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A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT

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Executive Summary

In this report, we:[1] (1) predict incremental coal plant retirements and pollution control retrofits resulting from US Environmental Protection Agency (EPA) proposed and forthcoming air regulations;[2] and (2) assess their impact on electric system reliability. The specific air regulations we considered in our analysis are the EPA's proposed Clean Air Transport Rule regulating SO_2/NO_x interstate pollution transport (Transport Rule) and forthcoming hazardous air pollutants regulations (utility MACT) described more fully in the Introduction section of this paper. Implementing these regulations will require some coal generators to install pollution control equipment in order to continue operations. However, given the recent discoveries of abundant, domestic natural gas supplies, a competing fuel for electric generation, as well as reduced electricity demand, coal plant owners may elect to retire some existing plants rather than investing the capital necessary to install pollution controls. Nonetheless, we conclude that electric system reliability can be maintained while the industry complies with EPA's air regulations.

The number of projected coal plant retirements nationwide is relatively small compared to historical US net additions of generation capacity, and the electric sector has demonstrated repeatedly the ability to expand the generation fleet at a rate well in excess of projected capacity needs. Although we predict that a handful of areas will have de minimis or modest shortfalls due to predicted retirements, adequate reserve margins can be maintained by better utilizing existing supply capacity, installing new generation, and increasing load management. Additionally, existing federal statutory, state regulatory, and regional transmission organization (RTO) market safeguards can be utilized to maintain a reliable electric system.

Some observers have expressed concern that accelerated coal unit retirements might adversely impact electric system reliability. To evaluate that concern, we:

1. Forecasted coal retirements in the US under an aggressive policy representation consistent with the Transport Rule and utility MACT (utility MACT/CAIR NO_x).[3]

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[1] This report was prepared by Charles River Associates (CRA) for Exelon Corporation.

[2] Notably, approximately 6 GW of retirements are already planned, driven by low power prices which are due to low natural gas prices and low electricity demand.

[3] EPA has indicated that the Transport Rule's NO_x cap will be tightened in the near future ("Transport Rule II"), so we modeled the Clean Air Interstate Rule (CAIR) NO_x policy instead of the current Transport Rule's NO_x policy because it is more stringent and likely a better representation of Transport Rule II.

2. Provided a reliability analysis for the Eastern Interconnection[4] based on expected load growth, likely new generation additions, and projected coal retirements at the RTO level,[5] North American Electric Reliability Corporation (NERC) regional level, and NERC subregional level.

3. Identified actions that can be taken to maintain system reliability.

Our conclusion that EPA air regulations can be implemented without adversely impacting electric system reliability comports with other industry reports that have been released in the past several months.[6] Most recently, NERC published its assessment of possible impacts of four EPA regulations, including the air regulations examined in this paper. NERC concluded that of the four regulations assessed, EPA's potential 316(b) water regulations would have the greatest impact on reliability, and further urged coordinating implementation of EPA's various regulations to mitigate reliability impacts.

When considering EPA's air regulations alone, NERC actually predicts fewer retirements than we do, even under its "strict case" scenario. Additionally, NERC, as well as the M.J. Bradley & Associates/Analysis Group report, identify a suite of industry tools, some of which are discussed in this paper, that can be utilized to mitigate any reliability impact of the EPA air regulations.[7]

Specifically, our analysis reaches the following conclusions:

- **Coal plant retirements will not adversely impact reliability**. The existing US coal fleet has about 314 GW of capacity, about 265 GW of which is located in the Eastern Interconnection. When considering both the currently planned 6 GW of retirements, plus those driven by an aggressive utility MACT/CAIR NO_x policy, we project a total of 35 GW of coal retirements in the Eastern Interconnection and 39 GW nationwide

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[4] See definition of Eastern Interconnection in footnote 21. The US portion of the Eastern Interconnection contains about 73% of the electric generation capacity in the US.

[5] The RTOs in the Eastern Interconnection are: Independent System Operator (ISO) New England, the New York ISO, the PJM Interconnection, the Midwest ISO, and the Southwest Power Pool.

[6] M. J. Bradley & Associates/Analysis Group, "Ensuring a Clean, Modern Electric Generation Fleet while Maintaining Electric System Reliability," August 2010 (http://www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf); North American Electric Reliability Corporation, "2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential US Environmental Regulations," August 2010 (http://www.nerc.com/files/EPA_Scenario_Final_20101026.pdf); and ICF International, "EEI Preliminary Reference Case and Scenario Results," May 21, 2010.

[7] NERC 2010 Special Reliability Scenario Assessment Report, p. 40 and M. J. Bradley/Analysis Group Report, pp. 22-23.

by 2015. To put that in perspective, the 35 GW represents less than 5% of the Eastern Interconnection's more than 730 GW of total capacity.

- These projected retirements are relatively small in comparison to historical US net additions of generation capacity. For example, during the five-year period between 1999 and 2004, the net increase in US generating capacity was 177 GW, more than four times what is projected to retire in the US by 2015.

- Notably, the average age of the projected retiring units in the Eastern Interconnection is 55 years.[8] Many of these older units are already nearing the end of their design life expectancy.

- **After projected coal retirements, all five eastern RTOs have sufficient capacity to maintain reliability without any new resources beyond those that are already under construction.** Even excluding planned new generation in the permitting and site preparation stage, and after accounting for coal retirements resulting from the aggressive utility MACT/CAIR NO_x policy, all of the eastern RTOs have more than sufficient total resources to meet overall RTO reserve margin requirements in 2015. Although we project a few localized resource needs within the RTOs, these can be addressed through existing capacity markets and other tools discussed in this paper.

- **Modest capacity needs projected in the NERC regions and subregions can be easily met**. At the NERC regional level our analysis shows the utility MACT/CAIR NO_x policy drives only de minimis capacity shortfalls in two regions and a modest shortfall in another. At the NERC subregional level, one larger – but still manageable – shortfall is expected.[9] Two other subregional shortfalls are de minimis and modest. We believe that all of these shortfalls can be met with existing industry tools, such as:

  - **New Gas Generation Construction** – Our economic modeling shows that when new capacity is required, gas-fired generation is often the most economic alternative. In fact, the existence of abundant, inexpensive domestic natural gas resources not only is a driver of retirements but also will facilitate the transition to a cleaner generation fleet. History has shown that new gas units can be planned, permitted, and constructed in short periods of time. For example, in the Virginia-Carolina NERC subregion (VACAR), which our analysis indicates has the greatest need, almost 12 GW of gas-fired capacity

[8] CRA calculated the capacity-weighted average age of the coal units that retire by 2015 in the Eastern Interconnection in its simulation of the utility MACT/CAIR NO_x policy. The result of the calculation was 55 years.

[9] This larger projected subregional shortfall would mostly exist in the absence of the forthcoming air pollution regulations assessed in this paper.

came online between 2000 and 2004, which is significantly more than its projected capacity shortfall of 6.3 GW.

- **Load Management** – Load management tools, such as demand response and energy efficiency programs, are growing rapidly and have the capability to offset some of the projected coal retirements. Some of the NERC subregions with larger capacity shortfalls also have the greatest untapped potential for substantially increasing load management resources. For example, in the VACAR region, load management accounts for 3.4% of resources at peak, while in the New England region, load management accounts for close to 10% of peak resources.

- **Coal to Gas Conversion -** Depending on the local availability of natural gas, existing coal units can be converted to natural gas for a relatively modest cost.[10] For example, in the Southeast Reliability Corporation (SERC) region, which has a de minimis projected capacity shortfall of 0.6 GW, about 11 GW of coal plants already have natural gas pipeline service and have natural gas as a secondary fuel option.

- **Alternative Technologies and Tools** - Application of alternative and lower cost pollution control technologies and other regulatory tools could realistically result in even less coal plant retirements than we predict by 2015.[11]

- **Additional regulatory safeguards exist to protect reliability.** To address any remaining reliability concerns, the EPA Administrator, the Secretary of Energy, and the President each have authority under the Clean Air Act to extend compliance by one to two years under specific circumstances. For example, in August 2005, to protect reliability, the Secretary of Energy used his authority to prohibit Mirant from retiring its Potomac River plant. Mirant subsequently retrofitted the Potomac River plant, which is still in service today.[12] Additionally, RTOs have market rules and

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[10] In its December 20, 2000 regulatory finding, EPA decided that natural gas-fired electric steam generation units are not subject to HAPs regulation (65 FR 79826). This finding did not apply to combustion turbines.

