

Coal Capacity at Risk for Retirement in PJM:

Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants

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PJM Interconnection



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Executive Summary

In its role of maintaining reliability and resource adequacy, PJM has been following the finalized Cross State Air Pollution Rule (CSAPR)¹ and proposed National Emissions Standards for Hazardous Air Pollutants (NESHAP),² issued by the United States Environmental Protection Agency (EPA), affecting electric generating units, and coal-fired units in particular. PJM has been in the process of estimating the impacts of these rules on the amount of coal-fired generating capacity that may retire, rather than install pollution control retrofits by examining the retrofit status of coal capacity by the age and size of coal-fired units.

Installation of Pollution Control Retrofits will be Essential to Comply with CSAPR and NESHAP

Compliance with CSAPR and NESHAP will likely require the installation of some combination of the following controls: 1) sulfur dioxide (SO₂) controls such as limestone-based flue gas desulfurization (FGD) or dry sorbent injection (DSI); 2) nitrogen oxide (NO_x) controls such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR); 3) activated carbon injection (ACI) for mercury; and 4) a fabric filter (also known as a baghouse) for the particulates associated with heavy metals and the use of ACI or DSI.

As of June 30, 2011, there is over 78,000 MW of installed coal capacity in PJM inclusive of the recently integrated ATSI zone and soon to be integrated Duke Ohio and Kentucky (DEOK) zone.³ Almost 25 percent of coal capacity is in the Mid-Atlantic region (MAAC) of PJM. Table 1-ES shows the total coal capacity in PJM without pollution control retrofits and broken down by region.⁴ As much as 37 percent of total coal capacity in PJM may need at least two retrofits that would be required to comply with the combined CSAPR and NESHAP rules.

Table 1-ES: Total Coal Capacity in PJM without Pollution Controls

	PJM RTO	MAAC	Rest of PJM
Total Coal	78,613	18,761	59,852
No SO ₂ Controls	30,069	4,281	25,788
No SCR for NO _x Reduction	36,618	8,805	27,813
No Fabric Filter	69,115	13,020	56,095
No SO ₂ and No SCR	22,866	2,723	20,143
No SO ₂ and No Fabric Filter	29,457	3,756	25,701

Using the same retrofit cost models as used by EPA in its analysis of the CSAPR and NESHAP rules, PJM estimates the average installed costs of these retrofits in PJM to be \$802/kW for an FGD, \$369/kW for an SCR, \$172/kW for ACI and a fabric filter, and \$118/kW for DSI.⁵

Economic Environment Faced by Coal Capacity in Need of Pollution Control Retrofits

Coal-fired generation can cover its going forward costs, inclusive of returns on new investments made in generation plant, through a combination of net energy and ancillary service market revenues and capacity market revenues. Net energy market revenues in particular are driven by electricity demand and the spread between coal and natural gas prices. The economic conditions under which retrofit and retirement decisions are being made include:

- Reduced natural gas/coal price spreads from \$5-\$7/mmBtu in 2006-2008 to \$2-\$3/mmBtu in 2009 that are forecast by the Energy Information Administration to continue until 2016.⁶ This reduces the net energy market revenues available to cover the costs of environmental retrofits.
- Lower forecast average hourly energy demand that leads to lower cost resources on the margin setting price and lower net energy market revenues available to cover the costs of environmental retrofits. Moreover, less efficient units will not run as often, further eroding net energy market revenues available to cover retrofit costs.
- Over the past four years, the combination of reduced natural gas/coal price spreads and lower demand have already resulted in lower capacity factors that have fallen from 65 percent in 2007 to about 40 percent in 2010 for coal-fired units less than 400 MW and more than 40 years old.⁷ At the same time coal-fired units greater than 400 MW, regardless of age, have maintained relatively constant capacity factors in the face of reduced hourly demands and reduced fuel price spreads.
- Overall, the decline in the gas/coal price spread and average hourly demand have resulted in declining net energy market revenues for all coal capacity, but net revenues remain lowest for coal-fired units less than 400 MW and more than 40 years old.⁸

Physical Screen for Coal-fired Capacity Most at Risk for Retirement in PJM

Coal-fired units more than 40 years old and less than 400 MW are less efficient, run less frequently on average, and accordingly, have seen their capacity factors and net energy revenues decline since 2007. These older, smaller units, therefore, seem likely candidates for retirement should they require substantial environmental retrofits. They also do not enjoy economies of scale in retrofit costs that larger units possess. Therefore, any older, smaller unit in need of at least one major retrofit should be considered at risk for retirement.

Table 2-ES shows the quantity of coal-fired capacity more than 40 years old and less than 400 MW that does not yet have some type of emissions controls.⁹ Table 2-ES also shows, in parentheses, the percentage these older, smaller units represent of total coal-fired capacity fitting the emissions control status defined in the far left column. In general, these older, smaller units account for only 29 percent of total coal capacity, but account for more than half of the total coal capacity (in percentage terms) in need of major sulfur dioxide and nitrogen oxide retrofits as shown in Table 2-ES regardless of region. As much as 20,000 MW of coal-fired capacity are at risk for retirement in PJM (inclusive of DEOK and ATSI), with as much as 4,400 MW of that capacity located in the Mid-Atlantic region (MAAC) east of the west-to-east transmission constraints in PJM.

Table 2-ES: Coal-fired Capacity More than 40 Years Old, Less than 400 MW in Size by Control Status and Percentage of Category Total

	PJM	MAAC	Rest of PJM
Total	22,907 (29%)	5,769 (31%)	17,138 (29%)
No SO₂ Controls	17,387 (58%)	2,560 (60%)	14,827 (57%)
No Fabric Filter	20,104 (29%)	3,729 (28%)	16,375 (29%)
No SO₂ Control and No Fabric Filter	16,775 (57%)	2,035 (54%)	14,740 (57%)
No SCR	18,762 (51%)	4,456 (50%)	14,306 (51%)
No SO₂ Control and No SCR	14,541 (63%)	2,236 (82%)	12,305 (61%)

Economic Screen for Coal-fired Capacity at Risk for Retirement in PJM

Using known net energy market revenues from PJM’s Energy and Ancillary Service Markets from 2007-2010,¹⁰ PJM has derived the needed additional revenues, expressed in dollars per megawatt-day of installed capacity (\$/MW-day ICAP) that generating units would be expected to require to continue operating into the future. PJM estimated retrofit costs from EPA-supplied cost models assuming a 20-year recovery period using the capital recovery factors in the PJM tariff, and estimated tariff-defined avoidable costs for the years 2007-2010.¹¹ Units in the ATSI and DEOK regions are not included in this analysis because of the lack of PJM-market specific net energy and ancillary service market revenues for these units during 2007-2010. The needed additional revenues are then compared to the Net Cost of New Entry (Net CONE) from the 2014/2015 Base Residual Auction, expressed in installed capacity terms, to determine how many megawatts of coal-fired generation are at risk for retirement.¹²

- Capacity requiring greater than Net CONE are deemed to be “most at risk” for retirement as they could be cost-effectively displaced by the Reference Resource CT that defines Net CONE. If capacity requires more than 1.5 Net CONE, this exceeds the maximum price in RPM.
- Capacity requiring between 0.5 Net CONE and Net CONE are deemed to be “at some risk” and their decisions to go forward will depend upon capacity market prices, all else being equal.
- Capacity requiring less than 0.5 Net CONE are considered “not at risk”, and most of this capacity has installed most, if not all, required retrofits required to remain in service.

The 2007-2010 period offers a natural experiment with respect to the impact of natural gas prices on the economic viability of coal units to continue operating into the future. Net energy market revenues in 2007-2008 were high along with natural gas prices. Conversely, net energy market revenues were low in 2009-2010 along with low natural gas prices. Given the forecast of continued low coal-natural gas price spreads and lower forecast average hourly demands into the future, the economic viability of coal units using 2009-2010 net energy and ancillary service market revenues seems to be the most reasonable assumption regarding the future viability of coal-fired generation in PJM under the CSAPR and NESHAP rules.

Table 3-ES: Capacity Economically at Risk for Retirement

Additional Revenue Needed	PJM	MAAC	Rest of PJM
< 0.5 Net CONE	38,334	12,634	25,700
0.5 Net CONE – 1.0 Net CONE	14,147	2,908	11,239
> 1.0 Net CONE	11,051	3,194	7,857

Table 3-ES summarizes PJM’s estimate of coal-fired capacity economically at risk. Capacity “most at risk” is shaded in red, capacity “at some risk” is shaded in yellow, and capacity deemed “not at risk” is shaded in green. There is 11,051 MW of coal-fired capacity “most at risk”, shaded in red in Table 3-ES, with 3,194 MW in MAAC and 7,857 MW in the remainder of the RTO excluding ATSI and DEOK. Of the capacity “most at risk”, the average unit size is less than 200 MW, and the average age is over 50 years old.

There is also another 14,147 MW of capacity “at some risk” for retirement as shown in Table 3-ES and shaded in yellow. The average size is close to 400 MW, and the average age is 37 years old. In contrast, capacity deemed “not at risk” is on average just under 500 MW and 34 years old.

Effects of the EPA Rules Have Already Been Observed in the PJM Market

In the RPM Base Residual Auction (BRA) conducted in May 2011 for the 2014/2015 Delivery Year, the amount of coal capacity cleared was 6,895 MW UCAP lower than what cleared in the BRA conducted in May 2010 for the 2013/2014 Delivery Year, a reduction of 16 percent or about 7,350 MW of installed capacity less.¹³ Of the \$98.26/MW-day increase in the RTO Locational Deliverability Area (LDA) in the 2015/2015 BRA, PJM has been able to discern the addition of pollution control retrofit costs contributed in approximately \$60-\$80/MW-day to the price increase.¹⁴

Additionally, there have been public announcements of the intent to retire an approximately additional 7,000 MW of coal-fired installed capacity by 2015, due to EPA rules, from AEP and Duke that satisfy their resource adequacy requirements outside of the RPM auction construct through the Fixed Resource Requirement (FRR) option.¹⁵ In total, there is over 14,000 MW of installed coal-fired capacity that already appears headed toward retirement largely due to EPA rules. This initial market response to the EPA rules is more than 25 percent greater than the 11,000 MW of capacity requiring more than Net CONE to continue going forward suggesting additional capacity requiring between 0.5 Net CONE and Net CONE may elect to retire rather than retrofit.

Resource Adequacy Does Not Currently Appear at Risk in Spite of Projected Retirements

Even with almost 7,000 MW less coal capacity clearing for the 2014/2015 Delivery Year, PJM estimates the RTO will carry a reserve margin of 19.6 percent for the Delivery Year, including the demand and capacity commitments of FRR entities.¹⁶ Even with the potential retirement of coal capacity already announced by FRR entities, there are also announced commitments to replace a portion of that capacity with new gas-fired capacity such that the RTO would still carry a reserve margin at or above of the target 15.3 percent installed reserve margin. Add into the mix the potential for new entry from Demand Resources, as has been the trend in recent years, and resource adequacy does not appear to be threatened.¹⁷

Although no system-wide capacity problem is apparent in PJM from the announced retirements, this does not mean that localized reliability concerns may not arise given the location of particular units and the unique locational services they provide such as congestion management of particular transmission facilities, voltage support for the transmission system, or black start services. It is for this reason that PJM proposed, in its comments to the EPA in the NESHAP rulemaking, a “reliability safety valve” to be included in the final EPA NESHAP rule to address these particular circumstances. The key is whether replacement resources or transmission reinforcements can be timely added given the breadth of the potential retirements and the pressure on outside vendors to supply new turbines and related resources.¹⁸

As long as resource adequacy and local reliability are assured, the cycle of generation retirement and new resource entry are market-driven outcomes that can be reliability and efficiency enhancing. Newer, more efficient generation resources that replace retiring generation may have lower forced outage rates and thus, are more dependable than older generation resources that may be nearing the end of their useful lives. Additionally, new resources, whether it is new generation, demand response, or energy efficiency, may also provide lower cost alternatives to achieve resource adequacy.

Conclusions and Caveat

- Of the approximately 78,000 MW of coal capacity in PJM, at least 30,000 MW (38 percent) requires sulfur dioxide controls to help comply with both the CSAPR and NESHAP rules.
- Coal units less than 400 MW and more than 40 years old only account for 29 percent of the PJM total (almost 23,000 MW), but account for more than half of the capacity without one or more of the necessary sulfur dioxide or nitrogen oxide retrofits to comply with CSAPR and NESHAP.
- Coal units less than 400 MW and more than 40 years old are less efficient, run at lower capacity factors, and have the lowest net energy revenues per MW of capacity. As much as 20,000 MW of older, smaller capacity requires at least one major retrofit to comply with the CSAPR and NESHAP rules.
- Approximately 11,000 MW of coal capacity is “at high risk” for retirement because this capacity requires revenues exceeding Net CONE to cover the costs of pollution control retrofits assuming a 20 year cost recovery and gas/coal price spreads that persist as they have over the past two years. An additional 14,000 MW of capacity is “at some risk” as it requires between 0.5 Net CONE and Net CONE to cover the costs of retrofits under the same assumptions.
- In the 2014/2015 RPM BRA, approximately 7,000 MW less coal capacity cleared than in the 2013/2014 BRA and public announcements by FRR entities AEP and Duke indicate the intent to retire approximately 7,000 MW of coal capacity in response to EPA regulations.

One caveat must be kept in mind in considering the range of outcomes discussed in this report. Ultimately, the decision to retrofit or retire a unit will be made by an individual generation owner based on its own needs for cost recovery (e.g. term and internal rate of return), expectations regarding future economic conditions (e.g. gas prices and demand) and the shape of future environmental policy or rules that could affect the electric power industry (e.g. climate change policy).

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Introduction and Organization

Since the proposal of EPA's Transport Rule in July 2010,¹⁹ PJM has been assessing coal-fired capacity "at risk" for retirement due to EPA air pollution control rules. In particular, PJM has focused on the now finalized Transport Rule (now known as the Cross State Air Pollution Rule or CSAPR)²⁰ and the National Emissions Standards for Hazardous Air Pollutants rule (known as HAP MACT or NESHAP).²¹ To date PJM has attempted to identify coal-fired capacity "at risk" for retirement based upon the physical unit characteristics such as age, size, relevant pollution controls installed, unit capacity factors, and unit heat rates. Such identification provides a helpful screen to begin to determine the magnitude of units at risk for retirement. In addition to updating screens based on physical characteristics, PJM has further refined its assessment by examining the economic viability of coal units to earn sufficient revenues to cover the costs of pollution control retrofits to meet the emissions caps or standards defined by the CSAPR and the NESHAP rule.

However, PJM's analysis is not intended as a substitute for asset owners providing PJM with the earliest possible notice as PJM requested in its comments responding to the proposed NESHAP rule (at least two years before the effective date of the EPA rules) to allow PJM to secure alternative resources or undertake needed transmission upgrades resulting from the unit retirement.²² Unit retirements are complex decisions based on a number of factors known only to the asset owner. PJM's screen analysis is intended to provide the public with information on the potential magnitude of retirements but not substitute for those unit-specific decisions which well could vary individually and cumulatively from the results of PJM's screen analysis.

Coal capacity accounted for 41 percent of installed capacity and provided of 49 percent of total generation in 2010.²³ Given PJM's responsibility for reliability in terms of facilitating resource adequacy through the Reliability Pricing Model (RPM) Capacity Market, and transmission security through the Regional Transmission Planning (RTEP) Process, it is essential for PJM to begin the process of developing estimates of coal-fired capacity that may retire in response to finalized and proposed EPA regulations. The RPM Capacity Market will send price signals and commit resources on a least-cost basis to achieve resource adequacy so that retirement decisions will be made in the context of those market signals. However, with respect to transmission security, an estimate of specific coal units likely to retire, along with timely actual notice of an asset owner's intentions, can aid PJM in ensuring that appropriate transmission upgrades can be identified and placed into service. This will allow coal-fired capacity to retire as the least-cost compliance option with the EPA rules without harming transmission reliability.

Report Organization

Following this Introductory section, the next section in the report provides an overview of the CSAPR and NESHAP rules which is then followed by an explanation of the types of control technologies that will likely be required to comply with both rules and their respective costs. Next, the report presents an estimation of coal-fired capacity “at risk” for retirement based on the physical characteristics of coal-fired units such as age, size, pollution control status, capacity factor, and heat rate. The estimation based on physical characteristic also alludes to the economics of coal capacity by age and size which is supported by the heat rate and capacity factor information and provides a transition into the economic analysis.

To set the stage for the economic analysis, the next section in the report provides a broad economic context with an emphasis on narrowing coal-natural gas price spreads and the trend in projected lower load growth and ties this back to the historic trends in unit capacity factors and heat rates over time. The next section then provides background information and assumptions used in developing the economic assessment, and is immediately followed the economic estimate of coal-fired capacity at risk for retirement based upon historic net energy and ancillary service market revenues and estimated compliance costs under different scenarios.

The last section summarizes the key conclusions providing bounds for the potential coal-fired capacity at risk of retirement due to the CSAPR and NESHAP rules.

Summary of EPA Air Pollution Rules Analyzed

The United States Environmental Protection Agency (EPA) has in the last year proposed and issued regulations that would require the owners of certain generation resources to make capital investments in air pollution control technologies in order to continue operating the resources. These rules include the Cross-State Air Pollution Rule (CSAPR) issued on July 6, 2011²⁴ and the National Emission Standards for Hazardous Air Pollutants Rule (NESHAP or HAP MACT) proposed on March 16, 2011²⁵ (hereto referred to together as the “rules”) These rules will impact fossil-fuel-fired generation, primarily coal-fired generation.

Specifically, the CSAPR and NESHAP rules indicate the need for coal-fired generation to install sulfur dioxide (SO₂), mercury (Hg), particulate control, and possibly nitrogen oxide (NO_x) control technologies if they have not already done so. The costs associated with these controls impact the economic viability of generators, which we attempt to analyze in this report. A summary of these rules is provided below.

