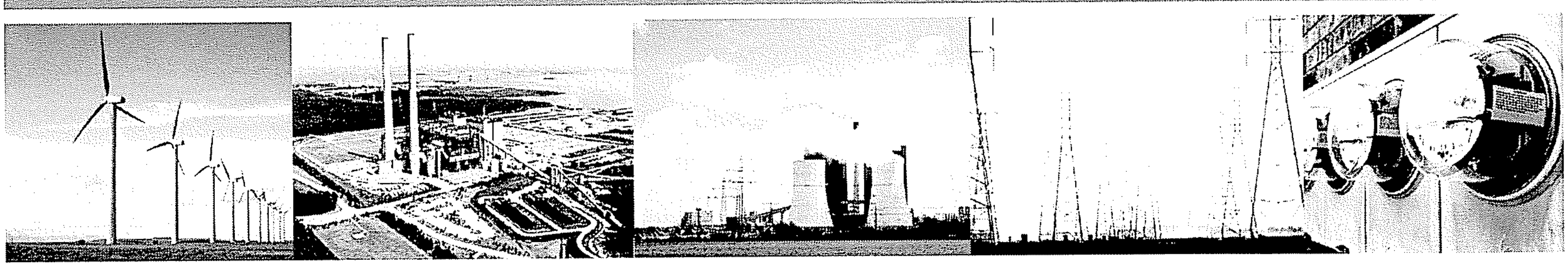


Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability

August 2010



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Acknowledgements

The following report was prepared on behalf of the Clean Energy Group's Clean Air Policy Initiative, a coalition of electric companies dedicated to responsible energy and environmental stewardship. The participating companies (listed below) are some of the nation's largest generators of electricity, with over 170,000 megawatts of electric generating capacity (including 110,000 megawatts of fossil generating capacity) throughout the U.S., and serve nearly a fifth of all U.S. electric customers.

Calpine Corporation
Constellation Energy
Entergy Corporation
Exelon Corporation
NextEra Energy
National Grid
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Executive Summary

In the 20 years since the Clean Air Act ("CAA") Amendments of 1990, electric power companies throughout the United States have deployed a wide range of pollution-control technologies, new power plants with relatively low emissions, and demand-side measures to reduce air emissions from electricity production. The Environmental Protection Agency ("EPA") has found, however, that despite this significant progress in reducing emissions, in 2008 about 127 million Americans still lived in counties with unhealthy air—many of which are located along the Ohio River Valley, in the Middle Atlantic, and in the Southeast.[1,2]

To begin to address these issues, on August 2, 2010, EPA published its draft Clean Air Transport Rule (the "Transport Rule"), regulating emissions in 31 Eastern states and the District of Columbia where controlling emissions will produce the greatest public health benefit.[3] EPA plans to implement the Transport Rule on January 1, 2012. Additional rulemakings are also underway to regulate hazardous air pollutants ("HAPs"), with EPA under court order to promulgate its final "Utility MACT" rule by November 2011. According to EPA, compliance would be required by early 2015.[4]

These new rules regulating air emissions from fossil fuel-fired power plants will require certain uncontrolled plants to install pollution control equipment. Third-party analysts have concluded that some coal plant owners may choose to retire units in lieu of such installations. For example, two recent studies suggested that between now and 2015, the combination of low energy prices and EPA air regulations could result in the retirements of between 25 to 40 gigawatts ("GW")[5,6] of the nation's 1,030 GW of electric generating capacity.[7]

Although some of the nation's less efficient power plants may be retired, many existing coal plants will be retrofit with new pollution controls. Approximately half of the nation's coal-fired generating capacity (150 GW) has already installed SO_2 scrubbers, another 55 GW plan to install scrubbers, and a significant number of coal units have already announced plans to retire,[8] leaving approximately one-fourth of the nation's coal-fired generation to add pollution controls, switch to a cleaner fuel, or retire. Companies may also have the option to purchase allowances or adjust dispatch to comply with certain rules.

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[1] U.S. EPA, *Draft FY 2011-2015 EPA Strategic Plan*, at p. 7. Collectively, power plants are responsible for 66 percent of SO_2 emissions, 19 percent of NOx emissions, and 39 percent of CO_2 emissions in the U.S. Also, in 2002, the EPA cataloged emissions in the United States and concluded that fossil-fuel-fired power plants were responsible for the following percentages of nationwide emissions for the following HAPs (all figures are approximate): hydrochloric acid (60%); mercury compounds (45%); arsenic compounds (35%); and nickel compounds (25%). U.S. EPA, *2002 National Emissions Inventory Booklet*.

[2] According to the recent National Academy of Sciences, *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use* (2010), "after ranking all the [power] plants according to their damages, we found that the most damaging 10% of plants produced 43% of aggregate air-pollution damages from all plants, and the least damaging 50% of the plants produce less than 12% of aggregate damages" …(and) the most damaging 10%...account for approximately one quarter of electricity generated at the 406 plants." (at p. 88).

[3] Office of Air and Radiation, U.S. EPA, *Air Transport Rule Factsheet*, at p. 1.

[4] U.S. EPA, *Proposed Rule: Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*. August 2, 2010.

[5] PIRA Energy Group ("PIRA"), *EPA's upcoming MACT; Strict Non-Hg Can Have Far-Reaching Market Impacts*, April 8, 2010.

[6] ICF International, *EEI Preliminary Reference Case and Scenario Results*. May 21, 2010.

[7] Energy Information Administration ("EIA"), *Electric Power Monthly*, July 2010. (Based on preliminary 2009 capacity, capacity additions and retirements up through April 2010.)

[8] PIRA, *supra* n.5.

Some in the industry have raised concerns about the combined effects over the next five years of anticipated power plant retirements and outages required to install new pollution control equipment. Clearly, the nation must carefully consider how to maintain electric system reliability, while also improving our nation's health and environmental quality.

In this paper, we highlight the impact of EPA's upcoming air regulations, with a focus on the issue of possible power plant retirements on electric reliability. We conclude that, without threatening electric reliability, the industry is well-positioned to respond to EPA's proposed road map to "help millions of Americans breathe easier, live healthier,"[9] provided that EPA, the industry and other agencies take practical steps to plan for the implementation of these regulations and adopt appropriate regulatory approaches. In particular, we conclude the following:

1. **Even though some units likely will retire in lieu of complying with the new regulations, electric system reliability will not be compromised if the industry and its regulators proactively manage the transition to a cleaner, more efficient generation fleet.**

    - Power system reliability relates not only to generation capacity and availability, but also to consumption levels and patterns, and transmission capacity and use. As such, all these factors must be considered when assessing reliability impacts. Existing power system capacity well in excess of minimum reserve levels, relatively modest projections of load growth over the next several years, a large amount of proposed generating resources, and the availability of load management practices indicate the system can handle the level of projected retirements.

    - Each North American Electric Reliability Corporation ("NERC") reliability region has excess capacity, totaling over 100 GW of excess capacity nationwide. Therefore, considering only the projected level of coal unit attrition relative to existing capacity resources, it appears there will be no capacity shortages even if projected retirement scenarios prove accurate.

    - Further, economic conditions have reduced the demand for electricity in recent years providing an additional capacity cushion to assist in managing any power plant outages required to install pollution controls.

    - The industry has a proven track record of adding new generating capacity and transmission solutions when and where needed and of coordinating effectively to address reliability concerns. In the three years between 2001 and 2003, the electric industry built over 160 GW of new generation—about four times what analysts project will retire over the next five years.

    - Notably, many of the regions of the country with organized wholesale markets, including many parts of the Midwest, Mid-Atlantic, and Northeast, have developed effective tools such as capacity markets and reserve sharing mechanisms enabling electric generators to access other companies' available resources to assure regional reliability.

    - Additionally, the industry is deploying enhanced demand response actions, expanded energy efficiency programs, and new "smart grid" advances to manage consumption during the transition to cleaner, more efficient generation.

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[9] U.S. EPA, *supra* n.1, at p. 2.

2. **Industry data counter concerns that it will cost the industry too much to comply with EPA's proposed air regulations, that pollution controls cannot be installed soon enough, or that the EPA regulations will lead to the closure of otherwise economically healthy power plants.**

    - The proven technologies for controlling air pollution emissions, such as NO_x, SO_2, mercury and acid gases, are commercially available and have already been, or soon will be, installed on the majority of the nation's coal plants (65 percent with scrubbers; 50 percent with advanced NO_x controls), demonstrating that the costs can be managed.

    - The industry has a demonstrated ability to schedule and sequence unit outages in an efficient and reliable manner and is capable of installing additional pollution control systems to comply with the Transport Rule and Utility MACT Rule.

    - Many of the coal units that are the most likely candidates to shut down are smaller, 40 to 60 year old units, which are nearing the end of their design life expectancy and are already economically challenged.

    - Additionally, the retirement of some existing generating capacity will create room on the transmission grid to accommodate additional power flows, or new generating capacity, without requiring attendant upgrades in transmission, thus mitigating reliability concerns while reducing the cost of transitioning to a cleaner, more efficient generation fleet.

3. **EPA, the Federal Energy Regulatory Commission ("FERC"), the Department of Energy ("DOE") and State utility regulators, both together and separately, have an array of tools to moderate impacts on the electric industry.**

    - EPA may, and if needed, should exercise its statutory authority under the CAA to grant, on a case-by-case basis, extensions of time to complete pollution control installations where appropriate.

    - To the extent that its legal authority allows, EPA should adopt regulatory approaches that allow for cost-effective compliance, such as the emissions trading mechanism proposed in the Transport Rule.

    - In circumstances in which power plant retirements trigger localized reliability concerns, EPA and DOE should follow established precedent, including use of consent decrees, to permit continued operation for reliability purposes only, pending necessary upgrades or generation additions. Additionally, the various federal agencies and offices with responsibility for assuring reliability for the nation's electricity capability should work together to help support the industry and states in complying with EPA's new air regulations.

    - Transparent, well-established market rules approved by FERC and overseen by independent market monitors, particularly the forward capacity markets relied on by some Regional Transmission Operators ("RTOs"), as well as state regulatory agency oversight, provide additional safety nets to help ensure adequate capacity.

- Although EPA is under court order to promulgate its air regulations, the Agency can and should coordinate the implementation of anticipated water regulations under Section 316(b) of the Clean Water Act ("CWA") and new waste regulations to avoid possible reliability concerns.[10]

[10] EPA should also consider the possible greenhouse gas emissions implications of its 316(b) regulations. In 2007, the U.S. Supreme Court found the EPA has clear statutory authority to regulate greenhouse gases under the CAA. Transitioning to a cleaner generating fleet will help EPA fulfill this obligation.

I. MANAGING ELECTRIC SYSTEM RELIABILITY WHILE IMPLEMENTING NEEDED ENVIRONMENTAL IMPROVEMENTS WITH SIGNIFICANT PUBLIC HEALTH BENEFITS

A. The Electric System Has Substantial Excess Generating Capacity and Appropriate Processes in Place to Assure Reliable Electricity Supply to Consumers

Currently, there are more than 17,000 electric generation units in the United States with a combined nameplate capacity of over 1,030 GW.[11] In 2009, coal-fired generation produced 45 percent of the nation's electricity, followed by natural gas (23 percent) and nuclear (20 percent), with the remaining amount produced through a combination of hydroelectric power, oil, wind and other miscellaneous fuel types.[12]

Power plant owners, transmission system owners, and power system operators plan and operate their systems according to numerous federal, state and local regulations, policies and protocols, applying planning requirements designed to ensure electricity suppliers have adequate resources to meet current and future demand, and operational standards to ensure power is available when consumers turn on the lights.

Power system reliability is tied to many things: generation plant capacity and availability, consumption levels and patterns, and transmission capacity and use. As such, electric system planners must consider all of these relevant system infrastructure and demand factors in assessing whether sufficient capacity will be available to maintain reliability. Existing power system capacity well in excess of minimum reserve levels, relatively modest projections of load growth over the next several years, a large amount of proposed generating resources throughout the country, and the availability of load management practices indicate the electric system should be able to handle the transition to a cleaner, more efficient generation fleet.

Under FERC's oversight, NERC sets standards to ensure the reliability of the nation's electric system. NERC comprises eight regional reliability organizations (or "regions," as shown below), whose members include grid operators, utilities, generating companies and others in the electric industry.

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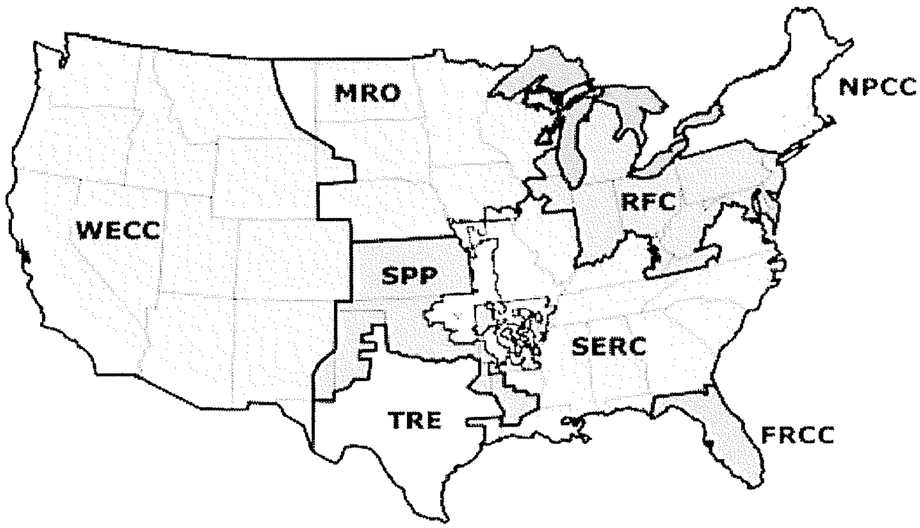
[11] EIA, *supra* n.7.

[12] EIA, *Net Generation by Energy Source*, http://www.eia.doe.gov/cneaf/electricity/epm/table1_1.html (accessed July 31, 2010).

Figure/Table 1 - NERC Electric Reliability Regions



FRCC – Florida Reliability Coordinating Council	**SERC** – Southeast Reliability Corporation
MRO – Midwest Reliability Organization	**SPP** – Southwest Power Pool, RE
NPCC – Northeast Power Coordinating Council	**TRE** – Texas Regional Entity
RFC – Reliability First Corporation	**WECC** – Western Electricity Coordinating Council
Note: NERC regional results shown in this presentation include the continental US only	

Most of the nation's regional reliability organizations cover multiple states and each manages and monitors compliance with NERC's reliability standards, including maintenance of minimum target reserve margins, a key indicator of resource adequacy. Actual or expected reserve margins measure the extent to which generating capacity exceeds (or falls short of) peak electricity demand. All regions must have capacity above expected demand to accommodate power plant outages, transmission failures, unexpectedly high demand, or other contingencies. Most regions have a minimum target reserve margin at or below 15 percent.[13] In recent years, actual reserve margins around the country have been well above the minimum target levels, due not only to new power plant additions in most regions, but also to reduced demand attributable to the economic recession and increasingly robust load management programs.[14]

Table 2, below, illustrates that, in 2013, all NERC regions expect to have actual capacity levels well in excess of minimum reserve requirements. Although this provides only one metric of reliability, and each region will undertake more granular analysis in the months ahead, these capacity "cushions" indicate there should not be a capacity shortage even if projected retirement scenarios prove accurate. As the table further highlights, on an aggregate basis across all NERC regions, the electric sector is expected to have over 100 GW of surplus generating capacity in 2013, about three times the 30 to 40 GW of retirements projected by PIRA Energy Group.[15,16] Reliability First Corporation ("RFC") and the Southeast Reliability Corporation ("SERC") regions, for example, where most of the uncontrolled coal plants are located, are

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[13] Some regions are below 15%, such as TRE (12.5%), SPP (13.6%), WECC (14.7%). Regions that don't establish a formal target are assigned one for planning purposes by NERC, with 15% for regions like the Midwest and 10% for regions with substantial hydroelectric power. NERC, *2010 Summer Reliability Assessment*, May 2010.
[14] *Id.*
[15] NERC, *2009 Long-Term Reliability Assessment: 2009-2018*, October 2009.
[16] PIRA, *supra* n.5.

expected to have high reserve margins at 24.3 percent and 26.3 percent, respectively.[17] These regions could retire 17.1 GW (RFC) and 23.9 GW (SERC) of capacity and still maintain the 15 percent NERC reserve margin target.

Table 2 - Estimated Reserve Margins in All NERC Regions: Adequate Generating Capacity

NERC Electric Reliability Region	Projected Reserve Margin (1) in 2013	Cushion Above NERC Target Reserve Margin (2) In 2013
TRE	23.9%	7.8 GW
FRCC	28.6%	6.1 GW
MRO	22.1%	3.2 GW
NPCC	24.4%	5.9 GW
RFC	24.3%	17.1 GW
SERC	26.3%	23.9 GW
SPP	30.3%	7.7 GW
WECC	42.6%	35.6 GW
Total		**107.3 GW**

[1] Includes capacity defined by NERC as Adjusted Potential Reserve Margin, which is the sum of deliverable capacity resources, existing resources, confidence factor adjusted future resources and conceptual resources, and net provisional transactions minus all derates and net internal demand expressed as a percent of net internal demand. Source: NERC, *2009 Long-Term Reliability Assessment: 2009-2018*, October 2009, p. 396 (Summer Demand).
[2] Capacity in excess of what is required to maintain NERC Reference Margin or the regional target reserve levels.

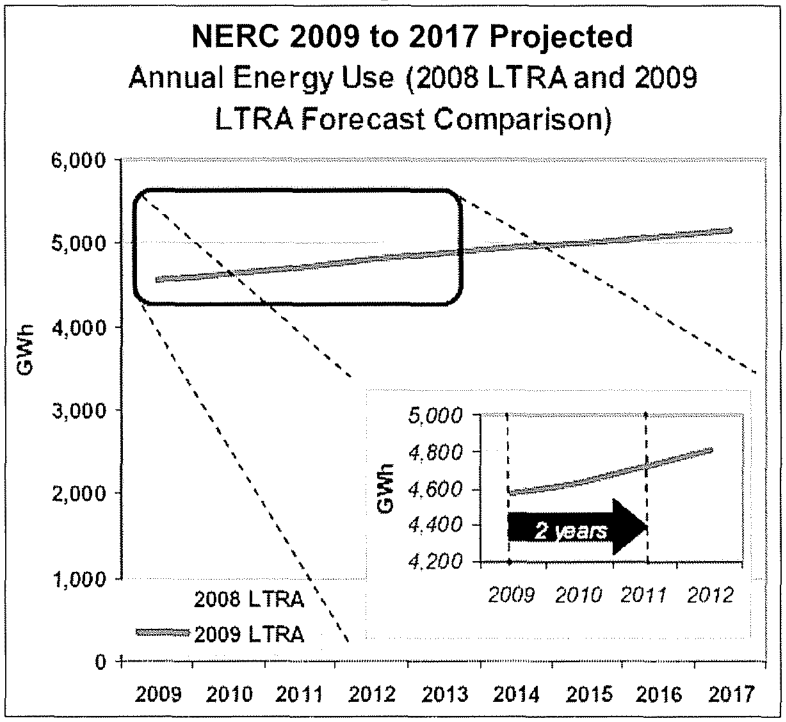
Source: NERC, *2009 Long-Term Reliability Assessment: 2009-2018,* October 2009.

Experience in the RFC region, which encompasses thirteen states in the Midwest and Mid-Atlantic regions, is illustrative of the electric system's ability to tolerate retirements without jeopardizing reliability. Generators in the PJM Interconnection ("PJM") retired about 6,000 MW of capacity between 2004 and 2007, and over 3,000 additional MW of capacity have been announced for retirement in PJM by 2012.[18] Despite almost 10,000 MW of retirements over this seven year period, the RFC region is still forecast to have a reserve margin of over 24 percent in 2013, or an excess of 17,000 MW of generation above the 15 percent NERC target reserve margin target.