[11] The Institute of Clean Air Companies (ICAC) stated in recently filed comments, "ICAC would like to emphasize that the competition in the [air pollution control] industry in the last decade has matured and diversified the industry and has led to the development of many emission reduction technologies that are not as capital-intensive as the 'big-ticket' items of SCR, FGD, and baghouses. However, these less capital-intensive technologies can obtain significant reductions that, depending on the regulatory requirements, may allow a much more economical approach in the short-term." ICAC comments in *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers (ICI) and Process Heaters;* 75 FR 32006-32073 (June 4, 2010), filed on August 23, 2010, p. 2.

[12] In 2005, Mirant Corporation ceased operations at its Potomac River Generating Station in Alexandria, Virginia, after learning the plant's operations were causing exceedances of the National Ambient Air Quality Standards (NAAQS). In response, the Secretary of Energy responded to a petition and issued an

procedures under the Federal Energy Regulatory Commission's (FERC) jurisdiction that will serve to mitigate reliability impacts, as do state regulatory commissions in traditional cost-of-service states. Current EPA, Department of Energy (DOE), and FERC coordination should also considerably mitigate any reliability concerns.[13]

In summary, modeling an aggressive policy implementation of EPA's proposed and forthcoming air regulations, we demonstrate, consistent with other industry reports, that with prompt action and industry coordination, electric system reliability can be maintained. Of the areas we analyzed - 5 RTOs, 6 NERC Regions, and 7 NERC subregions - we project that after predicted coal retirements, most still have capacity surpluses. At the NERC regional level, we predict that two regions will have de minimis shortfalls (relative to resource adequacy requirements) and another region will have a modest shortfall. At the NERC subregional level, there are three subregions that emerge as having shortfalls – one is de minimis, one is modest, and the other is larger, but still manageable. Notably, the larger shortfall would exist even in the absence of the forthcoming EPA regulations and planning processes, new gas-fired plants, and incremental load management can easily address this shortfall.

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emergency order under Federal Power Act section 202(c) directing Mirant to operate the coal-fired plant only under certain, limited circumstances tailored to relieve the reliability risk while also mitigating the air quality issues.

[13]An interagency task force among FERC, EPA, and the White House Council on Environmental Quality already exists and has been meeting for months to consider and model solutions to address the impact of the various EPA regulations. In an October 26 *Electric Light & Power* article, FERC Chairman Jon Wellinghoff responded to the NERC 2010 Special Reliability Scenario Assessment Report by saying, "We are aware of the potential problems, and we are working in an interagency way to solve them….it doesn't raise any concerns that I wasn't already aware were there." http://www.elp.com/index/from-the-wires/wire_news_display/1290063498.html

Introduction

Proposed and Forthcoming Air Regulations

In the two decades following the Clean Air Act Amendments of 1990 (CAA), the majority of coal plants have installed pollution controls to reduce air emissions. Over the next several years, the EPA will implement regulations that will further reduce harmful air emissions. Specifically, on July 6, 2010, the EPA proposed the Clean Air Transport Rule to reduce SO_2 and NO_x "emissions within 32 states in the eastern United States that affect the ability of downwind states to attain and maintain compliance with the 1997 and 2006 fine particulate matter (PM2.5) national ambient air quality standards (NAAQS) and the 1997 ozone NAAQS."[14] The Transport Rule is intended to replace CAIR, which was remanded to EPA by the DC Circuit Court of Appeals in December 2008. At the time of writing this paper, however, CAIR is still the rule in effect since the final Transport Rule is not anticipated until the spring of 2011.

In addition, pursuant to consent orders, by the end of 2011, EPA is required by the court to issue final "utility MACT" rules regulating hazardous air pollutants (HAPs) emitted by electric generators, using maximum achievable control technology (MACT) standards as set forth in Section 112(d) of the CAA.[15] Utility MACT will likely regulate mercury, non-mercury metals (e.g., arsenic, lead, nickel, chromium), and acid gases (e.g., hydrochloric acid, hydrofluoric acid, cyanide), all of which the CAA designates as HAPs. Utility MACT will impact coal-generating units in particular,[16] causing some units to install pollution control equipment and others to retire.

[14] 75 FR 45210 (August 2, 2010); 31 states and the District of Columbia are covered by the Transport Rule.

[15] EPA attempted to regulate HAPs from coal plants and other sources through the Clean Air Mercury Rule (CAMR), but in 2008, the court vacated the rule as invalid. Among other things, the court found that EPA was required to regulate HAP emissions from power plants using MACT standards pursuant to Section 112 of the CAA. Shortly after, the American Nurses Association and other organizations sued EPA, resulting in a consent decree requiring EPA to issue draft MACT standards by March 16, 2011, and final MACT standards by November 16, 2011.

[16] EPA is under no compulsion to establish MACT standards for gas-fired steam electric generation units. During the Clinton administration, EPA determined under section 112(n)(1)(A) that gas-fired steam electric generation units did not warrant regulation under section 112 and therefore decided not to list them as targets for the MACT standard-setting process. That decision has never been challenged in the DC Circuit. EPA's determination did not apply to combustion turbines.

Assumptions Used for Analysis

As stated above, the purpose of this analysis is to assess the retirement and reliability implications of the proposed Transport Rule and forthcoming utility MACT regulations.[17] As the utility MACT rule has not yet been proposed, we made certain assumptions for our analysis. The key unknown element of utility MACT is which technologies will be required for compliance. Many observers believe that utility MACT will require wet scrubbers, sorbent injection (e.g., activated carbon), and advanced particulate control (e.g., fabric filters) for HAPs control. Others, however, believe that MACT compliance may allow lower cost and relatively inexpensive dry scrubbing options using sorbents to capture acid gases and metals (e.g., trona with activated carbon injection).[18] For purposes of our modeling, we assumed the more expensive technologies will be required, that is, activated carbon sorbent injection (ACI), fabric filter, and wet flue gas desulfurization (FGD) scrubbers.[19]

With respect to the Transport Rule, it has a relatively strict SO_2 cap, particularly when it tightens in 2014. However, as our aggressive utility MACT representation forces scrubbers to be installed on every operating coal unit, we do not model the Transport Rule SO_2 cap because it will be met *a priori* when a unit complies with our assumed utility MACT policy. On the other hand, the NO_x requirements under CAIR are more stringent in aggregate than the state-specific requirements under the proposed Transport Rule. EPA indicated in its Transport Rule Notice of Proposed Rulemaking that further

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[17] There are other potential regulations that could impact coal unit retirement decisions. Such regulations address cooling water, 316(b), and ash containment/disposal. In this paper, we do not address or discuss the electric sector impacts of future water and ash regulations.

[18] See, e.g., the ICAC letter to Senator Thomas Carper, November 3, 2010; http://www.icac.com/files/public/ICAC_Carper_Response_110310.pdf; pp. 1, 3, in which they stated "Less resource- and time-intensive technologies are available to be quickly deployed, offering the electric generating industry the needed flexibility to comply with the proposed Clean Air Transport Rule and the upcoming utility MACT. For example, direct sorbent injection (DSI) and dry scrubbing technology installation times are approximately 12 and 24 months, respectively" and "Going forward, ICAC expects a wide range of technologies will be available to provide flexibility for utility compliance strategies. In particular, we expect greater use of both DSI and dry scrubbing technologies, such as circulating dry scrubbers (CDS) and spray dryer absorber (SDA) technology, due to future backend water and disposal requirements. The added advantages of using these technologies are fewer resources required and shorter installation times – 12 months for DSI and 24 months for a dry scrubber. Moreover, the next round of [electric generation unit] control installations will likely be on smaller coal-fired units, and DSI and dry scrubbing are well-suited to smaller footprints and high-sulfur bituminous coal applications."

[19] Selective catalytic reduction units (SCRs) are another technology that oxidizes elemental mercury into a form that can be more easily captured in a scrubber. There is the potential that SCR requirements could also be part of the utility MACT. We have not included SCRs in our utility MACT representation and have therefore not chosen the most expensive representation possible. However, our utility MACT representation is likely towards the more expensive end of the spectrum of what utility MACT might entail, particularly if wet scrubbing is not determined to be MACT.

complementary action on NO_x was forthcoming, perhaps in concert with a more strict ozone NAAQS. Thus, to represent future NO_x policy, we model the more aggressive CAIR NO_x requirements. Although we do not impose or model the CAIR requirements on a state-level because CAIR does not restrict interstate trading as the Transport Rule does, the CAIR NO_x policy is more stringent in aggregate than proposed in the Transport Rule.