Cross-State Air Pollution Rule

On July 6, 2011, the EPA introduced a rule to limit the interstate transport of emissions of nitrogen oxides (NO_x) and sulfur dioxide (SO₂) that contribute to harmful levels of fine particle matter (PM_{2.5}) and ozone in downwind states. EPA identified emissions within 27 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 national ambient air quality standards (NAAQS) and the 1997 ozone NAAQS.²⁶

EPA also issued a supplemental proposal to request comment on its conclusion that six additional states significantly affect downwind states' ability to attain and maintain compliance with the 1997 ozone NAAQS.²⁷

CSAPR was developed to replace the Clean Air Interstate Rule (CAIR), which was remanded by the U.S. Court of Appeals for the District of Columbia Circuit in 2008.²⁸ The final rule considered comments on the proposed Clean Air Transport Rule, and differs from the proposed rule in a number of areas.²⁹ This rule does not replace the Title IV “Acid Rain” program for SO₂, which remains intact.³⁰

The CSAPR covers all fossil fuel-fired units greater than 25 MW that produce electricity for sale. Cogeneration and solid waste combustion units are exempt for the most part, and the regulation does not allow non-covered units to opt in. All states in PJM's footprint are covered, with the exception of Delaware, and the District of Columbia, which were removed because they did not significantly impact downwind states.³¹ The regulation is set to be implemented rather quickly, with Phase 1 starting on January 1, 2012, and Phase 2 beginning January 1, 2014. To facilitate this schedule, the EPA is using Federal Implementation Plans (a federal regulation that the states must follow).³² The states do have the ability to submit State Implementation Plans (SIPs) to replace the federal plans for compliance beginning in 2013, and, importantly, may propose applicability down to a nameplate capacity of 15 MW.³³

State Emissions Budgets (Allowance Allocations)

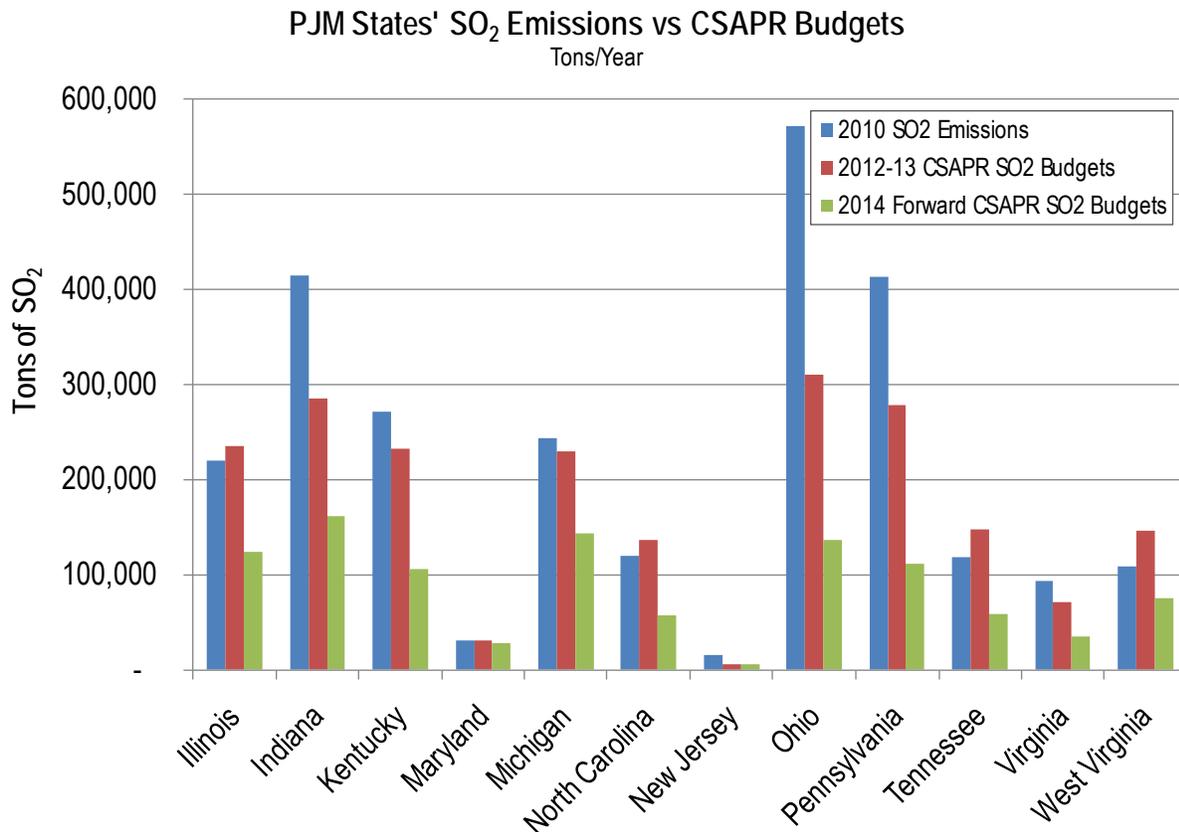
CSAPR limits emissions from each state based their contribution to air pollution transport and contribution non-attainment of the fine particulate and ozone NAAQS at assumed cost thresholds reduction SO₂ or NO_x emissions.³⁴ The rule separates states into two groups for SO₂ reductions based upon their contribution to non-attainment. Group 1 states have larger contributions to non-attainment and therefore have greater SO₂ reductions that must be made by 2014. Group 2 states have smaller contributions and their emissions reductions are not as great as those of Group 1 states.³⁵ All affected

states in PJM are Group 1 states.. CSAPR also separates NO_x emissions into two categories based on Annual and Ozone Season emissions. All affected PJM states are subject to both Annual and Ozone Season NO_x emissions limits.

The CSAPR incorporated updated emissions inventories and revised modeling due to comments received in response to the proposed rule. Incorporated in the final Integrated Planning Model were corrections to the heat rates and emissions rates used for cogeneration units; use of 2009 data for nitrogen oxide emissions rates rather than 2007 data; correction to an out-of-date decision rule for determining nitrogen oxide emissions rates; revised sulfur dioxide removal rates for flue gas desulfurization (FGD) controls based on historical performance data rather than on engineering design data; limitations to unrestricted switching from bituminous to sub-bituminous coal; limitations on short-term coal switching; and corrections to the prices of waste coal.³⁶ This in turn changed the impact of upwind states on downwind states, and the subsequent allowance allocations (budgets) to affected states. The allocations were also affected by the change in the allocation methodology to heat input-based, which reduced the allocations from the proposal.³⁷

Figure 1 shows the 2012-2013 state budgets for SO₂ for affected PJM states alongside 2010 state level emissions in those states.³⁸ Figure 1 shows Indiana, Ohio, and Pennsylvania require significant emissions reductions (over 100,000 tons each) beginning in 2012-2013. All PJM states affected by the rule will face significant reductions from 2010 levels by 2014.

Figure 1: State Sulfur Dioxide Budgets under CSAPR



Figures 2 and 3 show state budgets for Annual and Ozone Season NO_x emissions alongside 2010 Annual and Ozone Season emissions.³⁹ Figures 2 and 3 show the amount of required emissions reductions from 2010 levels are much smaller in absolute terms, and in general much more constant over the 2012-2014 period, than the SO₂ reduction levels.

The emissions budgets (allowance allocations) are not set in stone, however. EPA established procedures to update the CSAPR rule after revisions to NAAQS. The next revision due is to the ozone NAAQS, which was expected in July, but was delayed to later this year. The EPA stated in the CSAPR rule that it “anticipates that additional upcoming actions, including likely additional interstate transport reductions to help states attain the upcoming new ozone NAAQS, will result in significant additional nitrogen oxide reductions in the future.”⁴⁰ EPA also stated that it “is mindful of the need for SIPs to provide for continuing ozone progress to meet the 75 ppb level of the 2008 NAAQS, or possibly lower levels based on the reconsideration.”⁴¹ This likely translates to tighter restrictions on nitrogen oxide emissions, a precursor to ozone, which in turn may result in more units requiring selective catalytic reduction, selective non-catalytic reduction or other similarly performing control technology to meet these nitrogen oxide restrictions.

Figure 2: State Annual Nitrogen Oxide Budgets under CSAPR

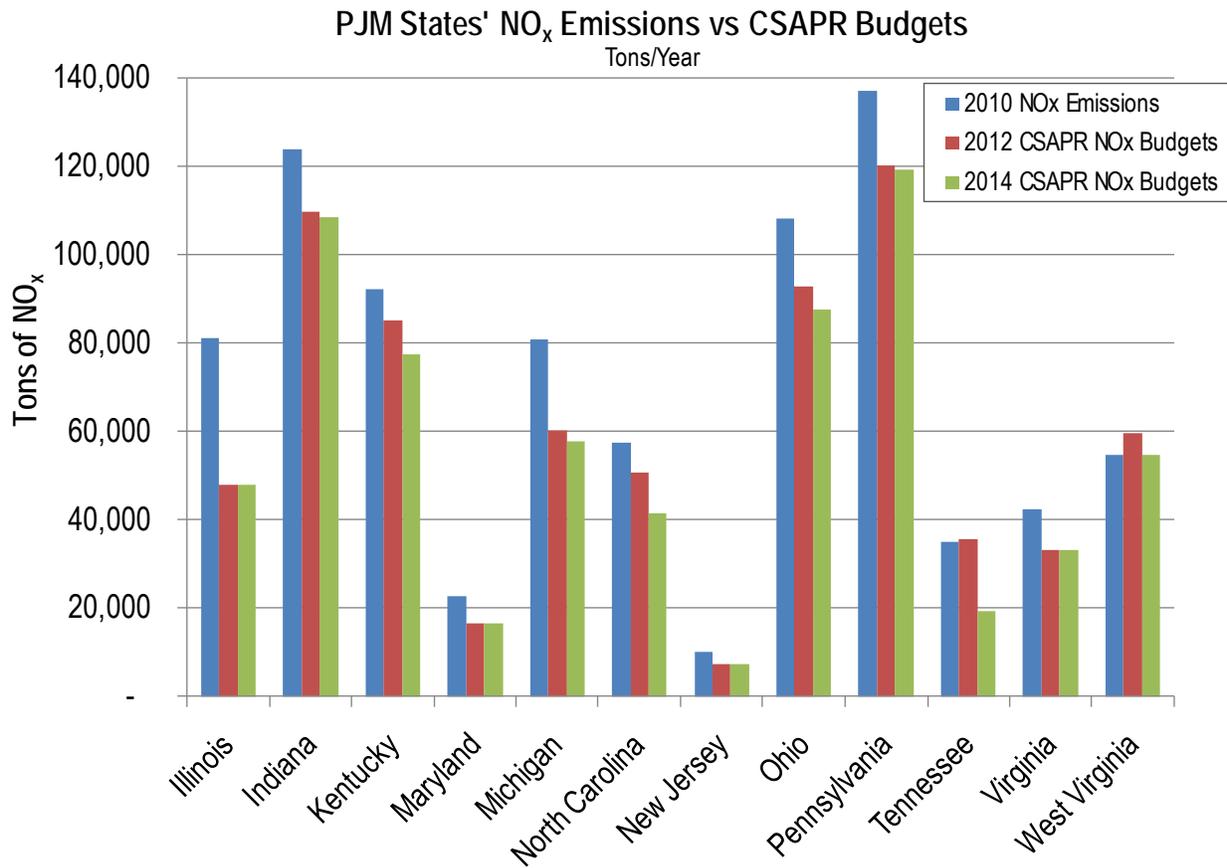
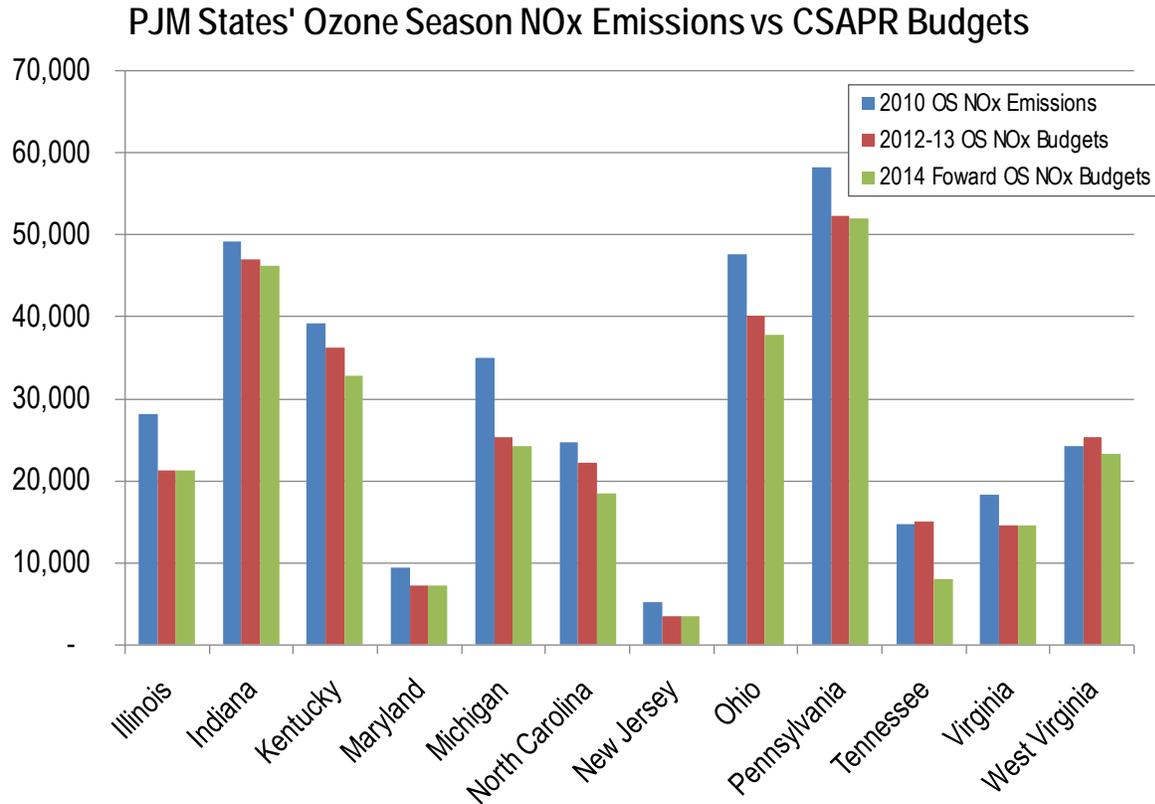


Figure 3: State Nitrogen Oxide Ozone Season Budgets under CSAPR



Emissions Trading

CSAPR creates four separate allowance trading programs – Annual NO_x, Ozone Season NO_x, Group 1 SO₂ (a more stringent group comprised of 16 states), and Group 2 SO₂ (a more moderate group comprised of seven states). As such, EPA's state budgets do not utilize CAIR allowances, and in contrast to CAIR, do not allow Title IV SO₂ allowances to be used.⁴² Similarly, CSAPR SO₂ allowances will not be valid in the Acid Rain Program.

All allowances are to be allocated to existing and new sources. For the 2012 Federal Implementation Plan there will be potential to auction allowances. For State Implementation Plans beginning in 2013, states may also decide whether to re-allocate allowances among the covered units, allocate to other entities, such as renewable energy facilities, or auction the allowances.⁴³ Additionally, the EPA modified the rule so that if a unit ceases operations for two years, it will only receive allocations for two years past the two non-operating years, instead of for three years after three non-operating years that was proposed.⁴⁴

CSAPR allows for interstate trading of allowances between sources so long as at the end of the compliance period (calendar year or Ozone Season) emissions do not exceed the overall cap, and for each state, emissions do not exceed the state allowance budget plus a variability limit. The EPA refers to this rule as an "air quality assured trading program".⁴⁵ CSAPR defines variability limits, which are a fixed amount of emissions over the state budget that may be emitted each year; however, based on the inherent variability in emissions from electricity generators due to changes in dispatch driven by fuel price differentials or patterns of demand from one year to the next.⁴⁶ If the state budget plus the variability limit is

exceeded, assurance provisions are triggered. Assurance provisions require covered units in the state that exceeded their budget to submit two allowances for every ton of their share of the emissions exceedance.⁴⁷

National Emission Standards for Hazardous Air Pollutants Rule

On March 16, 2011, the EPA proposed the *National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units* also known as the NESHAP Rule. The proposed NESHAP Rule requires coal-fired steam and solid fuel oil (petroleum coke) steam generators to meet an emissions rate standard, based on the maximum achievable control technology (MACT), for mercury, hydrogen chloride (HCl) and total particulate matter (PM), with HCl being a surrogate for all acid gases and PM being a surrogate for non-mercury heavy metals.⁴⁸ NESHAP also requires liquid oil fired steam generators to meet limits on total HAP metals (including mercury), HCl and hydrogen fluoride (HF). The proposed rule controls emissions of dioxins/furans and other organic HAPs for all five subcategories through work practice standards rather than emission standards. EPA is proposing numerical emission limits for Hg, particulate matter (PM), HCl, and HF as surrogates for the larger group of hazardous air pollutants that must be controlled under *Clean Air Act § 112(d)*.

Under *Clean Air Act § 112(d)*, existing coal- and oil-fired electric generating units have three years after the proposed *NESHAP Rule* is finalized to comply with the emissions limits. The anticipated compliance deadline is January 1, 2015. An additional (fourth) year to comply may be granted by the local (state) permitting authority effectively pushing the compliance deadline for units granted an extension to January 1, 2016. Because the emissions standards proposed in NESHAP are based on the MACT standard, the rule effectively requires affected generating units to install pollution control technologies in some combination that will result in emissions rates at or below the standards. PJM provided comments to the EPA regarding the compliance timeframe in the proposed NESHAP Rule, and the necessity for the EPA to provide a vehicle for targeted case-by-case compliance extensions where warranted by the time required to address any bulk power grid reliability issues.⁴⁹

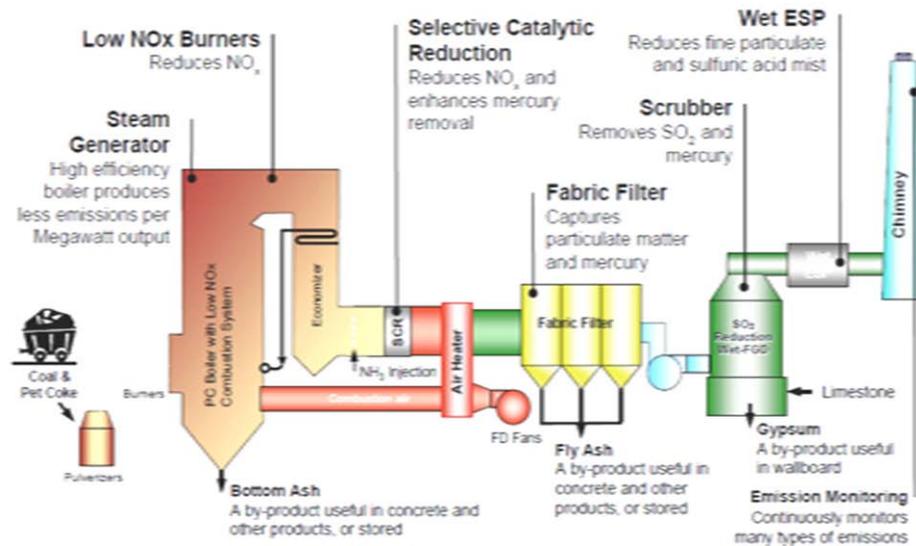
The proposed NESHAP rule employs five subcategories of standards depending upon the characteristics of fuel burned by the affected generating unit, and by combustion technology: one for units firing coal with a heating value $\geq 8,300$ Btu/lb, one for units firing coal (lignite) with a heating value $< 8,300$ Btu/lb), one for units firing liquid oil, one for units firing solid oil-derived fuel, and one for integrated gasification combined-cycle units. Additionally, the proposed NESHAP rule allows emissions averaging among similar units at the same facility, the ability to use surrogates to monitor emissions compliance: hydrogen chloride for acid gases and particulate matter for hazardous metals, the designation of five separate subcategories with tailored limits, and separate monitoring provisions for limited use oil-fired units.