Moreover, as a result of the economic recession, NERC projects "significant reductions in projected long-term energy use in North America" [19], which provide an additional capacity cushion. While total demand is still projected to increase in most regions, it will do so at a slower pace and from a lower starting point. See, for example, Figure 2 which shows the decrease in forecast energy use from NERC's 2009 long-term reliability assessment as compared to its 2008 forecast. Additionally, summer peak demand has decreased over 10 GW per year for two consecutive years.[20] Furthermore, in all regions of the country, well-established tools exist to analyze potential regional power system impacts, and to facilitate planning, managing and operating the system to ensure ongoing reliability.

[17] NERC, *supra* n.15.
[18] PJM, *Generation Retirement Summaries,* http://www.pjm.com/planning/generation-retirements/gr-summaries.aspx (accessed July 31, 2010).
[19] NERC, *supra* n.15, at p. 13.
[20] NERC, *supra* n.13, at p. 1.

Figure 2



Source: NERC, *2009 Long-Term Reliability Assessment: 2009-2018,* October 2009, p. 13.

B. The Electric Industry Has Proven Its Ability to Avoid Capacity Problems in the Past—Through Power Plant Capacity Additions, Fuel Conversions, Transmission Solutions, and Load Management Techniques

1. New Capacity is Already in the Pipeline

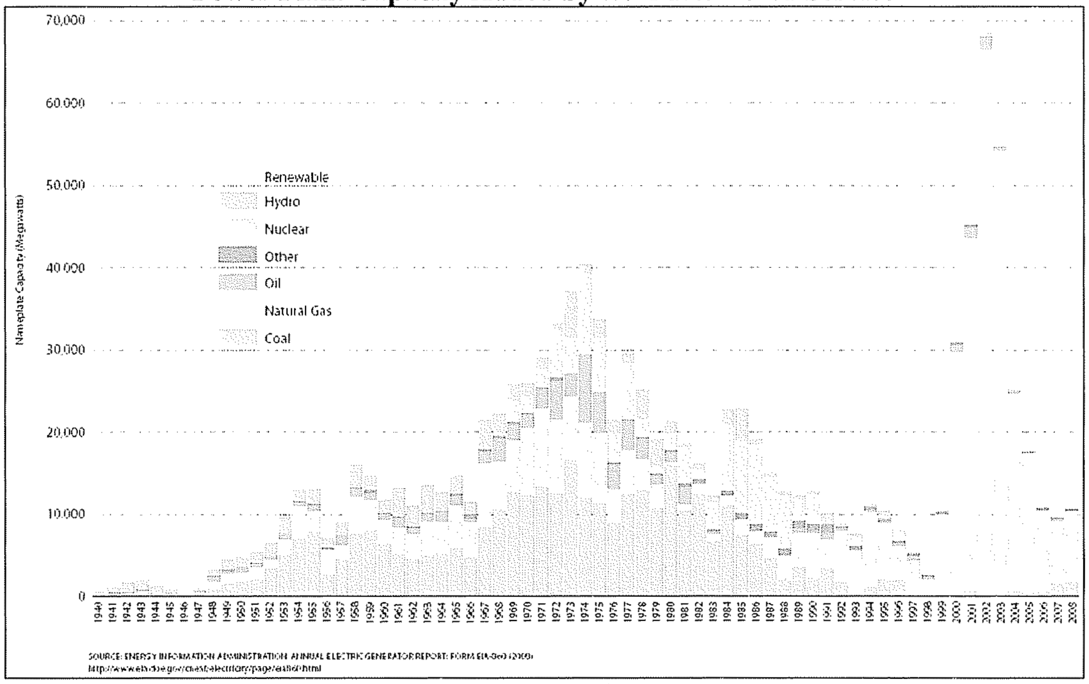
Even with the robust reserve margins in all NERC regions, industry participants are pursuing various measures to safely and reliably transition to cleaner, more efficient electric supply resources. Plans are underway for a variety of new plants, even as less efficient ones are retired. While economics remains the major consideration in deciding whether to develop or expand generating capacity or to mothball older plants, other major drivers, including reliability and environmental improvements, are in play. For example, the implementation of forward capacity markets in certain Independent System Operators (ISOs) has provided more price transparency, enabling the industry to see the value of various generation resources.

Moreover, the industry has shown previously that it can efficiently add capacity or respond adequately to potential reliability issues. Between 1999 and 2008, for example, in response to a variety of market, regulatory and economic signals, the electric sector added almost 270 GW of natural gas-fired generating capacity, the equivalent of more than 80 percent of the entire existing U.S. coal fleet.[21] (See Figure 3 below, which shows the significant investment in new gas plants during the past decade.) Indeed, in just three years between 2001 and 2003, the electric industry built over 160 GW of new generation,[22] about four times what analysts project will retire over the next five years. Although conditions a decade ago

[21] EIA, *Annual Electric Generator Report: Form EIA-860*, 2008.
[22] *Id.*

differ in several respects, this robust construction cycle suggests that developers and investors will respond to strong signals if new capacity is needed.

Figure 3
Power Plant Capacity Added by Year It Entered Service



Source: Ceres, et al., *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States*, June 2010.

There are also examples in which the industry responded quickly and effectively to resolve looming reliability problems. In the mid-1990s, for example, three large nuclear generating units in Connecticut, totaling almost 3,000 MW, were unexpectedly and simultaneously unavailable during lengthy outages[23], transforming Connecticut from a power exporter to a net importer. To avert any reliability problems over the extended outages, the regional grid operator, along with the region's utilities and public officials, instituted a variety of measures including adjusting unit maintenance schedules, executing additional interruptible contracts with large commercial customers, installing new generation and transmission equipment, and coordinating closely with neighboring power systems to maximize out-of-state power purchases.[24] If necessary, the industry could employ similar strategies in response to future coal plant retirements.

Further, as indicated in Table 3 below, substantial new capacity build has been announced, planned or is seeking grid interconnection studies. Across the NERC regions, a recent report identified over 55 GW of proposed generation in advanced stages of development in the queue for 2013. Although, not all of these plants will be built, strong market incentives and signals from regulators that new capacity will be needed will promote generation development proposals beyond those announced to date.

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[23] Western Massachusetts Electric Company, *Form 8K*, November 25, 1996, "Other Events."
[24] PRNewswire, *NEPOOL: Power Supplies May be Tight in New England This Summer*, June 11, 1996.

Table 3 - Proposed New Build – 2013[25]

NERC Region	New Generation Proposed to Be Built (in Transmission Queues for 2013)
TRE	4.3 GW
FRCC	2.0 GW
MRO	3.6 GW
NPCC	7.5 GW
RFC	8.7 GW
SERC	10.3 GW
SPP	2.8 GW
WECC	16.3 GW
Total	**55.5 GW**

Note: There are substantial additional generating facilities in the queue in each region.

Numerous electric companies have already announced substantial new capacity additions, many at the sites of existing coal units that will be retired. Georgia Power, which recently demolished a coal plant in Georgia and stated its intention to retire another, announced it plans to build three 840 MW combined cycle gas turbines ("CCGTs") in Georgia.[26] Oglethorpe Power Corporation has proposed a 605 MW CCGT[27] and a 100 MW biomass facility in Georgia.[28] Also in the Southeast, Progress Energy plans to build a 950 MW CCGT at the site of three coal units, which will retire when the gas plant comes online.[29] In Tennessee, TVA is building an 878 MW CCGT at the site of its John Sevier coal plant, and the City of Vineland New Jersey plans to replace its 25 MW coal plant with a 60 MW gas plant.[30,31]

Also, although they do not operate in the same base load mode as do nuclear or many coal plants, low emission energy facilities have expanded rapidly over the past several years.[32] For example, the total wind power capacity now operating in the U.S. is over 35,600 MW. In 2009 alone, the U.S. wind industry broke all previous records by installing nearly 10,000 MW of new generating capacity, enough to serve over 2.4 million homes. Additionally, over 400 MW of solar was installed throughout the nation in 2009. Solar installations are poised to grow about 50 percent annually in the next three years, reaching 1.5 GW to 2 GW of new installations in 2012.[33]

The retirement of inefficient coal units may spur further development of cleaner generating capacity. Regional transmission studies include capacity even if it runs infrequently. Freeing room for new capacity through retirements means some low emission generation resources, including gas plants, can be accommodated without having to invest in new transmission.

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[25] ICF International, *supra* n.6.
[26] Georgia Power, *From Coal to Natural Gas*, http://www.georgiapower.com/generation/home.asp (accessed July 31, 2010).
[27] Oglethorpe Power, *Oglethorpe Power to Build Gas-Fired Generating Plant*, March 10, 2010.
[28] Power-Gen Worldwide, *Oglethorpe plans a biomass plant*, June 29, 2010.
[29] Energy Business Review, *Progress Energy Wins Approval To Build 950MW Gas-fired Plant*, October 2, 2009.
[30] Marketwire, *TVA Prepares to Begin Construction on 880-Megawatt Combined-Cycle Unit*, March 16, 2010.
[31] NJ Spotlight, *NJ Coal Plants Face Cleanups and Closures*, July 10, 2010.
[32] Wind and solar are intermittent resources; therefore, only part of their output is credited for reliability purposes.
[33] GTM Research, *The United States PV Market Through 2013: Project Economics, Policy, Demand and Strategy*, December 2009.

2. Existing Gas Units Have Untapped Power Production Potential

Given the significant addition of gas-fired capacity in the past decade, as detailed earlier in Figure 3, and the relative price advantage of coal versus natural gas in the period from 2007 to 2008, gas plants were not operated at their full design capability in many parts of the country. As detailed in Table 4 below, gas-fired CCGT power plants in 2008 had an average utilization rate of only 33 percent, as compared to coal's 56 percent. Despite declines in natural gas prices, existing gas units have significant untapped power production potential, which can be expanded during off peak periods without constructing new generation. This excess capacity can assist in managing power plant outages required to install pollution control systems.

Table 4 – Estimated Utilization of U.S. Coal and Gas Plants (CCGT) by Region (2008)

		Coal		Gas	
Region	*Plant Size (MW)*	*Total Installed Capacity (MW)*	*% Utilization*	*Total Installed Capacity (MW)*	*% Utilization*
	> 500	7,981	67%	17,678	46%
FRCC	200 - 500	1,628	64%	2,410	26%
	< 200	199	53%	1,389	20%
	> 500	18,113	73%	3,033	15%
MRO	200 - 500	4,915	59%	1,246	15%
	< 200	3,111	42%	506	10%
	> 500	2,407	79%	13,791	44%
NPCC	200 - 500	2,548	70%	4,326	36%
	< 200	1,079	47%	2,843	21%
	> 500	99,474	61%	28,087	19%
RFC	200 - 500	11,479	54%	2,709	13%
	< 200	4,664	48%	1,794	34%
	> 500	91,188	66%	40,529	24%
SERC	200 - 500	10,699	57%	4,995	29%
	< 200	4,109	36%	1,229	33%
	> 500	17,970	71%	12,051	32%
SPP	200 - 500	2,361	72%	2,116	37%
	< 200	647	44%	465	22%
	> 500	15,193	80%	28,869	44%
TRE	200 - 500	1,213	82%	5,025	36%
	< 200			1,020	24%
	> 500	30,081	73%	37,435	47%
WECC	200 - 500	2,992	78%	6,835	40%
	< 200	2,465	60%	5,042	49%
	> 500	**282,407**	**67%**	**181,473**	**35%**
All US Plants	**200 - 500**	**38,277**	**60%**	**30,136**	**32%**
	< 200	**16,616**	**45%**	**15,966**	**30%**

Source: MJB&A analysis based on U.S. Energy Information Administration's Form EIA-860 (2008) and EIA-923 (2008)

Additionally, many coal plants have the potential to repower their units, by replacing conventional coal-fired steam electric generating units with CCGTs, thus increasing the units' efficiency *and* reducing air emissions—an approach already being used today by the industry. For example, Xcel Energy has replaced a 270 MW coal plant in Saint Paul, Minnesota with a 515 MW CCGT, reducing SO_2 emissions by 99.7 percent, NOx emissions by 96.9 percent, and eliminating mercury emissions.[34] It also repowered

[34] Utility Engineering, *Twin Cities to breathe easier thanks to UE*, Value Connection, Issue 2, 2007.

two coal units in Minneapolis.[35] In New Jersey, Calpine has announced its intent to convert an 83 MW coal unit to a 158 MW gas unit.[36]

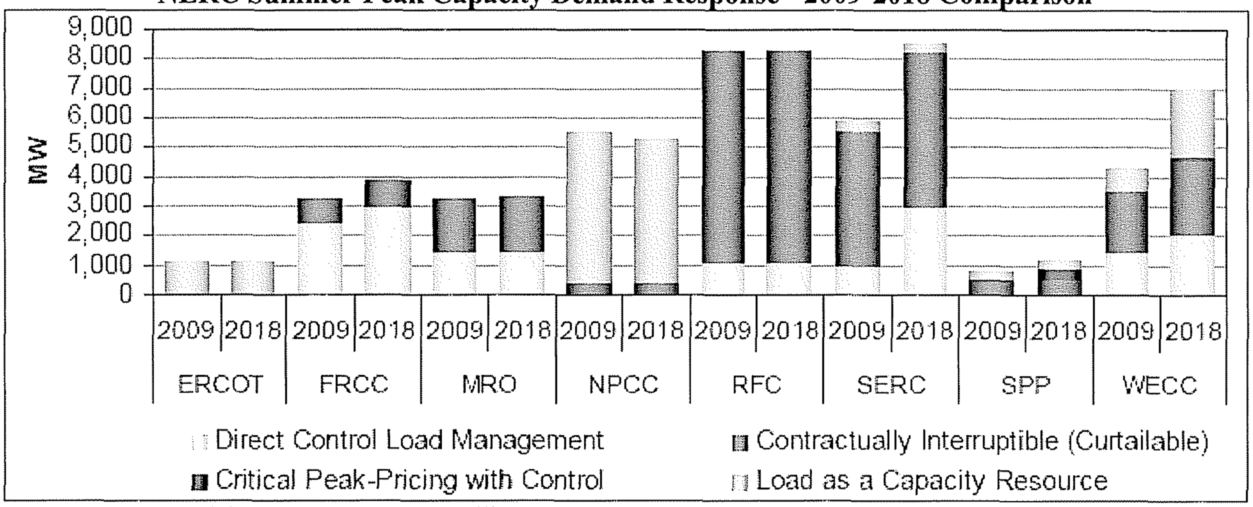
3. Enhanced Load Management Programs Can Be Deployed to Meet System Reliability Needs Economically

Historically, grid operators have dispatched plants to meet customers' electricity requirements. Over the years, the industry has recognized that decreasing load requirements can be more efficient and economical than increasing supply by dispatching generation. As a result, load management tools, such as demand response ("DR") and energy efficiency ("EE") programs have been widely implemented across the nation.

DR programs manage load by temporarily reducing or shifting electricity use by homes or businesses during critical times like hot summer days. EE programs, on the other hand, primarily seek to reduce consumers' energy use on a permanent basis through the installation of energy efficient technologies and conservation measures. Both means of load management provide an additional tool for system operators to manage electric reliability.

DR programs operate in all of the NERC Regions, as shown in Figure 4 below. In some regions, such as RFC, SERC, WECC, and MRO, a substantial fraction of the DR resources are available in the form of "contractually interruptible" or curtailable loads. These typically entail contracts between a utility and an industrial customer, in which the customer agrees to curtail part of its usage when requested for a specified number of times during a certain period, in exchange for electric rate discounts. The other forms of DR—direct control load management, critical peak pricing with control, and load as a capacity resource—are more dynamic forms of supply, in which the grid operator, in effect, dispatches the load to respond with a reduction or shift in load, much like a generating facility.

Figure 4
NERC Summer Peak Capacity Demand Response - 2009-2018 Comparison



Source: NERC, Long-Term Reliability Assessment, 2009, Figure 7 (page 18).

In particular, these other forms of DR have increased steadily in organized wholesale competitive markets. In PJM, for example, DR has increased five-fold in the past five years and continues to grow.[37]

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[35] North Dakota Home Town Times, *Xcel Energy Switches Minneapolis Coal Plant to Natural Gas*, October 13, 2009.
[36] NJ Spotlight, *supra* n.31.

In the most recent PJM capacity auction, DR offers increased 32 percent over last year and over 9,000 MW cleared, which represents about six percent of total available capacity resources.[38] DR is expected to reduce the peak electricity use this summer in PJM by 8,525 MW, the equivalent output of ten large power plants.[39]

DR is not just increasing in PJM. According to the ISO/RTO Council, competitive markets are "shattering barriers" in terms of attracting DR resources.[40] In FERC's recently released *National Action Plan on Demand Response*, it highlighted that DR has tripled in recent years in the New England region[41] and identified strategies to further enhance DR. Already, about half of electric utilities across the nation have some type of DR program. With continued support from regulatory agencies like FERC and the advancement of "smart grid" technologies, DR is expected to continue to grow as a viable supply alternative to traditional generation.

As with DR, EE programs have increased dramatically in the past several years. According to information compiled by the Consortium for Energy Efficiency, and as highlighted in Figure 5, the total budget for all US ratepayer-funded EE and DR programs has increased 80 percent since 2006 to $4.4 billion in 2009.[42] These programs resulted in savings of almost 105,000 gigawatt hours ("GWh") of electricity in 2008—the equivalent of the total electricity consumption in Tennessee in the same year.[43] By 2018, new EE programs alone are expected to reduce summer peak demands by almost 20,000 MW (a full year's growth).[44]

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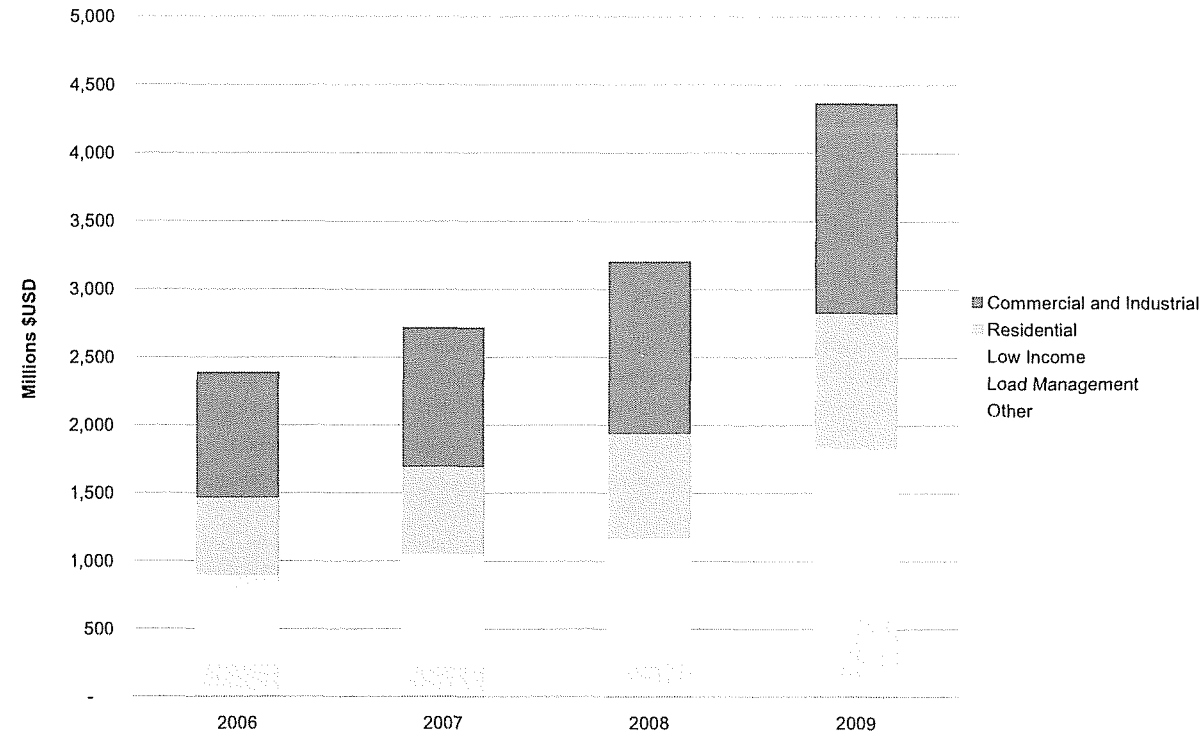
[37] PJM, *Demand Response To Play Significant Role In Meeting PJM's Higher Summer Peak Electricity Use*, http://pjm.com/~/media/about-pjm/newsroom/2010-releases/20100505-summer-2010-outlook.ashx (accessed August 6, 2010)
[38] PJM, *2013/2014 RPM Base Residual Auction Results*, at p. 1.
[39] PJM, *supra* n.37.
[40] ISO/RTO Council, *2009 State of the Markets Report*, September 22, 2009.
[41] The Federal Energy Regulatory Commission Staff, *National Action Plan on Demand Response*, June 17, 2010, at p. 7.
[42] Consortium for Energy Efficiency ("CEE"), *The State of the Efficiency Program Industry: Budgets, Expenditures, and Impacts*, 2009, at p. 7.
[43] *Id.*
[44] NERC, *supra* n.15, at p. 12.