As for timing, the applicable consent decree requires a final utility MACT rule by November 2011 and pollution control equipment is required to be installed within three years of utility MACT promulgation.[20] This also coincides with CAIR's tightened NO_x requirement; therefore, when evaluating retirements and reliability impacts, we used 2015 as the implementation date.

In summary, our representation of future SO_2, NO_x, and HAPs policy is aggressive and assumes the CAIR NO_x policy plus a package of ACI, fabric filter, and FGD scrubber technology requirements to represent utility MACT. Together, we call this the utility MACT/CAIR NO_x policy. The technology requirements must be met by 2015 while CAIR stays on its current schedule (which tightens in 2015). If we had performed the modeling with 2016 as the first year of implementation, the level of retirements would have been virtually the same as we found for 2015.

Methodology

We used CRA's North American Electricity and Environment Model (NEEM) to estimate coal unit retirements under the utility MACT/CAIR NO_x policy representation described above. NEEM optimizes generation operation in each major region in the US, taking into account power transfer limits among regions. NEEM optimizes retirements, unit environmental retrofits, and new capacity additions by region over a 60-year period, taking into account the operating and cost characteristics of existing capacity and the capital and operating costs of potential new capacity. Appendix B details NEEM's input assumptions on load growth, fuel costs, and pollution control equipment. We used NEEM's forecasted coal retirements as the key inputs to our 2015 reliability analysis.

[20] CAA Section 112(i).

Reliability Implications of Projected Retirements

NERC is the electric reliability organization certified by FERC to establish and enforce reliability standards for the North American bulk-power system. The eight NERC reliability regions are shown in Figure 1.

Some NERC regions are divided further into subregions as shown in Figure 2. In the eastern US, the SERC region is subdivided into five subregions (Central, Delta, Gateway, Southeastern, and VACAR), while the NPCC region is divided into two subregions (New York and New England). As can be seen from Figure 3, which shows the RTOs in the Eastern Interconnection,[21] the New York and New England subregions in NPCC correspond to the New York ISO and the New England ISO, respectively, and the Southwest Power Pool (SPP) NERC region corresponds to the SPP RTO.

Aggregate Projected Coal Retirements

The US currently has about 314 GW of coal-fired capacity installed, with about 10 GW more scheduled to come online over the next two years. Of the 314 GW of existing coal-fired capacity, 169 GW already have FGD scrubbers and 52 GW are scheduled to add FGD scrubbers over the next four years, leaving about 92 GW, or only 30% of existing coal capacity that will need to either install pollution control equipment or retire.[22]

Our analysis projects approximately 35 GW of coal retirements in the Eastern Interconnection between 2010 and 2015, which includes about 6 GW of already announced retirements. Accordingly, we project approximately 29 GW of incremental retirements as a result of the aggressive utility MACT/CAIR NO_x policy we modeled. Table 1 shows these projected retirements, the bulk of which are in the ReliabilityFirst (RFC) and SERC regions.[23]

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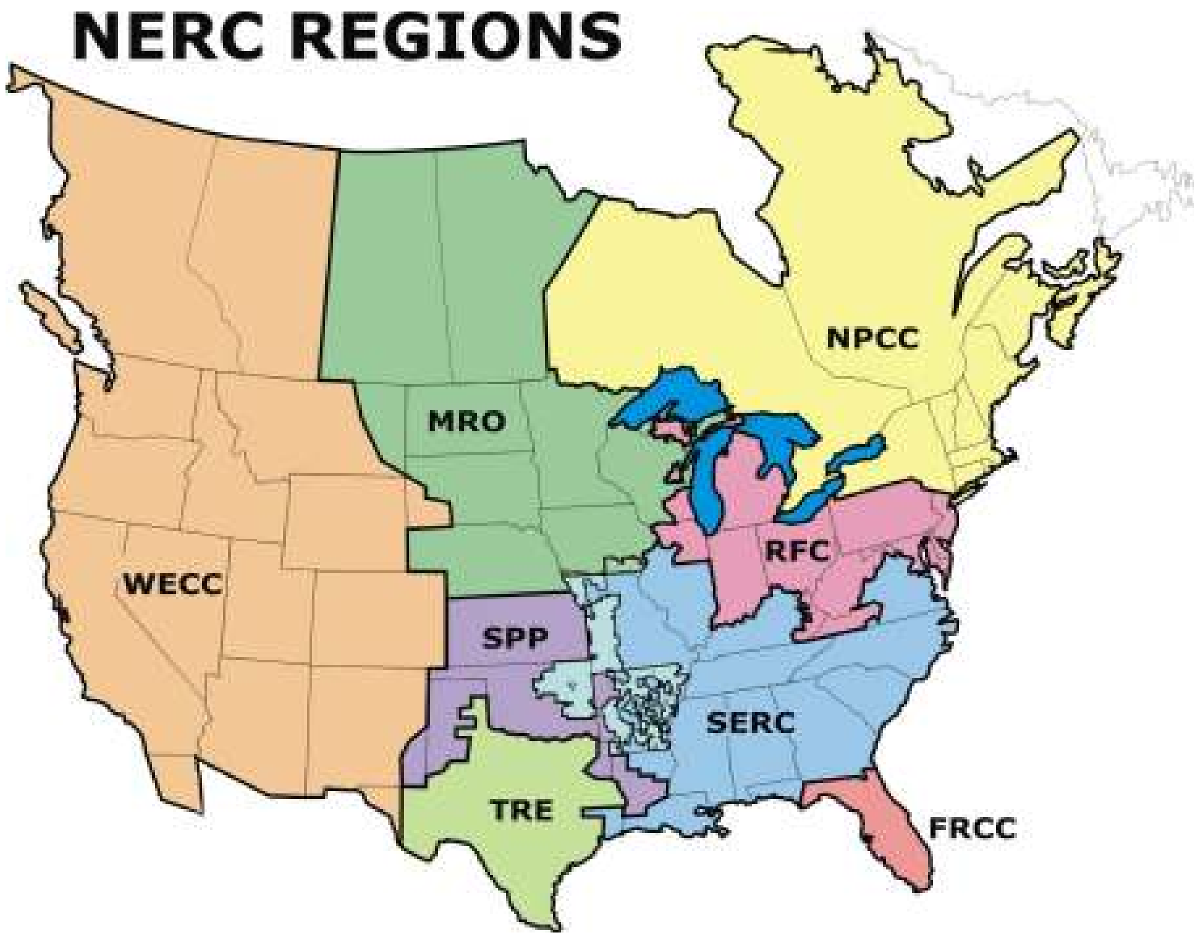
[21] The Eastern Interconnection consists of a large portion of the US and Canadian transmission system east of the Continental Divide, with the exception of a large portion of Texas, which is a separate interconnected system. Today, the Eastern Interconnection consists of six NERC reliability regions and five RTOs. All of the Eastern Interconnection transmission and generation is in one of the NERC regional reliability organizations, but only a portion of the generation and transmission is in an RTO. Although the NERC regions have responsibility for monitoring and enforcing NERC reliability standards in practice, within the RTO footprints the RTOs are ultimately responsible for taking the actions needed to ensure reliability in their control areas.

[22] New coal plants will have FGDs, SCRs, and fabric filters. Any additional controls that may be required to control HAPs at new coal plants (e.g., sorbent injection) will require little additional cost.

[23] We project only 4 GW of additional coal retirements outside of the Eastern Interconnection under the utility MACT/CAIR NO_x policy, bringing the total US projected coal retirements to 39 GW, when considering already planned retirements as well as those driven by the utility MACT/CAIR NO_x policy.