Overview and Costs of Pollution Controls Likely Required for Compliance

Figure 4 provides a graphic overview of the range of pollution control technologies that are likely to be installed in response to the CSAPR and the NESHAP Rule. Many of the pollution control technologies represented in Figure 4 can serve to help coal-fired generation to meet the emissions reduction requirements of both rules. For example, scrubbers, also known as Flue Gas Desulfurization (FGD), can achieve sulfur dioxide removal rates of up to 98 percent, which help reduce sulfur dioxide emissions targeted by the CSAPR.⁵⁰ At the same time, FGDs also aid in the removal of acid gases and mercury that is targeted by the NESHAP Rule. Of all the control technologies that coal-fired generation may need to install, FGDs are the most capital intensive as can be seen in Tables 2 and 3 below.⁵¹

A lower capital cost option to FGDs is known as dry sorbent injection (DSI). While having a lower capital cost (about one-tenth of an FGD at a 500 MW unit size), DSI has higher variable operation and maintenance (VOM) costs as seen in Tables 2 and 3.⁵² DSI is not as effective at sulfur dioxide removal, achieving only up to 50 percent removal efficiencies for generally medium to lower sulfur coals.⁵³ DSI can also be employed to reduce acid gases and mercury under the NESHAP Rule, but would need to be accompanied by the installation of a baghouse in order to meet particulate emission standards that are already in place and to further help reduce mercury emissions.⁵⁴

Figure 4: Representation of Pollution Control Retrofits⁵⁵



Source: Brattle Group

Selective Catalytic Reduction (SCR) as shown in Figure 4 is designed to remove nitrogen oxide emissions that are targeted by the CSAPR. In addition, SCR can provide co-benefits in mercury removal to the extent that if it is paired with an FGD, it should not be necessary to use other controls for mercury removal under the NESHAP Rule.⁵⁶ SCRs typically achieve 70-80 percent removal efficiencies for nitrogen oxides.⁵⁷

An alternative to SCR is Selective Non-Catalytic Reduction (SNCR), which has a lower cost than SCR as seen in Tables 2 and 3, but also has lower nitrogen oxide removal efficiencies (typically 25-35 percent).⁵⁸ SNCR, unlike SCR, does not have co-benefits with respect to mercury removal.

Finally, a fabric filter (also known as a baghouse), as shown in Figure 1, in combination with activated carbon injection (ACI) can be used to help reduce mercury and other heavy metal emissions from coal-fired generation to meet the requirements of the NESHAP Rule, as well as complement DSI as mentioned above. Fabric filters in combination with ACI have capital costs similar to SCRs as shown in Tables 2 and 3.⁵⁹ The ACI cost component is less than one-tenth the cost of the fabric filter.

Table 2: Pollution Control Retrofit Costs for a Representative 500 MW Coal Unit⁶⁰

Control Technology	Capital Cost (\$/kW)	Fixed O&M (\$/MW-yr)	Variable O&M (\$/MWh)
FGD	\$501	\$8,150	\$1.81
DSI	\$40	\$590	\$7.92
SCR	\$197	\$720	\$0.66
SNCR	\$19	\$260	\$1.33
Fabric Filter + ACI	\$155+\$9	\$630+\$40	\$0.15+\$0.93

While Table 2 provides a snapshot of pollution control costs for a representative 500 MW unit, pollution control retrofit capital costs, fixed O&M, and to some extent variable O&M vary with the size of the unit in question. In general, there are economies of scale in retrofit installations, with smaller units facing larger capital costs per kW of capacity, larger fixed O&M costs per MW of capacity, and potentially higher variable costs per MWh of generation output. The implication is that smaller coal-fired units will face greater costs per unit of capacity than larger units that can take advantage of economies of scale in retrofit installation and operation.

Table 3 shows an estimated range of pollution control retrofit costs for coal-fired units in PJM that are derived from cost models developed for the EPA and used in their analyses of the CSAPR and the NESHAP Rule. These cost estimate ranges reflect PJM analysis to determine which pollution control retrofits would be necessary for each coal-fired generator to continue operating while simultaneously complying with the CSAPR and NESHAP rules. Table 3 clearly shows the wide range of costs depending on a unit's size, with the estimates at the higher end of the ranges applying to small units and the lower costs applying to large units.

These higher costs mean that small units will require greater revenues per MW of capacity to pay for pollution control retrofits than will large units. From this fact alone, one may draw the conclusion that smaller coal-fired units in need of major pollution control retrofits will be at greater risk for retirement due the CSAPR and NESHAP rules than will larger units in need of similar retrofits, but which can take advantage of economies of scale. Moreover, given large ranges seen in Table 3, pollution control retrofit costs are unit specific based on size, and no doubt with respect to other factors that only unit owners are aware, making it difficult to draw more specific or definitive retrofit or retire conclusions based on the cost estimates alone. An understanding of the available revenues to cover these costs is also necessary.

Table 3: Pollution Control Retrofit Cost Estimate Ranges for Coal Generation in PJM⁶¹

Control Technology	MW Size Range	Capital Cost (\$/kW)	Fixed O&M (\$/MW-yr)	Variable O&M (\$/MWh)
FGD Range	28-1,300 MW	\$331-\$1,149	\$1,580-\$44,710	\$1.01-\$3.81
(Average)	(211 MW)	(\$677)	(\$12,100)	(\$1.93)
DSI Range	43 – 1,320 MW	\$9-\$273	\$170-\$5,670	\$2.00-\$15.54
(Average)	(408 MW)	(\$89)	(\$1,780)	(\$5.71)
SCR Range	16 – 554 MW	\$175-\$427	\$550-\$15,600	\$0.20-\$1.41
(Average)	(161 MW)	(\$263)	(\$4,130)	(\$0.47)
SNCR Range	45 – 1,300 MW	\$11-\$136	\$140-\$4,900	\$0.34-\$2.16
(Average)	(256 MW)	(\$48)	(\$1,190)	(\$1.12)
Fabric Filter + ACI Range	16 – 1,320 MW	\$118-\$468	\$520-\$9,340	\$0.52-\$1.59
(Average)	(299 MW)	(\$225)	(\$1,990)	(\$1.09)

In order to place the pollution control retrofit costs in Tables 2 and 3 into context, it is helpful to view them in comparison to the costs to build and operate new natural gas combustion turbines and combined cycle units. In a paradigm in which generation remains traditionally regulated, the cost of building new gas generation would likely be compared to the cost of environmental retrofits to see which is more cost-effective. In a wholesale market environment such as PJM, a comparison of costs of new gas generation to the cost of retrofits provides a market-based benchmark to determine whether retrofitting existing coal-fired generation is cost-competitive with new entry gas resources. Such a market-based benchmark provides some indication of which coal units are at greater risk for retirement if they are not cost competitive with new entry gas resources. Table 4 provides a range of cost estimates for new natural gas simple cycle (no steam generator) combustion turbines and combined cycle (include a heat recovery steam generator) combustion turbines recently developed for PJM and supplemented with information from a recent Energy Information Administration study on the cost of new build generation technologies.⁶²

Table 4: Costs of New Entry Natural Gas Technologies

	Capital Cost (\$/kW)	Fixed O&M (\$/MW-yr)	Variable O&M (\$/MWh)
Simple Cycle CT	\$665-\$975	\$6,700-\$6,980	\$9.87-\$14.60
Combined Cycle CT	\$1,000-\$1,150	\$21,600	\$3.23

For a representative 500 MW unit with retrofit costs as described in Table 2, it appears that installing an FGD and SCR retrofit that would comply with both CSAPR and the NESHAP rules would be cost competitive with new entry gas technologies on a capital and fixed O&M cost basis alone. For smaller units it is not clear that installing a full suite of retrofits necessary to comply with the CSAPR and the NESHAP rules is cost competitive. For example, it would appear that for smaller units, installing an FGD and SCR is higher cost than a new entry combustion turbine on a capital and fixed O&M cost basis. However, if smaller units could install a different combination of technologies such as DSI, SNCR, and baghouse in combination with ACI, a unit could meet the NESHAP requirements and remain cost competitive with new entry gas generation on a capital and fixed O&M cost basis, but the sulfur dioxide and nitrogen oxide emissions reductions for CSAPR would not be nearly as great, and would leave smaller units more exposed to potentially high allowance prices and by extension higher running costs.

While cost comparisons provide a useful indicator, they are not dispositive. Ultimately, retrofit or retirement decisions will be based on costs, as well as on the potential to earn revenues in wholesale markets in the future. Part of the potential to earn revenues into the future depends upon the overall market environment.

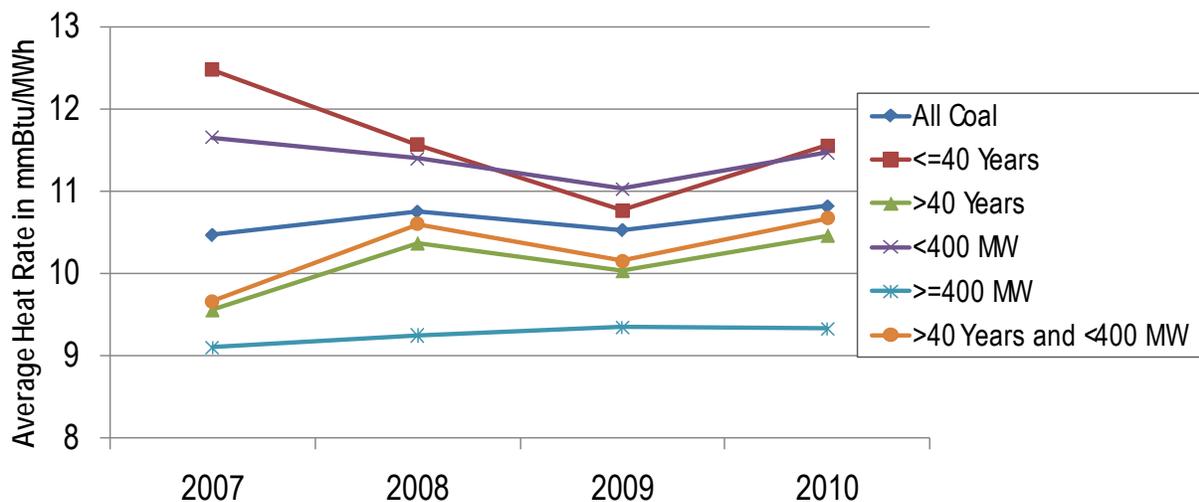
Economic Environment Influencing Retrofit, Repower, and Retirement Decisions

Coal-fired generation can cover its going forward operating costs, inclusive of returns on new investments made in generation plant such as emissions control retrofits, through a combination of net energy and ancillary service market revenues and through capacity market revenues. Net energy market revenues for a coal-fired unit are driven by a combination of three main factors: 1) The efficiency of the unit as measured by its heat rate; 2) the average hourly demand for energy; and 3) the spread between coal and natural gas prices.

Efficiency of Coal Units by Age and Size and the Effect on Net Energy Market Revenues

The efficiency of the coal-fired generating unit determines the order in which it will be dispatched for energy relative to other coal-fired units facing similar fuel prices, and has a bearing on the order in which it will be dispatched relative to other generating units using other fuels, such as natural gas. Units that are more efficient should be dispatched more often, and therefore earn higher net energy and ancillary service market revenues compared to their less efficient counterparts. Those more efficient units then have greater opportunity to cover the cost for pollution control retrofits. Intuitively, one would expect smaller and older generating coal-fired units, all else being equal, to operate at lower efficiencies (higher heat rates) regardless of other market conditions. Figure 5 shows that units in excess of 400 MW in size, regardless of age, operate at lower heat rates (greater efficiency), and are approximately 20 percent more efficient than units less than 400 MW in size regardless of age. Figure 5 also shows that for units more than 40 years old, units less than 400 MW in size are also less efficient than the average for their age class. Overall, smaller and older coal-fired units are likely to be dispatched less often and therefore earn lower net energy and ancillary service market revenues that can be used to cover costs of pollution control retrofits.

Figure 5: Gross Heat Rate of Coal-fired Generation by Age and Size: 2007-2010⁶³

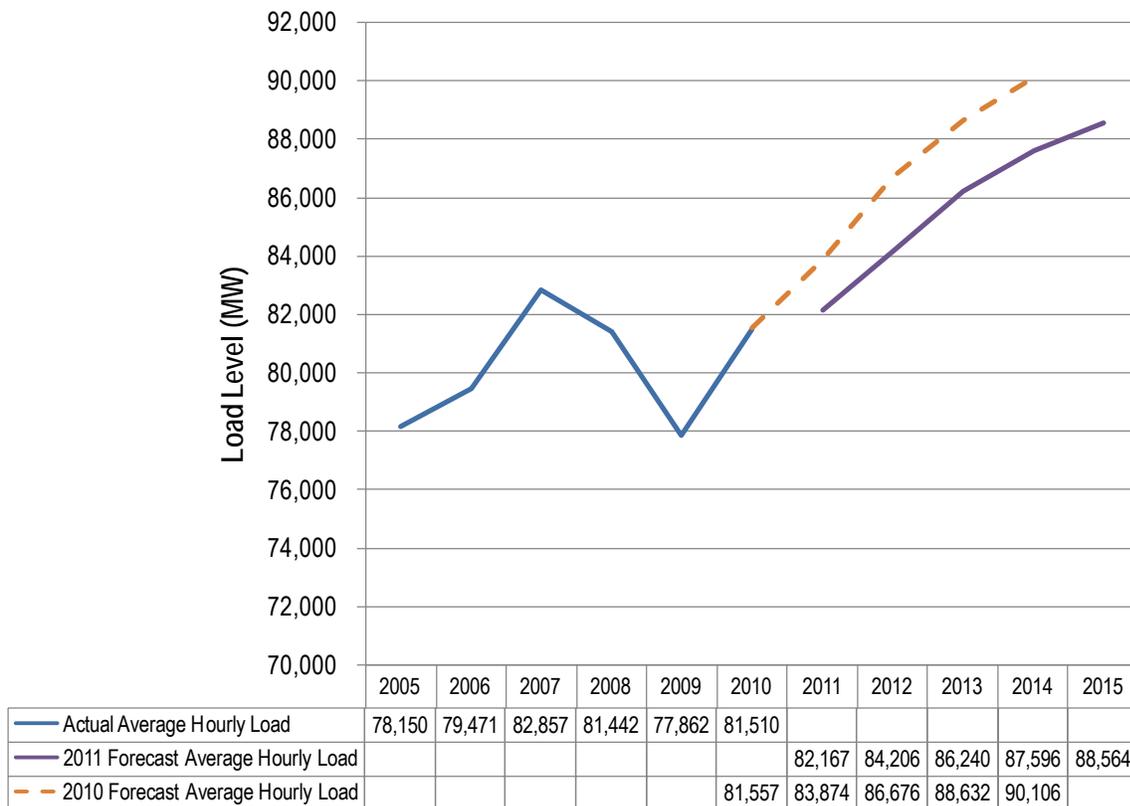


Trends in Average Hourly Demand and the Impact on Net Energy Market Revenues

The average hourly demand for energy is also a driver for net energy and ancillary service market revenues for coal-fired units. The higher the average hourly demand, the more expensive and/or less efficient the marginal unit for energy will be to balance supply and demand on the system, and a higher market clearing price for energy. All else equal, the higher energy demand leads to greater net energy and ancillary service market revenues through higher energy prices. Less efficient coal-fired units benefit from higher demand in that they will be dispatched more often than would be the case with lower average hourly demand, leading to higher net energy and ancillary service market revenues.

For the 2007-2010 period, we can see the declining average hourly demand in 2008 and 2009 due to the recession, and slight bounce back in 2010 as shown in Figure 6.⁶⁴ The forecasts for average hourly demand have fallen significantly from 2010 to 2011, showing an average load 2,500 MW lower in each hour in 2014, reflecting the continued expectation of a slow economic recovery. The implication is that if forecasts of average hourly demand remain low, then the expectation is that net energy revenues will be lower in future years for all coal-fired units, all else equal. In addition, this effect is magnified for smaller and older coal-fired units since they will also likely be dispatched less often relative to expectations of higher average hourly demands shown in Figure 6.

Figure 6: PJM Average Hourly Loads: Actual and Forecast



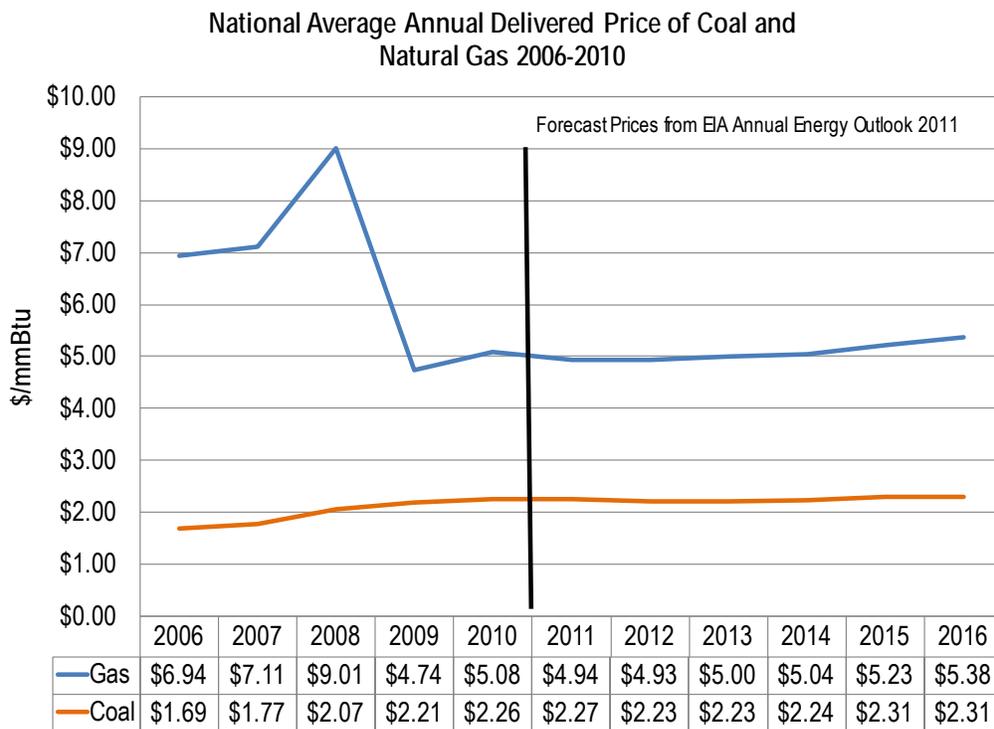
Coal-Natural Gas Price Spreads and the Effect on Net Energy Market Revenues

Net energy and ancillary service market revenues for coal-fired generation will also be affected by the spread between coal and natural gas prices. Historically during peak periods, natural gas fired generation is the marginal unit type dispatched by PJM to balance supply and demand and therefore determines the price of energy during those periods. The higher the gas

price, the higher will be energy prices during peak periods, and given the cost of coal, the higher will be net energy market revenues for coal generation. For less efficient coal-fired units, a large coal-natural gas price spread implies they will be dispatched ahead of natural gas generation, whereas a small coal-natural gas price spread may result in combined cycle natural gas generation being dispatched ahead of inefficient coal units given the efficiency advantage of combined cycle gas.