Figure 5
Energy Efficiency and Demand Response Program Budgets, 2006-2009



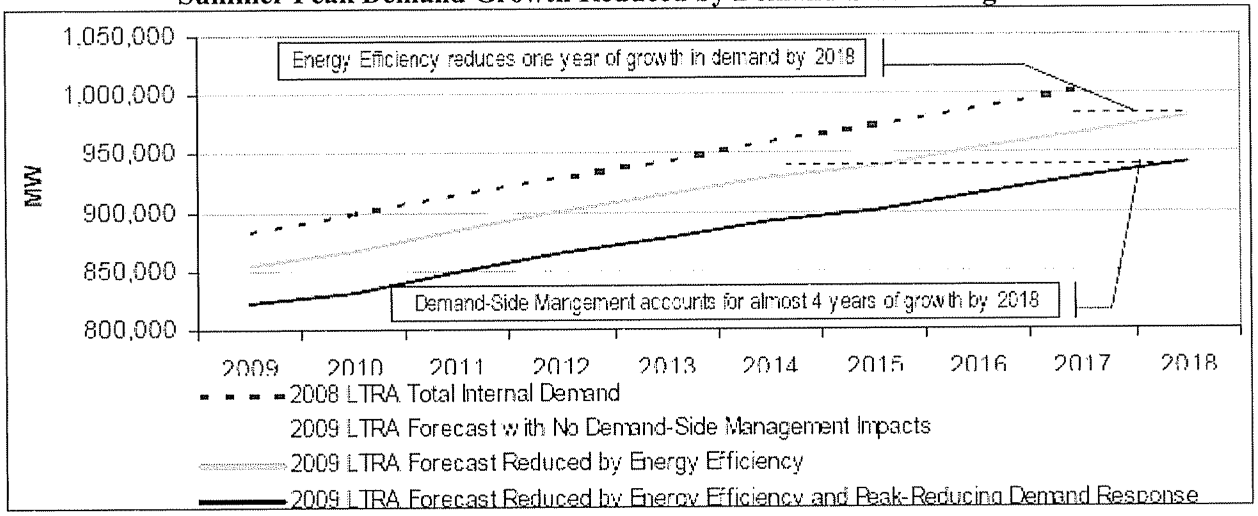
Source: Consortium for Energy Efficiency, *The State of the Efficiency Program Industry: Budgets, Expenditures, and Impacts*, 2009

Although California and the Northeast account for over half of the total, budgets for ratepayer-funded EE programs are expanding in all regions of the country. In 2009, EE budgets for Illinois, Wisconsin, and Iowa increased in 2009, year-on-year, by 60 percent, 40 percent, and 36 percent, respectively.[45] In the Southeast, Alabama, Mississippi, North Carolina, and Louisiana reported ratepayer-funded EE budgets for the first time in 2009.[46] EE's use as a capacity resource is increasing in organized wholesale markets as well. For example, EE resources accounted for 757 MW of the resources offered into the most recent PJM RPM auction, an increase of 33 percent over the prior year. Of those resources, 90 percent, or 680 MW cleared the auction to serve as a firm capacity resource.[47]

NERC estimates that current levels of EE and DR will shave off certain portions of expected growth in demand, as shown in Figure 6, below, underscoring growing acceptance of these load-management tools.

[45] CEE, *supra* n.42, at p. 15.
[46] *Id.* at p. 16.
[47] PJM, *supra* n.38.

Figure 6
Summer Peak Demand Growth Reduced by Demand-Side Management



Source: NERC, Long-Term Reliability Assessment, 2009, at p. 18.

Based on the experience of states and organized competitive wholesale markets that have implemented EE and DR, it is clear these programs provide yet another cost-effective tool to help maintain reliability in the face of generation retirements.

II. THE INDUSTRY HAS THE CAPACITY TO TIMELY RESPOND TO EPA'S FUTURE AIR REGULATIONS

A. The Majority Of Coal Plants Have Already Installed Air Pollution Controls

Proven pollution control technologies are widely available to dramatically reduce emissions of NO_x, SO_2, mercury, and other HAPs from coal plants, which account for 98 percent of the electric sector's SO_2 emissions, 86 percent of its NOx emissions, and 98 percent of its mercury emissions.[48,49]

Over the last 20 years, the industry has deployed a number of different technologies to comply with federal and state SO_2 and NOx regulations. The three basic options for reducing SO_2 emissions from coal plants include: (1) switching from higher to lower sulfur coal; (2) blending higher sulfur coal with lower sulfur coal; or (3) installing flue gas desulfurization ("FGD") control systems, commonly referred to as scrubbers. Wet scrubbers, which use a sorbent to capture SO_2, can typically achieve at least 95 percent SO_2 removal. Widely available NOx control technologies for coal generation can be grouped into two broad categories: combustion modifications and post-combustion controls. Post-combustion controls can reduce NOx emissions by 90 percent or more by removing the NOx after it has been formed in the boiler. The most common post-combustion control is selective catalytic reduction ("SCR") technology, in which ammonia (NH_3) is injected, combining with the NOx in the flue gas to form nitrogen and water.

The majority of coal plants have already installed such controls. Of the 310 GW of coal capacity in the United States, 150 GW have installed FGD systems and another 55 GW have FGD controls planned,[50] representing 65 percent of the existing coal fleet. As detailed in Attachment A, numerous scrubber installations have been recently completed or soon will be completed. Additionally, about 50 percent of coal capacity in the U.S. has installed or soon will be retrofit with advanced NOx controls (SCR and selective non-catalytic reduction ("SNCR") technologies).[51]

To date, most studies put a heavy emphasis on deploying scrubbers to comply with the new EPA air regulations. Retirements occur where the costs of installing scrubbers does not make economic sense based upon the unit's characteristics. However, a number of companies have announced that they will use other less costly technologies in lieu of scrubbers. For example, on August 5, 2010, Edison Mission International, one of the nation's largest merchant coal generators, announced it could achieve compliance without installing scrubbers by using trona injection technology.[52]

B. With Proper Planning, the Industry Can Install the Necessary Pollution Controls on a Timely Basis

EPA projects that about 14 GW of additional coal-fired generating capacity will need to be retrofit with scrubbers and less than 1 GW with SCR controls by 2014 to comply with the recently proposed Transport Rule.[53] This number of retrofits is significantly less than the industry has added in past construction

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[48] EIA, *U.S. Electric Power Industry Estimated Emissions by State (EIA-767 and EIA-906)*, Electric Power Annual 2008, http://www.eia.doe.gov/cneaf/electricity/epa/emission_state.xls (accessed July 30, 2010)
[49] U.S. EPA Office of Air Quality Planning and Standards, *National Emissions Inventory for Hazardous Air Pollutants*, 1999.
[50] PIRA, *supra* n5, at p. 7.
[51] U.S. EPA, *National Electric Energy Data System ("NEEDS")*, version 3.02.
[52] Trona is a naturally occurring sorbent that can be injected directly into boilers to remove harmful air toxics without the use of FGD scrubbers. Given that the PIRA and EEI analyses did not consider trona and other less costly compliance options, the predicted retirement scenarios are very likely overstated. Nonetheless, this report uses the predicted retirements as a conservative input to test all of the reliability considerations.
[53] U.S. EPA, *Proposed Rule: Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, August 2, 2010.

cycles. For example, during the peak of scrubber construction, between 2008 and 2010, approximately 60 GW of coal capacity was retrofit with scrubber controls,[54] highlighting the industry's ability to complete a substantial number of retrofits over a short period of time. In 2009 and 2010, the industry completed between 50 and 60 scrubber retrofits each year.[55]

Moreover, the industry's past successful installation of pollution controls on numerous units underscores its ability to schedule and sequence any required unit outages in an efficient and reliable manner. To help ensure reliability, generators and transmission owners provide reasonable advance notice of any planned outages to the respective transmission authorities. In turn, the transmission authorities develop a coordinated outage schedule to prevent any deliverability problems. This illustrates a key benefit of a fully integrated national transmission system.

Further, the CAA allows three years for existing sources to comply with the Utility MACT rule with the possibility of a one-year extension. EPA is under a court-imposed deadline to complete its regulations by November 2011, with compliance required by late 2014. As numerous states have adopted regulations limiting mercury emissions from coal-fired power plants, many companies have already begun to install mercury control technologies. Also, the scrubber and particulate control systems installed to comply with the Transport Rule and other EPA regulations will help companies to comply with future air toxics regulations.

In the event, however, that any required retrofit construction schedules could not be completed within the pre-compliance period, EPA may, and should, exercise its authority under Section 112(i)(3)(B) of the CAA to provide up to one-year extensions to complete pollution control installations. In addition, to protect the national security interest of maintaining adequate electrical grid reliability, the President has the authority under Section 112(i)(4) of the CAA to grant one or more compliance extensions of up to two years each. Any such extensions would be unit-specific and based on clear demonstration that the technology to implement such standards is not available.

These federal tools combined with market rules and signals, industry reliability standards and enforcement mechanisms, and utility regulatory requirements and incentives, provide a robust portfolio of techniques to assure compliance with health-based air regulations while maintaining reliable electricity supply.

C. The Coal Plants Most Likely To Retire Are Nearing The End Of Their Design Life Expectancies And Are Already Economically Challenged

As indicated by Table 5 below, many of the uncontrolled coal units, which are the most likely to retire, are smaller (250 MW and below) and are 40 to 60 years old. Thus, the coal plants most likely to retire are already nearing the end of their design life expectancies, as confirmed in recent coal plant retirement announcements, detailed in Attachment B.

[54] M. J. Bradley & Associates analysis based on U.S. EPA NEEDS Database v. 3.02.

[55] *Id.*

Table 5 - Characteristics of U.S. Coal Plants

Unit Age	Units		Capacity		Avg. Unit Size	Pollution Control Installed (% of units)			
	Count	%	MW	%	(MW)	SNCR	SCR	Scrubber	Uncontrolled
> 60 years	46	5%	1,762	1%	38	2%	4%	11%	87%
51 - 60 years	313	31%	39,787	13%	127	21%	9%	19%	64%
41 - 50 years	233	23%	58,078	20%	249	15%	19%	33%	53%
31 - 40 years	229	23%	114,090	38%	498	4%	43%	65%	27%
11 - 30 years	163	16%	80,165	27%	492	6%	29%	66%	31%
10 years or younger	7	1%	2,444	1%	349	43%	29%	57%	29%
Total	1,004		297,639			13%	23%	41%	48%

Data Sources: 2007/2008 EPA IPM, ARP, NBF Databases & Commercial Sources, MJB&A Analysis

Information included in the most recent annual *State of the Market Report* prepared by PJM's Independent Market Monitor ("IMM") suggests that fundamental economics, not the EPA regulations, are already challenging those units most likely to retire. In that report, the IMM identified over 11 GW of coal units at risk for retirement, since they "did not recover avoidable costs even with capacity revenues."[56] Of the 11 GW identified in the report, most operated less than 1,000 of the 8,760 hours in 2009 and tended to be significantly smaller with an average installed capacity of only 73 MW.[57] Of the 122 coal units in PJM with capacity less than or equal to 200 MW, 35 failed to recover their avoidable costs and another 52 were close to not recovering those costs. Therefore, in PJM, a region covering 13 states and DC, in addition to approximately 10 GW of coal generation that has or will be retired during the seven years from 2004 to 2011, another 11 GW faces a troubling economic outlook. As such, the units' economics already place them at risk of shutdown, regardless of EPA's future air regulations.

In reducing the air pollution emissions from some of the nation's most inefficient uncontrolled units, EPA will facilitate the development of cleaner, more efficient generation while improving air quality and reducing greenhouse gas emissions. The current levels of air pollution in certain regions of the country require industrial facilities and power plants to obtain emission offsets to expand their operations. This requirement discourages economic development due to the increased permitting and financial obligations compared to areas that meet federal and state air quality standards. Significantly as well, as shown in Figure 7, because these non-attainment areas are concentrated in highly populated areas, reducing emissions there will facilitate the development of cleaner, more efficient generation near electric load centers where it is needed most.

Additionally, the retirement of generating capacity that has been previously supported by transmission investment could create room on the transmission grid to handle power flows both within and outside the regions, or the addition of new generating capacity, without requiring attendant transmission upgrades. These considerations, too, will help mitigate reliability concerns and reduce the cost of upgrading the nation's power system infrastructure.

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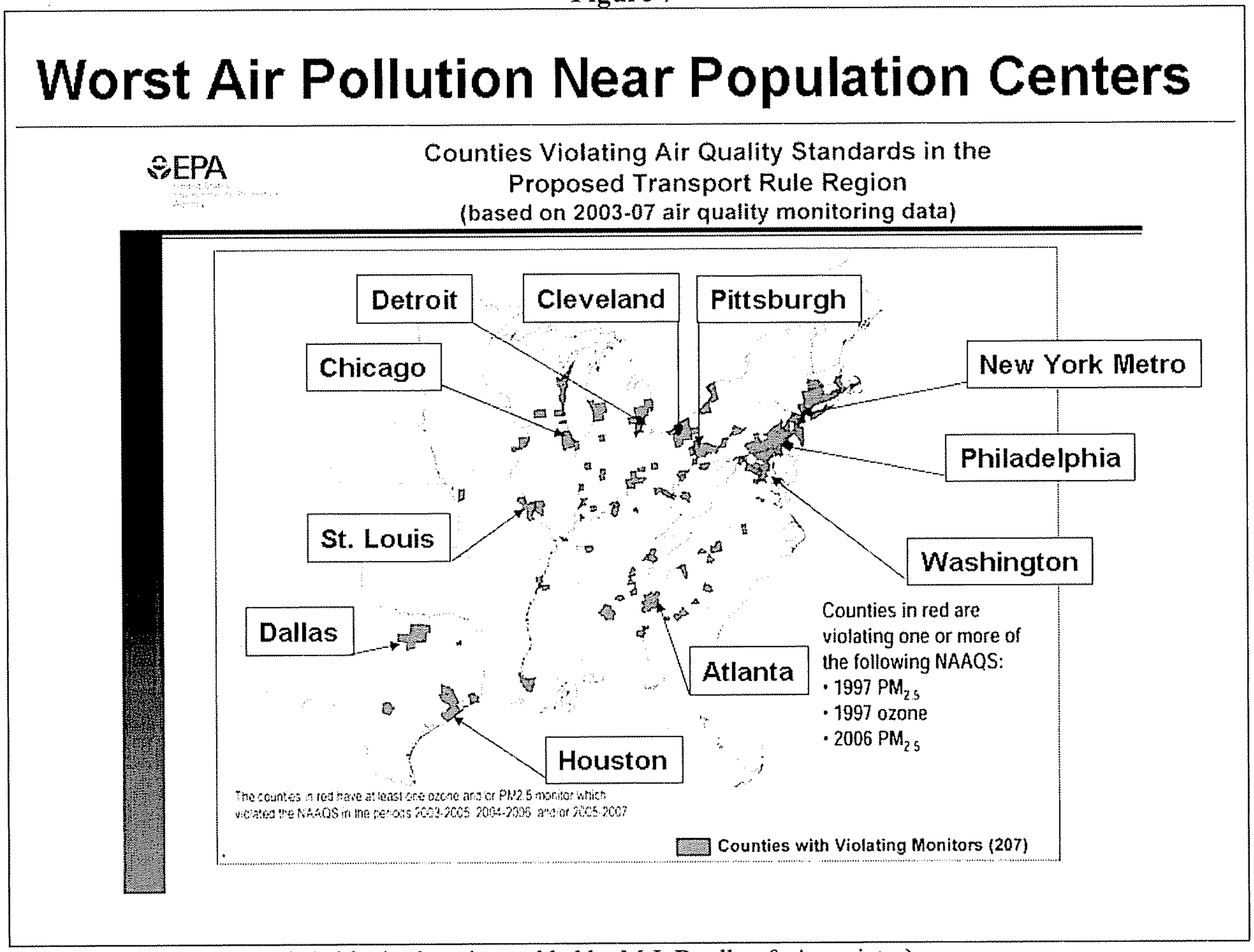
[56] PJM, *State of the Market Report*, Vol. 1, March 11, 2010, p. 21.
[57] *Id.* Vol. 2 at p. 176.

Figure 7



Source: U.S. EPA (with city locations added by M.J. Bradley & Associates)

III. EPA, DOE, FERC AND STATE UTILITY REGULATORS HAVE THE TOOLS TO MODERATE IMPACTS ON THE ELECTRIC INDUSTRY AND MANAGE ELECTRIC SYSTEM RELIABILITY.

A. Statutory, Regulatory and Market Safeguards Exist To Mitigate Risks of Retirement On Reliability

Assorted risk management procedures under the CAA, the Federal Power Act ("FPA") and other statutes provide EPA, DOE, FERC, and the President tools to moderate potential impacts on electric system reliability. The procedures serve as a bridge, if necessary, to a permanent solution, helping ensure reliability while minimizing exposure to harmful air pollutants. EPA also has the authority to develop cost-effective regulatory approaches, such as the emissions trading mechanism proposed in the Transport Rule, that will enable greater compliance flexibility and flexibility in managing potential reliability issues.

In addition to the EPA's and President's authority to extend deadlines for installation of pollution controls described in Section II B, where necessary to maintain electric system reliability, DOE has the power under Section 202(c) of the FPA to override CAA-derived control requirements in limited emergency circumstances. In such emergency situations, including extended periods of insufficient power supply as a result of shortage of electric facilities, DOE has the discretion to issue unit-specific orders designed to maximize CAA compliance and minimize health risks.

Two examples of DOE's exercise of this authority illustrate the point. In 2003, the Secretary of Energy ordered energizing a new underwater cable connecting New Haven, Connecticut to Long Island, which had previously been constructed but remained inoperable due to legal actions appealing permits. Citing August 2003's massive electric service outage, the Secretary invoked his authority to alleviate the reliability emergency.[58]

DOE's actions related to the Potomac River plant serving Washington, DC provide another example. In 2005, the plant's owner, Mirant, had decided to shut down all five generating units at its Potomac River plant located outside Washington, DC. The DC Public Service Commission requested that DOE issue an emergency order directing Mirant to continue to operate the units, as their shutdown would have "immediate" and "drastic" effects on DC's electric system reliability. In conjunction with the EPA, which required Mirant to enter into a consent decree, DOE issued an Order[59] requiring Mirant to operate the plants under specific and limited circumstances tailored to relieve the risk of a DC area blackout, while avoiding to the full extent possible exceedances of federal air quality standards.

The well-established consent decree template, as used to address the Potomac River situation, provides EPA yet another tool to synthesize reliability and environmental concerns. By restricting a unit to operate for reliability purposes only, pending completion of any required transmission upgrades or replacement

[58] DOE, *Order No. 202-03-2*, August 28, 2003. "I hereby determine that an emergency continues to exist in the Northeast United States due to a shortage of electric energy, a shortage of facilities for [...] the transmission of electric energy and other causes. [...] On August 14, 2003, the Northeast and Upper Midwest areas in the United States, as well as portions of Canada, experienced the largest electric transmission grid failure and electric service outage ever to occur in North America. Tens of millions of people were affected by this outage, and it presented profound risks to the public health and safety throughout the affected areas. [...] Only hours after the outage occurred, and after considering the unanimous recommendation of the North American Electric Reliability Council, the New York Independent System Operator (NYISO), ISO New England, Inc. (ISO-NE), and electric utilities in both New York and Connecticut in support of the issuance of an emergency order, I issued an order directing the NYISO and ISO-NE to require the Cross-Sound Cable Company, LLC (CSC) to operate the Cross-Sound Cable and related facilities as necessary to alleviate the disruptions in electric transmission service. The Cable was energized a short time thereafter."