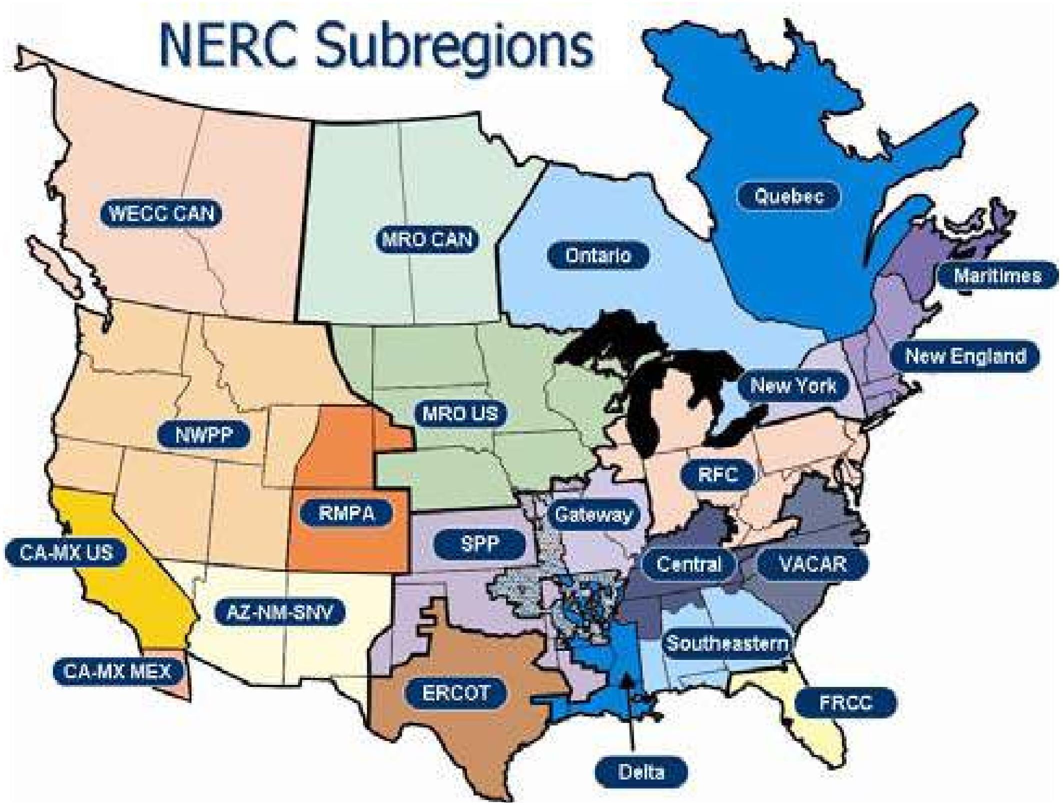
Notably, many of the already announced retirements, and projected retirements under our analysis, are driven by low natural gas prices caused primarily by the existence of abundant, inexpensive domestic natural gas resources. In other words, if we had used the higher natural gas prices that had existed only a few years ago in our modeling of the utility MACT/CAIR NO_x policy, the predicted retirement results would have been very different. Although low-priced natural gas presents economic challenges for existing plants, it will facilitate America's transition to a modern, cleaner generation fleet.

Figure 1. NERC Regions



Source: North American Electric Reliability Corporation (NERC)

Figure 2. NERC Subregions



Source: North American Electricity Reliability Corporation (NERC)

Figure 3. The Eastern Interconnection and RTOs

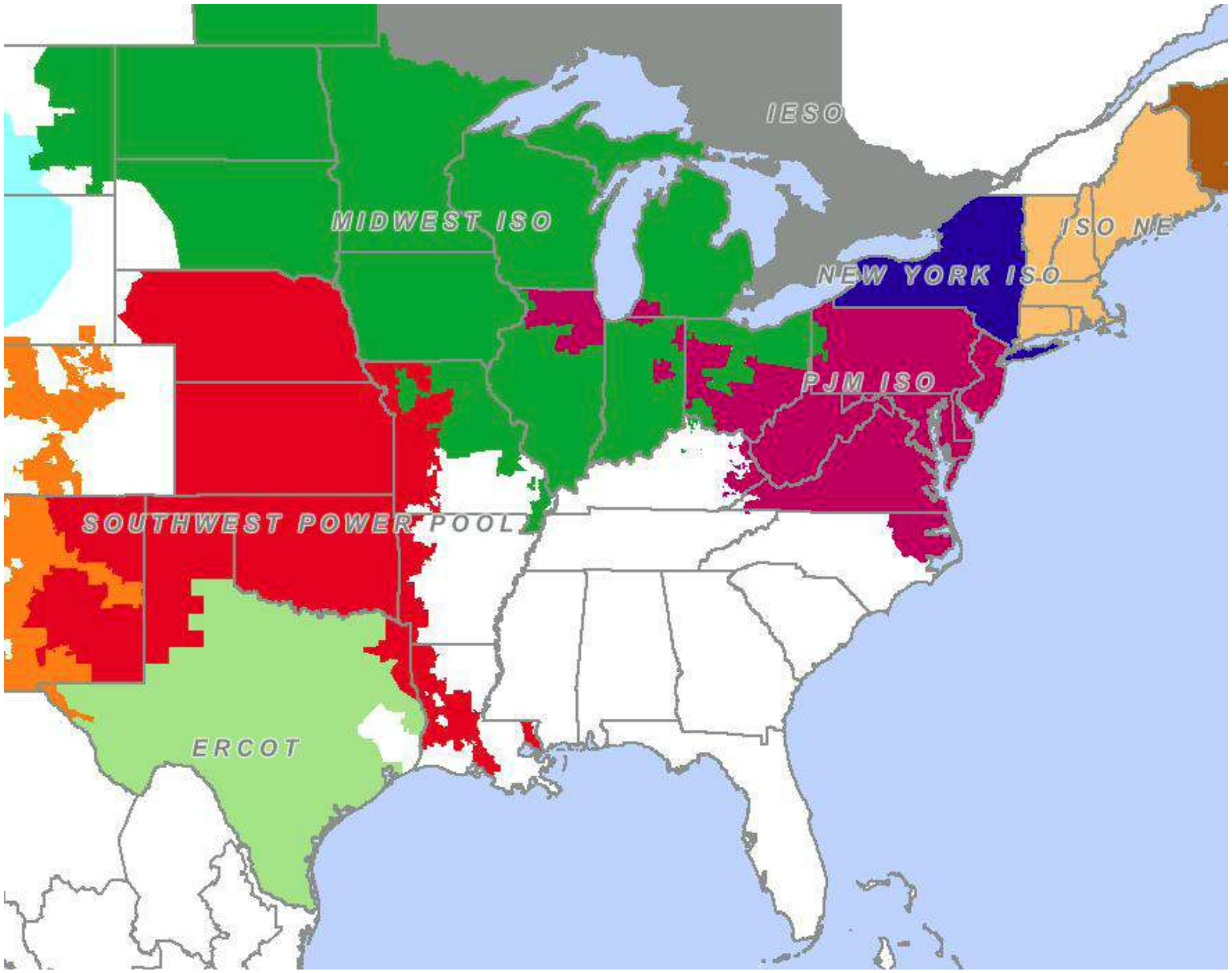


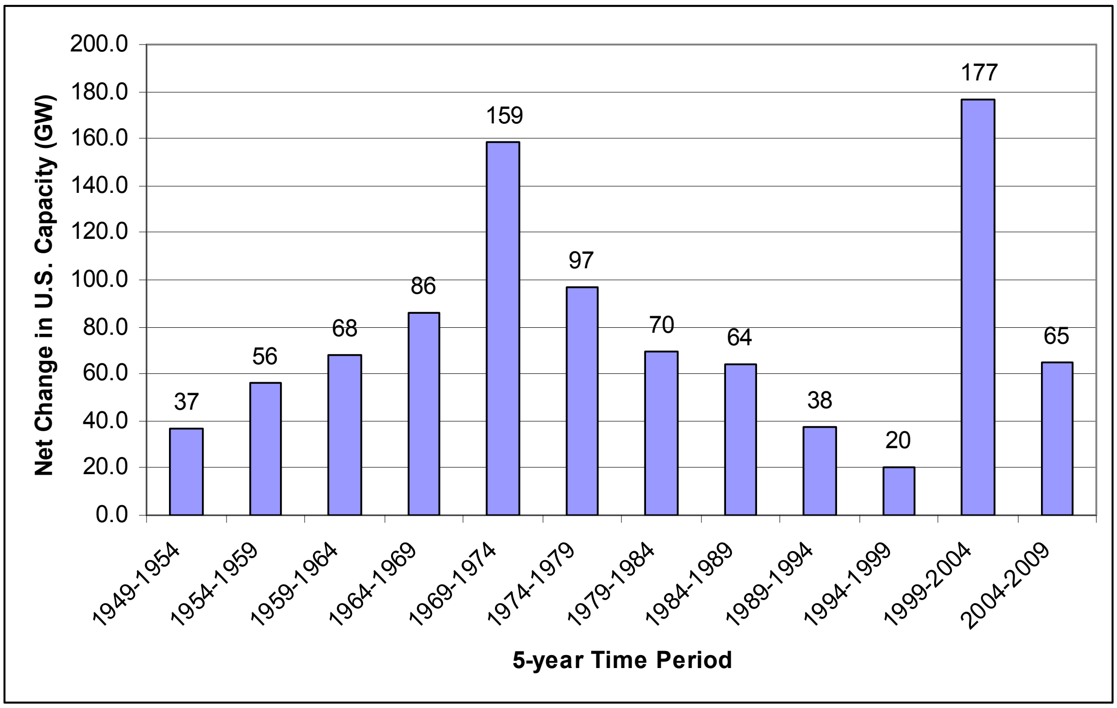
Table 1. Projected Coal Unit Retirements in the Eastern Interconnection under Utility MACT/CAIR NO_x