The spread between coal and natural gas prices has fallen significantly, from over \$5.00/mmBtu in 2006-2008 to \$2.50-\$2.80/mmBtu in 2009 and 2010. As forecasted by the Energy Information Administration in its *2011 Annual Energy Outlook* the spread will remain below \$3.00/mmBtu through 2015 as shown in Figure 7.⁶⁵ The decreasing coal-natural gas spread means lower net energy market revenues for all coal units, including large, base-load coal units, in every hour they operate. For smaller, older coal units that are less efficient, they may actually be displaced by natural gas units in addition to earning smaller margins when they do operate.

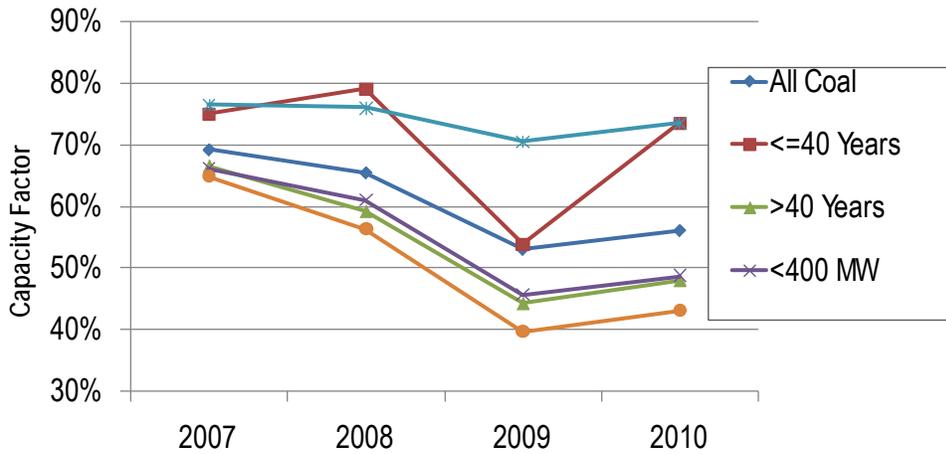
Figure 7: Actual and Forecast Coal-Natural Gas Price Spreads



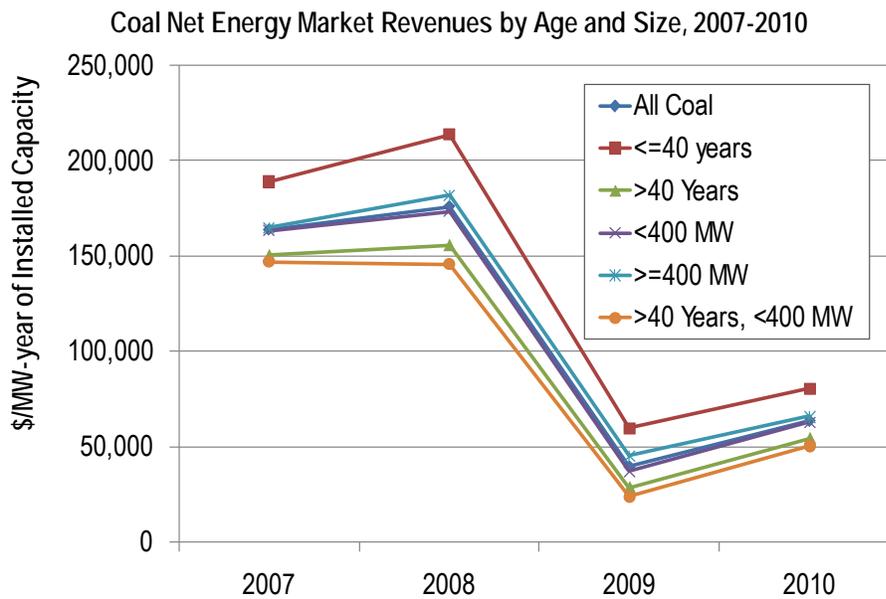
Cumulative Effect on Capacity Factors and Net Energy Market Revenues by Age and Size

The cumulative effect of the declining average hourly demand and spread in coal and natural gas prices have led to a decline in coal-fired generation capacity factors (units running fewer hours) for smaller and older units that are less efficient as seen in Figure 8.⁶⁶ Coal-fired generation that is less than 400 MW in size and more than 40 years old saw its capacity factor decline from approximately 65 percent in 2007 to just over 40 percent in 2010. In stark contrast, units greater than 400 MW in size, regardless of age, saw a relatively small decline in their capacity factors. The reduced average hourly demand and narrowed coal-natural gas price spread has adversely affected the utilization of smaller, older units, which will have a considerable downward impact on net energy and ancillary service market revenues.

Figure 8: Coal Capacity Factors by Age and Size 2007-2010



While larger units have not seen an appreciable erosion in utilization with the changing electricity demand and fuel price conditions, these conditions also have led to declining net energy market revenues based on reduced margins in the hours they do run. Figure 9 shows that all coal units saw a dramatic fall in net energy market revenues for the 2009-2010 period after much higher revenues in 2007-2008 when both average hourly demand fell and the coal-natural gas price spread narrowed. However, Figure 9 shows that larger coal units, greater than 400 MW in size, still held an advantage in terms of net energy market revenues on dollars per MW year basis with 30-50 percent higher net energy market revenues in 2009-2010 compared to coal-fired units that are more than 40 years old and less than 400 MW in size.

 Figure 9: Net Energy Market Revenues by Age and Size⁶⁷


Given the recent history of demand and coal-natural gas price spreads, along with forecasts for lower demands than previously expected and the forecast coal-natural gas price spread, the net energy market revenue outlook for older and

smaller coal units that continue operating does not appear as attractive as it was during 2007-2008 with higher demands and higher gas prices. The prospects of lower net energy market revenues in the presence of environmental rules that would require significant capital investment will make it more difficult to cover the costs of necessary future environmental retrofits.

Examination of Pollution Controls Currently in Operation as a Screen for Coal-fired Capacity at Risk

As noted in the preceding two sections, smaller, older coal-fired generation is seemingly at greater risk for retirement due to the CSAPR and NESHAP rules than larger units because they are less efficient on average. These units have higher retrofit costs per unit of capacity due to economies of scale, and lower net energy and ancillary service market revenues on average. Coal-fired generating units will only be at risk due to the CSAPR and NESHAP if they do not yet have pollution control technologies installed and in-service, and would have to make capital expenditures to comply with these rules.

Table 5 provides the composition of coal-fired capacity in PJM as of June 30, 2011, inclusive of generation in the recently integrated ATSI zone, the soon to be integrated DEOK (Duke Ohio and Kentucky) zone, and capacity resources external to PJM.⁶⁸ These capacity figures do not include 2,799 MW of coal-fired capacity that has already deactivated since January 1, 2009 or has filed to be deactivated by as late as January 1, 2015.

Capacity is broken down by age and size and broad locations reflecting major west-to-east transmission constraints: the Mid-Atlantic region (MAAC) and the rest of the RTO. Table 5 shows there is just over 78,000 MW of summer net dependable coal-fired, installed capacity in PJM. With the focus on smaller and older units “at greatest risk”, it is notable that approximately 23,000 MW (29.5 percent) are less than 400 MW in size and more than 40 years old. One-third of coal-fired capacity is less than 400 MW in size regardless of age.

Table 5: Composition of Coal-fired Capacity in PJM by Age, Size, and Location

	PJM RTO	MAAC	Rest of PJM
Total Coal	78,613	18,761	59,852
Coal > 40 years	41,815	12,334	29,481
Coal < 400 MW	26,645	7,162	19,483
Coal > 40 years, < 400 MW	22,907	5,769	17,138

The breakdown of capacity by region is such that roughly one-quarter coal-fired capacity is in the Mid-Atlantic (MAAC) and the remainder is in the rest of the RTO. As mentioned previously, PJM expects older and smaller units would likely have greater costs per unit of capacity for emissions control retrofits and consequently would require higher RPM or Energy Market revenues to continue operating. Additionally, uncontrolled units in the MAAC region may have a greater impact on transmission reliability and congestion than in the rest of the RTO, and therefore may warrant additional attention.

The precise number of megawatts requiring emission control retrofits is difficult to identify because CSAPR is a limited cap and trade rule with some flexibility and the NESHAP rule mandates emission rate standards for acid gases, mercury, and non-mercury heavy metals that can potentially be met by different combinations of emissions control technologies. What

does seem clear is that some sort of SO₂ and particulate technology would be required to comply with the NESHAP rule that will also provide co-benefits toward meeting the requirements under CSAPR.

Composition of Coal-Fired Capacity without at least One Control Technology

In general, the fewer controls that need to be installed, the lower the costs that must be incurred to comply with the proposed EPA rules if a coal unit wishes to continue operating beyond the proposed NESHAP compliance deadline of January 1, 2015, and be available to operate at high capacity factors under the CSAPR. Table 6 shows the amount of coal-fired capacity without technologies to control sulfur dioxide emissions such as FGD and DSI, or that uses circulating fluidized bed (CFB) combustion technology.⁶⁹

Table 6: Coal-Fired Capacity in PJM without Sulfur Dioxide Controls by Age, Size and Location

	PJM RTO	MAAC	Rest of PJM
Total Coal	30,069	4,281	25,788
Coal > 40 years	24,217	3,794	20,423
Coal < 400 MW	17,444	2,617	14,827
Coal > 40 years, < 400 MW	17,387	2,560	14,827

The presence of sulfur dioxide controls, or lack thereof, is indicative of potentially large costs that may need to be incurred by coal-generation to comply with the NESHAP rule for acid gas and mercury reductions, and achieve significant sulfur dioxide reductions that would allow the unit to operate at higher capacity factors under the CSAPR. A total of only 38 percent of coal generation in PJM does not yet have in service some kind of sulfur dioxide control. Yet, nearly 76 percent of smaller, older coal units do not possess any sulfur dioxide controls, and these units account for more than half of the total capacity that does not possess sulfur dioxide controls. By region, MAAC only has 2,500-2,600 MW of smaller, older capacity without sulfur dioxide controls, or 14 percent of the total capacity less than 400 MW and more than 40 years old without sulfur dioxide controls.

In many cases fabric filters appear to be necessary to comply with the NESHAP rule to aid in the control of mercury emissions, or to help offset the increased particulate emissions from the use of ACI for mercury, or DSI for acid gases. Table 7 provides the breakdown of coal-fired capacity that does not have a fabric filter installed.⁷⁰ Almost 88 percent of coal-fired capacity does not have a fabric filter installed, with the same percentage of smaller, older units also currently operating without a fabric filter. However, fabric filters appear to be slightly more prevalent in the eastern part of PJM (MAAC) than in the rest of the RTO, with smaller and older units in MAAC accounting for only 18 percent of the total capacity less than 400 MW and more than 40 years old without a fabric filter.

Table 7: Coal-Fired Capacity in PJM without Fabric Filters by Age, Size and Location

	PJM RTO	MAAC	Rest of PJM
Total Coal	69,115	13,020	56,095
Coal > 40 years	37,796	9,736	28,060
Coal < 400 MW	21,035	3,786	17,249
Coal > 40 years, < 400 MW	20,104	3,729	16,375

As discussed above, even if coal-fired generators wished to install lower cost sulfur dioxide controls such as DSI, and also install ACI to control mercury, a fabric filter installation would most likely be necessary to achieve the proposed emission rate standards under the NESHAP Rule, while ensuring there was no increase in particulate emissions.⁷¹

Selective catalytic reduction (SCR) is not essential for complying with the NESHAP rule, but the large reductions in nitrogen oxide emissions allow coal-fired generation to operate at higher capacity factors given the stringent caps under the CSAPR. As mentioned above, an SCR in combination with an FGD can most likely meet the acid gas and mercury emissions standards under the NESHAP Rule without the need to install ACI or a fabric filter. Table 8 shows composition of coal capacity without an SCR installed.⁷²

Table 8: Coal-fired Capacity in PJM without Selective Catalytic Reduction by Age, Size and Location

	PJM RTO	MAAC	Rest of PJM
Total Coal	36,618	8,805	27,813
Coal > 40 years	26,481	6,905	19,576
Coal < 400 MW	21,818	5,405	16,413
Coal > 40 years, < 400 MW	18,762	4,456	14,306

Only 46 percent of coal-fired capacity across the RTO does not have installed SCR, but for smaller, older units, almost 82 percent doesn't have installed SCR for the control of nitrogen oxides. Of the smaller, older units without SCR, only 24 percent reside in MAAC with the remainder in the rest of the RTO.

Composition of Coal-fired Capacity Lacking More than One Control Technology

Coal-fired generation requiring the installation of more than one of the more expensive pollution control technologies is arguably at greater risk for retirement than requiring the installation of only one technology. For example, while SCR may not be required to comply with the NESHAP Rule, it does provide co-benefits with an FGD for mercury reductions and reduces nitrogen oxide emissions, which are capped under the CSAPR, and should allow the unit to operate more in the energy market, thus earning more revenue to pay for controls. Alternatively, a coal unit may elect to install a combination of DSI and a fabric filter to comply with the NESHAP Rule, and may forego installing an SCR in favor of a lower cost SNCR in the belief that the additional cost of an SCR is more than the revenues it could earn by running additional hours.

Table 9 presents the composition of coal capacity that does not have sulfur dioxide controls *and* does not also have a fabric filter.⁷³ Almost 63 percent of coal capacity within PJM has at least a sulfur dioxide control or a fabric filter, but given the information in Tables 6 and 7, it is most likely the case that a sulfur dioxide control is installed rather than a fabric filter.

Table 9: Coal-Fired Capacity in PJM without Sulfur Dioxide Controls and Fabric Filter by Age, Size and Location

	PJM RTO	MAAC	Rest of PJM
Total Coal	29,457	3,756	25,701
Coal > 40 years	23,605	3,269	20,336
Coal < 400 MW	16,832	2,092	14,740
Coal > 40 years, < 400 MW	16,775	2,035	14,740

The set of smaller, older coal units without both controls is smaller than the capacity requiring just one control. However, 96 percent of coal capacity less than 400 MW and more than 40 years old that does not have sulfur dioxide controls also does not have a fabric filter installed. The implication from Table 9 and Table 6 is that almost 17,000 MW of coal capacity that is smaller and older will require multiple pollution control retrofits to comply with the NESHAP rule. The question then remains as to what combination of controls would be installed if these coal units decide to continue operating in compliance with the NESHAP Rule rather than retire, considering the caps on sulfur dioxide emissions under the CSAPR. Without considering controls for nitrogen oxide emissions and the possible co-benefits for mercury reduction, the decision on installing DSI or FGD will rest upon whether the coal unit owner believes the incremental costs of FGD over DSI are less than the additional energy market revenues the unit may earn by being able to further reduce sulfur dioxide emissions to allow it to run profitably in more hours under the CSAPR.

Table 10 shows the coal capacity in PJM that does not have installed both sulfur dioxide controls *and* SCR for nitrogen oxide reductions.⁷⁴ As has been discussed, the combination of an FGD for sulfur dioxide and SCR for nitrogen oxide reductions would allow a coal unit to run more hours given the caps under CSAPR, while also being able to achieve the emissions rate standards under the NESHAP Rule.

Table 10: Coal-Fired Capacity in PJM without Sulfur Dioxide Controls and SCR by Age, Size and Location

	PJM RTO	MAAC	Rest of PJM
Total Coal	22,866	2,723	20,143
Coal > 40 years	17,644	2,236	15,408
Coal < 400 MW	14,598	2,293	12,305
Coal > 40 years, < 400 MW	14,541	2,236	12,305

RTO-wide, only 29 percent of all coal capacity lacks both a sulfur dioxide control and SCR. However, 63 percent of smaller, older units lack both an SCR and some type of sulfur dioxide control. Again, a sulfur dioxide control like an FGD or DSI will be necessary to reduce acid gas emissions targeted under the NESHAP Rule, but an SCR is a control that would allow a unit to run more often under the nitrogen oxide caps of the CSAPR. The decision by unit owners on the combination of controls to install, given a decision to continue operating, will depend upon the unit owner's assessment of what would make the most sense from a financial standpoint.

Assessment of Coal Capacity at Risk Based on Pollution Control Status

Given the economies of scale in the costs of pollution control retrofits, and the historical evidence of lower net energy market revenues for smaller and older units, the need to install any type of pollution control retrofit for these units less than 400 MW and more than 40 years old places such a unit at some risk for retirement. In the class of units less than 400 MW and more than 40 years old, there are at least 20,000 MW lacking a key control (fabric filter) as shown in Table 7. As much as 4,400 MW of that smaller, older capacity located east of the west-to-east transmission constraints in PJM may require some additional retrofit as shown in Table 8.

Still, units that require more than one pollution control retrofit are likely at an even greater risk for retirement because additional controls will increase costs and further diminish the financial viability of continuing in commercial operation beyond January 1, 2015. By this metric, there are nearly 17,000 MW of smaller, older coal units that lack sulfur dioxide controls and a fabric filter.

While an examination of control status by age and size is indicative of the risk of retirement, it is not dispositive as there may be conditions at some of these smaller, older units that PJM cannot observe that would allow the unit to retrofit with a lower cost. For example, a group of small units sharing a common stack could be retrofit more efficiently than the same size units on separate stacks. There may also be conditions at larger units that would make it unattractive or infeasible to install retrofits that cannot be observed by PJM, putting such units at risk for retirement.

Finally, while average cost and revenue trends can be discerned for units of different ages and sizes to provide an intuitive indication of which coal units would be at risk for retirement by control status, the ultimate driver for the retrofit/retirement decision will be the specific economic conditions faced by each unit owner. Such conditions include the location, availability, and unit specific fuel costs in addition to the overall economic environment.

Economic Assessment of Coal Capacity at Risk for Retirement: Setting the Stage

Owners of coal-fired generation subject to the CSAPR and NESHAP rules will only install the necessary pollution control retrofits to continue operating in compliance with the aforementioned rules if they believe they can earn sufficient revenues in the Energy and RPM Capacity Markets in excess of costs (including the costs of retrofits) that will allow them to earn their target return on investment. It is this “simple” decision rule that informs the economic assessment of coal generation that is at risk for retirement. Yet, in spite of the simplicity of the decision rule, the actual inputs into that decision may be far more complex, uncertain, and rely on conditions at units known only to the owners themselves, or on expectations of future operating conditions that are unique to each unit owner.

PJM Evaluation of Pollution Controls Required to Comply with CSAPR and NESHAP

The controls associated with sulfur dioxide and nitrogen oxide reductions required under the CSAPR are well known and understood as discussed above in the section summarizing pollution control technologies. There also is available information on sulfur dioxide and nitrogen oxide emissions levels and rates by which to evaluate the need for control technologies.