[59] DOE, *Order No. 202-05-03*, December 20, 2005.

generation, such consent decrees can maintain reliability while minimizing adverse environmental impacts to the fullest extent possible.

Many regional wholesale competitive markets also have well-established forward capacity markets such as PJM's Reliability Pricing Model and New England's Forward Capacity Market, which are approved by FERC and overseen by independent market monitors, to facilitate and provide advanced notice of the retirement of inefficient units while maintaining reliability. Reliability impact studies are conducted for units that have announced retirement or fail to clear the forward capacity auctions, and those identified as being needed for reliability may continue to operate past their planned retirement date pursuant to "reliability must run" ("RMR") agreements. To help ensure reliability while minimizing adverse environmental impacts, the RMR agreements can provide the units operate only to maintain reliability. For example, Exelon Generation recently coordinated with PJM and the Pennsylvania Department of Environmental Protection ("PA DEP") to negotiate a consent decree and operating procedures related to an RMR agreement for its two retiring coal units, which require the units operate for reliability purposes only.[60]

In addition to these established ISO/RTO procedures, advance analysis in the long range reliability planning processes should lead to rational and timely investments in new transmission that will mitigate any service reliability issues associated with future generation retirements. The local transmission owners currently play an important supplemental role in accomplishing this objective. For example, Commonwealth Edison ("ComEd"), the local transmission owner in Chicago, proactively filed an application with the Illinois Commerce Commission[61] seeking permission to enhance its transmission system. In its application, ComEd noted the identified upgrades would be required to maintain system reliability in the event that two of Midwest Generation's at-risk coal units, Fisk and Crawford, were to retire.[62]

Procedures also exist to protect electric system reliability in regions where coal plants are not part of an organized wholesale competitive market, but are owned by vertically-integrated utilities in traditionally regulated monopoly regimes. Generators regulated by state regulatory commissions have a legal obligation to reliably serve their customers, and to conduct long range resource planning. Typically, generators will have many options to meet their statutory obligation to serve including, but not limited to: (1) investing in existing plants; (2) building new plants; (3) decreasing load through DR and EE programs; (4) building transmission; or (5) a prudent combination of all those tools. Too, state regulators may adopt ratemaking policies to encourage such actions, including ones that address utilities' financial disincentives where aggressive EE and DR programs would otherwise produce lower revenues.

As such, FERC and other relevant agencies have a number of tools available to moderate the impacts of air emission regulations, while maintaining reliability and minimizing adverse environmental impacts. Moreover, EPA is also developing new water regulations under Section 316(b) of the Clean Water Act ("CWA"), new waste regulations, and greenhouse gas regulations affecting the electric power sector. EPA should consider efficiently coordinating these rules as it moves forward with its rulemakings to avoid possible reliability concerns.

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[60] *Commonwealth of Pennsylvania Department of Environmental Protection v. Exelon Generation Company, LLC.*, No. 382 MD 2010 (Pa. Cmmw. April 16, 2010) included in *Operating Procedures for Cromby Generating Station Unit No. 2 and Eddystone Generating Station Unit No. 2 as Required for Reliability Purposes* at Appendix 1, http://pjm.com/planning/generation-retirements/~/media/planning/gen-retire/must-run-operating-procedures.ashx (accessed August 6, 2010).

[61] Commonwealth Edison Company, *Application for authorization under Section 4-101 of the Illinois Public Utilities Act ("Act"), 220 ILCS § 5/4-101, or alternatively, for a Certificate of Public Convenience and Necessity, pursuant to Section 8-406 of the Act, to install, operate and maintain two new 345,000 volt electric transmission lines in Cook County, Illinois*, No. 10-0385 (Ill. Cir. June 11, 2010).

[62] Direct Testimony of Thomas W. Leeming, p. 2, Lines 25-35.

IV. CONCLUSION

Current industry practice and a review of applicable system data indicate the industry is well-positioned to respond to EPA's mission to "help millions of Americans breathe easier and live healthier" without threatening electric reliability. Generation plant capacity and availability, consumption levels and patterns, and transmission capacity and use must all be considered when judging the reliability impacts of environmental regulatory action.

The existing substantial excess capacity, the industry's proven track record to timely construct new generation and to efficiently coordinate the scheduling of planned outages, together with capacity upgrades, transmission enhancements, "smart grid" investments, fuel conversions, DR, and EE, should mitigate reliability concerns.

The industry has already successfully employed these various strategies to reliably meet customers' energy needs while reducing environmental impacts, and it will continue to do so in response to EPA's new regulations. As a final backstop, existing statutory, market and regulatory safeguards will facilitate the retirement of inefficient units, and an orderly transition to cleaner, more efficient generation.

ATTACHMENT A

Sampling of Recent Announcements of Scrubber Installations

Plant	Unit	State	Size (MW)	Highlights
Brandon Shores	1	MD	643	This significant environmental upgrade supports Constellation Energy's environmental stewardship efforts by: Reducing Maryland's coal-fired power plant's SO_2 emissions by an estimated 95 percent; Reducing existing mercury emissions by 90 percent; and Significantly reducing acid gases. http://www.constellation.com/portal/site/constellation/menuitem.38d5d085b395c0cb2adedd10d66166a0/
Brandon Shores	2	MD	643	
Kingston	1	TN	135	The two scrubbers added at Kingston will control sulfur dioxide from all nine boilers at the fossil plant, which can generate 10 billion kilowatt-hours of electricity per year. "We now have state-of-the-art control equipment on all of our units at Kingston, allowing us to generate the electricity needed by our customers," Kingston Plant Manager Leslie Nale said. "This translates into cleaner air in the Great Smoky Mountains and across the region." http://www.tva.gov/news/releases/aprjun10/kingston_scrubbers.html
Kingston	2	TN	135	
Kingston	3	TN	135	
Kingston	4	TN	135	
Kingston	5	TN	177	
Kingston	6	TN	177	
Kingston	7	TN	177	
Kingston	8	TN	177	
Kingston	9	TN	178	
Miller	3	AL	750	During peak construction, Alabama Power's $1.7 billion scrubber initiative was responsible for creating more than 2,300 jobs. "This investment is not only good for the environment, it's also good for Alabama's economy," Charles McCrary, Alabama Power president and CEO, said. http://southerncompany.mediaroom.com/index.php?s=43&item=2074
Miller	4	AL	750	
Gaston	5	AL	861	
Barry	5	AL	750	
Coffeen	1	IL	340	"Our investment in these technologies reflects our commitment to environmental stewardship and our support for the communities we serve," says Chuck Naslund, AER chairman, president and chief executive officer. "Through these projects, we have not only offered continued permanent employment to hundreds of Illinoisans, but we have also provided jobs to contract employees who call Illinois home. Clearly these projects have had a positive impact on the economies of central and southern Illinois – areas hard-hit by tough economic conditions." http://www.bloomberg.com/apps/news?pid=conewsstory&tkr=AEM:SP&sid=a.W8.1491R8g
Coffeen	2	IL	560	
Cardinal	1	OH	600	According to Buckeye Power, one of the owners of the Cardinal Plant, "the addition of these scrubbers means the Cardinal plant is able to reduce emissions while using Ohio coal, meaning jobs and economic benefits for eastern Ohio and the region." The unit 3 scrubber is still under construction. http://www.buckeyepower.com/pages/buckeye-power-2
Cardinal	2	OH	600	
Cardinal	3	OH	630	
Monroe	4	MI	775	DTE Energy will also be installing two additional FGD systems at Monroe units 1 and 2. According to DTE, "the $600 million project will create 900 jobs and be one of the largest construction projects in Michigan over the next few years." http://www.prnewswire.com/news-releases/dte-energy-environmental-project-will-create-900-jobs-78770632.html
Monroe	3	MI	795	
Cliffside	5	NC	550	According to Duke, the scrubber control installation at Cliffside Unit 5 will be completed by the Fall of 2010. Duke already has emission-control scrubbers on all its large Carolinas coal plants—Allen, Marshall and Belews Creek. According to Duke spokesman Andy Thompson, Duke has reduced its NOx emissions by 80% since 1997 and SO2 emissions have fallen 70% since 2005. http://www.bizjournals.com/charlotte/blog/power_city/2010/07/duke_energy_assessing_new_epa_rules.html
Bowen	1	GA	713	Scheduled for completion in early 2010, according to Georgia Power. http://www.georgiapower.com/pluggedin/construction_2009_08.asp
Crist	6	FL	302	According to Gulf Power, since 1992, the company has reduced regulated emissions by more than 70 percent despite increased electricity demand from 120,000 new customers. With the scrubber system fully operational, Gulf Power will have reduced overall regulated emissions by more than 85 percent since 1992. http://www.renewablesbiz.com/article/09/12/gulf-power-begins-scrubber-startup
Crist	7	FL	477	
Clifty Creek	1	IN	217	"The addition of these FGD systems represents a major commitment to environmental quality in southeastern Ohio and southeastern Indiana," said David L. Hart, vice president and assistant to the president of OVEC-IKEC. "The projects will also produce an economic boost to the two regions." The scrubber installations at Clifty Creek and Kyger Creek are scheduled for completion in 2010. http://www.prnewswire.com/news-releases/ovec-ikec-to-invest-820-million-for-environmental-controls-at-kyger-creek-and-clifty-creek-power-plants-56325052.html
Clifty Creek	2	IN	217	
Clifty Creek	3	IN	217	
Clifty Creek	4	IN	217	
Clifty Creek	5	IN	217	
Clifty Creek	6	IN	217	
Kyger Creek	1	OH	217	

Plant	Unit	State	Size (MW)	Highlights
Kyger Creek	2	OH	217	
Kyger Creek	3	OH	217	
Kyger Creek	4	OH	217	
Kyger Creek	5	OH	217	
Chalk Point	1	MD	342	"We are making a major investment in emission reduction technologies," said Edward R. Muller, Mirant chairman and CEO. "This equipment offers an excellent solution for substantially improving air quality while maintaining system reliability and efficient power generation for consumers and businesses." http://investors.mirant.com/releasedetail.cfm?releaseid=351567
Chalk Point	2	MD	341	
Morgantown	1	MD	624	
Morgantown	2	MD	620	
Dickerson	1	MD	182	
Dickerson	2	MD	182	
Dickerson	3	MD	182	
Brunner Island	1	PA	344	According to PPL's website, "[t]he unit's scrubber is now operating as designed, thanks to plant employees who safely made the final connections between the plant and the scrubber during a recent maintenance outage." http://www.pplweb.com/ppl+generation/ppl+brunner+island.htm
Brunner Island	2	PA	397	
Brunner Island	3	PA	754	
Hatfields Ferry	1	PA	530	According to an Allegheny Energy fact sheet, "[t]he 'scrubbers' will remove approximately 95 percent of the sulfur dioxide (SO_2) emissions and significantly reduce mercury emissions from the station…In addition to improving the environment, the scrubber system will enable Hatfield's Ferry to purchase more local coal, which will preserve regional coal mining and related coal mining support jobs. The project will bring approximately 350 construction jobs to the region for a period of about three years. Additional full-time positions will be added to operate and maintain the scrubbers." http://www.alleghenyenergy.com/Newsroom/Scrubber.Hat.2page.pdf
Hatfields Ferry	2	PA	530	
Hatfields Ferry	3	PA	530	
Hudson	2	NJ	583	According to PSEG Power, advanced emissions controls would be installed at Hudson by 2010. Scrubbers at its Mercer plant are scheduled for completion in late 2010, http://www.reuters.com/article/idUSN1450072120080514
Mercer	1	NJ	315	
Mercer	2	NJ	310	

Source: MJB&A analysis.

ATTACHMENT B

Recent Coal Plant Retirement Announcements

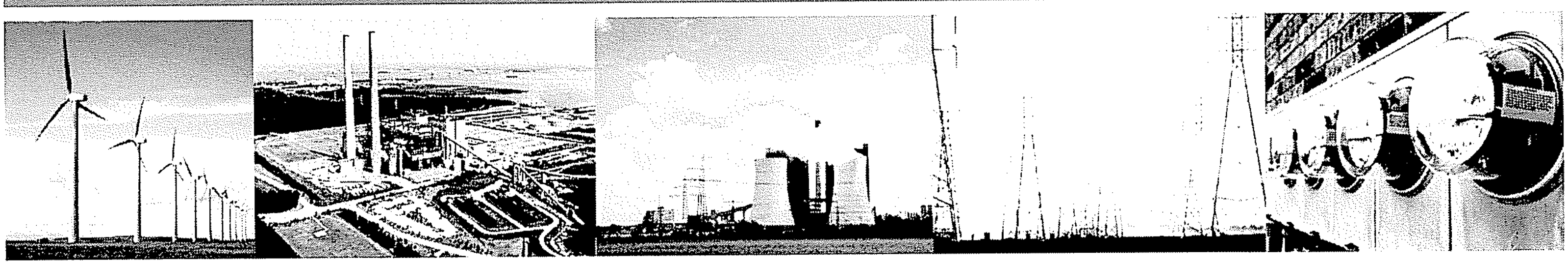
Name	Owner	State	Installed Capacity (MW)	Age (years)	Advanced SO_2/NOx Controls
Weatherspoon	Progress Energy	NC	48	60	None
Weatherspoon	Progress Energy	NC	49	59	None
Weatherspoon	Progress Energy	NC	76	57	None
L V Sutton	Progress Energy	NC	93	55	None
L V Sutton	Progress Energy	NC	102	54	None
L V Sutton	Progress Energy	NC	403	37	None
H F Lee	Progress Energy	NC	74	57	None
H F Lee	Progress Energy	NC	77	58	None
H F Lee	Progress Energy	NC	248	47	None
Cape Fear	Progress Energy	NC	172	51	SNCR
Cape Fear	Progress Energy	NC	144	53	SNCR
Cameo	Xcel Energy	CO	54	49	None
Arapahoe	Xcel Energy	CO	47	58	None
Arapahoe	Xcel Energy	CO	121	54	None
Wabash River	Duke Energy	IN	95	53	None
Wabash River	Duke Energy	IN	85	55	None
Wabash River	Duke Energy	IN	85	56	None
Wabash River	Duke Energy	IN	85	54	None
Wabash River	Duke Energy	IN	318	41	None
John Sevier	TVA	TN	176	53	SNCR
John Sevier	TVA	TN	176	52	SNCR
John Sevier	TVA	TN	176	54	SNCR
John Sevier	TVA	TN	176	54	SNCR
Cromby	Exelon	PA	144	55	SNCR + Scrubber
Eddystone	Exelon	PA	309	49	SNCR + Scrubber
Eddystone	Exelon	PA	279	50	SNCR + Scrubber
Richard Gorsuch	American Municipal Power	OH	50	59	None
Richard Gorsuch	American Municipal Power	OH	50	59	None
Richard Gorsuch	American Municipal Power	OH	50	59	None
Richard Gorsuch	American Municipal Power	OH	50	59	None
Indian River	NRG Energy	DE	82	53	None
Indian River	NRG Energy	DE	177	40	None
Jack McDonough	Southern Co	GA	258	46	None
Jack McDonough	Southern Co	GA	259	45	None
Hunlock	UGI	PA	50	51	None
Will County	Midwest Generation	IL	188	55	None
Will County	Midwest Generation	IL	184	55	None
Boardman	Portland General Electric, Others	OR	585	29	None
Howard Down	Vineland Municipal Electric Utility	NJ	25	40	None
TOTAL	-	-	4,939	-	-

Source: MJB&A analysis based on U.S. EPA Acid Rain Program database and U.S. EIA File 860.

FALL 2011 UPDATE

Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability

November 2011



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Acknowledgements

The following report was prepared on behalf of the following electric companies dedicated to responsible energy and environmental stewardship. The participating companies (listed below) are some of the nation's largest generators of electricity, with over 146,000 megawatts of electric generating capacity (including 93,000 megawatts of fossil generating capacity) throughout the U.S.

Calpine Corporation
Constellation Energy
Exelon Corporation
NextEra Energy
National Grid
Public Service Enterprise Group

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Executive Summary

This marks the third installment in a series of reports focusing on the reliability implications of two U.S. Environmental Protection Agency ("EPA") clean air rules affecting the electric power sector: (1) the Cross-State Air Pollution Rule ("Transport Rule")[1] and (2) the national emission standards for hazardous air pollutants from coal- and oil-fired electric utility steam generating units ("Utility Toxics Rule").[2]

The first report, published in August 2010, concluded that the electric industry is well-positioned to comply with EPA's proposed air regulations without threatening electric system reliability. The summer 2011 update, published in August, supplemented the original analysis in light of new information and reaffirmed the prior report's major conclusion that the electric industry can comply with EPA's air pollution rules without threatening electric system reliability. The August report noted that proper planning and implementation can secure important public health benefits, reliable electric service, and efficient market outcomes.

This "Fall 2011 Update" focuses on the many tools that are available for ensuring electric reliability as companies comply with the EPA rules by installing modern pollution control systems, utilizing allowances or retiring portions of the fleet that are uneconomic to retrofit.

Federal and state regulators agree that the industry has the tools to maintain electric system reliability even in the face of coal plant retirements. In testimony to Congress, FERC Commissioner John Norris stated "[i]n short, based on the information I have reviewed to date on EPA's regulations, I am sufficiently satisfied that the reliability of the electric grid can be adequately maintained as compliance with EPA's regulations is achieved."[3]

1. **The electric power sector relies on a wide range of planning and operational tools and market mechanisms to ensure the reliability of the Nation's bulk electric power system.**

    - Long-term reliability planning is an ongoing process involving industry participants, system operators and regulators that ensure adequate resources are available to satisfy future electricity demand—with an added margin of safety in the event of unplanned contingencies, such as an unexpected generation plant shutdown or extreme weather event.

    - A full reliability assessment considers not only the generating assets available to supply the grid, but also the transmission facilities, the interconnections with neighboring power systems and the demand side resources grid operators can dispatch or otherwise call upon to balance the system's supply and demand.

    - In recent years, actual reserve margins around the country have been well above the minimum target levels, because of new power plant additions, as well as reduced demand attributable to the economic recession and increasingly robust load management programs.

    - According to reports published by the North American Reliability Corporation ("NERC"), the group responsible for overseeing compliance with national reliability rules, the projected reserve margins

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1 The Transport Rule is sometimes referred to as CASPR rule.

2 The Utility Toxics Rule is sometimes referred to as MATS (mercury and air toxics) rule.

3 Testimony of Commissioner John R. Norris Federal Energy Regulatory Commission Before the House Subcommittee on Energy and Power Of the Committee on Energy and Commerce United States House of Representatives. September 14, 2011.

in 2014 range from *28% to over 40%,* with a large amount of excess generating capacity (150 GW nationwide) above the target reserve margins.

NERC Electric Reliability Region	**Projected Reserve Margin [1] in 2014**	**NERC Target Reserve Margin**	**Cushion Above NERC Target Reserve Margin [2] In 2014**
TRE	31.0%	12.5%	12.5 GW
FRCC	31.7%	15.0%	7.4 GW
MRO	28.3%	15.0%	5.5 GW
NPCC	30.1%	15.0%	9.5 GW
RFC	34.0%	15.0%	34.8 GW
SERC	29.4%	15.0%	30.4 GW
SPP	40.3%	13.6%	12.3 GW
WECC	40.2%	14.7%	33.2 GW
Total			**145.7 GW**

[1]Includes capacity defined by NERC as Adjusted Potential Reserve Margin, which is the sum of deliverable capacity resources, existing resources, confidence factor adjusted future resources and conceptual resources, and net provisional transactions minus all derates and net internal demand expressed as a percent of net internal demand. Source: NERC, *2010 Long-Term Reliability Assessment*, October 2010, p. 32 (Summer Demand).
[2]Capacity in excess of what is required to maintain NERC Reference Margin or the regional target reserve levels.

Source: NERC, *2010 Long-Term Reliability Assessment*, October 2010.