	Planned Retirements			Economic Retirements			Total Retirements		
NERC Region/Sub-Region	No. Units	Retired Coal Capacity (MW)	Average Size (MW)	No. Units	Retired Coal Capacity (MW)	Average Size (MW)	No. Units	Retired Coal Capacity (MW)	Average Size (MW)
Florida Reliability Coordinating Council	-	-	-	4	1,335	334	4	1,335	334
Midwest Reliability Organization	1	29	29	81	3,640	45	82	3,668	45
Northeast Power Coordinating Council	1	109	109	12	718	60	13	827	64
New England	1	109	109	5	370	74	6	479	80
New York	-	-	-	7	348	50	7	348	50
ReliabilityFirst	18	2,355	131	130	10,306	79	148	12,660	86
SERC Reliability Corp	28	3,232	115	122	12,716	104	150	15,948	106
Central	-	-	-	39	4,329	111	39	4,329	111
Delta	-	-	-	7	343	49	7	343	49
Gateway	-	-	-	10	641	64	10	641	64
Southeastern	5	750	150	30	4,407	147	35	5,157	147
VACAR	23	2,482	108	36	2,997	83	59	5,479	93
Southwest Power Pool Inc	-	-	-	17	664	39	17	664	39
Total	**48**	**5,724**	**119**	**366**	**29,378**	**80**	**414**	**35,102**	**85**

Note: Economic retirements are those that are not already planned, but are driven by environmental policy and increasing operating and maintenance costs.

To put the magnitude of the forecasted retirements in perspective, we reviewed the Energy Information Administration Annual Energy Review 2009 data, shown in Figure 4 for the entire US, indicating the historical net changes in electric generation capacity in the US over all of the five-year periods between 1949 and 2009. As the data reveal, the electric sector has repeatedly demonstrated the ability to expand the generation fleet at a rate well in excess of capacity needed to replace our projected retirements. For example, in the 1999-2004 period, the net increase in US generating capacity was 177 GW, more than four times the amount of US capacity we project to retire by 2015 due to the utility MACT/CAIR NO_x policy. As shown below, since 1949, in nine out of twelve periods the electric sector has added more capacity than is needed to replace the net projected US retirements arising from the utility MACT/CAIR NOx policy we modeled.

Figure 4. Net Changes in US Generating Capacity (GW)



Accordingly, based on the historical information in Figure 4, it is completely reasonable to expect that the 39 GW of projected coal retirements, and any incremental capacity needed due to demand growth, could be met easily with new capacity construction alone. In addition to new capacity, however, the industry possesses several other tools to manage reliability, such as increased load management programs and coal-to-gas conversion, discussed later in this paper.

Reliability Analysis at RTO Level

Our reliability analysis shows that all of the RTOs have sufficient resources to meet reserve margin requirements by 2015, even after accounting for coal retirements that result from the utility MACT/CAIR NO_x policy. This is true even if planned new additions in the permitting and site preparation stages are excluded from the calculations.

Table 2 shows the balance of loads and capacity resources for each RTO.[24] A more detailed table is provided in Appendix D. Our modeling first determined that all RTOs in the Eastern Interconnection have sufficient resources to meet reserve margin requirements by 2015 before accounting for the utility MACT/CAIR NO_x policy (see Column A). We then reduced the reserve margins to reflect the estimated coal plant retirements from the utility MACT/CAIR NO_x policy and found that reserve margin requirements would still be exceeded in all RTOs (see Column B). Finally, we added in all new additions in the permitting stage expected to be in service by 2015, which again shows that reserve margin requirements will be exceeded in all RTOs in the Eastern Interconnection (see Column C).

Table 2. Loads and Resources by 2015, RTO Level

RTO	*2015 Net Internal Demand Estimate (MW)	Required Reserve Margin (%)	Required Capacity (MW)	Projected Capacity PLUS Net Firm Transactions (MW), 2015	(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)	Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)	(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)	+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity	(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)	Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)
PJM	146,441	15.3%	168,846	178,061	9,215	7,529	1,686	2,350	4,036	2.8%
MISO	91,001	15.4%	105,015	127,088	22,073	7,074	14,999	435	15,434	17.0%
New England	26,180	15.0%	30,107	32,630	2,523	370	2,153	1,094	3,247	12.4%
New York	31,803	15.0%	36,573	38,892	2,318	348	1,970	192	2,162	6.8%
SPP	45,284	13.6%	51,442	53,409	1,966	664	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment" (for New England, New York, and SPP). For PJM, the PJM 2013/14 RPM Base Residual Auction Planning Parameters, total RTO load net of load management. For MISO, 2015 Coincident Net Internal Demand, Midwest ISO Transmission Expansion Plan (MTEP) 2009.

\+ Planned new additions that are in the "permitted" or "site prep" status categories.

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[24] Column A shows the 2015 capacity resource surplus/(shortfall) before the coal retirements driven by the utility MACT/CAIR NO_x policy that we have estimated using NEEM. Column A reflects both planned additions (additions either under construction or in the testing phase as indicated by Energy Velocity) and planned retirements. Column B shows the surplus/(shortfall) after adjusting for our incremental coal retirement projections through 2015. Column C shows the surplus/(shortfall) after adding permitted additions (i.e., planned additions that have acquired permits or have both acquired permits and begun site preparation). Column C represents the resource adequacy surplus/(shortfall) that could be achieved under utility MACT/CAIR NO_x policy by doing nothing other than completing projects that are under construction and building those that already have been permitted. These calculations are explained further in the ***Estimating Reliability Impacts*** section in Appendix B.

Moreover, these RTOs have mechanisms in place to ensure that resource adequacy is maintained and new capacity is planned and built when needed. Each RTO has an installed reserve margin requirement and load serving entities (LSEs) are responsible for securing sufficient resources to meet those requirements. In the case of PJM and ISO New England, a centralized forward capacity market mechanism has been implemented, with the market operator acting as central buyer of capacity resources and allocating the costs back to LSEs.

In New York, the ISO has a short-term market for capacity designed to provide adequate compensation to new generation resources when needed. The monthly market is designed to support development of new capacity and provide incentives for LSEs to secure new capacity resources in order to avoid high short-term market prices.

The MISO market depends on self-supply and bilateral contracting by LSEs, supplemented by a voluntary short-term market, to meet the mandated requirements. LSEs that have not secured sufficient capacity are subject to substantial financial penalties. The MISO is also considering adopting a forward market mechanism for resource adequacy.

While SPP has no centralized capacity market, LSEs are subject to reserve margin requirements and must either develop new resources when needed or enter bilateral contracts with other suppliers.

Reliability Analysis at the NERC Regional Level

At the NERC regional level, our analysis reveals modest resource adequacy shortfalls that can be easily addressed by new capacity additions and other industry tools.