From EPA analysis of data provided by generation owners in developing the NESHAP rule, the technologies that can control mercury, acid gases, and non-mercury heavy metals in particulates are also well known and understood. Unfortunately, there is not the same extensive unit level data on hazardous air pollutant emissions by which to evaluate the need for specific control technologies. Consequently, PJM determines the control technologies that will be required based upon data submitted to EPA that were used to determine the NESHAP emissions rate standards.⁷⁵ For compliance with

CSAPR, PJM bases retrofits needs on current sulfur dioxide and nitrogen oxide emissions rates compared to a desired emissions rate level that PJM assumes will allow generation resources to achieve compliance with CSAPR in the absence of liquid emissions allowance trading.

Sulfur Dioxide Reductions

The analysis targets a sulfur dioxide emissions rate of 0.15 lbs/mmBtu of heat input.⁷⁶ This emissions rate is chosen to achieve sulfur dioxide emissions reductions that would allow a coal unit to continue operating under CSAPR as it would have without CSAPR. Because sulfur dioxide is used as a proxy measure for acid gases, this would also achieve the required acid gas emissions rate standard under NESHAP. The decision rule for sulfur dioxide emissions controls is:

- Install a wet limestone FGD if a sulfur dioxide emission rate reduction of more than 50 percent is required to achieve the target 0.15 lb/mmBtu emissions rate level; or
- Install dry sorbent injection (DSI) if a sulfur dioxide emissions rate reduction of 20-50 percent is required to achieve the target 0.15 lb/mmBtu emissions rate level.

Nitrogen Oxide Reductions

Similar to sulfur dioxide reductions, the analysis targets a nitrogen oxide emissions rate of 0.15 lbs/mmBtu of heat input.⁷⁷ This emissions rate would allow a coal unit to continue operating under CSAPR as it would have without CSAPR. The decision rule for nitrogen oxide emissions controls is:

- If an emissions rate reduction of more than 60 percent is required to achieve the 0.15 lbs/mmBtu emissions rate target, an SCR would be installed.
- If an emissions rate reduction of 20-60 percent is required to achieve the 0.15 lbs/mmBtu emissions rate target, an SNCR would be installed.

Mercury Reductions

If a combination of a wet limestone FGD and SCR are installed on a unit, no other controls are assumed to be needed to further reduce mercury or non-mercury heavy metal emissions as the combination of those have been shown to achieve the mercury emissions rate standard. Otherwise, activated carbon injection (ACI) must be installed to control mercury emissions.

Particulates and Non-mercury Heavy Metals

If a unit installs ACI or DSI, then a fabric filter installation will be required even if the unit already has an electrostatic precipitator (ESPs) in service for the control of particulates. A fabric filter ensures the particulates from ACI and DSI bonding to and capturing the hazardous air pollutants are themselves captured and not emitted to the atmosphere.

Factors Influencing the Retrofit/Retirement Decision of Generation Owners

Each generation owner almost certainly has different views regarding the inputs into the retrofit/retirement decision for coal generation impacted by the CSAPR and NESHAP rules. These owner specific beliefs regarding the future profitability of coal units include, but are not limited to the following issues.

- Unit or site specific considerations that are only known to the generation owner. For example, if a unit owner believes there are significant clean-up liabilities once a unit is retired, the owner may choose to install retrofits to continue operating to avoid those liabilities. Conversely, a unit that appears to be financially viable with retrofits may be unable to install them if the site does not have the space to allow for such retrofits except at much higher costs.
- Differing expectation on future environmental policies (e.g. climate change), natural gas prices and average hourly energy demand that will affect future net energy market revenues. Unit owners that are bullish on future market revenues may opt to install retrofits on units that would at first glance appear uneconomic. Along similar lines, some units that appear economic for retrofits may retire if the unit owners are bearish on future energy market prospects.
- Differences in required return on investment and period for retrofit cost recovery. Unit owners willing to recover retrofit costs over longer periods or with lower hurdle rates of return on investment, all else equal, will be more likely to opt for retrofits than for retirement. On the other hand, unit owners with shorter recovery periods and/or higher hurdle rates of return on investment will be more likely to opt for retirement, all else equal, than for the installation of retrofits as the required annual revenue streams to recover retrofits costs will be higher.
- Expectations regarding the extent of new entry of Demand Resources and natural gas technologies as well as growth in peak demand and the cumulative impact on RPM Capacity Market prices. If unit owners believe peak demand growth will recover and growth in new entry will be slow, then RPM revenues are more likely to support retrofits. Conversely, unit owners that believe there will be sluggish growth in peak demand and continued expansion of Demand Resources may opt to retire units if they believe RPM revenues cannot help support retrofit costs.

As part of the economic analysis defined below, PJM has presented different scenarios based on different natural gas price and demand conditions as well as differing time periods for retrofit cost recovery. Other expectations or unit specific considerations are difficult to account for completely as these are only known by the generation owner.

Framework for Analyzing the Economic Viability of Pollution Control Retrofits under the Rules

PJM's analysis of the economic viability of coal-fired capacity to continue operating relies on retrospective data on net energy and ancillary service market revenues from 2007-2010 and detailed cost models of pollution control retrofits used by the EPA in its analysis of the CSAPR and NESHAP rules. It also uses Avoidable Cost Rate (ACR) data from the PJM tariff adjusted using the Handy-Whitman index to derive non-environmental avoidable costs for coal generation during the 2007-2010 period and various capital recovery factors (CRFs) provided for in the PJM Tariff, Attachment DD for differing periods of cost recovery for environmental retrofits.⁷⁸

The PJM analysis determines the cost of pollution control retrofits for a given CRF period (4 years to 20 years), adds in the non-environmental avoidable costs (ACR) defined from the PJM Tariff, and then subtracts the net energy and ancillary service market revenues for the relevant period. The resulting figure is the additional revenue, in the form of capacity payments, necessary for the unit to continue operating in compliance with the CSAPR and NESHAP rules.

Net Energy Market Revenues: Defining Scenarios for Economic Conditions

PJM and the IMM collect the Net Energy and Ancillary Service Revenues from generation owners in conjunction with the market power mitigation procedures for the RPM Capacity Market. The Net Energy and Ancillary Service Market Revenues are used to compute Market Seller Offer Caps in RPM.

As shown above, the 2007-2010 period can be broken up into two distinct scenarios: 1) 2007-2008 when natural gas prices were high, average hourly energy demand was high and consequent net revenues were higher; and 2) 2009-2010 when natural gas prices were low, average hourly energy demand was lower, and consequent net revenues were also lower. A third scenario can be defined as the averaging of the two scenarios over the entire 2007-2010 period.

The retrospective net revenue data therefore provides a natural experiment whereby the outcomes under a high gas price/high demand scenario can be compared to a low gas price/low demand scenario and can be linked to forecasts of future market conditions to draw some tentative conclusion regarding the economic viability of pollution control retrofits under different conditions.

Differing Periods for Capital Recovery Factors

The PJM Tariff, Attachment DD permits units owners to choose the capital recovery factor (CRF) period for the recovery of investments in existing generating units under the Allowance for Project Investment Recovery (APIR) that is a part of the Avoidable Cost Rate (ACR) that goes into determining Market Seller Offer Caps.⁷⁹ Given the mandatory nature of the NESHAP rule, generating units that must install emission control technologies may choose to include such costs under the Mandatory CapEx Option which expresses the cost of the retrofits in terms of a four-year recovery period, or units may elect to express these costs under the next highest option for units 25 years and older which allows for the costs to be expressed under a five-year recovery period.⁸⁰

However, unit owners may view the decision to install pollution control retrofits as a much longer term investment and may have expectation of recovering the investment in pollution control retrofits over a longer period such as 10, 15, or even 20 years. The PJM Tariff provides CRF factors for each of these time periods under the assumption of a 10 percent weighted average cost of capital. Because PJM does not know or have access to individual unit owners' hurdle rates for investment, cost of capital, or desired length of time to recover retrofit costs, the PJM analysis calculates retrofit costs for each of the tariff-defined CRFs under each economic scenario discussed above.

Necessary Revenues to Remain Economically Viable

For each combination of economic scenario and CRF employed for each coal-fired unit in PJM, the analysis calculates the necessary revenues that would need to be collected from the RPM Capacity Market, expressed in \$/MW-day of installed capacity. The analysis does not seek to compare this number to actual RPM revenues collected during the 2007-2010 period as RPM prices and the associated revenues would not have accounted for the costs of pollution control retrofits associated with the CSAPR and NESHAP rules.

The necessary revenues to be economically viable are more appropriately benchmarked against the Net Cost of New Entry (Net CONE) for a simple cycle natural gas combustion turbine that serves as the Reference Resource in the RPM Capacity Market.

Net CONE as the Benchmark to Define Capacity at Risk for Retirement in the Economic Analysis

Net CONE is defined as the 20-year nominal levelized cost of building a new natural gas combustion turbine less Net Energy and Ancillary Service Market revenues. In the context of the RPM Capacity Market, the Net CONE is the benchmark price of capacity at which PJM would maintain resource adequacy at the peak load plus the Installed Reserve Margin. Consequently, the Net CONE serves as a useful benchmark by which to evaluate the necessary revenues for coal capacity to cover the costs of environmental retrofits, less net energy and ancillary service market revenues. The relevant Net CONE for benchmarking necessary revenues to continue operating would be from the 2014/2015 Base Residual Auction which corresponds to the first year by which coal units must achieve compliance with the NESHAP rule absent any extensions.

For the purposes of categorizing capacity at risk relative to Net CONE, PJM has defined four categories by which to assess the risk of retirement to coal units based on the necessary additional revenues to cover costs relative to Net CONE.

1. ***Necessary revenues greater than 1.5 Net CONE.*** 1.5 Net CONE is the maximum price that could be achieved in any Locational Deliverability Area (LDA) in RPM. If the necessary revenues to cover retrofit costs exceed 1.5 Net CONE, the coal unit would not be economically viable, and not be committed in RPM, even if RPM commits capacity at approximately 3 percent below the peak load plus the installed reserve margin or less. A coal unit in such a position would be “at very high risk” for retirement.
2. ***Necessary revenues greater than or equal to Net CONE, but less than or equal to 1.5 Net CONE.*** In this case new entry natural gas combustion turbine would be more competitive in the RPM Capacity Market than the coal unit requiring retrofits. In the absence of new entry CTs, it is possible for the coal unit to clear the RPM Capacity Market and remain in operation, but the coal unit would still be “at high risk” for retirement because it is not cost competitive with new entry from the Reference Resource.
3. ***Necessary revenues greater than 0.5 Net CONE but less than Net CONE.*** A coal unit in this situation is more cost competitive than a new entry natural gas CT. The determinant of whether a coal unit in this situation clears in RPM and stays in service or retires will depend upon other market dynamics, such as the penetration of demand response, updated load forecasts, expectations about future fuel price and economic conditions. Coal units in this situation are “at risk” for retirement, but the retrofit/retirement decision will depend on a great many variables.
4. ***Necessary revenues less than or equal to 0.5 Net CONE.*** A coal unit in this situation is quite likely to install retrofits and continue operating. Historically in the Mid-Atlantic Region (MAAC), RPM prices have exceeded this value. With the ability of units to include the costs of retrofits in their offers, the price of capacity appears likely to stay above this threshold. In the rest of the RTO, capacity prices have been above and below 0.5 Net CONE. But with the ability to include the costs of environmental retrofits into RPM offers, and the recent 2014/2015 Base Residual Auction, capacity prices are once again approaching 0.5 Net CONE. Coal units in this position are likely “at low risk” for retirement, with any potential retirement decisions based upon factors that PJM cannot observe from the available data.

While there may be other, more granular, benchmark categories relative to Net CONE, the above defined categories can serve as a tool to group coal units in a manner that provides useful information while not being too complicated. However retrofit/retirement decisions eventually made by coal units facing retrofit costs may depend upon factors that cannot be observed from the data by PJM staff.

Economic Assessment of Coal Capacity at Risk for Retirement: Results

Coal Capacity at Risk absent the CSAPR and NESHAP Rules

One question that is certain to arise regarding this analysis is the extent to which lower peak demands, lower overall energy consumption, and lower gas prices would place coal units at risk for retirement even if there were no CSAPR and NESHAP rules. Such a scenario provides a baseline by which to measure the impacts of the rules being analyzed, and provides an indication of how the rules interact with economic conditions in placing coal capacity at risk for retirement.

Figure 10 shows necessary revenues to continue operating by unit size category and by historic gas price/demand scenario. Figure 10 indicates that even under the low gas price scenario using 2009-2010 net revenues, the necessary revenue to continue operating is below \$100/MW-day on average for units of different sizes.⁸¹ Whereas under the scenarios that have high gas prices and demand (2007-2008) and the scenario that averages revenues across the entire 2007-2010 period, the necessary revenues to continue operating were negative, meaning coal capacity earned sufficient net revenues from the energy and ancillary service markets to continue operating.

Figures 11 and 12 show the amount of capacity with revenue needs benchmarked against the Net CONE (expressed in installed capacity or ICAP terms) in the MAAC and Rest of RTO regions in PJM.⁸² The first thing to notice is there is no capacity that would require more than Net CONE to continue operating regardless of gas price/demand scenario. The second observation is that even in the high gas price/low demand scenario, only about 4,000 MW of capacity would require more than ½ Net CONE to continue forward, with most of that located in the rest of RTO region. The main conclusion from examining the case of no CSAPR or NESHAP rules is that coal capacity would generally not be at risk for retirement due to the recently changed economic environment alone. This is not to say that the changing economic conditions do not have an effect on the economic viability of coal units, but it will be due to the interactions of the changing economic environment with the CSAPR and NESHAP rules.

Figure 10: Necessary Revenue to Continue Operating without CSAPR and NESHAP

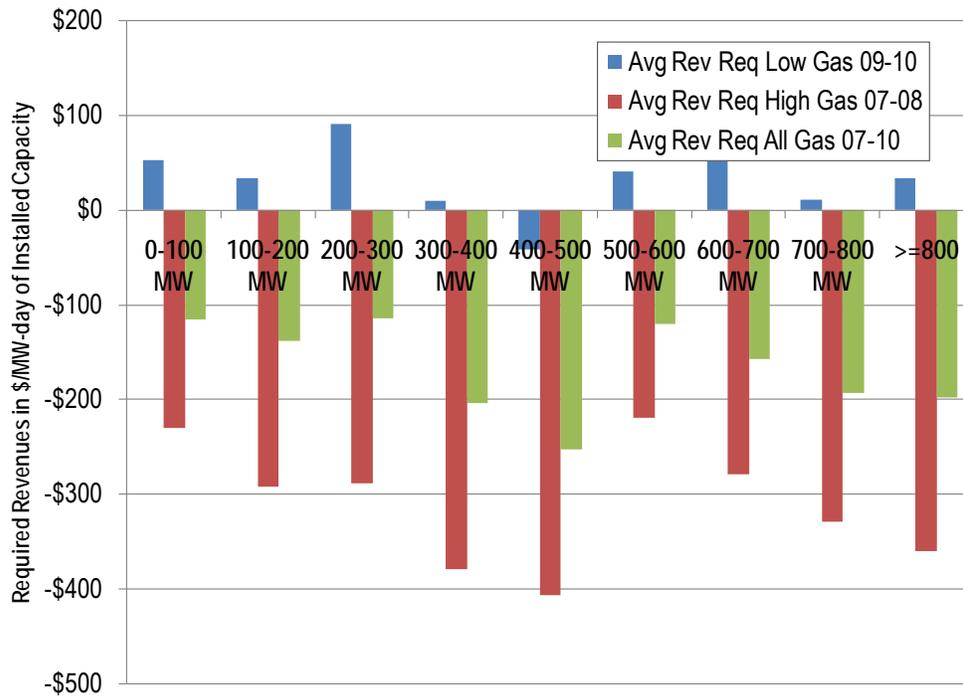


Figure 11: MW of Installed Capacity with Needed Revenues Benchmarked against Net CONE in MAAC

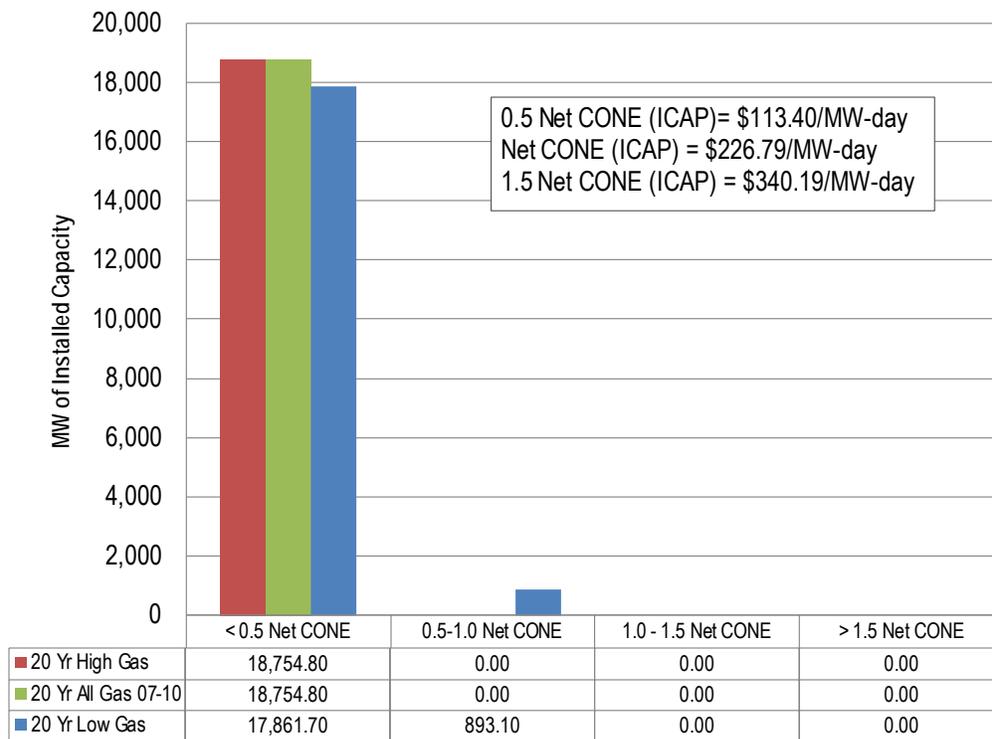
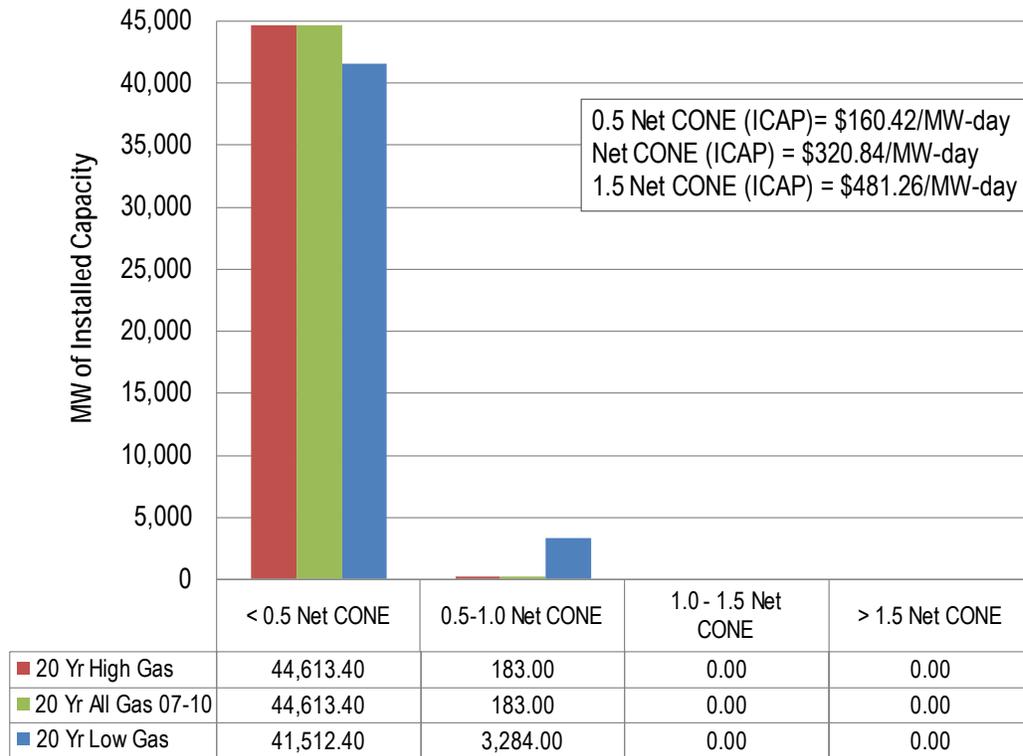