- System operators routinely perform power flow and power system studies to evaluate the implications of generating unit retirements. If they identify reliability concerns, system operators will establish mitigation measures to implement before the unit retires, including, for example, upgrades to existing power lines, upgrades to substations, adding additional transformers, building new transmission lines, and/or entering into reliability-must-run ("RMR") agreements with the retiring unit.

- Many power projects are in development. Expanded domestic natural gas production is facilitating a transition to a cleaner generation fleet. For example, at present, there are 38 gigawatts ("GWs") of generating capacity under construction, 18 GWs of which is natural gas-fired; and there are another 12 GWs of natural gas-fired generation capacity in advanced stages of development. In normal market conditions, it may typically take 2-3 years to fully develop, permit and construct a peaking facility, and 3-4 years to fully develop, permit and construct a gas-fired power plant. Demand-side resources, however, can be brought on line with much-shorter lead times (e.g., less than one year).

- Lisa Jackson, Administrator of the U.S. EPA, recently stated: "[i]n 40 years, the Clean Air Act has never caused a reliability problem."[4] A review of recent outages on the bulk power system confirms her statement. Recent outages have been caused by trees touching power lines, operator errors, substation fires, substation malfunctions, and weather-related system failures, not by implementing EPA clean air rules.

[4] Lisa Jackson, verbal testimony, U.S. House of Representatives, Committee on Energy and Commerce Hearing. September 22, 2011.

2. Options are available under existing law to manage electric system reliability as the industry makes the investments necessary to comply with EPA's clean air rules.

- A survey of recent corporate earnings statements shows that many of the Nation's generating companies impacted by the EPA clean air rules are well positioned to comply because of earlier investments in their fleets. See Appendix A.

- Companies representing half of the nation's coal-fired generating capacity—eleven out of the top 15 largest coal fleet owners in the U.S.—have indicated that they are well positioned to comply with EPA's clean air rules because of early investments in their generating fleets.

- Some electric generating units (or whole generating facilities) may choose to retire in lieu of installing air pollution controls. The Bipartisan Policy Center, for example, projects about 20 GW of coal plant retirements as a result of EPA's air, water, and coal ash rules.

- EPA and state regulatory authorities have the discretion to grant, on a unit-by-unit basis, an additional 12 months for the installation of pollution control systems where appropriate, beyond the three years allowed under the Clean Air Act ("CAA"). Existing regulations detail the process for requesting additional time for the installation of pollution control systems.

- Permitting authorities have used the one-year extension provision in the past under previous air toxics rules. For example, the following industrial facilities were granted 10-12 month extensions to comply with prior MACT (Maximum Achievable Control Technology) standards: (1) Lincoln Paper and Tissue in Lincoln Maine, (2) Biscoe Iron Foundry in Biscoe North Carolina, (3) Boral Bricks Salisbury Plant in Rowan County North Carolina, (4) Iowa Army Ammunition Plant in Middletown Iowa, and (5) Kaiser's aluminum works in Tacoma Washington.

- If four years is still not enough time to install the necessary pollution control systems, EPA has the statutory authority to enter into administrative orders of consent under §113(a)(4) of the CAA or consent decrees with power plant operators, allowing additional time for the installation of controls.

- EPA and the states also have existing legal authority to address potential reliability concerns associated with the retirement of electric generating units. Five of the nation's RTO's have submitted public comments to EPA proposing a "targeted backstop reliability safeguard" to address situations where additional time is required for a unit retirement. The joint RTO commenters anticipate that the reliability safeguard "would not need to be invoked often, if at all".[5]

- If additional time is provided for the installation of pollution control systems or to accommodate the retirement of a unit that is needed for reliability purposes, units should operate only for reliability purposes to limit the plant's air pollution emissions during the extension period. The CAA directs EPA specify "any additional conditions" for the protection of public health during the extension period. This approach ensures that reliability standards are maintained, while minimizing air pollution emissions, without an across-the-board delay in the implementation of the clean air rules.

[5] Joint Comments of the Electric Reliability Council of Texas, the Midwest Independent Transmission System Operator, the New York Independent System Operator, PJM Interconnection, L.L.C., and the Southwest Power Pool.

I. Electric System Reliability Planning and Implementation

The electric power system in the United States, despite its scope and complexity, has proven to be a very robust and reliable system. The power system operates pursuant to a detailed set of operating standards, as designed and implemented by the North American Electric Reliability Corporation (NERC) and approved by the Federal Energy Regulatory Commission (FERC). This comprehensive system of standards and regulatory oversight guides the efforts of electric utilities and grid operators to ensure reliable energy supplies. Numerous stakeholders help maintain the reliability of the electric system, including regional reliability organizations, regulators, utilities, grid operators, and other market participants. Together, the policy infrastructure, industry participants, and planning tools provide a critical backdrop for assessing the changes underway as the electric industry responds to EPA's upcoming clean air rules.

A. Reliability Planning: Systems are in place to ensure the reliability of the Nation's bulk electric power system

Reliability planning and coordination is an ongoing process to ensure that adequate resources are available to satisfy peak electricity demand—with an added margin of safety in the event of unplanned contingencies, such as an unexpected generation plant shutdown or extreme weather event. Industry planners engage in long-term planning for peak-day "resource adequacy", while also conducting special assessments of the localized implications of generating unit retirements or new plant interconnections.

1. Resource Adequacy: Planning for peak demand days

System planners conduct long-term resource adequacy studies, to ensure that there are sufficient resources available to satisfy the demand for electricity on peak days. The resources evaluated include: generating facilities; transmission facilities; interconnections with neighboring power systems; and demand side resources (e.g., emergency generators) which the grid operator can dispatch or otherwise call upon to balance the system's supply and demand.

Most regions observe the "one day in 10 year" loss-of-load expectation (LOLE) standard, where the objective is to experience no more than one involuntary service interruption (e.g., blackout) every ten years.[6] To meet the resource adequacy standard, planners for each electrical region use probability models to determine the amount of resources needed to meet end-use demand for electric power. To assess whether additional resources are needed to meet the LOLE standard, these studies review: scheduled and unplanned/forced outage rates; availability of capacity on transmission connections to neighboring systems; on-call demand-reduction resources; and higher-than-expected peak-load use.

2. System Assessments: Planning to accommodate reliable operations when a plant retires or is added to the system

Additionally, system planners conduct periodic reliability assessments when infrastructure changes are anticipated to occur on the system. For example, system impact studies are performed when: (1) a company plans to interconnect a new generating facility to the grid; (2) an existing generating unit plans to retire from service; or (3) a company plans to construct a new transmission facility. The goal is to ensure that, even with the changes in the physical components of the system, the system will continue to operate reliably at all times and under a variety of operating conditions and contingencies. These system impact

[6] The standard focuses on outages caused by insufficient deliverable generation and other resources installed on the system, rather than weather-related and other events that take out transmission and distribution facilities, and thus interrupt service to customers.

studies may also identify associated changes (e.g., transmission system upgrades) required to maintain voltage support, reliable power system flows, or other critical grid operating capabilities.

Planners also perform special assessments of emerging issues—such as how fuel supply and delivery issues might affect the ability of power plants to operate at certain times of the year; how limitations on the operations of a power plant (e.g., due to constraints on air emissions) might limit the grid operator's ability to dispatch generating units; or how penetration of non-dispatchable generating resources (such as wind, or solar) might impact system operations and reliability. These studies identify issues that operators may need to consider as they dispatch plants and operate the system.

3. Real-Time System Operations: Systems to assure operational reliability at all times

System operators also plan for secure system operations in real time by equipping operators with a variety of tools. Some of the tools provide power plant dispatch signals that reflect inherent technical operating constraints related to particular plants (e.g., how long it takes them to start up, or to ramp up from low operating levels to full output). Other tools reflect regulatory agreements controlling plant output. These agreements include, for example, RMR agreements which keep an otherwise uneconomic plant operating under certain system conditions to provide voltage support or other reliability functions, or ones limiting plant dispatch to maintain required emissions levels. Other critical tools provide real-time communications and control devices advising grid operators of facility operations' status, to avoid operational disturbances which would shut down parts of the system, and to enable operators to manage any unexpected reliability problems by responding immediately to changing system conditions, including through automatic control devices.

B. Reliability Entities: Multiple parties play a role in ensuring the reliability of the Nation's bulk electric power system

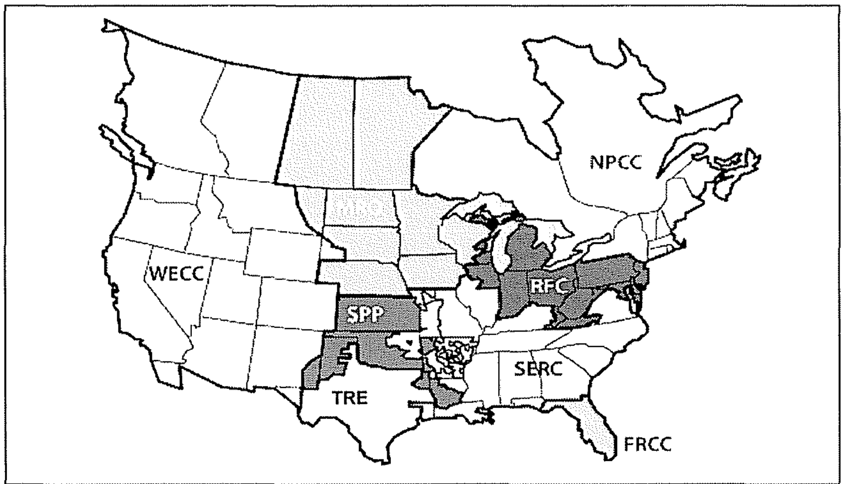
1. Roles of NERC, the regional reliability councils, electric utilities, and others

NERC establishes and maintains standards to ensure the reliability of the North American bulk electric system.[7] These standards define the reliability requirements for planning and operating the system, which includes three major regions of interconnected electrical systems: the Eastern Interconnection (covering most of eastern North America); the Western Interconnection (a large area spanning from the Great Plains to the Pacific Coast); and the ERCOT Interconnection, comprising most of Texas.

NERC works with eight regional reliability entities, whose participants include grid operators, utilities, generating companies and other key stakeholders in the electric industry. As shown in the map below, the regional entities include: the Western Electric Coordinating Council (WECC) covering the Western Interconnection; the Texas Reliability Entity (TRE), covering most of Texas; and the Nation's Eastern Interconnection served by the Midwest Reliability Organization (MRO); the Southwest Power Pool (SPP); the Northeast Power Coordinating Council (NPCC); the Reliability First Corporation (RFC); the SERC Reliability Council (SERC); and the Florida Reliability Council (FRCC).

[7] Under the authorities established in the Energy Policy Act of 2005, FERC certified NERC as the Nation's independent electric reliability organization (ERO), with the responsibility to establish and enforce the reliability standards for the bulk power electric system. All reliability standards and enforcement actions proposed by NERC must be approved by FERC. Also, FERC's authority is limited to the bulk-power system—not the distribution system. Bulk-power system outages, as opposed to outages on the distribution system, can affect large areas with significant regional and national implications.

NERC Regional Entities



Source: North American Energy Reliability Corporation.

Most of the Nation's regional reliability entities cover multiple states. Each monitors and enforces compliance with NERC's reliability standards, and assesses the maintenance of minimum target reserve margins, a key indicator of resource adequacy. All regions plan to have capacity above expected demand to accommodate unplanned power plant outages, transmission failures, unexpectedly high demand, or other contingencies. Most regions maintain minimum target reserve margins of about 15 percent.

Actual or expected reserve margins measure the extent to which generating capacity exceeds (or falls short of) peak electricity demand. In recent years, actual reserve margins around the country have far exceeded the minimum target levels, due not only to new power plant additions, but also to reduced demand attributable to the economic recession and increasingly robust load management programs.

NERC Electric Reliability Region	**Projected Reserve Margin [1] in 2014**	**NERC Target Reserve Margin**	**Cushion Above NERC Target Reserve Margin [2] In 2014**
TRE	31.0%	12.5%	12.5 GW
FRCC	31.7%	15.0%	7.4 GW
MRO	28.3%	15.0%	5.5 GW
NPCC	30.1%	15.0%	9.5 GW
RFC	34.0%	15.0%	34.8 GW
SERC	29.4%	15.0%	30.4 GW
SPP	40.3%	13.6%	12.3 GW
WECC	40.2%	14.7%	33.2 GW
Total			**145.7 GW**

[1] Includes capacity defined by NERC as Adjusted Potential Reserve Margin, which is the sum of deliverable capacity resources, existing resources, confidence factor adjusted future resources and conceptual resources, and net provisional transactions minus all derates and net internal demand expressed as a percent of net internal demand. Source: NERC, *2010 Long-Term Reliability Assessment*, October 2010, p. 32 (Summer Demand).
[2] Capacity in excess of what is required to maintain NERC Reference Margin or the regional target reserve levels.

Source: NERC, *2010 Long-Term Reliability Assessment*, October 2010.

Within the different regions, the reliability councils, transmission owners, electric utilities, power plant owners, and independent system operators are responsible for compliance with different aspects of NERC's reliability standards. They rely on various tools to ensure a reliable power supply:

- Regional entities carry out the fundamental resource adequacy assessments and identify surpluses and shortfalls.

- System operators and transmission companies conduct long-term transmission planning to assess future reliability conditions, in light of load growth, planned resource additions (or retirements), and other anticipated changes in the system infrastructure. Transmission plans are developed with considerable public input.

- Regulated utilities prepare integrated resource plans ("IRP"), which serve as comprehensive road maps for providing reliable electric service to customers while addressing economic trade-offs of different supply options (e.g., new power plants, new transmission facilities, energy efficiency) and associated risks and uncertainties. As with long-run transmission plans, IRPs are developed with considerable public input.

- Many independent system operators—like PJM Interconnection, L.L.C. ("PJM"), the New York ISO (NYISO), and ISO New England (ISO-NE)—rely on forward capacity market designs to encourage investment in new and existing resources and conduct periodic auctions to secure commitments to supply future capacity. In June 2011, ISO-NE announced that it had procured sufficient generation and demand-side resources to meet the region's reliability needs in 2014-2015.[8] In May 2011, PJM also announced that it had secured sufficient resources to meet its reliability needs in 2014-2015; PJM secured resources sufficient to maintain a 20 percent reserve margin for the region.[9]

- Transmission operators (e.g., Regional Transmission Organizations (RTO) like the Midwest ISO (MISO), the Southwest Power Pool (SPP), PJM, NYISO, and ISO-NE) as well as electric utilities in parts of the country without an RTO also conduct studies to identify transmission overloads, voltage limitations and other potential reliability standards violations. Also, they develop transmission plans to resolve violations that could otherwise lead to overloads and black-outs.

- Before commencing commercial operation, power plant developers request transmission operators perform system impact studies to determine, any reliability issues arising from the new plant's interconnection to the grid. Using power flow models to examine a variety of operating conditions with the new plant in place, these system impact studies and subsequent facility studies identify reliability concerns and proposed measures (such as transmission system upgrades) to mitigate any potential concerns.

- Before retiring or deactivating a generating unit, existing power plant owners must provide the RTOs notice so that system operators can evaluate the reliability implications of the retirement or deactivation using power flow and other power system modeling. Factors considered in such an assessment include, but are not limited to, "the operating characteristics of a unit, the number of

[8] ISO-NE. Fifth Forward Capacity Market Auction Secures Power System Resources for 2014-2015: More than 40,000 Megawatts of Resources Competed to Meet the Region's Capacity Needs. June 8, 2011.

[9] As discussed in the Summer Update, PJM recently announced the results of its forward capacity auction for the period when EPA's clean air rules will be in effect. The results of the auction confirm that the PJM region will have ample electricity supply after EPA's rules take effect. The market response represents a 20.6 percent reserve margin for the region. PJM. Demand Resources and Energy Efficiency Continue to Grow in PJM's RPM Auction. May 13, 2011.
PJM. 2014/2015 RPM Base Residual Auction Results. PJM DOCS #645284.

proposed retirements and the location of the units." The respective RTOs/ISOs require the following advance notice requirements:[10]

RTO/ISO	**Advance Notice Requirements**
ERCOT	90 days notice (for units to be taken out of service for periods that exceed 180 days)[11]
MISO	26 weeks[12]
NYISO	180 days (for generators larger than 80 MW) and 90 days (for generators smaller than 80 MW)[13]
PJM	90 days[14]
SPP	45 days[15]

Despite these tariff requirements, however, power plant operators have historically given several years advance notice. Several RTOs have suggested that notification of retirements associated with EPA's rules should be made within 12 months of EPA issuing its final regulations.[16] From a timing perspective, PJM, for example, will typically complete a deactivation study within 30 days, testing for violations of NERC reliability criteria including stability, thermal line loadings and voltage limits. In 2011, PJM received eight unit deactivation requests; seven of the reliability studies identified no reliability impacts.[17]

- If a power flow and other power system analyses identify reliability concerns, system operators will specify mitigation measures that need to be implemented before the unit retires. This could include upgrades to existing power lines, upgrades to substations, adding additional transformers, or building new transmission lines. ISOs/RTOs can neither compel the construction of new generating facilities nor prevent an existing generating unit from retiring. "Rather, the ISO/RTO model is based on a market platform that provides financial incentives designed to facilitate resource adequacy consistent with applicable reliability standards". By contrast, transmission assets are regulated, and as a result, the ISO/RTOs plan for, and have the authority pursuant to their tariffs to direct the expansion of the transmission grid to address reliability issues."[18] Additionally, to help mitigate reliability impacts of retiring generation units, the ISO/RTOs use their transmission planning reports as well as these system impact studies, to signal to the market the need for market response solutions, such as the addition of generation, demand response or energy efficiency resources.[19]

- Where a retirement might lead to a local reliability concern, ISOs/RTOs may attempt to enter into RMR agreements with the owner of a power plant to prevent it from retiring the plant. An RMR agreement identifies the terms and conditions under which the plant may operate for grid reliability purposes, in exchange for the users of the system paying the plant owner its costs to keep the plant in operation. For example, when PJM determined that two proposed-to-be-retired power plants in

[10] Joint Comments of the Electric Reliability Council of Texas, the Midwest Independent Transmission System Operator, the New York Independent System Operator, PJM Interconnection, L.L.C., and the Southwest Power Pool, p. 3.
[11] ERCOT Protocol Section 3.14.1.1.
[12] MISO Tariff section 38.2.7 and Attachment Y.
[13] NYSPC Case No. 05-E-0889.
[14] PJM Tariff section 113.1 and 113.2.
[15] SPP EIS Protocols Section 12.
[16] Joint Comments of the Electric Reliability Council of Texas, the Midwest Independent Transmission System Operator, the New York Independent System Operator, PJM Interconnection, L.L.C., and the Southwest Power Pool.
[17] PJM. Generator Deactivations as of September 7, 2011.
[18] Joint Comments of the Electric Reliability Council of Texas, the Midwest Independent Transmission System Operator, the New York Independent System Operator, PJM Interconnection, L.L.C., and the Southwest Power Pool. p. 3.
[19] Joint Comments of the Electric Reliability Council of Texas, the Midwest Independent Transmission System Operator, the New York Independent System Operator, PJM Interconnection, L.L.C., and the Southwest Power Pool. p. 4.