Table 3 shows the balance of loads and capacity resources for each NERC region.[25] A more detailed table is provided in Appendix D. Our modeling first determined that all NERC regions in the Eastern Interconnection have sufficient resources to meet reserve margin requirements by 2015 before accounting for the utility MACT/CAIR NO_x policy

[25] Column A shows the 2015 capacity resource surplus/(shortfall) before the coal retirements driven by the utility MACT/CAIR NO_x policy that we have estimated using NEEM. Column A reflects both planned additions (additions either under construction or in the testing phase as indicated by Energy Velocity) and planned retirements. Column B shows the surplus/(shortfall) after adjusting for our incremental coal retirement projections through 2015. Column C shows the surplus/(shortfall) after adding in permitted additions (i.e., planned additions that have acquired permits or have both acquired permits and begun site preparation). Column C represents the resource adequacy surplus/(shortfall) that could be achieved under utility MACT/CAIR NO_x policy by doing nothing other than completing projects that are under construction and building those that already have been permitted. These calculations are explained further in the ***Estimating Reliability Impacts*** section in Appendix B.

(see Column A). When considering the utility MACT/CAIR NO_x policy, and including all planned new additions,[26] we found modest shortfalls in only three NERC regions (as shown in Column C): (1) 2,528 MW (6%) in MRO; (2) 583 MW (< 1%) in RFC; and (3) 638 MW (< 1%) in SERC.[27]

These modest shortfalls can be managed easily with construction of new gas-fired power plants and/or incremental load management. Not only can new gas units be planned, permitted, and constructed in less than three years,[28] filling most, if not all, of any capacity shortfalls, but regional shortfalls should also make construction of these units economically attractive. Any remaining shortfalls could be addressed by expanded load management programs.

Table 3. Loads and Resources by 2015, NERC Regional Level

NERC Region	*2015 Net Internal Demand Estimate (MW)	Required Reserve Margin (%)	Required Capacity (MW)	Projected Capacity PLUS Net Firm Transactions (MW), 2015	(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)	Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)	(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)	+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity	(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)	Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)
FRCC	47,330	15.0%	54,429	55,760	1,331	1,335	(4)	2,550	2,546	5.4%
MRO	42,681	15.0%	49,083	49,818	735	3,640	(2,905)	377	(2,528)	-5.9%
NPCC	60,894	15.0%	70,028	71,521	1,494	718	776	1,286	2,062	3.4%
RFC	186,008	15.0%	213,909	221,280	7,371	10,306	(2,935)	2,351	(583)	-0.3%
SERC	213,891	15.0%	245,975	252,120	6,145	12,716	(6,571)	5,934	(638)	-0.3%
SPP	45,284	13.6%	51,442	53,409	1,966	664	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment."

\+ Planned new additions that are in the "permitted" or "site prep" status categories.

[26] Permitted units are included in these estimates and can be completed quickly as they confront no regulatory hurdles.

[27] The FRCC, NPCC, and SPP regions do not have resource adequacy shortfalls, even after accounting for our projected retirements due to the utility MACT/CAIR NO_x policy.

[28] For example, in August 2009, the Tennessee Valley Authority (TVA) decided to construct an 880 MW combined-cycle facility adjacent to the John Sevier plant in Tennessee. The need for the new gas plant was determined after the US District Court in Western North Carolina set an aggressive timeline for installing new emission controls for the John Sevier coal plant or retiring that plant. TVA will have the new gas capacity online by January 1, 2012, less than two-and-a-half years from the date of the decision to build.

Reliability Analysis at the NERC Subregional Level

Based on our analysis, all but one of the NERC subregions in the Eastern Interconnection have sufficient resources to meet reserve margin requirements by 2015 before accounting for the utility MACT/CAIR NO_x policy. The exception is VACAR, which is projected to have a shortfall of 5,200 MW by 2015, prior to implementation of the utility MACT/CAIR NO_x policy.

Table 4 shows our loads and resources balance at the NERC subregional level.[29] A more detailed table is provided in Appendix D. After accounting both for already announced retirements plus incremental retirements driven by the utility MACT/CAIR NOx policy, six subregions have no resource adequacy shortfalls: FRCC, NPCC-New England, NPCC-New York, SERC-Delta, SERC-Gateway, and SPP (see Column C). We project the following three SERC subregions (in addition to MRO and RFC which were already identified and discussed in the NERC Regional Level section) to have resource adequacy shortfalls:[30] (1) 1,403 MW (3%) in Central; (2) 681 MW (1%) in Southeastern; and (3) 6,322 MW (9%) in VACAR. Significantly, only about 1,100 MW of VACAR's projected 6,322 MW shortfall results from the utility MACT/CAIR NO_x policy implementation.

Just as with the NERC regional analysis, the shortfalls in all the subregions can be addressed by construction of new gas-fired power plants and/or incremental load management, even in VACAR where the capacity needs are greatest. For example, in the VACAR region there is an opportunity for expanding load management to offset much of the projected economic retirements since load management resources only represent about 3.4% of peak load.[31] As other regions of the Eastern Interconnect demonstrate, load management resources can be used to meet much higher percentages of peak load. In the New York ISO, for example, about 7.5% of capacity resources are load management resources, and in the New England ISO they represent about 10% of capacity. In PJM, a total of 14,000 MW of load management, or about 9% of peak, has been offered into the

[29] Column A shows the 2015 capacity resource surplus/(shortfall) before the coal retirements driven by the utility MACT/CAIR NO_x policy that we have estimated using NEEM. Column A reflects both planned additions (additions either under construction or in the testing phase as indicated by Energy Velocity) and planned retirements. Column B shows the surplus/(shortfall) after adjusting for our incremental coal retirement projections through 2015. Column C shows the surplus/(shortfall) after adding in permitted additions (i.e., planned additions that have acquired permits or have both acquired permits and begun site preparation). Column C represents the resource adequacy surplus/(shortfall) that could be achieved under utility MACT/CAIR NO_x policy by doing nothing other than completing projects that are under construction and building those that already have been permitted. These calculations are explained further in the ***Estimating Reliability Impacts*** section in Appendix B.

[30] The MRO and RFC subregions are identical to the MRO and RFC regions, and accordingly the shortfalls presented in Table 4 for those subregions are the same as those presented in Table 3. As already discussed, those shortfalls are modest and can be readily addressed by new capacity additions and other industry tools.

[31] NERC 2010 Summer Assessment Table 2b, p. 15.

Reliability Pricing Model (RPM) market, with almost half clearing, or about 6,800 MW clearing. Some of the increased load management resources in VACAR could come from the PJM RPM market in Dominion's region. Also notably, much of the uncleared load management resources are in locations that have a current surplus but are expected to have retirements, creating an opportunity for load management growth in those areas in the future.

New gas-fired capacity could also be added to manage any capacity shortfall. Our modeling shows that in many cases, building new gas-fired plants is an economic alternative to retrofitting older coal units with pollution control equipment. In fact, in the 2000 to 2004 period, almost 12,000 MW of gas-fired capacity came online in VACAR, about 6,000 MW greater than the projected shortfall.

Table 4. Loads and Resources by 2015, NERC Subregional Level

NERC Sub-Region	*2015 Net Internal Demand Estimate (MW)	Required Reserve Margin (%)	Required Capacity (MW)	Projected Capacity PLUS Net Firm Transactions (MW), 2015	(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)	Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)	(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)	+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity	(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)	Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)
FRCC	47,330	15.0%	54,429	55,760	1,331	1,335	(4)	2550	2,546	5.4%
MRO	42,681	15.0%	49,083	49,818	735	3,640	(2,905)	377	(2,528)	-5.9%
NPCC - New England	26,180	15.0%	30,107	32,630	2,523	370	2,153	1094	3,247	12.4%
NPCC - New York	31,803	15.0%	36,573	38,892	2,318	348	1,970	192	2,162	6.8%
RFC	186,008	15.0%	213,909	221,280	7,371	10,306	(2,935)	2351	(583)	-0.3%
SERC - Central	44,956	15.0%	51,699	53,262	1,563	4,329	(2,766)	1363	(1,403)	-3.1%
SERC - Delta	30,167	15.0%	34,692	40,111	5,419	343	5,077	513	5,590	18.5%
SERC - Gateway	19,883	11.9%	22,250	23,819	1,569	641	929	62	991	5.0%
SERC - Southeastern	52,889	15.0%	60,822	62,427	1,604	4,407	(2,802)	2121	(681)	-1.3%
SERC - VACAR	67,838	15.0%	78,014	72,814	(5,200)	2,997	(8,197)	1874	(6,322)	-9.3%
SPP	45,284	13.6%	51,442	53,409	1,966	664	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment."

+ Planned new additions that are in the "permitted" or "site prep" status categories.