Figure 12: MW of Installed Capacity with Needed Revenues Benchmarked against Net CONE in Rest of RTO



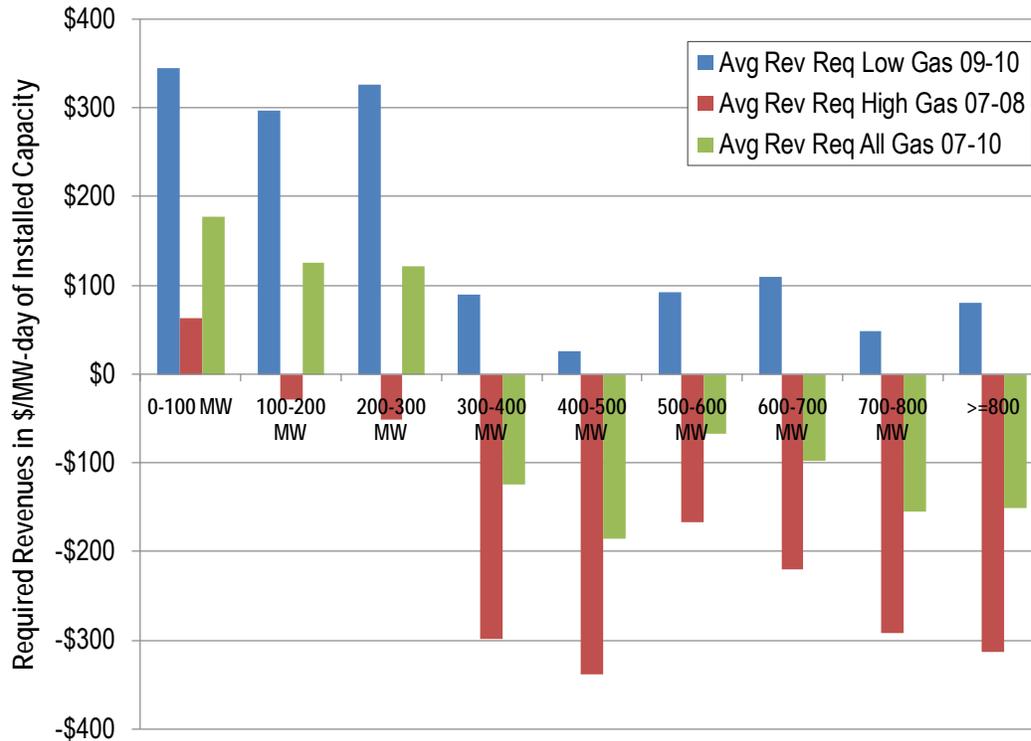
Coal Capacity at Risk Due to the CSAPR and NESHAP Rules

If the owner of a coal unit makes the decision to make investments in pollution control retrofits, it would be reasonable to expect that the unit owner is making a long-term investment in that unit and that the payback period on the retrofit investment would be similar to investing in a new natural gas combined cycle plant or simple cycle combustion turbine. Under the PJM Tariff and market rules this period is 20 years for the new entry reference resource. In thinking about the pollution control retrofit along the same lines as investment in new entry natural gas, it allows for the benchmarking of the costs with retrofits against the Net CONE of the reference resource as discussed above.

In considering future economic conditions, such as gas prices and demand, it is reasonable to use a historic scenario that corresponds as closely as possible to forecasts of future gas prices and energy demand. The required revenues under this scenario would enable retrofit/retire decisions based on forecasts currently in place.

Figure 13 shows the necessary revenues to continue forward for coal units by size and natural gas price/demand scenario. Compared to the results in Figure 10 without CSAPR and NESHAP, the required revenues to continue operating are higher, especially for smaller units. For units below 300 MW in size, the needed revenues are at least \$300/MW-day of installed capacity in the high gas price/low demand case, and for all units on average the needed revenues to go forward are greater than zero. Even in the other gas price cases, the economics of smaller units on average have been significantly eroded. This result demonstrates that older, smaller units are less efficient, run less often and will not have the same kind of net revenues to cover retrofit costs, and will also not be able to take advantage of any economies of scale in retrofit installations. For larger units, more than 300 MW in size, the revenues needed to continue operating are generally less than \$100/MW-day on average.

Figure 13: Necessary Revenues to Continue Forward by Unit Size and Case



Figures 14 and 15 present the MW quantities of capacity, benchmarked against different levels of Net CONE in MAAC and the rest of RTO. Figure 11 shows that there is about 3,200 MW of installed capacity that requires more than Net CONE to go forward in MAAC under the low gas price/low demand scenario. A total of almost 1,500 MW require more than 1.5 Net CONE, which is the maximum price that could prevail in MAAC if it were a separate LDA. In the rest of RTO, as shown in Figure 15, there is more than 7,800 MW of capacity requiring more than the Net CONE in the low gas price/low demand case. In total across the RTO, there is just over 11,000 MW of capacity that would require more than the Net CONE to continue forward in the low gas price/low demand case. The focus is on the low gas price/low demand case as forecasts of future gas prices and demand are on a much lower trajectory than was otherwise the case just a few years before, and closely match up with gas prices that prevailed in 2009-2010.

Figures 14 and 15 also show capacity revenue needs under the other higher gas price/higher demand cases. If gas prices and demand had remained at 2007-2008 levels, there is slightly less than 1,500 MW of installed capacity that would require more than Net CONE to continue operating. In the case that blends the economic conditions from 2007-2010, this figure would be around 4,300 MW.

Given the baseline considering needed revenues to go forward in the absence of CSAPR and NESHAP, it is clear that these rules are driving the need for increasing revenues to incent coal capacity to continue operating. And the effects of these rules are exacerbated by the low gas price/low demand environment that is forecast to continue.

Figures 14 and 15 also show that across the entire PJM footprint, there another approximately 14,000 MW of coal-fired capacity in the low gas price/low demand case that would require between 0.5 Net CONE and Net CONE to continue forward. Coal capacity in this area is at some risk for retirement, but it would be difficult to precisely estimate how much of

this capacity would retrofit or retire. As explained above, the retrofit/retirement decision will depend upon factors that cannot be observed by PJM, such as unit specific conditions not immediately available to PJM, and owner expectations about the future economic and policy conditions.

Figure 14: MW of Installed capacity in the MAAC Region by Revenue Needs Relative to Net CONE

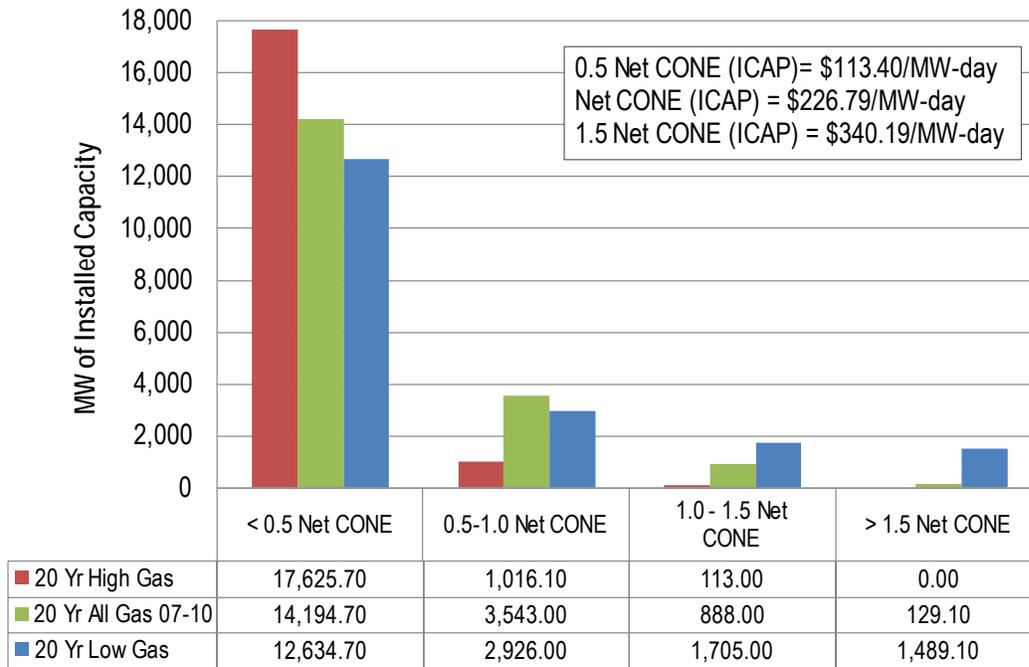
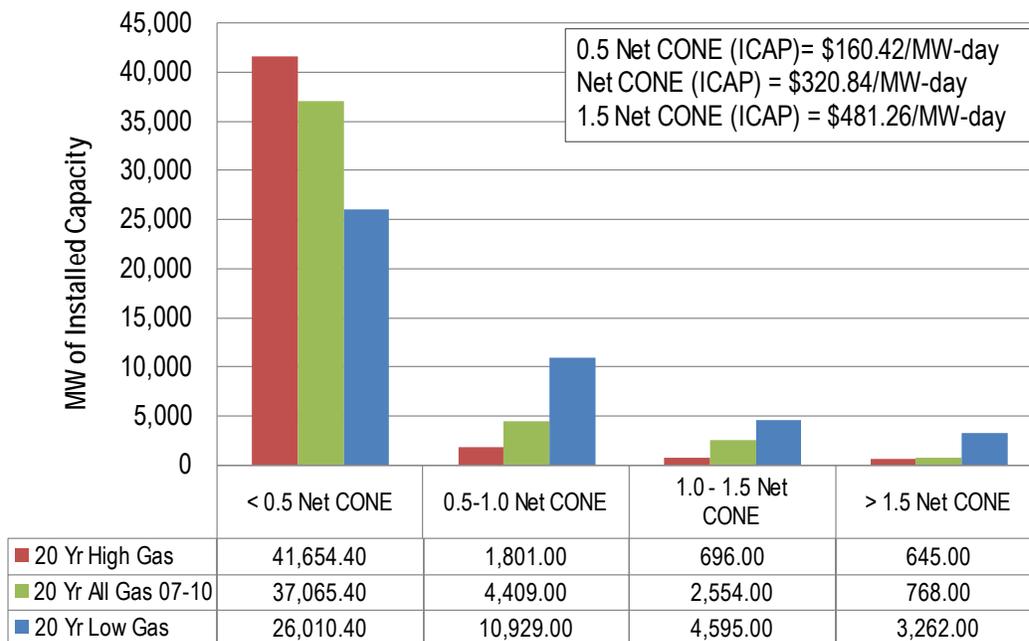


Figure 15: MW of Installed Capacity in the rest of RTO by Revenue Need Relative to Net CONE



Benchmarking PJM's Assessment of Capacity at Risk with Known Market Responses

In the 2014/2015 RPM Base Residual Auction (BRA), there was 6,985 MW of UCAP (unforced capacity), equivalent to approximately 7,350 MW ICAP (installed capacity) less coal-fired capacity that cleared the auction than was the case in the 2013/2014 BRA.⁸³ Some of this change was due to the cost of environmental retrofits making coal-fired capacity uneconomic relative to lower cost alternative capacity resources, such as demand response, as well as the reduced forecast demand for the 2014/2015 delivery year.⁸⁴ Combined there is a RPM Capacity Market response that indicates just over 7,000 MW of installed capacity is likely to retire in response to the CSAPR and NESHAP rules.

In addition to the response in the RPM Capacity Market, there are entities in PJM that satisfy their resource adequacy obligations through the Fixed Resource Requirement (FRR) that allows load serving entities to satisfy their obligations outside of the RPM Capacity Market through their own generation and/or through bilateral contracts with other generation owners. One FRR entity currently in PJM included in the economic analysis, AEP, has publicly announced 6,000 MW of coal retirements. Duke Energy Ohio and Duke Energy Kentucky, to be integrated into PJM at the end of 2011, have announced just over 1,000 MW of coal retirements in response to the CSAPR and NESHAP rules.⁸⁵

The over 14,000 MW that have not cleared in RPM or have publicly announced retirements is consistent with the range coal capacity identified as at risk for retirement from the CSAPR and NESHAP rules in the economic assessment.

Sensitivity of Capacity at Risk to Assumed Payback Periods

The economic assessment of coal capacity "at risk" assumes a 20 year recovery period for retrofit investments along the same lines as the recovery period assumed for the Reference Resource, a natural gas, simple cycle combustion turbine. The choice of 20 year recovery period allow for direct comparability with the cost of the Reference Resource and is a reasonable assumption given that environmental retrofits costs are long-lived investments that will significantly extend the life of a coal unit.

However, the rules governing the RPM Capacity Market in the PJM Tariff allow generation owners to include such investment costs under APIR for recovery for much shorter periods. For example, give the nature of the EPA rules, it is reasonable to assume that generation owners may include retrofit costs under the Mandatory CapEx option and include retrofit costs for a 4 year period as opposed to a 20 year period. This would go into defining the Market Seller Cap for the coal unit, although a unit owner could choose to offer the unit into RPM at a lower price. Generation owners, based on their own expectations and beliefs, may wish to recover the costs of environmental investments over any period between 4 and 20 years as has been discussed previously.

PJM Tariff Attachment DD, Section 6.8 provides for CRFs that correspond to differing recovery periods for capital investment: 20, 15, 10, 5, and 4 years depending on the age of the unit. PJM has used these CRFs to provide sensitivity analysis under the low gas price case to illustrate the effect of shortening the recovery period from 20 years as would be allowed under the PJM Tariff.

Figure 16 shows the effect of moving from a 20 year recovery period to shorter recovery periods down four years recovery period. For recovery periods of 10 years or less, units smaller than 300 MW would need at least the RTO LDA price cap of 1.5 Net CONE or more in order to continue to operate. The net effect of shortening the recovery period generally would be to make retrofitted coal less competitive with new entry gas, and price small units entirely out of the market.

Figure 16: Sensitivity of Needed Revenues to Recovery Period in the Low Gas Price Case

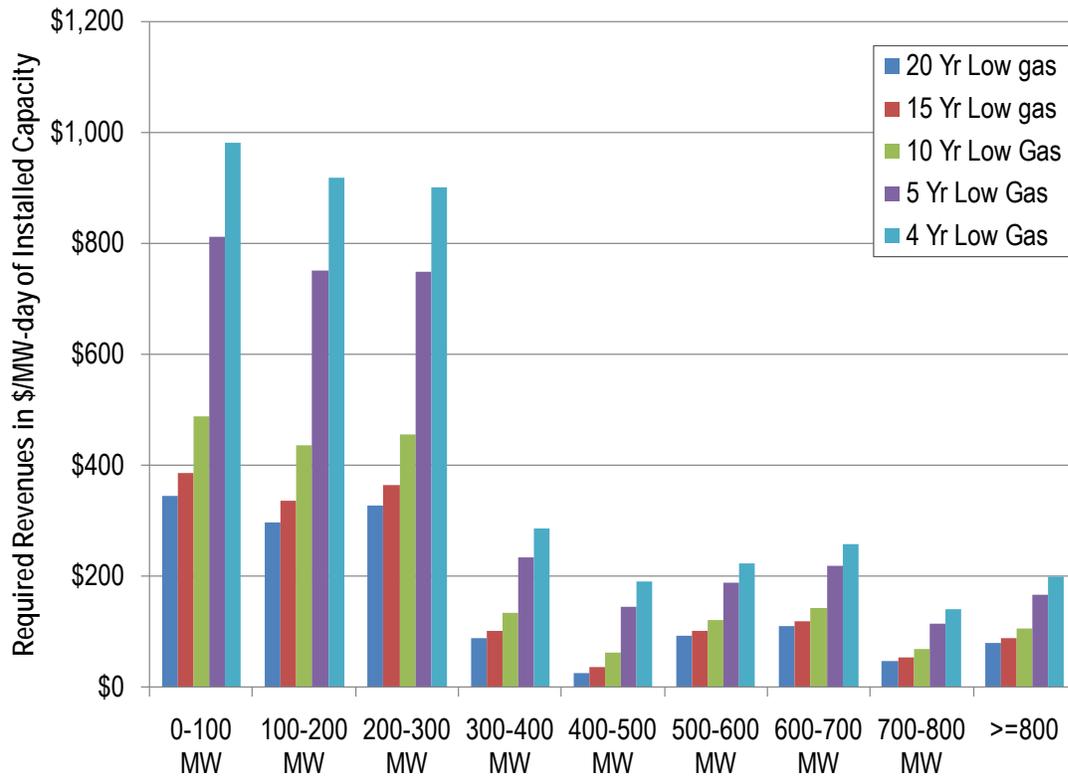


Figure 17: Sensitivity of Capacity Revenue Needs Benchmarked against Net CONE by Recovery Period in MAAC