Pennsylvania were needed to maintain local reliability, PJM entered into an agreement to keep the plants operating until completion of required transmission upgrades. The agreement included "explicit operating procedures that would prevent the dispatch of these units except for 'Reliability Purposes,' defined as the commitment of the units only 'after all [generation] resources have already been committed and additional units are required to help alleviate a 'Transmission Security Emergency…."[20]

2. The Role of the Federal Energy Regulatory Commission

Since 2005, FERC has been responsible for ensuring electric system reliability. As noted above, under the Energy Policy Act of 2005's amendments to the Federal Power Act ("FPA"), Section 215, FERC approves NERC's adoption and enforcement of electric reliability standards. "By law, Reliability Standards cannot include any requirement to enlarge Bulk-Power System facilities or to construct new transmission capacity or generation capacity."[21]

The District of Columbia Circuit Court of Appeals has upheld FERC's authority under the FPA to approve, even over state commission or local utility objections, reserve capacity requirements assigned by RTOs to those entities (e.g., electric distribution companies, other providers of retail electricity supply to end-users), and to require they pay for such capacity obligations.[22] FERC can also authorize ISO determinations approving or disallowing the resources that are allowed to count for resource adequacy purposes.[23] The FPA does not, however, authorize FERC to engage in "direct regulation of generation facilities", because this activity is reserved to the states.[24]

FERC expects transmission entities (e.g., ISOs/RTOs; transmission companies) to carry out long-term planning to ensure reliable service. Also, "the Commission does and will review studies to determine the changes that occur due to a change in the mix and location of resources in a region. The Commission also does and will review planning-related proposals that account for implementation of these proposed EPA regulations."[25] FERC also assesses periodically the ability of demand-response resources to play a role in assuring resource adequacy.[26]

In response to an owner's decision to retire the Potomac River Generating Station in Virginia because of various air pollution standards violations, FERC required an RTO (PJM) and a transmission company (PEPCo) to submit a plan to preserve reliability in the District of Columbia ("DC") in the absence of that generating facility. In that case, the U.S. Department of Energy prohibited the plant from shutting down to maintain the DC area's electric reliability.[27] PEPCo and PJM recommended investing in various transmission upgrades, most of which have now been built and have commenced commercial operation[28],

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[20] Testimony of John Hanger, former Pennsylvania Secretary of Environmental Protection, before the House Energy and Commerce Committee, September 14, 2011, p. 7.

[21] Statement of FERC Chairman Jon Wellinghoff before the House Energy and Commerce Committee, September 14, 2011, pp. 5-6, citing 16 U.S.C. § 824o(a)(3) (2006).

[22] FPA Section 206(a), *Connecticut Department of Public Utility Control v. FERC*, 569 F.3d 477 (D.C. Circuit 2009) , *cert. denied*, 130 S. Ct. 1051(2010).

[23] *Sacramento Municipal Utility District v. FERC*, 616 F.3d 520 (D.C. Cir. 2010). (*per curium*).

[24] FPA Section 201(b).

[25] Statement of FERC Chairman Jon Wellinghoff before the House Energy and Commerce Committee, September 14, 2011, pp. 5-6, citing 16 U.S.C. § 824o(a)(3) (2006).

[26] See, for example, FERC Staff, Assessment of Demand-Response and Advanced Metering, November 2011. http://www.ferc.gov/legal/staff-reports/11-07-11-demand-response.pdf

[27] U.S. Department of Energy, Order No. 202-05-2 (December 20, 2005).

[28] See Paul Hibbard, Pavel Darling, and Susan Tierney, "Potomac River Generating Station: Update on Reliability and Environmental Considerations," Analysis Group, Inc., July 19, 2011.

and, according to PJM, have relieved the associated reliability problems.[29]

3. The Role of the States

Many states have direct authority to ensure resource adequacy, or can accomplish that end through a variety of ratemaking authorities. States that exercise traditional regulation over vertically integrated electric companies (and even in some states with restructured electric industries that allow for customer choice) often use integrated resource planning processes to ensure that electric distribution companies build and/or otherwise arrange for sufficient resources to meet projected load and reserve requirements in a least-cost fashion. To ensure resource adequacy, some states also require traditionally regulated utilities to add cost-effective energy efficiency resources, to develop and construct generating resources, to conduct competitive solicitations to determine whether to enter into long-term contracts for energy and capacity, and/or to develop and construct transmission facilities.

4. The Role of the Market

In most parts of the U.S., and particularly in the regions with organized wholesale electricity markets administered by ISOs/RTOs, the market itself plays an important role in ensuring the development and construction of new generation facilities and other supplies needed for resource adequacy. As noted previously, several ISOs/RTOs rely on forward capacity markets to procure the amount of generating capacity and demand-side resources needed to meet future resource requirements.

In those market regions, and in other states, utility and non-utility companies plan for, permit, engineer and construct new power projects. In normal market conditions, it may typically take 2-3 years to fully develop, permit and construct a simple cycle gas turbine that could support peak demand periods, and 3-5 years to fully develop, permit and construct a gas-fired power plant.[30] New coal projects and nuclear plants will likely require much more time. Demand-side resources, however, can be brought on line with much-shorter lead times (e.g., less than one year).

Throughout the country, many projects are underway, spurred by the relatively low prices for natural gas, renewable energy requirements, and the potential retirement of some number of existing power plants. For example, at present, there are 38 GWs of generating capacity under construction (18 GWs of natural gas-fired generating capacity) with another 12 GWs of natural gas-fired generation capacity in advanced stages of development.

New Capacity Additions by In-Service Year

Planned In-Service Year	Lower 48: Total Under Construction Capacity (MW)
2011	6,653
2012	19,623
2013	9,018
2014	1,858
>2014	792
Total	**37,944**

Source: SNL Financial – as of 11-11-2011

[29] Letter from Michael Kormos, PJM, to Chairman Betty Ann Kane of the DC Public Service Commission, September 29, 2011. http://www.dcpsc.org/pdf_files/hottopics/PJM_Evaluation.pdf

[30] There are situations where reliability concerns have caused states to allow for expedited permitting of power plants. See, for example, Susan Tierney and Paul Hibbard, "Siting Power Plants in the New Electric Industry Structure: Lessons from California and Best Practices for Other States," Electricity Journal, June 2002, page 35. Also, directives to state permitting agencies to coordinate their permitting processes can lead to complex permits being issued within a year, as occurred in Colorado when the various public health agencies and the Colorado Public Service Commission reviewed and approved the proposed Xcel power projects under Colorado's Clean Air-Clean Jobs Act of 2010.

New Capacity Additions by Region

NERC Region (Lower 48)	Total Announced Capacity (MW)	Total Under Construction Capacity (MW)
WECC	145,749	12,940
SERC	43,319	13,200
RFC	48,875	5,078
ERCOT	43,907	1,491
MRO	41,263	1,291
SPP	33,544	1,324
NPCC	17,399	1,171
FRCC	11,063	1,449
Total	**385,119**	**37,944**

Source: SNL Financial – as of 11-11-2011

Natural Gas Capacity Additions by Region

		New Power Plant Capacity (Lower 48) - MW			
Region	Power Plant Technology	Under Construction	Advanced Development	Announced	Total
ERCOT	Natural gas - combined cycle	-	2,977	6,449	9,426
	Natural gas - gas turbine	-	1,400	790	2,190
	Natural gas - other (CAES, fuel cell)	-	-	335	335
	Total Natural Gas	-	**4,377**	**7,574**	**11,951**
FRCC	Natural gas - combined cycle	1,295	1,295	2,135	4,725
	Natural gas - gas turbine	-	-	1,282	1,282
	Natural gas - other (CAES, fuel cell)	-	-	-	-
	Total Natural Gas	**1,295**	**1,295**	**3,417**	**6,007**
MRO	Natural gas - combined cycle	300	-	1,645	1,945
	Natural gas - gas turbine	60	-	2,176	2,236
	Natural gas - other (CAES, fuel cell)	-	-	288	288
	Total Natural Gas	**360**	-	**4,109**	**4,469**
NPCC	Natural gas - combined cycle	-	350	3,920	4,270
	Natural gas - gas turbine	512	246	-	758
	Natural gas - other (CAES, fuel cell)	-	37	177	214
	Total Natural Gas	**512**	**632**	**4,097**	**5,241**
RFC	Natural gas - combined cycle	938	667	9,163	10,768
	Natural gas - gas turbine	352	-	1,265	1,617
	Natural gas - other (CAES, fuel cell)	6	-	716	722
	Total Natural Gas	**1,297**	**667**	**11,144**	**13,107**
SERC	Natural gas - combined cycle	7,079	1,300	4,108	12,487
	Natural gas - gas turbine	731	-	1,869	2,600
	Natural gas - other (CAES, fuel cell)	-	-	-	-
	Total Natural Gas	**7,810**	**1,300**	**5,977**	**15,087**
SPP	Natural gas - combined cycle	-	-	-	-
	Natural gas - gas turbine	42	-	223	265
	Natural gas - other (CAES, fuel cell)	-	-	-	-
	Total Natural Gas	**42**	**-**	**223**	**265**
WECC	Natural gas - combined cycle	3,409	3,411	13,176	19,996
	Natural gas - gas turbine	3,214	350	2,215	5,779
	Natural gas - other (CAES, fuel cell)	3	-	317	320
	Total Natural Gas	**6,626**	**3,761**	**15,708**	**26,095**
TOTAL Lower 48	Natural gas - combined cycle	13,022	10,000	40,595	63,617
	Natural gas - gas turbine	4,912	1,995	9,821	16,728
	Natural gas - other (CAES, fuel cell)	9	37	1,834	1,879
	Total Natural Gas	**17,942**	**12,032**	**52,250**	**82,223**

Source: SNL Financial – as of 11-11-2011
Note: CAES = compressed air energy storage

B. Reliability Outcomes: System performance including past power outages and blackouts

The U.S. bulk-power system is generally very reliable, delivering uninterrupted power to customers through an interconnected network of transmission lines. As described above, large outages are infrequent because of the many "defense-in-depth" reliability tools in place to protect the bulk power systems.[31]

NERC maintains and reports industry-wide and regional metrics on the performance of the system, including reserve levels, loss of load due to transmission-related outages, and other variables.[32] Most outages on the system arise from weather-related events, not problems in the bulk power system itself.

However, even a short outage can be very disruptive to households and businesses. The largest blackout in American history occurred on August 14, 2003, affecting eight states in the northeastern U.S. and parts of Canada. The blackout affected 50 million people and caused the loss of between $4.5 billion and $12 billion in economic activity.[33] The event was triggered by tree contacts with several high-voltage power lines in Ohio, although the ultimate causes were attributed to violations of multiple NERC standards, which were not enforceable prior to the Energy Policy Act of 2005.[34] Other recent outages have been caused by substation fires, substation malfunctions, and weather-related system failures.

Examples of major U.S. bulk power system outages and their causes

Event	Date	Areas affected	Description and proximate cause
Northeast blackout of 2003	August 14, 2003	Large area including the Northeast, Midwest and Canada	Several high-voltage power lines in Ohio were damaged by trees, causing other lines to trip in a cascade of events that eventually led to over 50 million people in the Northeastern U.S. and Canada losing power.[i] The breadth of the blackout arose from several violations of NERC standards.
2008 Florida blackouts	February 26, 2008	Florida	The combination of a failed switch, operator errors, and a fire at a substation outside of Miami led to multiple power plants across the state going offline, ultimately resulting in over two million people losing power.[ii]
2011 Texas rolling blackouts	February 2, 2011	Texas	Unusually low winter temperatures caused both a spike in demand (two thirds of Texas households heat their home with electricity) as well as cold weather-related failures at power plants. Over 7 GW of capacity was shut down, leading ERCOT to implement rolling blackouts across the state. Over 1 million households lost power for up to an hour.[iii]
2011 Southwest blackout	September 8-9, 2011	Southern California, Arizona and northwestern Mexico	Over 7 million people lost power after a malfunction at a substation in Yuma, Arizona led to cascading events throughout the region. Investigation of the cause is still under investigation[iv]

i. Time Magazine, "Can we prevent another blackout?" 8/11/2008 http://www.time.com/time/health/article/0,8599,1831346,00.html
ii CNN, "Power restored to parts of Florida after outage" 12/26/2008 http://articles.cnn.com/2008-02-26/us/florida.power_1_outage-normal-electric-service-electrical-substation?_s=PM:US
iii. Reuters, "Texas weathers rolling blackouts as mercury drops." 2/2/11 http://www.reuters.com/article/2011/02/02/us-ercot-rollingblackots-idUSTRE7116ZH20110202
iv. Yuma Sun, "Massive power outage not caused by one worker: Officials." 10/27/11 http://www.yumasun.com/news/power-74029-outage-utility.html

[31] In the U.S.-Canada Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," April 2004 (page 9), the task force identified these "defenses in depth":

1. A range of rigorous planning and operating studies, including long-term assessments, year-ahead, season-ahead, week-ahead, day ahead, hour-ahead, and real-time operational contingency analyses....
2. Preparation for the worst case. ...
3. Quick response capability...
4. Maintain a surplus of generation and transmission....
5. Have backup capabilities for all critical functions

[32] NERC website: http://www.nerc.com/page.php?cid=4|331

[33] U.S. Department of Energy, Transforming the Grid to Revolutionize Electric Power in North America.

[34] U.S.-Canada Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," April 2004, Chapter 3.

II. Managing Reliability in the Context of EPA's Clean Air Rules

The EPA is finalizing two important air pollution regulations limiting power plant air emissions: the Transport Rule and the Utility Toxics Rule. As the industry prepares to comply with these new environmental requirements, the key issues will be to: (1) manage the retirement and replacement of existing generating units that are uneconomic to retrofit with modern pollution controls; and (2) coordinate any facility outages required to complete pollution control system installations. System operators need to coordinate these outages across the grid so that adequate generating capacity is available to meet peak demand.

Several mechanisms are available under existing law to manage electric system reliability as the industry transitions to a cleaner, more efficient generation fleet.

A. Company Plans: Financial disclosures and statements confirm that many of the Nation's generating companies are well positioned to comply

A survey of recent corporate earnings statements shows that many of the Nation's generating companies impacted by the EPA rules are well positioned to comply because of earlier investments in their fleets. The results of this survey are in Appendix A, with quotes from a sampling of electric company executives indicating that: (1) companies have long anticipated these rules; (2) early investments have positioned these companies well; and (3) the impact on electricity rates is manageable. The quoted companies indicating they are well positioned to comply with the EPA air pollution regulations represent about half of the nation's coal-fired generating capacity and eleven out of the top 15 largest coal fleet owners in the U.S.

B. Additional time for the installation of controls under the Utility Toxics Rule

Under the CAA Congress requires existing, affected sources to comply with the Utility Toxics Rule "as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard." EPA plans to finalize the rule by December 16, 2011. As a result, affected coal-fired and oil-fired power plants will need to comply with the emissions limits of the Utility Toxics Rule by the beginning of 2015. As detailed in Appendix A, most generating facilities have indicated they expect to comply with the Utility Toxics Rule within the Act's timeframe. Notably, however, the CAA also contains exceptions allowing additional time for installation of controls. EPA and state regulatory authorities have the discretion to grant, on a unit-by-unit basis, an additional 12 months for the installation of pollution control systems where necessary.[35] EPA is also considering extending this compliance flexibility to units converting to cleaner burning fuels.

Permitting authorities have used this provision in the past under previous air toxics rules. For example, the following industrial facilities were granted 10-12 month extensions to comply with prior MACT standards: (1) Lincoln Paper and Tissue in Lincoln Maine, (2) Biscoe Iron Foundry in Biscoe North Carolina, (3) Boral Bricks Salisbury Plant in Rowan County North Carolina, (4) Iowa Army Ammunition Plant in Middletown Iowa, and (5) Kaiser's aluminum works in Tacoma Washington. Under existing regulation for all MACT standards, to qualify for a compliance extension, sources must file a request 120 days prior to the compliance date. A request for a compliance extension must include: (1) a description of the controls to be installed to comply with the standard; (2) the schedule for construction and installation of the controls; and (3) the completion date. To facilitate reliability planning and outage scheduling, several of the Nation's

[35] See CAA section 112(i)(3)(B). The process for requesting an extension under a MACT standard is detailed at 40 CFR Part 63.6.

RTOs have recommended that utility companies should provide this information to EPA and system operators within one year of EPA issuing its final Utility Toxics Rule.[36]

The CAA provides companies the flexibility to schedule the installation of controls across multiple outage periods, thus maintaining electric system reliability while facilitating expeditious installation. Companies will typically construct pollution control systems while their power plants continue to operate. The equipment is then connected or "tied-in" to the plant during a scheduled outage period, coordinated with other generating facilities to ensure reliability. This will typically occur during a month or month(s) when the demand for electricity is relatively low to avoid the hottest summer months and the coldest winter months. A 12-month extension would provide plant operators with an additional two shoulder periods to schedule outages and stagger the installation of controls across a control region.

In granting an extension of time for the installation of controls, existing regulation requires EPA or states to specify "any additional conditions" for the protection of public health during the extension period. To limit the emissions of harmful pollutants, stakeholders have recommended limiting operations of any EGU receiving any compliance extension to only times required to maintain reliability (i.e., "Reliability-Only Dispatch").[37] Operating limitations are commonly placed on generating units and reflected in dispatch decisions, including RMR agreements, startup times, and fuel use restrictions.

If four years is still not enough time to install the necessary controls, EPA has the statutory authority to enter into administrative orders of consent under Section 113(a)(4) of the CAA or consent decrees with power plant operators, allowing additional time for the installation of controls. Again, to protect the public and maximize health benefits during the extension period, such orders or decrees can limit a unit to operating only when required to maintain reliability.

C. Managing unit retirements

Some electric generating units (or whole generating facilities) may choose to retire in lieu of installing air pollution controls. The Bipartisan Policy Center, for example, projects about 20 GW of coal plant retirements as a result of EPA's air, water, and coal ash rules (see table below).

FERC Commissioners recently testified before the House Subcommittee on Energy and Power that they do not expect widespread reliability concerns due to retirements. The FERC Commissioners acknowledged, however, that the retirement of significant amounts of generation could cause some localized reliability issues, for example, voltage stability concerns. FERC Commissioner Cheryl A. LaFleur explained that "in such cases, a time-limited waiver of EPA regulations may be needed. In some cases, a 'reliability must-run' ("RMR") contract may also be needed to allow the power plant to operate within certain discrete parameters for a limited period of time."[38] LaFleur also noted that this process is not unique to EPA regulations, but rather used as a process for any retirements, including those due to market conditions, and the need for such solutions "must be targeted and discrete".

Generating capacity retirements will need to be evaluated by system operators for reliability purposes with several possible outcomes: (1) unit can retire with no adverse reliability impact before the compliance deadline in 2015; (2) transmission system upgrades or new capacity additions are required to avoid reliability concerns and upgrades or replacement power can be completed within 12 months of the compliance deadline; or (3) transmission system upgrades or new capacity additions are required to avoid

[36] Joint Comments of the Electric Reliability Council of Texas, the Midwest Independent Transmission System Operator, the New York Independent System Operator, PJM Interconnection, L.L.C., and the Southwest Power Pool.

[37] Hanger, John. Reliability-Only Dispatch. 2011.

[38] Testimony of Commissioner Cheryl A. LaFleur Federal Energy Regulatory Commission Before the House Subcommittee on Energy and Power of the Committee on Energy and Commerce United States House of Representatives. September 14, 2011.

reliability concerns, but upgrades or replacement power cannot be completed within 12 months of the compliance deadline.

EPA and the states have the statutory authority to address each of these scenarios, just as they have the authority to address reliability concerns in the context of pollution control retrofits. In fact, five of the nation's RTOs have submitted comments to EPA proposing a "targeted backstop reliability safeguard" to address situations requiring additional time. The Joint RTO Commenters anticipate that the reliability safeguard "would not need to be invoked often, if at all".[39] As with retrofit extensions, units can be restricted to operating for reliability purposes only to limit the plant's air pollution emissions during the extension period. This targeted, limited approach ensures that reliability standards are maintained without a blanket delay in implementing these important air pollution rules.

Estimated Projections of Retrofits and Retirements through 2015

Source	Projected Coal Retirements (GW)	Projected Pollution Control Retrofits (and existing controls)[1]				
		Scrubbers	**Baghouses**	**DSI (Trona)**	**ACI**	**SCR**
Bipartisan Policy Center Modeling of Utility MACT, Transport Rule, BART, 316(b), coal ash, and various state rules through 2015 (low NG price scenario)	35 GW **Note:** 18 of which is attributed to new air, ash, and water regulations	92 GW	203 GW[2]	20 GW	137 GW	32 GW
Existing Control Installations in the U.S.		190 GW	79 GW	<5 GW	49 GW	123 GW

1. Retrofit figures reflect total retrofits through 2015, not simply the incremental retrofits above Reference Case levels.

2. BPC makes a conservative assumption that control of metals will require a fabric filter for all coal units. Studies indicate that existing electrostatic precipitators (or upgrades to existing precipitators) may be sufficient to comply.