Tools for Addressing Local and Regional Capacity Resource Needs

In addition to the industry tools discussed previously, such as construction of new generation and increased load management, several other tools and market and regulatory safeguards exist to alleviate any reliability issues caused by coal plant retirements. First, coal units can convert to natural gas to meet existing state pollution control requirements and anticipated utility MACT obligations. Second, in traditional cost-of-service markets, regulators can apply local regulatory protections to mitigate reliability concerns. Third, competitive electricity markets have proven, transparent rules and policies specifically designed to ensure sufficient resource adequacy and mitigate retirement impacts. Finally, existing broad statutory and regulatory safeguards can help preserve reliability in the unlikely event the tools discussed above prove inadequate.

Coal to Gas Conversion

EPA has determined that natural gas-fired electric steam generation units do not fall under HAPs regulations.[32] Thus, if a coal-fired unit were converted to natural gas, it would meet its obligations under the utility MACT. Many utilities are already doing exactly that to achieve their pollution control requirements. For example, Public Service Colorado (PSCo) planned to convert a coal unit, Arapahoe 4, to natural gas as part of a package of measures that also includes environmental retrofits, retirements, and unit replacement in response to Colorado's "Clean Air-Clean Jobs Act."[33] The Public Utilities Commission of the State of Colorado modified PSCo's plan to also convert Cherokee 4, a 352 MW coal unit to natural gas as well.[34]

Of the 264 GW of coal capacity in the Eastern Interconnection, about 41 GW have natural gas pipeline access and can use natural gas as a secondary fuel, and accordingly could pursue a similar strategy. In some circumstances, the cost of converting units can be economic[35] and the time to convert relatively short. In effect, a gas conversion

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[32] See December 20, 2000 regulatory finding (65 FR 79826). This finding does not apply to combustion turbines.

[33] See also, *Denver Post*, August 8, 2010, http://www.denverpost.com/frontpage/ci_15775014, "Xcel will start retrofitting its Denver-based Cherokee plant next year, converting 717 megawatts of generation to natural gas. The smaller Arapahoe plant would switch one unit to natural gas and another to a system designed to improve grid reliability, both by the end of 2013." "Xcel lays out natural-gas conversion plan for metro area."

[34] Final Order Addressing Emission Reduction Plan, Docket No. 10M-245E, Public Utilities Commission of the State of Colorado, December 15, 2010.

[35] "Complementary Technology and Conversion of Coal-Fired Plants to Natural Gas - Calpine will use natural gas as the primary fuel source for the Conectiv fleet, including two plants that were previously fueled by coal." Calpine Investor Relations Statement, July 1, 2010, http://phx.corporate-

replaces a coal unit with a natural gas peaking unit with about the same capacity as the original unit.

Market Safeguards

All markets in the Eastern Interconnection have procedures in place to protect electric system reliability. These market safeguard procedures include analysis and planning to enable rational and timely action to avoid capacity shortfalls. For example, in some regional wholesale competitive markets operated by RTOs, forward capacity markets facilitate advanced notice of capacity needs and provide price signals to incent new entry. In wholesale markets with vertically-integrated, traditionally regulated utilities, there is a legal obligation to serve load and state regulatory commissions require long-range, integrated resource planning.

RTO Markets

PJM and New England ISO's market-based forward capacity programs play an essential role in maintaining reliability, ensuring that any capacity shortfall is identified and addressed well in advance of any reliability issue. At the core of PJM's RPM is a region-wide Base Residual Auction (BRA), conducted about 40 months prior to each Delivery Year.[36] All existing capacity resources are required to submit an offer into each BRA, and developers may submit offers of proposed resources.

RPM provides a mechanism for including either the replacement cost or the economic cost of retrofitting existing coal facilities to comply with new environmental policies. Existing resources that face mandatory capital expenditures to comply with environmental regulations are eligible to include these costs in the offers. These resources include an adder in their capacity offer price equal to the amortized project expense "reasonably required to enable a Generation Capacity Resource … to continue operating…."[37] This "Avoidable Project Investment Recovery Rate" allows coal plants facing the new utility MACT/CAIR NO_x requirements to reflect the costs of compliance into their BRA offers. Because of the resulting higher offer prices, those offers will only

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ir.net/phoenix.zhtml?c=103361&p=irol-newsArticle&ID=1443628&highlight; "Planning for an Uncertain Future Case Study: Replacing Coal Units with Gas," Presentation at 2010 NARUC Annual Meeting, Sam Walters, Progress Energy, November 2010.

[36] Delivery Years begin on June 1 of a year and continue to May 31 of the following year. Hence, the "2012–2013 BRA," conducted in May 2009, secured capacity commitments for the twelve months beginning June 1, 2012.

[37] PJM Tariff, Attachment DD, § 6.8(a).

clear the BRA if they are the most economic alternative resource to satisfy either local or aggregate reliability needs.

RPM's facilitation of economic environmental upgrades was demonstrated when Maryland's *Healthy Air Act*[38] required substantial reductions in NO_x, SO_2, and mercury emissions from large coal-burning power plants beginning in 2010. Owners of the Maryland plants faced a choice similar to that under utility MACT: retrofit the existing facilities to comply, or shut them down. The cost of retrofitting was very high: at Mirant's plants alone, the publicly stated cost was $1.67 billion.[39] The cost of these retrofits was directly reflected in capacity offers for the 2009–2010 Delivery Year (when the *Healthy Air Act* reductions took effect) and contributed to an increase in the capacity price in Maryland.[40] These higher capacity prices, which were necessary to maintain local reliability, imposed an obligation on owners of these coal-fired plants that cleared to undertake those upgrades, funded by the higher capacity payments pledged in the future.

If an offer containing the retrofit recovery cost clears the RPM auction, the resource owner is required to make those upgrades. If it does not clear the RPM auction, and instead a less expensive resource is available to meet the region's capacity needs, the resource owner is free to file a deactivation request and retire the unit at the beginning of the Delivery Year covered by the BRA in which it did not clear.[41] The forward nature of the RPM auction provides advance notice that will help the resource owner and the RTO facilitate a smooth transition to a cleaner fleet.

Importantly, the RPM market furnishes locational capacity price signals, with premiums paid in areas with more critical resource adequacy needs, or with more costly resources available for providing resource adequacy. This locational aspect is significant in that capacity must be deliverable to load to maintain reliability. Due to limitations of the transmission system, some amount of capacity must be located near load centers. Without the locational aspect of the market, local resource adequacy needs might not be satisfied, as market-wide prices would not send price signals to support supply in the areas where it is most needed.

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[38] Annotated Code of Maryland, Environment: Title 2, Ambient Air Quality Control; Subtitle 10, Health Air Act; Sections 2-1001–2-1005.

[39] Power-Gen Worldwide, "FGD Systems Start Operating at 7 Mirant Coal-Fired Units," December 21, 2009, *available at*: http://www.powergenworldwide.com/index/display/articledisplay/371998/articles/power-engineering/projects-contracts-2/2009/12/fgd-systems-start-operating-at-7-mirant-coal-fired-units.html

[40] PJM Market Monitoring Unit, "Analysis of the 2009–2010 RPM Auction," pp. 25–26, *available at* http://www.monitoringanalytics.com/reports/Reports/2008/20092010-rpm-review.pdf.

[41] Although this is true as a general matter, in rare cases the generator may provide some location-specific reliability service, such as local-area voltage support, that may require transmission upgrades or other remedies before the unit can be deactivated.

PJM's RPM market has been a success at incenting both new generation resources and new load management. PJM reported that "[o]ver the period covering the first seven RPM Base Residual Auctions, 11,582 MW of new generation capacity was added, which was partially offset by 7,185 MW of capacity derations or retirements over the same period. Additionally, 12,967 MW of new Demand Resources were offered over the last seven auctions, an increase of more than 10,000 MW over that period, and 733 MW of new Energy Efficiency resources were offered in the 2013/2014 auction. The total net increase of installed capacity in PJM over the period of the last seven RPM auctions was 17,887 MW."[42]

In addition to RPM helping ensure adequate resources, RTOs also have market rules that can mitigate any reliability impacts of retirements. For example, PJM conducts reliability impact studies for all units that announce retirement, and requests that those identified as needed for reliability temporarily operate past their planned retirement date pursuant to "reliability must run" (RMR) agreements. To minimize any adverse environmental impacts, RMR agreements can be structured to limit a unit's operations for reliability purposes only. For example, Exelon Generation recently coordinated with PJM and the Pennsylvania Department of Environmental Protection to negotiate a consent decree and operating procedures related to an RMR agreement for its two retiring coal units, which require the units operate for reliability purposes only.[43]

Furthermore, transmission owners in RTOs have an ability to proactively manage long-range reliability issues relating to expected retirements. For example, Commonwealth Edison (ComEd), the local transmission owner in Chicago, proactively filed an application with the Illinois Commerce Commission[44] seeking permission to enhance its transmission system. In its application, ComEd noted the identified upgrades would be required to maintain system reliability in the event that two of Midwest Generation's at-risk coal units, Fisk and Crawford, were to retire.[45]

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[42] http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2013-2014-base-residual-auction-report.ashx, p. 14.