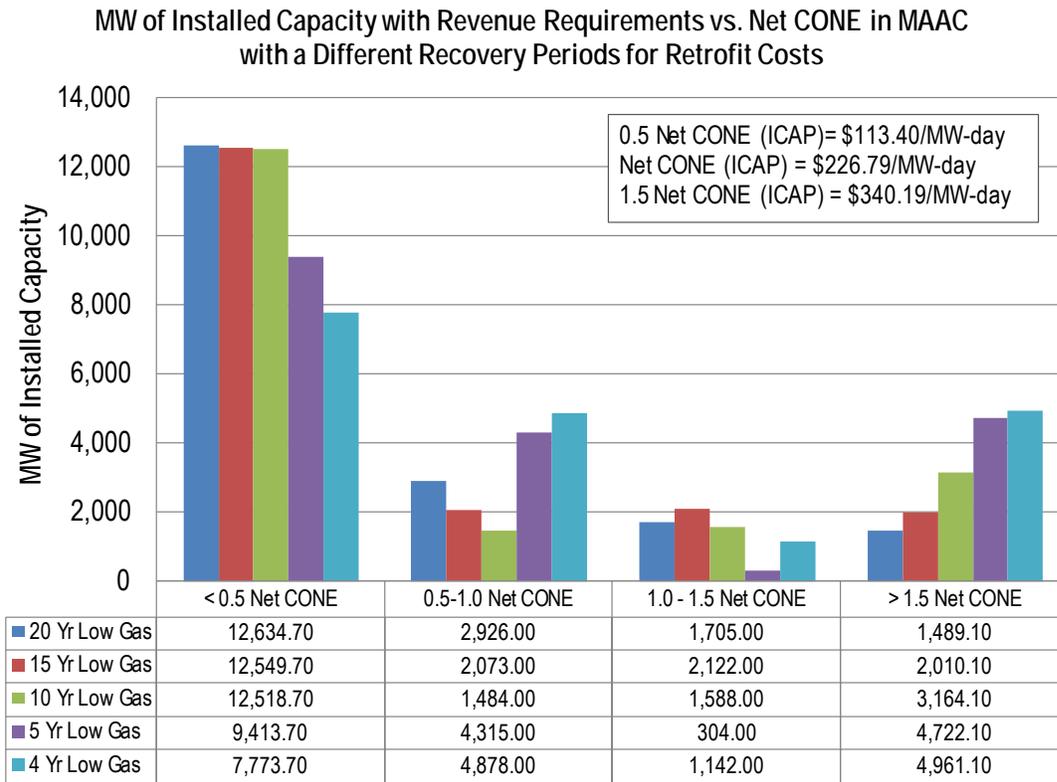
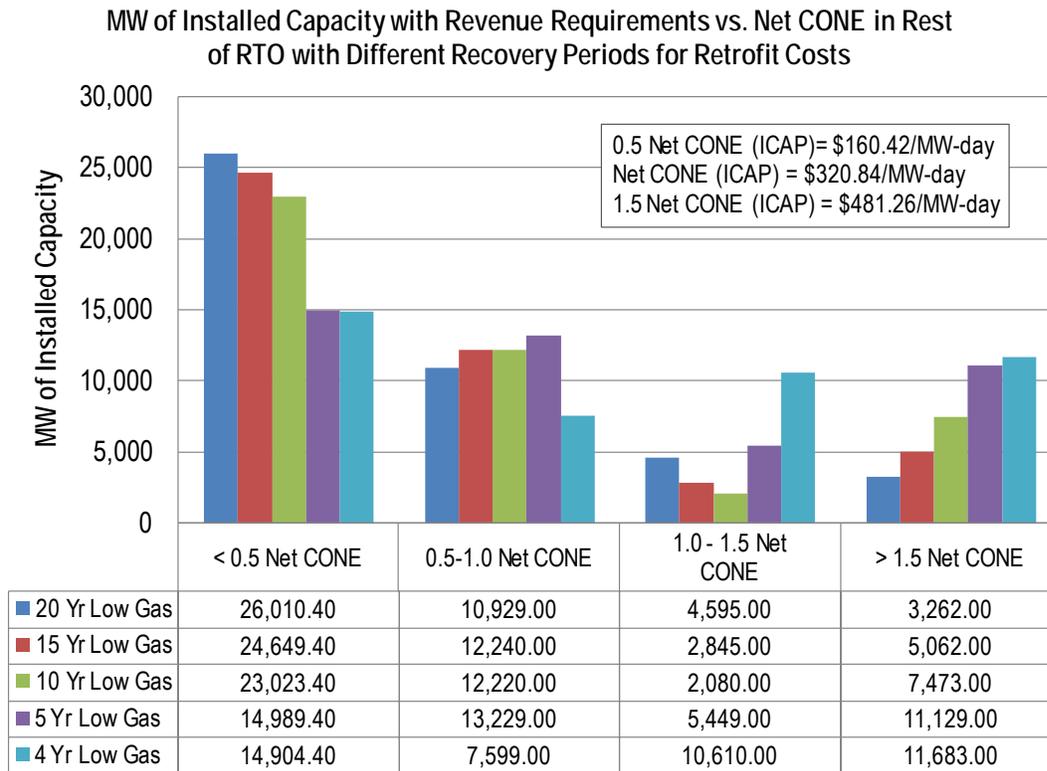


Figure 17 illustrates the effect of decreasing the cost recovery period in MAAC region. Decreasing the recovery period from 20 years to 4 years results in an almost doubling of capacity requiring more than Net CONE. Figure 18 provides that same information for the Rest of RTO region, except that moving from a 20 year recovery period down to a 4 year recovery period almost triples the amount of capacity that requires more than Net CONE to continue forward.

Figure 18: Sensitivity of Capacity Revenue Needs Benchmarked against Net CONE by Recovery Period in Rest of RTO



Conclusions Regarding Coal Capacity Potentially at Risk for Retirement

The CSAPR and NESHAP rules will require coal capacity to make retrofit or retirement decisions that will be implemented in the 2012-2015 period. For example, of the approximately 78,000 MW of coal capacity in PJM at least 30,000 MW (38 percent) requires sulfur dioxide controls to help comply with both the CSAPR and NESHAP rules.

PJM's assessment, based on actual pollution controls installed to date, and physical and operational characteristics of units finds that coal units smaller than 400 MW and more than 40 years old are "at greatest risk for" retirement due to the CSAPR and NESHAP rules. The almost 23,000 MW of capacity smaller than 400 MW and more than 40 years old (29 percent of total PJM coal capacity), generally accounts for more than half of all units that likely require at least one major sulfur dioxide or nitrogen oxide retrofit. As much as 20,000 MW of this smaller, older capacity requires at least one major pollution control retrofit.

Under the assumption of a 20-year recovery of pollution control retrofit investments, and continued low gas prices and lower trajectory of forecast demand, PJM's economic assessment indicates that more than 11,000 MW of coal-fired capacity would require more than Net CONE, or the net cost of a new entry of a simple cycle gas turbine, to continue operating. And of that 11,000 MW, approximately 4,750 MW would need more than 1.5 Net CONE, or the maximum price in an LDA, to continue forward.

In addition, PJM's economic assessment indicates almost 14,000 MW of additional capacity would require between 0.5 Net CONE and Net CONE to continue forward. Benchmarking the economic assessment against market responses to date shows the range of estimates using the physical and economic assessments conducted by PJM are in line with the

approximately 7,000 MW of coal that did not clear in the last BRA, but not yet requested deactivation, and the 7,000 MW of announced retirements by FRR entities.

Resource Adequacy is Projected to be Maintained

For the 2014/2015 Delivery Year, PJM estimates that the RTO will carry a reserve margin of 19.6 percent, including the demand and capacity commitments of FRR entities. Even with the potential retirement of coal capacity already announced by FRR entities, there are also announced commitments to replace a portion of that capacity with new gas-fired capacity. This means that the RTO would still carry a reserve margin in excess of the target 15.3 percent installed reserve margin. In short, include the potential for new entry from other resources that has occurred in recent years and a system-wide resource adequacy problem does not appear imminent in PJM from the reduction in cleared coal capacity in RPM and from announced retirements.

However, this does not mean that localized reliability concerns may not arise given the location of particular units that may retire and the unique locational services they provide such as congestion management of particular transmission facilities, voltage support for the transmission system, or black start services, as PJM noted in its comments to the EPA in the NESHAP rulemaking.⁸⁶ It is for this reason that PJM proposed a “reliability safety valve” to be included in the final EPA NESHAP rule to address these particular circumstances. The key is whether replacement resources or transmission reinforcements can be timely added given the breadth of the potential retirements and the pressure on outside vendors to supply new turbines and related resources.

Resource retirement and new resource entry are part of the natural cycle of any well-functioning and competitive wholesale power market. The cycle of retirement and new entry may also help facilitate major policy changes in a more cost-effective manner. Absent resource adequacy and/or local reliability problems, generation retirements are not, *per se*, an operational negative and may result in enhanced operational reliability and lower costs, taking the public policy context as given.

Newer, more efficient generation resources that replace retiring generation may have lower forced outage rates and thus, are more dependable than older generation resources that may be nearing the end of their useful lives. Additionally, new entry generation, demand response and energy efficiency resources may also provide lower cost alternatives to achieve resource adequacy and local reliability.

Retrofit, Repower, Retire Decisions Depend on Individual Unit Owner Needs and Expectations

One caveat must be kept in mind in considering the range of coal-fired capacity “at risk” for retirement based upon physical characteristics or based on the economic assessment discussed in this report. The ultimate decision by a generation owner on whether to retire a generating unit or to expend money on required environmental retrofits or repowering to continue operating is based upon owner specific expectations regarding future market conditions or other considerations. Market conditions can be defined by load growth, coal prices, natural gas prices, future environmental or energy policy, and the mix of generating capacity.

Other owner specific considerations may include, but are not limited to, the willingness to earn lower returns on equity, retirement costs associated with site clean-up, the ability to attract lower cost debt financing than implicitly assumed by economic analysis, potential economies of scale for retrofits on units associated with a common stack, or the willingness to retrofit coal units that may appear marginal as a portfolio hedge against over-dependence on natural gas and possible

future natural gas price volatility. While these are all valid considerations that go into the retrofit, repower or retire decision, these considerations constitute private, commercially sensitive information to which PJM does not have access.

Providing Information for PJM Stakeholders and Policymakers

PJM believes the analysis provided in this report will provide information to PJM stakeholders and the PJM stakeholder process that would otherwise not be generally available. Such information may be useful to help guide PJM stakeholders in their discussion of various issues related to market design and transmission planning. The framework for this analysis can serve as a basis for examining other proposed EPA rules and state rules that may result in additional capacity retirements that may not be limited to coal-fired capacity. PJM believes this analysis, and similar subsequent analyses, will provide useful information to market participants and inform the PJM stakeholder process about the impact of forthcoming environmental regulations.

Endnotes

- ¹ *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone Correction of SIP Approvals*, EPA-HQ-OAR-2009-0491, 76 FR 48208 (Federal Register Vol. 76, No. 152, p. 48208), August 8, 2011 (“Cross State Air Pollution Rule” or “CSAPR”), available at <http://www.gpo.gov/fdsys/pkg/FR-2011-08-08/pdf/2011-17600.pdf>.
- ² *National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA-HQ-OAR-2009-0234, 76 FR 24976 (Federal Register Vol. 76, No. 85, p. 24976), May 3, 2011 (“NESHAP” or “HAP MACT”), available at <http://www.gpo.gov/fdsys/pkg/FR-2011-05-03/pdf/2011-7237.pdf>
- ³ Capacity values are based on summer net dependable capacity or installed capacity in eRPM, and includes resources in the ATSI and DEOK (Duke) zones integrated on June 1, 2011 and January 1, 2012 respectively. For generation in service in PJM as of January 1, 2009, this can be found in PJM’s EIA-411 submittal available at <http://pjm.com/documents/reports/~media/documents/reports/2009-pjm-eia-411-data.ashx>. For generation coming into PJM as part of the integration of the ATSI Zone, see “ATSI Stakeholder Meeting”, October 2, 2009 at 7, available at <http://pjm.com/markets-and-operations/market-integration/~media/committees-groups/stakeholder-meetings/feisq/20091002/20091002-meeting-presentation.ashx>. For generation coming into PJM as part of the Duke integration, see “Duke Energy – Ohio, Duke Energy – Kentucky Integration”, June 3, 2010, available at <http://pjm.com/~media/committees-groups/committees/mc/20100603/20100603-item-09-duke-energy-integration.ashx>. Capacity includes OVEC units at Clifty Creek and Kyger Creek which are co-owned by multiple PJM Members. Finally, the 2008 EIA-860 database, available at <http://www.eia.gov/cneaf/electricity/page/eia860.html>, was used to confirm capacity values and ownership. This capacity does not include generation resources still in operation, but that have already filed a formal deactivation request to cease commercial operation by January 1, 2015. The list of units deactivated or with pending for deactivation requests are available at <http://pjm.com/planning/generation-retirements/~media/planning/gen-retire/generator-deactivations.ashx> and <http://pjm.com/planning/generation-retirements/~media/planning/gen-retire/pending-deactivation-requests.ashx>.
- ⁴ Pollution control retrofit status as of June 30, 2011. The EPA Clean Air Markets Division maintains and updates the database of generation characteristic including emissions levels, heat input, facility attributes, and gross generation. Information from the database can be customized through and SQL query system. The database is available at <http://camdataandmaps.epa.gov/gdm/>.
- ⁵ Pollution control retrofits exhibit economies of scale. Smaller units have larger costs per kW of capacity than do larger units. The cost models for pollution control retrofits are available from the EPA as part of its documentation of the Integrated Planning Model used evaluate the impacts of the CSAPR and NESHAP rules. The cost models for FGDs for sulfur dioxide control and SCR and SNCR for nitrogen oxide control are available at <http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html>. The cost models for ACI, DSI and fabric filter baghouse are available at <http://www.epa.gov/airmarkets/progsregs/epa-ipm/toxics.html>. See also *Infra Notes 51, 52, 56, 58 and 59*.
- ⁶ All prices are delivered prices in nominal dollars. See United States Energy Information Administration *Electric Power Monthly*, Table 4-2, available at http://www.eia.gov/cneaf/electricity/epm/epm_sum.html for historical data. For forecast fuel price data, see United States Energy Information Administration *Annual Energy Outlook 2011*, Reference Case Tables available at <http://www.eia.gov/analysis/projection-data.cfm>, Table A13 for natural gas and Table A15 for coal.
- ⁷ See *supra* note 3 for data source, and Figure 8.
- ⁸ See Figure 9.
- ⁹ See *supra* note 3 and *supra* note 4 for data sources.
- ¹⁰ PJM staff is grateful to the Monitoring Analytics, the Independent Market Monitor for PJM for providing unit specific Net Energy and Ancillary Service Market Revenues that is used to determine Market Seller Offer Caps in the RPM Capacity Market.
- ¹¹ PJM Open Access Transmission Tariff (“PJM Tariff”), Attachment DD, Section 6.7(c) provides technology specific, tariff-defined avoidable cost rates for the 2010/2011 until 2012/2013. These rates were adjusted by the Handy-Whitman Index to determine avoidable cost rates for 2007-2010. Capital recover factors can be found in Attachment DD, Section 6.8(a).
- ¹² Net CONE for the RTO and MAAC expressed in Unforced Capacity (UCAP) terms can be found at <http://pjm.com/markets-and-operations/rpm/~media/markets-ops/rpm/rpm-auction-info/rpm-bra-planning-parameters-2014-2015.ashx>. These were then “grossed up” by dividing the Net CONE in UCAP terms by (1-EFORd), where EFORd is the pool-wide average EFORd of 0.0625, to derive the Net CONE in ICAP (Installed Capacity) terms.
- ¹³ “2014/2015 Base Residual Auction Report Addendum” at 1-2, available at <http://pjm.com/markets-and-operations/rpm/~media/markets-ops/rpm/rpm-auction-info/2014-2015-rpm-bra-results-report-addendum.ashx>.
- ¹⁴ *Id.* at 2. The RTO LDA price increased from \$27.73/MW-day in the 2013/2014 BRA to \$125.99/MW-day in the 2014/2015 BRA.

- ¹⁵ See American Electric Power, “AEP Shares Plan for Compliance with Proposed EPA Regulations”, June 9, 2011, available at <http://www.aep.com/newsroom/newsreleases/?id=1697>. In this news release, AEP states that it intends to retire approximately 6,000 MW of coal capacity. See also Duke Energy, “Duke Energy Anticipates Ohio Coal Plant Retirement”, July 15, 2011, available at <http://www.duke-energy.com/news/releases/2011071501.asp>. Duke Energy Ohio expresses the intent to retire 862 MW of coal capacity. See also Duke Energy Kentucky 2011 Integrated Resource Plan Case No. 2011-00235, June 1, 2011 at 6, available at http://psc.ky.gov/pscscf/2011%20cases/2011-00235/20110701_Duke%20Energy_Application%20and%20Petition.pdf. In its application Duke Energy Kentucky expresses the intent to retire 163 MW of coal capacity. These have not been formally submitted to PJM for deactivation as yet.
- ¹⁶ “2014/2015 Base Residual Auction Report ” at 1, available at <http://pjm.com/markets-and-operations/rpm/~media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx>.
- ¹⁷ At the estimated 19.6 percent reserve margin, the RTO has approximately 6,000 MW more installed capacity than is needed to meet the target 15.3 percent installed reserve margin. Duke Energy, as an FRR entity, would need to replace the retired capacity with additional resources to meet its FRR obligation, and it has committed to do so. See *supra* note 15. AEP in its press release expressed the intent to build approximately 1,200 MW of gas fired generation. On net, all other things being equal, the RTO would still be long by about 1,200 MW.
- ¹⁸ See “Corrected Comments of PJM Interconnection, L.L.C.” in EPA-HQ-OAR-2009-0234, August 4, 2011, available at <http://pjm.com/~media/documents/other-fed-state/20110804-epa-hq-oar-2009-0234comments.ashx>. See also “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” in EPA-HQ-OAR-2009-0234, August 4, 2011, available at <http://pjm.com/~media/documents/other-fed-state/20110804-epa-hq-oar-2009-0234-iso-rto.ashx>.
- ¹⁹ *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, EPA-HQ-OAR-2009-0491, (CATR) *Federal Register*, Vol. 75, No. 147, August 2, 2010, pp.45210-45465.
- ²⁰ See *supra* note 1.
- ²¹ See *supra* note 2.
- ²² See “Corrected Comments of PJM Interconnection, L.L.C.” in EPA-HQ-OAR-2009-0234, August 4, 2011, at 2-3, available at <http://pjm.com/~media/documents/other-fed-state/20110804-epa-hq-oar-2009-0234comments.ashx>.
- ²³ See Monitoring Analytics, LLC, Independent Market Monitor for PJM, *2010 State of the Market Report for PJM*, March 10, 2011, Table 3-42 at 203 and Table 3-43 at 204. This is prior to the integration of Duke and ATSI into PJM.
- ²⁴ *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone Correction of SIP Approvals*, EPA-HQ-OAR-2009-0491, 76 FR 48208 (Federal Register Vol. 76, No. 152, p. 48208), August 8, 2011 (“Cross State Air Pollution Rule” or “CSAPR”), available at <http://www.gpo.gov/fdsys/pkg/FR-2011-08-08/pdf/2011-17600.pdf>.
- ²⁵ *National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA-HQ-OAR-2009-0234, 76 FR 24976 (Federal Register Vol. 76, No. 85, p. 24976), May 3, 2011 (“NESHAP” or “HAP MACT”), available at <http://www.gpo.gov/fdsys/pkg/FR-2011-05-03/pdf/2011-7237.pdf>.
- ²⁶ See EPA’s Final Rule: *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*, EPA-HQ-OAR-2009-0491, 76FR48208 (Federal Register / Vol. 76, No. 152, p. 48208), August 8, 2011 available at <http://www.gpo.gov/fdsys/pkg/FR-2011-08-08/pdf/2011-17600.pdf>.
- ²⁷ See EPA’s Supplemental Notice of Proposed Rulemaking: *Federal Implementation Plans for Iowa, Kansas, Michigan, Missouri, Oklahoma, and Wisconsin To Reduce Interstate Transport of Ozone*, EPA-HQ-OAR-2009-0491, 76FR40662 (Federal Register / Vol. 76, No. 132, p. 40662), July 11, 2011 available at <http://www.gpo.gov/fdsys/pkg/FR-2011-07-11/pdf/2011-17456.pdf>.
- ²⁸ See EPA’s Final Rule: *Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NOX SIP Call*, EPA-OAR-2003-0053, 70FR25162 (Federal Register / Vol. 70, No. 91, p. 25162), May 12, 2005 available at <http://edocket.access.gpo.gov/2005/pdf/05-5723.pdf>.
- ²⁹ See EPA’s Proposed Rule: *Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*, EPA-HQ-OAR-2009-0491, 75FR45210 (Federal Register / Vol. 75, No. 147, p. 45210), August 2, 2010 available at <http://www.gpo.gov/fdsys/pkg/FR-2010-08-02/pdf/2010-17007.pdf#page=1>.
- ³⁰ Any Title IV sources subject to CSAPR provisions will still need to comply separately with all Acid Rain provisions. EPA notes that compliance with CSAPR would reduce SO₂ emissions in covered states substantially below their share of the 2010 Title IV cap. Thus, demand, as well as prices for Title IV allowances, would decrease. EPA states that this could potentially result in emissions increases at sources covered by the Acid Rain Program, but not CSAPR, as Title IV allowances become much less costly than emissions reductions. See *supra* 26, p. 48325, C. *Interactions With Title IV Acid Rain Program*