Source: BPC. Environmental Regulation and Electric System Reliability. June 2011.

[39] Joint Comments of the Electric Reliability Council of Texas, the Midwest Independent Transmission System Operator, the New York Independent System Operator, PJM Interconnection, L.L.C., and the Southwest Power Pool.

V. CONCLUSION

Reliable electric supply is essential to the nation's economy and the health of its citizens. The electric industry is well-positioned to maintain the reliability of the bulk electric system while transitioning to a cleaner, more efficient generating system.

The electric power sector relies on a wide range of proven planning and operational tools and market mechanisms to maintain the reliability of the nation's bulk electric power system. These include processes to ensure adequate electric resources to meet future need, including an added margin of safety to handle unexpected stresses on the electric grid. NERC, the Nation's electric reliability organization along with , regional reliability entities, system operators, RTOs, transmission companies, and other organizations routinely conduct assessments to identify reliability issues that need to be managed. The assessments include, for example, long-term system studies, unit or plant-specific analyses of upcoming generating capacity additions or retirements, as well as operational studies focusing on localized operating requirements.

These comprehensive, coordinated planning processes are overseen by federal and state regulators, as well as NERC. In many cases, the results of reliability assessments and system studies provide concrete information about actions that must be taken to maintain grid reliability. Other studies provide signals to market participants about the timing and location of needed resource additions, thus helping to inform investment and business decisions by generation developers and suppliers of demand response and other resources.

The market is responding already to the EPA air pollution rules. For example, new power projects are under construction, in part due to the availability of abundant, domestic natural gas resources as well as expectations of potential retirements. Developers of natural gas projects have 18 GWs under construction and another 12 GWs in advanced stages of development. Additionally, eleven out of the top 15 largest coal fleet owners in the U.S., representing half of the Nation's coal capacity, have indicated they are well positioned to timely comply with EPA's air pollution rules. According to FERC Commissioner Marc Spitzer, "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."[40]

Finally, a range of options are available under existing law to manage electric system reliability as the industry makes the investments necessary to comply with EPA's clean air rules. These tools include EPA's authority to make unit-by-unit determinations that allow for an additional 12 months for the installation of pollution control systems where appropriate, beyond the three years allowed under the CAA. If four years is still not enough time to install the necessary controls while also ensuring reliability, EPA has the statutory authority to enter into administrative orders of consent or consent decrees with power plant operators, allowing additional time for the installation of controls. Several of the Nation's RTOs have also proposed a "targeted backstop reliability safeguard" to address situations in which additional time is required before a unit retires. Any additional time provided for compliance should be accompanied by restrictions on plant operations so that they run only to meet reliability needs.

With the proper planning, communication and use of available tools outlined in this paper, the American public can have clean air and a reliable electric power system.

[40] Testimony of Marc Spitzer, Commissioner Federal Energy Regulatory Commission Before the House Subcommittee on Energy and Power of the Committee on Energy and Commerce United States House of Representatives. September 14, 2011.

APPENDIX A

Company Statements in Response to EPA Regulations – November 9, 2011

No.	Company	Statements
1	**AES**	"So we're not prepared to put a CapEx number out today, but the regulation, as you're aware, in Indiana would allow us to recover those costs through rates. The balance of our North America fleet is mostly already scrubbed and has NOx control, so we don't anticipate any significant capital on the balance of our fleet ... [W]e feel, overall, like we're in pretty good shape and certainly didn't get any what we would consider to be significant surprises, and I think anticipate that the MACT rules that come out will actually drive what the CapEx requirements will be." - Ned Hall, Q2 2011 Earnings Call, 8/5/2011 (transcript) "Outside of IPL and DPL, certainly, our plants that have contracts, or the few that are still remaining that are merchant, are largely scrubbed for SO_2 and NOx. So we're in pretty good shape as far as the CSAPR rules go from those facilities. IPL may have to actually make some investment. But there's clarity in how that would work ... that investment would be anticipated to be recovered through rates as it is made. And DPL is actually in pretty good shape in terms of NOx and SOx requirements as well. So overall, I think we're feeling like we're in a good position." - Ned Hall, Q3 2011 Earnings Call, 11/4/2011 (transcript [corrections by MJB&A])
2	**Ameren**	"This compliance strategy is a win for our customers, our shareholders, and the State of Missouri. As a result of this strategy, we will be able to avoid estimated rate increases for our customers of approximately 15% to 20% by 2017 that might otherwise have been required to meet the SO_2 emission standards of this rule. We believe that this strategy will benefit the State of Missouri by keeping Ameren Missouri's electric rates among the most competitive in the nation helping the State better retain and attract new businesses ... It's something we've been doing for some time to try and anticipate where these regulations were going to come and we were able to execute the strategy successfully." - Thomas Voss, Q2 2011 Earnings Call, 8/4/2011 (transcript)
3	**Buckeye Power Cooperative**	"The one-two punch of environmental regulations found in the new Cross-State Air Pollution Rule (CASPR) and pending Utility Maximum Achievable Control Technology (MACT) rule aimed at mercury emissions will reduce coal-fired power plant generation and require unit closures, but Buckeye Power, Inc. is well positioned for compliance. ... "We started down this path almost 10 years ago" with investment in selective catalytic reduction (SCR) systems and SO2 scrubbers at Cardinal units 2 and 3, O'Loughlin said ... O'Loughlin is confident Buckeye is poised to meet the new EPA regulations. "We've got the tools," he said. "We've got among the best scrubbers in the world." - (website 10/14/2011; cached)
4	**Calpine**	"On the environmental front, the EPA's cross-state air pollution rule is being challenged by group of coal generators in States seeking to stay the rule from becoming effective on January 1, 2012. Calpine has intervened to fully support the EPA and its efforts to enforce this long anticipated rule, for which the environmental control technologies have been available for decades ... We would not be surprised to see continued congressional efforts to blockade EPA action, but remain hopeful that the EPA will stay the course on both CSAPR and the Utility MACT." - Jack Fusco, Q3 2011 earnings call, 10/28/2011 (transcript)
5	**CMS Energy**	"The bottom line: we are well positioned to comply with these new laws with the plans we have in place." - John Russell, Q3 2011 Earnings Call, 10/27/2011 (transcript)
6	**Constellation**	"We believe EPA schedules for rule completion and for compliance are appropriate and feasible based on our own experience with available control technologies and installation timelines to make our own fleet cleaner. Because we already made investments in pollution controls and lower emitting generation plants, Constellation's fleet should benefit from the new and forthcoming EPA regulations as higher power and capacity prices more than offset any incremental costs of compliance." - Mayo Shattuck, Q2 2011 Earnings Call, 8/3/2011 (transcript)

No.	Company	Statements
7	**Dominion**	"There's a lot of activity around our generator facilities and we believe we are well-positioned to meet the challenges." - Thomas Farrell, Q1 2011 Earnings Call, 4/28/2011 (transcript) "[T]he so-called CSAPR rules have no material impact or significant impact on our environmental plans." - Thomas Farrell, Q2 2011 Earnings Call, 7/28/2011 (transcript)
8	**Duke**	"Even though CSAPR is more restrictive and the compliance periods are more aggressive than originally proposed, the provisions are within our long-term planning assumptions ... the anticipation of more stringent environmental regulations has long been part of our long-term strategic planning process." - Jim Rogers, Duke Q2 2011 Earnings Call, 8/2/2011 (transcript) "When our modernization program is complete, nearly 100% of our coal generation capacity will have scrubbers in operation. This positions us well, as the EPA continues to finalize more stringent environmental regulations ... We are well along with our strategy to achieve the new [CSAPR] compliance limits by January 1." - Jim Rogers, Duke Q3 2011 Earnings Call, 11/3/2011 (transcript) "I think three years is doable," Jim Rogers, chief executive of Duke Energy Corp., said in an interview, referring to Duke's compliance schedule for the EPA rules. - Jim Rogers, news article, 11/8/2011
9	**Dynegy**	"[W]e have made substantial capital investments in state-of-the-art air pollution control devices. Any efforts to delay or derail CSAPR would undermine the reasonable, investment-backed expectations of Dynegy." - CEO Ralph C. Flexon, letter to House Committee on Science, Space and Technology, 9/12/2011 (quoted in EESI issue brief)
10	**Edison International**	"We installed the necessary equipment [for compliance with the Toxics Rule] back in 2009 and are already achieving these limits. U.S. EPA's rule contained other draft provisions covering acid gases and non-mercury metals, which we can meet by installing the pollution control equipment we have been planning to use at Midwest Gen to meet our SO_2 emissions commitments to the Illinois EPA." - Theodore Craver, Q1 2011 Earnings Call, 5/2/2011 (transcript) "With respect to the coal fleet, EMG has met and continues to remain committed to meeting all of its environmental obligations on time, as spelled out in the 2006 Illinois Combined Pollutant Standard agreement and more recent U.S. EPA regulations. We believe that the efforts to identify cost-effective compliance solutions and the financing strategies to support them will serve us well in the long run even though they present considerable challenges for us in the near term." - Theodore Craver, Q2 2011 Earnings Call, 8/4/2011 (transcript)
11	**Exelon**	"Being clean is a competitive hallmark for Exelon. It will become even more advantageous as we move into this new era of EPA regulations. More and more, through a combination of economics, gas prices and pending environmental regulations, we expect to see the market bias towards cleaner forms of energy." - John Rowe, Q2 2011 Earnings Call, 7/27/2011 (transcript) "The rules have been in the works for about a decade, and the electric utility industry is well-positioned to respond, with more than 60% of coal-fired power plants already equipped with pollution controls," said Joseph Dominguez , senior vice president of federal regulatory affairs, public policy and communications for Exelon. "Those companies that have done little or nothing to improve or update antiquated, inefficient plants should start planning for compliance now, instead of lobbying for categorical extensions or legislative delays." ... "Exelon's experience demonstrates that there are existing mechanisms that would allow the health and economic benefits of the rules to take effect as quickly as possible, as opposed to a blanket compliance extension that would unnecessarily prolong the public's exposure to dangerous pollution," said Dominguez. "Implementation of the rule also provides the regulatory certainty utilities need to make substantial capital investments in modernizing the nation's electric system, which will create jobs." - Press release, 9/15/2011

No.	Company	Statements
12	**FirstEnergy**	Anthony Alexander: "Even so, today, we are much better positioned than many other companies to address these new requirements. In fact, more than 90% of our production is from non-emitting nuclear, low-emitting natural gas, scrubbed coal or renewable facilities." James Lash: "And as they evolve, we are confident we are well positioned to handle the final requirements that will come from [EPA's regulations] ... While we agree with others in our industry that current timetables are really unrealistic and that the impact on prices paid by customers will be significant, it is important to remember that unscrubbed supercritical coal is not significant in the context of our overall portfolio." - Anthony Alexander and James Lash, Q1 2011 Earnings Call, 5/3/2011 (transcript) "In general, we believe we are in pretty good shape relative to other coal generators, thanks to the work that has been completed across our fleet. Looking at our competitive base load generating capacity, most of the air pollution control equipment is already in place to meet the EPA's new NOx and SO2 emission reduction requirements." - Anthony Alexander, Q2 2011 Earnings Call, 8/2/2011 (transcript)
13	**GenOn**	"We expect to make some capital expenditures, but we expect those expenditures to be manageable ... We also expect that any reduction in GenOn's earnings as a result of those retirements will be more than offset by higher earnings from increases in market prices as a result of industry retirements." - Edward R. Muller, Q1 2011 Earnings Call, 5/9/2011 (webcast [quote transcribed by MJBA]) "We also expect that any reduction in GenOn's earnings from retirements of its units resulting from the environmental regulations, if and when implemented, will be more than offset by higher earnings from increases in prices resulting from industry retirements." - Edward R. Muller, GenOn Q2 2011 Earnings Call, 8/8/2011 (transcript)
14	**Great Plains Energy**	"Regardless of the outcome of the challenges, KCP&L is well positioned to meet the requirements of the new rules without having to involuntary shut down any units. Any shortfall in allocated allowances is anticipated to be addressed through a combination of permissible allowance trading, installation of nominal emission control equipment, changes in plant processes or purchases of additional power in the wholesale market." - M.J. Chesser, Q3 2011 Earnings Call, 11/4/2011 (transcript)
15	**Lower Colorado River Authority**	"With our scrubbers, we will be in compliance with (new EPA) air pollution rules," said Michael McCluskey , manager of generation resource development at the LCRA. When the rules take effect, "we will comply while other utilities may have difficulty taking steps to comply. It's a problem we've already solved." - Austin American-Statesman article, 8/1/2011
16	**NextEra**	"I don't believe that replacing 50-year-old fossil plants with new, more efficient units will be the train wreck we have been hearing so much about, nor do I believe that putting pollution controls on many of the remaining plants is all that terrible ... While there is no free lunch, the cost of this upgrade to the nation's generation fleet is likely to be far less than the costliest predictions. Consider our own utility. In 2010, FPL recorded a SO2 emissions rate 76% below the industry average, a NOx emissions rate 65% below the industry average and a CO2 emissions rate 36% below the industry average. Yet despite having one of the cleanest generation fleets of any utility in the nation, FPL's typical residential customer bills were 24% below the national average at the year-end 2010. We are proof that utility can be clean and cost-effective at the same time." - Lewis Hay, Q1 2011 Earnings Call, 4/29/2011 (transcript)
17	**Northeast Utilities**	"We believe that this technology will provide us with some of the cleanest coal burning units in the country and will position us well to meet the EPA's proposed rules on hazardous air pollutants." - Charles Shivery, Q1 2011 Earnings Call, 5/6/2011 (transcript)

No.	Company	Statements
18	NRG	"[T]he key takeaway is that we do not expect at this time any additional environmental CapEx beyond what we have previously announced ... So I think on our environmental CapEx, we really are focusing on controlling mercury through ACIs, and for Big Cajun, it's fabric filters to control mercury and SO_2. And we think that with that, we will be able to comply with the rules." - Mauricio Gutierrez, Q1 2011 Earnings Call, 5/5/2011 (transcript) "We believe that incremental compliance costs are not material and can largely be offset the by impact in electricity prices as we saw in the previous slide." - Mauricio Gutierrez, Q2 2011 Earnings Call, 8/4/2011 (transcript)
19	PowerSouth Electric Cooperative	"In response to the CAIR rule, PowerSouth constructed a $400 million Air Quality Control project at the Lowman Power Plant to build additional equipment to reduce SO_2 and NOx emissions at the plant. Because of PowerSouth's proactive approach to CAIR, Lowman Power Plant is already in compliance with the Cross-State Air Pollution Rule." - website, September 2011
20	PPL	"We stand to be in a very good position going forward in that we've already spent the money and spent it at the right time." - James Miller, Q4 2010 Earnings Call, 2/4/2011 (transcript) "Overall, we do not see the need to increase capital expenditures to comply with the CSAPR requirements. Overall, PPL's competitive supply fleet is well-positioned with respect to these rules and can clearly benefit from coal plant retirements that will tighten up the supply situation in PJM." - William Spence, Q2 2011 Earnings Call, 8/5/2011 (transcript)
21	Progress	"Over the past decade or so both companies have been aggressively installing new environmental controls on their largest coal plants ... As a result of these combined actions, we believe the new company will be well-positioned to meet the new EPA MACT regulations expected later this year and into 2012. We still have much work to do to comply with these new rules, which could require significant additional capital investments and additional announced plant closures. However, we are further down the road on compliance than many other companies with large coal fleets. We should also benefit by combining best practices in our fleet modernization efforts." - Bill Johnson, conference call announcing Duke-Progress merger, 1/10/2011 (transcript)
22	PSEG	"During the past 5 years, we have invested more than $2 billion to replace inefficient, older generating units and to upgrade our existing facilities to meet new environmental restrictions. PSEG is a long-time advocate of the Clean Air Act Regulations. We view the EPA's recent technical adjustments to the Cross-State Air Pollution Rule, more commonly referred to as CSAPR as favorable for our fleet. We are also well-positioned to meet the anticipated requirements under EPA's HAPs/MACT regulation, which is scheduled to be issued on December 16. We believe these regulations are long overdue. Our experience shows that it is possible to clean the air, create jobs and power the economy, all at the same time. The issuance of these regulations will also provide the industry with much-needed certainty to invest in long lived capital intensive projects such as power plants." - Ralph Izzo, Q3 2011 Earnings Call, 11/1/2011 (transcript)

No.	Company	Statements
23	**Santee Cooper**	"Fortunately, at Santee Cooper, proper planning and foresight has made us well positioned to comply with these new standards when they take effect next year ... I am happy to say that Santee Cooper has already installed the necessary equipment – SO_2 limestone scrubbers and NOx reducing selective catalytic reactors – to be well below any transport rule targets. In the past 10 years, in fact, we've reduced SO_2 and NOx emissions from our coal-fired units by 61 percent and 72 percent, respectively, while increasing coal-fired generation by 18 percent. We were well aware that at some point in the future, EPA would require reductions for a number of reasons. The key was to be able to do it at the lowest impact to our customers. A great example was finding a market for the scrubber byproduct created by the removal of SO_2. This material, synthetic gypsum, is used at the American Gypsum wallboard plant in Georgetown and has also been used in cement manufacturing and as soil amendment. Every bit is recycled. Good planning has put Santee Cooper in a position to comply with these new standards, while minimizing the impact to our customers and contributing to the local economy." - Company blog post, 7/13/2011
24	**SCANA**	"But in the short term we don't see any impacts to our fleet, and we believe that the scrubber and SCR technologies along with the baghouses and/or electrostatic precipitators we have installed in those bigger units should put us in compliance for those units." - Steve Byrne, Q3 2011 Earnings Call (Q&A), 10/26/2011 (transcript)
25	**Seminole Electric Cooperative, Inc.**	"If the EPA adopts a mercury rule as currently proposed, Seminole would already be meeting the standard," said Mike Opalinski, Seminole's senior vice president of energy policy ... While other utilities may have to choose between huge investments in pollution controls or shutting down plants, Seminole is not in that hard position. The investment in pollution-control equipment early on was good for the environment. It also proved to be cost effective ... So contrary to many opinions, today's modern coal plants can protect the environment while providing reliable and affordable electricity." - Website, 10/6/2011 (link)
26	**TECO Energy**	"TECO Energy is supportive of national and state efforts that encourage others to invest in pollution control technologies or repower or retire uncontrolled units ... Because of our on-going environmental accomplishments and initiatives, we believe that we are well positioned to comply with these emerging regulatory initiatives." - 2010-2011 Corporate Sustainability Report
27	**TVA**	"Yes, we will be able to comply with the new EPA rules and we will spend more money in doing so. We have announced scrubbers (to control sulfur dioxide) for Allen and Gallatin fossil plants and SCRs at Gallatin (to control nitrogen oxides); Allen already has SCRs. This new control equipment along with the 17 scrubbers and 21 SCRs we already have in place will help us meet all EPA rules as well as the mercury rule. We continuously review our clean air strategy and we are reviewing whether to retire, idle or control additional coal units in the TVA system." - Barbara Martocci, APR, TVA Media Relations 11/16/2011
28	**Vectren**	"As seen with EPA rules proposed in March, which focused on mercury and other hazardous pollutants, our significant investment in emissions control equipment for this region is again paying off and will ensure we comply with this new rule [CSAPR]," said Carl Chapman, Vectren's chairman, president and CEO ... "More than a decade ago, we chose to move forward with these investments to improve the air quality for our region, which has positively impacted southwestern Indiana's quality of life and serves as an advantage from an economic development standpoint," added Chapman. "As such, our customers' rates increased throughout the past 10 years to reflect the cost of these investments. However, we now find ourselves in a position to comply, while other regional utilities may be required to consider retiring some uncontrolled coal generation units or make significant investments to lower emissions." - Press release, 7/28/2011

No.	Company	Statements
29	**Wisconsin Energy**	"We really see very little impact on customer electric rates or our capital plan between now and 2015 as a result of all the new EPA regulations that have been proposed ... We might see 1% to 2% increase our best guess. So that gives you an example of how well we are positioned from the environmental standpoint in terms of complying with even the new proposed rule." - Gale Klappa, Q1 2011 Earnings Call, 5/3/2011 (transcript)
30	**Xcel**	"Our proactive steps to reduce emissions through the MERP project in Minnesota and our plans for the Clean Air-Clean Jobs Act in Colorado put us in good position to comply with these rules [utility MACT]." - Paul Johnson, Q1 2011 Earnings Call, 4/28/2011 (transcript)

Request No. 2

Refer to the Wilson Testimony at page 20, line 3. What level of demand side management ("DSM") is reasonable for a company such as Big Rivers Electric Corporation ("Big Rivers') that has smelters as 70 percent of its load?