- ³¹ See *supra* note 26, p. 48213-48214, *Executive Summary*
- ³² CAA section 302(y) defines the term “Federal implementation plan” as “a plan (or portion thereof) promulgated by the Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a State implementation plan, and which includes enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions of emissions allowances), and provides for attainment of the relevant national ambient air quality standard.” See *supra* note 26, p. 48287, footnote 80.
- ³³ “EPA notes that the final Transport Rule allows a state to submit a SIP revision (an abbreviated or full SIP) under which the state may—in addition to making certain types of changes concerning allowance allocations in the Transport Rule trading programs—expand the general applicability provisions of the Transport Rule NOX Ozone Season Trading Program to cover fossil-fuel-fired boilers and combustion turbines serving—at any time starting January 1, 2005 or later—a generator with a nameplate capacity as low as 15 MWe producing power for sale.” See *supra* note 26, p. 48274, *VII. B. Applicability*
- ³⁴ See *supra* note 26, pp.48259-48261. The cost threshold for SO₂ is \$500/ton reduced for 2012-2013 and \$2,300/ton per ton reduced for 2014 and beyond for Group 1 states, and \$500/ton reduced for all years for Group 2 states. The cost threshold for NO_x emissions is \$500/ton reduced.
- ³⁵ See *supra* note 26, pp.48212-48213. Table III-1 lists the states by group.
- ³⁶ See EPA’s *Documentation Supplement for EPA Base Case v.4.10_FTransport – Updates for Final Transport Rule* available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/CSAPR/docs/DocSuppv410_FTransport.pdf
- ³⁷ “After consideration of all comments, EPA decided to allocate allowances to individual units based on that units’ share of the state’s historic heat-input, but to ensure that no unit’s allocations exceed that unit’s historic emissions.” See *supra* note 26, p. 48288, *VII.D.1.b. Final FIP Allocation Methodology*
- ³⁸ See *supra* note 26, Table IV.D-3, pp. 48261-48262 for state SO₂ budgets. See *supra* note 3 for the source of state level emissions in 2010.
- ³⁹ See *supra* note 26, Table IV.D.3 and Table IV.D.4, pp. 48261-48263. See *supra* note 3 for the source of state level emissions in 2010.
- ⁴⁰ See *supra* note 26, p. 48349, *XII.J.1.a. Emission Reductions*
- ⁴¹ See *supra* note 26, p. 48219, *IV.C.1.d. Public Comments*
- ⁴² See *supra* note 26, p. 48325, *C. Interactions With Title IV Acid Rain Program*
- ⁴³ “In the state’s replacement provisions, the state may allocate allowances to Transport Rule units (whether existing or new units) 121 or other entities (such as renewable energy facilities) or may auction allowances. Additionally, state SIPs can address one or all of the pollutants addressed by the FIPs.” See *supra* note 26, p. 48327, *X. Transport Rule State Implementation Plans*
- ⁴⁴ “As discussed elsewhere in this preamble, EPA proposed that, if a unit with an existing-unit allocation does not operate for 3 consecutive years, the allowances that would otherwise have been allocated to that unit, starting in the seventh year after the first year of non-operation, would be allocated to the new unit set-aside for the state in which the retired unit is located. EPA is retaining this provision in the final rule but is changing the time of non-operation to 2 years and the time of allowance allocation to a non-operating unit to 4 years. Starting in the fifth year of non-operation, allowances will be allocated to the new unit set-aside for the state in which the non-operating unit is located.” See *supra* note 26, p. 48292, *VII.D.2.d. Addition of Allowances to New Unit Set-Asides*
- ⁴⁵ See *supra* note 26, pp. 48271-48273 for a description of how this will work in general.
- ⁴⁶ See *supra* note 26, pp. 48265-48268. State variability limits are published in Tables VI.F-1, VI.F-2, and VI.F-3, pp. 48269-48270.
- ⁴⁷ See *supra* note 26, pp. 48294-48296. The assurance provision allows generating units to group together under a common Designated Representative (DR) so as to pool the risk of allowance surrender under the assurance provision. For example, if a DR has some units with emissions over their allowance allocation and some units under their allocation, on net they may not have exceeded their aggregate allocation they would not be subject to the surrender of two allowances for one ton exceeded. Table VII.E-1, p. 48296 provides an example of how the assurance provision works. The assurance provision effectively limits the amount of interstate trading, thus reducing the cost-effectiveness of the emission trading program under CSAPR relative to the Title IV SO₂ Program and NO_x Budget Programs that allowed unlimited trading.
- ⁴⁸ Non-mercury heavy metals include antimony (Sb); arsenic (As); beryllium (Be); cadmium (Cd); chromium (Cr); cobalt (Co); lead (Pb); manganese (Mn); mercury (Hg); nickel (Ni); selenium (Se).
- ⁴⁹ See *supra* note 18.
- ⁵⁰ See the EPA’s National Electric Energy Data System (NEEDS) database v.4.10 P_Tox available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/NEEDSv410_PTTox.xlsx.

- ⁵¹ See Perrin, Quarles, and Associates, Inc. *IPM Model – Revisions to Cost and Performance of APC Technologies: Wet FGD Cost Development Methodology*, August 2010, Prepared by Sargent & Lundy, LLC, available at <http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Appendix51A.pdf>, and Perrin, Quarles, and Associates, Inc. *IPM Model – Revisions to Cost and Performance of APC Technologies: SDA FGD Cost Development Methodology*, August 2010, Prepared by Sargent & Lundy, LLC, available at <http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Appendix51B.pdf>.
- ⁵² See Perrin, Quarles, and Associates, Inc. *IPM Model – Revisions to Cost and Performance of APC Technologies: Dry Sorbent Injection Cost Development Methodology*, August 2010, Prepared by Sargent & Lundy, LLC, available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/append5_4.pdf.
- ⁵³ *Id.* at 4. If accompanied by a fabric filter baghouse, removal efficiencies are estimated to be as high as 75-80 percent. PJM staff conversations with generation owners place removal efficiencies even lower at around 30 percent.
- ⁵⁴ EPA also evaluated the efficacy for other control technology options including dry sorbent injection (DSI), as potential alternatives for scrubbers and activated carbon injection for mercury control. A dry sorbent is injected into the flue gas ductwork downstream of the boiler where it reacts with the SO₂ and HCl and forms a compound, which is then captured in a downstream fabric filter or ESP and removed as waste. EPA believes that DSI will be an attractive SO₂ and HCl control technology option for smaller and medium sized bituminous coal-fired generating units.
- ⁵⁵ See The Brattle Group, *Potential Coal Plant Retirements Under Emerging Environmental Regulations*, December 8, 2010, available at <http://botarobs.com/documents/UploadLibrary/Upload898.pdf>.
- ⁵⁶ See Perrin, Quarles, and Associates, Inc. *IPM Model – Revisions to Cost and Performance of APC Technologies: SCR Cost Development Methodology*, August 2010, Prepared by Sargent & Lundy, LLC, available at <http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Appendix52A.pdf>. EPA believes significant co-benefit air toxics emission reductions will be achieved at existing coal- and oil-fired generating units also subject to the CSAPR with existing or planned retrofits of advanced SCR and flue-gas desulfurization (FGD) pollution control systems for NO_x and SO₂ control, lowering the compliance burden on affected facilities. SCR is considered beneficial to mercury control since it enhances oxidation of elemental mercury, especially from bituminous coals, as the flue gas passes through the catalyst, this ionic mercury is water soluble and susceptible to capture in a downstream FGD control device. See NESCAUM, *Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants* (March 31, 2011) at 18-19.
- ⁵⁷ See the EPA's National Electric Energy Data System (NEEDS) database v.4.10 P_ToX available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/NEEDSv410_PToX.xlsx.
- ⁵⁸ See Perrin, Quarles, and Associates, Inc. *IPM Model – Revisions to Cost and Performance of APC Technologies: SNCR Cost Development Methodology*, August 2010, Prepared by Sargent & Lundy, LLC, available at <http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Appendix52B.pdf>. For the removal efficiency, see National Electric Energy Data System (NEEDS) database v.4.10 P_ToX available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/NEEDSv410_PToX.xlsx.
- ⁵⁹ See Perrin, Quarles, and Associates, Inc. *IPM Model – Revisions to Cost and Performance of APC Technologies: Particulate Control Cost Development Methodology*, March 2011, Prepared by Sargent & Lundy, LLC, available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/append5_5.pdf and See Perrin, Quarles, and Associates, Inc. *IPM Model – Revisions to Cost and Performance of APC Technologies: Mercury Control Cost Development Methodology*, March 2011, Prepared by Sargent & Lundy, LLC, available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/append5_3.pdf.
- ⁶⁰ See *supra* notes 27, 28, 31, 33, and 34.
- ⁶¹ See *supra* notes 27, 28, 31, 33, and 34.
- ⁶² See United States Energy Information Administration, *Updated Capital Cost Estimates for Electric Generating Plants*, November 2010, available at http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf. See also Pasteris Energy, Inc., *Cost of New Entry Combined Cycle Power Plant Requirements for PJM Interconnection, L.L.C.*, filed in support of PJM Interconnection, L.L.C. FERC Docket No. ER11-2875-000, February 11, 2011, available at <http://pjm.com/~media/documents/ferc/2011-filings/20110211-er11-2875-000.ashx>. See also Pasteris Energy, Inc., *Cost of New Entry Combustion Turbine Power Plant Requirements Additional CONE Area Evaluation for PJM Interconnection, L.L.C.*, November 16, 2009, available at <http://www.pjm.com/~media/committees-groups/committees/cmec/postings/20091130-cone-ct-revenue-requirements-report.ashx>.
- ⁶³ See *supra* note 3 for data sources.
- ⁶⁴ The forecast data are for the PJM footprint without the ATSI or DEOK zones to allow for a like comparison across years. See PJM Resource Adequacy Department, *PJM Load Forecast Report*, January 2011, available at <http://pjm.com/documents/~media/documents/reports/2011-pjm-load-report.ashx>, and the associated data, available at <http://pjm.com/documents/~media/documents/reports/2011-load-report-data.ashx>. For the 2010 see PJM Resource Adequacy Department, *PJM Load Forecast Report*, January 2010, available at <http://pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process/~media/documents/reports/2010-load-forecast-report.ashx>.

⁶⁵ See *supra* note 6.

⁶⁶ See *supra* note 3.

⁶⁷ Source of data is PJM Interconnection, L.L.C. and Monitoring Analytics, L.L.C., the Independent Market Monitor for PJM. This data is commercially sensitive and is not publicly available.

⁶⁸ See *supra* Note 3 for data sources. The capacity resources external to PJM are majority owned by a group of PJM members.

⁶⁹ See *supra* note 3 for data sources.

⁷⁰ See *supra* note 3 for data sources. Many units currently control particulate emissions with electrostatic precipitators (ESPs), but would not seem to be sufficient for controlling the additional particulates introduced by ACI and DSI controls, nor do ESPs help in reducing particulate heavy metals as well as a fabric filter baghouse.

⁷¹ "There are various reasons that a combined ACI plus additional baghouse would be required. These include situations where the existing ESP cannot handle the additional particulate load associate with the ACI or where SO₃ injection is currently in use to condition the flue gas for the ESP. Another cause for combined ACI and baghouse is use of PRB coal whose combustion produces mostly elemental mercury, not ionic mercury, due to this coal's low chlorine content." See EPA's *Documentation Supplement for EPA Base Case v4.10_PTox – Updates for Proposed Toxics Rules*, p83, Methodology for Obtaining ACI Control Costs available at <http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/suppdoc.pdf>

⁷² See *supra* note 3 for data sources.

⁷³ See *supra* note 3 for data sources.

⁷⁴ See *supra* note 3 for data sources.

⁷⁵ See EPA's List of facility/unit Hg stack emission averages from the EU MACT ICR Parts II and Part III available under Utility MACT ICR Data available at <http://www.epa.gov/ttn/atw/utility/utilitypg.html>

⁷⁶ Examination of the unit specific heat input and allowance allocations of sources subject to the SO₂ limits shows that the 2014 cap for all Group 1 and Group 2 states implies an emissions rate of 0.166 lbs SO₂/mmBtu. See *Final CSAPR Unit Level Allocations under the FIP and Underlying Data* available at <http://www.epa.gov/crossstaterule/pdfs/UnitLevelAllocData.xls>. The target SO₂ emission rates of 0.15 lb/mmbtu for coal and oil, and 0.125 for gas-fired boilers were selected in an attempt to determine the amount of SO₂ reduction, and thus the type of control that would be needed by the steam units to meet proposed CATR and acid gas limits (also keeping in mind that SIPS for the recently revised SO₂ NAAQS are being developed). The target is loosely based on the New Jersey mercury limits that included a 0.15 lb/mmbtu limit for boilers beginning in 2012. See *N.J.A.C. 7:27-27 Control and Prohibition of Mercury Emissions*, p. 13, Section 7(d)2, available at <http://www.nj.gov/dep/aqm/Sub27.pdf>. The Illinois mercury rule established a limit of 0.11 lb/mmbtu for coal boilers. See TITLE 35: ENVIRONMENTAL PROTECTION SUBTITLE B: AIR POLLUTION CHAPTER I: POLLUTION CONTROL BOARD SUBCHAPTER c: EMISSION STANDARDS AND LIMITATIONS FOR STATIONARY SOURCES PART 225 CONTROL OF EMISSIONS FROM LARGE COMBUSTION SOURCES Section 225.295 Combined Pollutant Standard: Emissions Standards for NO_x and SO₂ a) Emissions Standards for NO_x and Reporting Requirements, available at <http://www.ipcb.state.il.us/documents/dsweb/Get/Document-55740/>. SO₂ emission rates of 0.1 appear to be the average low end of the scale for units that are using FGD, with some units having controlled emission rates up around 0.3 lb/mmbtu. Again this number was not an attempt to find the lowest emission rate possible, it was an attempt to define the average emission rate that could be achieved by the fossil fuel-fired boilers employing FGD, so that a choice of FGD or DSI could be distinguished.

⁷⁷ Examination of the unit specific heat input and allowance allocations of sources subject to the NO_x limits shows that the 2014 cap for all states implies an emissions rate of 0.09 lbs NO_x/mmBtu. See *Final CSAPR Unit Level Allocations under the FIP and Underlying Data* available at <http://www.epa.gov/crossstaterule/pdfs/UnitLevelAllocData.xls>. The target emission rates of 0.15 for coal, 0.20 for residual oil, 0.10 for diesel oil, and 0.10 for gas-fired boilers were selected, as well, in an attempt to determine the amount of NO_x reduction, and thus the type of control that would be needed by the steam units to meet the proposed CATR rules (also keeping in mind co-benefits for mercury, and that ozone NAAQS are being revised). The target is based on the NJ HEDD limits for boilers of 1.5 lb/MWh for coal, 2.0 lb/MWh for oil, and 1.0 lb/MWh for gas and diesel beginning in 2015 (1.0 lb/MWh is roughly equivalent to 0.10 lb/mmbtu). See *N.J.A.C. 7:27 -19 Control and Prohibition of Air Pollution by Oxides of Nitrogen*, p.27, Table 3, available at <http://www.nj.gov/dep/aqm/Sub19.pdf>. The Delaware multi-pollutant rule established a limit of 0.125 lb/mmbtu for coal and residual oil boilers. See TITLE 7 NATURAL RESOURCES & ENVIRONMENTAL CONTROL DELAWARE ADMINISTRATIVE CODE 1146 *Electric Generating Unit (EGU) Multi-Pollutant Regulation*, p.3 NO_x Emissions Limitations, available at <http://regulations.delaware.gov/AdminCode/title7/1000/1100/1146.pdf>. Again this number was not an attempt to find the lowest emission rate possible, it was an attempt to define the average emission rate that could be achieved by the fossil fuel-fired boilers employing SCR, so that a choice of SCR or SNCR could be distinguished, and units with existing controls could determine if they needed to spend money on upgrades.

⁷⁸ ACR data for the 2010/2011 Delivery Year to the 2012/2013 Delivery Year is available in the PJM Tariff, Attachment DD, Section 6.7(c) for each generating technology categories. Capital Recovery Factors are available in Section 6.8(a) of Attachment DD.

⁷⁹ PJM Open Access Transmission Tariff (PJM Tariff), Attachment DD, Section 6.8.

⁸⁰ *Id.*

⁸¹ Even in the absence of pollution control retrofit costs, there are still additional costs, ACR-related costs defined in the PJM Tariff in Attachment DD, Section 6.8(a) that would need to be covered by additional revenues.

⁸² *See supra* note 12.

⁸³ *See supra* note 13.

⁸⁴ In addition there is close to another 1,000 MW of coal-fired capacity that has not cleared in the past two consecutive BRAs where it is not clear if the units will retire.

⁸⁵ *See supra* note 15.

⁸⁶ *See supra* note 18.