Response to Request No. 2 – Respondent: William Steinhurst

Please see Steinhurst Testimony at page 11, line 7, through page 12, line 12. Annual energy efficiency savings of at least 1% of non-smelter retail sales would be reasonable. Also, please see answer to BREC discovery request #2. In addition, transmission and distribution losses in serving all customer types should be examined for potential savings.

Request No. 3

Refer to the Wilson Testimony at page 20, lines 10-11. Given the depreciation study conducted by Burns & McDonald that assesses unit conditions and life extension concerns, what specific expectations would you have regarding further degradation of heat rate, forced outages, and availability of Big Rivers' generation units?

Response to Request No. 3 – Respondent: Rachel Wilson

Not inconsistent with the Burns & McDonald study, I might expect a pattern of degradation of unit heat rates over time as the units age. One might expect to see a gradual increase in heat rate over a period of several years as unit components wear out. When those component parts are replaced, heat rates might make sudden drop in a single year as efficiency improves due to the upgrades. Heat rates might then resume the gradual increase over time, and the cycle would continue. Similarly, forced outages and availability would be expected to vary from year to year as components age and require replacement.

Request No. 4

Refer to the Wilson Testimony at page 24, lines 26-28. Provide a listing of all of the instances where a utility's evaluation of a market replacement option resulted in a lower net present value revenue requirement ("NPVRR") when compared to a natural gas combined cycle ("NGCC") replacement option. Include the NPVRR for each option reviewed and the NPVRR difference between the market replacement option and the NGCC replacement alternative.

Response to Request No. 4 – Respondent: Rachel Wilson

In general in this region, one would expect the near-term cost of market replacement energy to be lower cost than the all-in cost of a new NGCC. If both gas and coal units set the marginal price of electricity, then the market price of energy will be a combination of the variable cost of production for coal and gas-fired generation (plus a capacity cost, if applicable). Generally speaking, this cost is lower than or approximately equal to the all-in cost of building and operating a new NGCC, which includes both the variable cost of production plus the capital of a new facility. If the all-in cost of building and operating a new NGCC were lower than the market price of electricity, one would expect numerous new entrants into the market. Over the long-term, one might expect that cost of market replacement energy approximates the all-in cost of a new NGCC if those are the most likely new entrants.

Over the last year, I have been involved in two cases where the cost of a new NGCC has been modeled explicitly against market energy replacement for a coal unit.

a) Recently, in Kentucky, Kentucky Power Company modeled the replacement of Big Sandy 2 in Docket 2011-00401. The Company compared the unit against a new NGCC in 2016 (Option 2, CPW = $7,075,297) and against extended market purchases followed by a new NGCC in 2020 (Option 4A, CPW = $6,917,767) or 2025 (Options 4B, CPW = $6,791,587). Both Options 4A and 4B were less expensive than Option 2, leading to the conclusion that replacement with market purchases were less expensive than replacement with a new NGCC. See Exhibit SCW-4A.

b) In January of 2012, PacifiCorp provided a confidential cash-flow model to interveners in its Integrated Resource Plan (IRP) process (Oregon Docket LC-52) to explore the cost-effectiveness of the Company's coal fleet against both market replacement and new NGCC replacement units. I am unable to share the results of this confidential analysis, but the analysis demonstrated that in every case, market purchases were less expensive than the costs of a new NGCC.

Exhibit SCW-4A

Big Sandy Unit 2 under BASE: "Fleet Transition-CSAPR" Commodity Pricing

Kentucky CPCN Filing Economic Analysis
Capacity Resource Optimization
Resource Plan Summary

Resource Plan Year	'BASE' Option #1 BS2 DFGD Retrofit 6/2016	Option #2 (1) RK Retires 1/2016 with (Brownfield) CC Replacement	Option #3 (1) RK Retires 1/2016 with BS2 CC Repwrng Replacement	Option #4A (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2020	Option #4B (1) RK Retires 1/2016 w/ PJM-Mkt Replacmnt to 2025	BS2 "Timing" Sensitivity Option #1A BS2 DFGD Retrofit Delayed until 1/2017 (~1-Yr EGU MACT Delay)
2011-2013				45 MW- ICAP	45 MW- ICAP	Big Sandy 1 Retire
2014	Big Sandy 1 Retire	Big Sandy 1&2 Retire	Big Sandy 2 Retire Big Sandy 1	225 MW- ICAP	225 MW- ICAP	Big Sandy 2 Mothball (1-yr)
2015		1 -904 MW NGCC	1 -780 MW Repower,	938 MW- ICAP	938 MW- ICAP	
2016	Big Sandy 2 Retrofit			922 MW- ICAP	922 MW- ICAP	Big Sandy 2 Retrofit
2017				930 MW- ICAP	930 MW- ICAP	
2018				934 MW- ICAP	934 MW- ICAP	
2019				1 -904 MW NGCC	938 MW- ICAP	
2020					939 MW- ICAP	
2021					951 MW- ICAP	
2022					957 MW- ICAP	
2023					967 MW- ICAP	
2024					1 -904 MW NGCC,	
2025	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1-407 MW CC	
2026						
~						
2040						
Life-Cycle Analysis Period (2011-2040) ($000)						
CPW of Revenue Requirements	6,724,489	7,152,559	7,079,239	6,811,507	6,487,042	6,721,898
Less: ICAP Revenue	(114,391)	77,262	(11,944)	(106,260)	(304,545)	(114,503)
CPW of Revenue Requirements, Net	6,838,879	7,075,297	7,091,182	6,917,767	6,791,587	6,836,401
A. Cost/(Savings) Over 'BASE' Case						
CPW of Revenue Requirements		428,070	354,750	87,018	(237,447)	(2,591)
Less: ICAP / Pool Revenue		191,652	102,447	8,130	(190,154)	(112)
CPW of Revenue Requirements, Net		236,418	252,303	78,888	(47,293)	(2,478)
B. Cost/(Savings) Over 'BASE' Case						
Impact of 20-Year (vs. 15-Year) RETROFIT Cost Recovery		37,200	37,200	37,200	37,200	37,200
CPW of Revenue Requirements, Net		273,618	289,503	116,088	(10,093)	34,722

Note:
- o The 'BASE' / Option 1 (Big Sandy 2 RETROFIT) analysis results assumes a 15-year recovery period for the incremental DFGD retrofit investment
- o Option #2 (Big Sandy 2 RETIRED & REPLACED w/ a [BS-site 'Brownfield'] CC) assumes a 30-year recovery period for the new-build CCs in all analyses
- o Option #3 (Big Sandy 2 RETIRED & REPLACED w/ a CC-Repowered Big Sandy U1) assumes a 20-year recovery period in all analyses
- o All cases (except Option #3) assume that Big Sandy 1 retired 1/2015
- o In all cases, effectively assumes replacement capacity & energy for BS1 would be 'delayed' until ~2025 in recognition of a) the (incremental) financing/cost burden to KPCo and its customers; and b) assumed limited (PJM) market availability of reasonably-priced replacement capacity & energy during the interim (~150-300 MW)
- o Evalution economics (all cases) reflect KPCo's 30% share (~195-MW) Purchase Entitlement from affiliate AEG Generating Cos.' 50% Ownership Share of both Rockport Units 1&2
- o "Retirement" options EXCLUDE costs associated w/ socio-economic impacts to the plant staff, supply vendors, or to the overall eastern-Kentucky region
- o "G" Revenue Requirements established on a KPCo "stand-alone" (basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)...

  Inclusive of:

  1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM; and
  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

Request No. 5

Refer to the Wilson Testimony at page 25, lines 1-14.

a. Provide details on how the effects of natural gas and CO_2 emission prices were removed from the hourly market forecast price.

b. Explain and provide sources to support the assertion that the marginal emission rate from coal-fired units is 1.0 – 1.1 tons CO_2/MWh and the marginal emission rate from natural gas-fired units is 0.6 – 0.7 tons CO_2/MWh.

c. Provide support for the conclusion that the PACE market prices forecast results in a marginal emission rate of 1.8 tons CO_2/MWh in later years.

Response to Request No. 5 – Respondent: Rachel Wilson

Synapse reviewed three elements of information in files provided by the Company from PACE modeling to determine the relative impact of natural gas price and CO_2 price on the anticipated cost of market energy. The following data and equations can be found in the attached workpaper entitled MarketPriceBreakdown.xlsx.

We extracted the tabs "Input CO2 Prices" and "Input Henry Hub Nat Gas" from the file PACE_Big_Rivers Data Request Inputs_120524.xlsx provided in response to KIUC DR 18 and Sierra DR 6 & 7. We also extracted the tab "Output Stochastic Energy Prices" from the file PACE_Big_Rivers Data Request Outputs_120524.xlsx provided in response to KIUC DR 18. These files contain 200 stochastic commodity price input runs (plus one "Reference Case") and the market prices for all 200 stochastic runs and the Reference Case. We assumed that each of the stochastic runs was consistently numbered from file to file. From the gas price tab, we extracted annual average HH price. From the market energy price information, we extracted the "All Hours" price of electricity. All of these tabs were restructured to yield long columns of all years and all runs (3819 rows long = 201 runs * 19 years. See columns D-F).

a) Synapse first extracted the effect of natural gas alone on the market energy price by removing CO_2 from the equation. To do this, we simply identified every run and year in which there was a zero CO_2 price used in the stochastic analysis (1709 out of 3800 data points, or 45%). For each year across all iterations with a zero CO_2 price, we derived a linear equation (slope and intercept) to describe the relationship between gas and market prices <u>in the absence of a CO_2 price</u> (see columns J&K). To review the impact of a CO_2 price on the market price, we backed out the the effect of gas price changes and examined the relationship between CO_2 prices and market prices. To do so, we created a column of values estimating the energy price as if there were no CO_2 price (using the slope and intercept noted above, see column M) and compared this to the actual market energy prices that included CO_2 prices. The change in energy price from this theoretical zero CO_2 energy price to one that had a CO_2 price (see column N) was compared against the actual CO_2 price in each run. We again derived a slope and intercept for each year describing the impact of a CO_2 price on the market electricity price difference (see columns R&S). The first linear equation thus describes the impact of gas prices on the electricity market rate, while the second linear equation describes the impact of CO_2 prices on the electricity market rate. It is notable that the slope of the CO_2 price against the market electricity price should describe the emissions rate of the average marginal unit in the electricity market price. This slope represents the ratio of market energy price ($/MWh) per unit change to CO_2 price ($/t$CO_2$). As a slope is defined by the change in the independent variable ($/MWh) over the dependent variable ($/t$CO_2$), the slope here is then equal to a factor of tCO_2/MWh, or an emissions rate. For fossil fired units, we would not expect this emissions rate to exceed about 1.2 tCO_2/MWh at the worst, and the rate could be far lower if new units added in the future are low emissions units. From our derivation, we find that this emissions rate starts at approximately 0.5-0.7tCO_2/MWh (years 2016-2018) but climbs to 1.8tCO_2/MWh by 2030 (see column R).

b) According to data pulled from the EPA's Clean Air Markets Division (CAMD) Air Markets Program Data (AMPD) database (http://ampd.epa.gov/ampd/), over the last six years, the average gross CO_2 emissions rate (weighted by generation) for coal-fired EGU was 1.04 t/MWh (1.0-1.05 33rd to 66th percentile), while the average gross CO_2 emissions rate for natural gas units was 0.67 tCO_2/MWh (0.56 – 0.73 33rd to 66th percentile).

c) See (a), above.

Request No. 6

Refer to the Wilson Testimony at page 26.

a. Is the testimony suggesting that the heat rates and availability assumed by Big Rivers are too high? If so, by how much? (Provide in percentage or absolute amounts).

b. Is this modeling assumption inconsistent with general practices?

c. What assumptions for heat rates and availability were used for other Midwest Independent Transmission System Operator, Inc. ("MISO") units that were used in the Big Rivers, PACE and ACES analyses?

Response to Request No. 6 – Respondent: Rachel Wilson

a. My testimony is suggesting that heat rates and availability of the BREC units are unlikely to stay constant over time, as was assumed by the Company.

b. Yes, I believe that assuming constant heat rates and availability over time is inconsistent with general practices.

c. The BREC financial analysis did not contain any assumptions about heat rates and availability for other generators in MISO. I believe the data for other units in MISO belonging to other utilities in the ACES analyses was stripped from the modeling database by Ventyx and the assumptions about heat rates and availability were therefore not available. I do not know what PACE assumed about the heat rate and availability of other units in MISO as those data were not made available to interveners.

Request No. 7

Refer to Wilson Testimony at page 27, lines 15-18. Given the uncertainty as to exact costs for new control technology – some experts suggesting it will go up in price as demand increases while others note that actual results indicate that prices are below expectations, what level of inflation should be used for the capital expenditures during the procurement and construction process? Explain your response.

Response to Request No. 7 – Respondent: Rachel Wilson

In my view the Company made an error in mixing up real and nominal dollars. In the absence of other information or argument the neutral and correct assumption is that costs will rise with some measure of the general inflation rate, e.g. the Consumer Price Index, the Gross National Product price deflator, or some other measure. BREC's own estimates of inflation over time would have been another appropriate measure of inflation to apply to capital costs of control technologies. In this case the Company provided no justification for implicitly assuming that the control costs will effectively escalate at a negative percentage value in real terms.

Request No. 8

Refer to the Wilson Testimony at page 28, lines 14-17. Provide the basis for the statement that one or more of Big Rivers units would likely require additional retrofits to be in compliance with the Mercury Air Toxics Rule.

Response to Request No. 8 – Respondent: Rachel Wilson

The basis for this statement is the Sargent & Lundy report commissioned by Big Rivers. As explained at pages 12-13 of my testimony, Sargent & Lundy developed its recommendations for MATS compliance on a limited amount of stack test data that was collected when units were running at operational loads with pollution control equipment in service. These stack tests tell very little about emissions from the unit during periods of startup and shutdown when control equipment may not be fully operational. Emissions may therefore be higher than indicated by the stack test data.

The Sargent & Lundy recommendations also state that retrofitting the BREC units with ACI and/or DSI will lead to additional loading of particulate matter, which may necessitate upgrades of existing electro static precipitators (ESPs) or installation of baghouses to satisfy particulate matter emission limits. Sargent & Lundy noted that it could model whether such ESP upgrades or baghouse installations would be needed (S&L MACT Supplement at p. 2), but BREC has yet to conduct such testing. .

Request No. 9

Refer to the Wilson Testimony at page 31, lines 21-24. Is there any evidence to support the argument that there are significant energy efficiency savings available that would reduce Big Rivers' load given the high level concentration of the smelter's load?

Response to Request No. 9 – Respondent: Rachel Wilson

Please see the response to PSC Staff Data Request 1-2.

Request No. 10

Refer to the Wilson Testimony at page 32, lines 6-15. Provide details on input assumptions that were different from those used by Big Rivers. Provide the range and an explanation as to why they were used.

Response to Request No. 10 – Respondent: Rachel Wilson

The assumptions used that were not taken directly from BREC include: 1) the characteristics of the NGCC replacement unit (see the "Gen Assumptions" tab in the spreadsheet model provided in response to KIUC Data Request 1-1 for documentation); 2) use of AFUDC rather than CWIP to represent the cost of borrowing; and 3) inclusion of effluent limitation guidelines compliance costs taken from a 2010 EPRI Report (see response to BREC Data Request 1-12). We also include the option to utilize the EIA's AEO 2012 natural gas price forecast, the PACE Global CO_2 price forecast, and two additional sensitivity CO_2 price forecasts.

Request No. 11

Refer to the Wilson Testimony at page 33, lines 4-8. Provide an electronic copy of the cash flow model with all inputs and assumptions.

Response to Request No. 11 – Respondent: Rachel Wilson

Please see the response to KIUC Data Request 1-1.

Request No. 12

Refer to the Wilson Testimony at page 33, Table 8 – Synapse Recommended Case. Provide all inputs, analyses and assumptions relied upon to produce this table. Include a listing of each assumption, the references to support the assumption, a listing of all data sources used, and the electronic versions of the spreadsheets or other applications used to calculate the values in the table.

Response to Request No. 12 – Respondent: Rachel Wilson

The Synapse Recommended Case includes the natural gas price forecast from EIA's AEO 2012, incorporation of the PACE Reference CO_2 emissions price forecast, and inclusion of the costs associated with the compliance technologies recommended by Sargent & Lundy for the NAAQS, CCR rule, and 316(b) rule. It also includes cost estimates for the effluent limitation guidelines. Please also see the response to KIUC Data Request 1-1 for a copy of the spreadsheet model. See the response to BREC Data Request 1-6 for information on documentation of assumptions. See also the response to BREC Data Request 1-12 for information on the estimates of cost to comply with the effluent limitation guidelines.

Request No. 13

Refer to the Direct Testimony of William Steinhurst ("Steinhurst Testimony") at page 10, line 29, which suggests that wind energy be considered as an effective alternative energy source to replace Big Rivers generation. Please explain how the addition of on-shore wind energy could result in a lower cost option.

Response to Request No. 13 – Respondent: William Steinhurst

The referenced testimony merely noted that wind could be part of a long-term diversified portfolio, along with increased levels of DSM, other renewable resources, and natural gas combined cycle that would meet customer needs without each and every coal upgrade proposed by BREC.

Request No. 15

Refer to the Steinhurst Testimony, page 11, lines 11-29. The testimony states that a larger DSM load reduction should be assumed. Recognizing that the majority of the load on the Big Rivers' system is associated with the two smelters, explain how the remaining load can be significantly reduced through further DSM programs so as to replace a Big Rivers generating unit. Provide specific programs and their estimated impact on demand.

Response to Request No. 15 – Respondent: William Steinhurst

As explained in my response to request number 2 above, and to BREC request number 2, leading utilities have been proven to be able to achieve at least 1% savings per year through DSM programs, which could be part of a portfolio of resources that is more cost effective than continued operation of BREC's coal units. Specific programs and estimated impact would require a detailed study. However, to illustrate the potential of energy efficiency, BREC's Plan calls for upgrades to a number of units of about 160 MW gross output. (Berry-3 at 2-3) That is equivalent to power delivered to the customer meter of about 0.90 * 160 MW or about 144 MW per unit. (For losses, see BREC IRP, App. D, page 4 of 90, for example.) An annual DSM savings on non-smelter load of about 1% per year for ten years would result in savings of about 10% of rural peak or about 0.10 * 550 MW = 55 MW. (Starting with 2013 load forecast from BREC IRP.) 55 MW is about 38% of the net power to the customer meter for one of the 160 MW units. This is a substantial enough fraction of output to contribute to rendering one such unit less cost effective than alternatives.

Request No. 16

Refer to the Steinhurst Testimony at page 12, lines 20-22. It states there "If BREC had done its analysis on a unit-by-unit basis, it is likely that DSM could have offset the need to retrofit or replace some units." Provide a detailed explanation in support of this statement. Include in the explanation the reasoning for concluding that the result is "likely."

Response to Request No. 16 – Respondent: William Steinhurst

As mentioned in response to question 15 above, some of the units proposed to be upgraded are of modest size and DSM (even on just rural load) could contribute to rendering one or more of those units not needed or not cost effective to upgrade.

Request No. 17

Refer to the Steinhurst Testimony, page 14. Provide a reference to the estimate provided in the scenario as presented at lines 1-12.

Response to Request No. 17 – Respondent: William Steinhurst

As presented, this is a hypothetical example to demonstrate that BREC's claim about being able to avoid sunk costs is economic nonsense. However, for that purpose, I chose the capital and operating cost values consistent with the results shown in Wilson's Table 8. The value for amortization of existing rate base and carrying costs is a hypothetical value, but as seen in my example, its size is immaterial to the outcome.