[43] The PJM Operating Procedures, which contain a copy of the consent decree, are posted at PJM's website at http://PJM.com/planning/generation-retirements.aspx.

[44] ICC Docket No. 10-0385; Commonwealth Edison Company; Application for authorization under Section 4-101 of the Illinois Public Utilities Act ("Act"), 220 ILCS § 5/4-101, or alternatively, for a Certificate of Public Convenience and Necessity, pursuant to Section 8-406 of the Act, to install, operate and maintain two new 345,000 volt electric transmission lines in Cook County, Illinois; filed June 11, 2010.

[45] Direct Testimony of Thomas W. Leeming, p. 2, lines 25-35.

Vertically Integrated Markets

In states with vertically integrated utilities, there is a legal obligation to serve load and state regulatory commissions require long-range, integrated resource plans (IRPs). For example, utilities in the VACAR region for which we project a possible 6,322 MW capacity shortfall, are state-regulated. A review of the IRPs of the major VACAR utilities[46] reveal that these companies plan to add about 2,800 MW of new gas-fired capacity before 2015, capacity we did not include in our capacity additions because the plants are not sufficiently advanced to pass our very conservative screen. Yet, these planned resources, such as Dominion's 1,100 MW Warren County Combined Cycle Plant (in the permitting phase), have state regulatory backing, which assures cost recovery. In addition, these IRPs include about 1,000 MW more load management than is shown in NERC's 2010 Summer Assessment. Thus, 3,800 MW of the potential 6,322 MW need in VACAR is already planned for under the required IRPs.

Statutory and Regulatory Safeguards

In the unlikely event that the mechanisms discussed in this paper are inadequate to mitigate reliability impacts of retirements, governmental and regulatory agencies have authority to grant delays or waivers of compliance in certain circumstances. First, EPA can exercise its statutory authority under the CAA to grant, on a case-by-case basis, extensions of time to complete pollution control installations. Under the CAA, the EPA can issue permits that grant a one-year extension beyond the normal statutory three-year period, "if such additional period is necessary for the installation of controls," providing a total of four years for compliance with the regulations.[47] Second, the President of the United States is authorized under Section 112 of the CAA to grant compliance extensions of up to two years on a case-by-case basis after a demonstration that the technology to implement utility MACT is not available. Finally, in certain emergency circumstances, the DOE has the authority under Section 202(c) of the Federal Power Act to override requirements under the CAA.[48]

Conclusions

To analyze the electric system reliability impacts of predicted coal-fired plant retirements on an RTO, NERC regional, and NERC subregional basis, we performed a detailed system modeling analysis of the Eastern Interconnection based on an aggressive policy

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[46] Dominion, Duke-North Carolina, Progress-North Carolina, Santee Cooper, and SCANA.

[47] CAA Sec 112(i)(3)(B).

[48] See footnote 12 for an illustration of such a remedy.

representation of the proposed and forthcoming EPA air regulations. We conclude that implementing EPA air regulations will not compromise electric system reliability. Rather, reliability can be maintained in all RTOs, and NERC regions and subregions through coal to gas conversions, new gas-fired generation, expansion of load management programs, and established market and regulatory safeguards. Of the areas we analyzed - 5 RTOs, 6 NERC Regions, and 7 NERC subregions - we project that after predicted coal retirements, most still have capacity surpluses. At the NERC regional level, we predict that two regions will have de minimis shortfalls (relative to resource adequacy requirements) and another region will have a modest shortfall. We predict that three subregions within SERC will have shortfalls. One such shortfall is de minimis, one is modest, and only one area, the VACAR subregion, has a larger shortfall. But notably, VACAR's 6,322 MW shortfall, only 1,100 MW of which are attributable to EPA's forthcoming air pollution regulations, can be easily managed: over half of the shortfall is already planned for under the required IRPs (new capacity and load management), and the rest, approximately 2,500 MW, could be addressed through construction of new gas-fired power plants or incremental load management.

Also significantly, the industry has consistently proven its ability to expand capacity relatively quickly to meet increased demand. In nine of the twelve five-year periods from 1949 to the present, at least 39 GW of new capacity was added nationwide, with 177 GW of mostly gas-fired capacity, or more than four times the projected US coal retirements, added in the 1999-2004 period alone. Futhermore, although projected retirements may cause some localized reliability issues, RTOs and state regulators are well-equipped to deal with any that arise.

Appendix A: Background Information on Reliability

Appendix B: Modeling and Methodology

Appendix C: PJM RPM Market Example

Appendix D: Detailed Calculations Tables

Appendix A: Background Information on Reliability

Generation resource adequacy is an integral part of reliability. In this section, we discuss how different areas of the country maintain resource adequacy. This background is important to our examination of the utility MACT/CAIR NO_x policy's potential effect on regional reserve margins to assess whether unit retirements could adversely affect electric reliability.

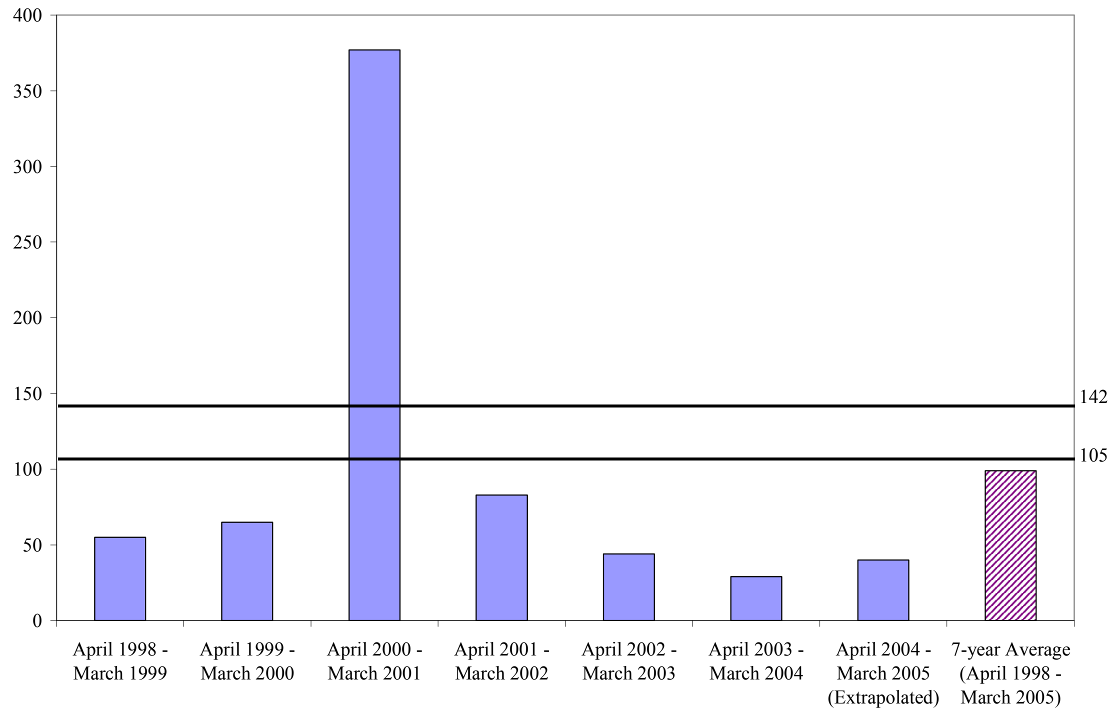
With a few notable exceptions, the electric utility industry has maintained an extremely high level of reliability. The first major reliability incident was in November 1965. Thirty million people lost power in the northeastern United States in what came to be called the "Northeast Blackout." In response, in 1968, NERC was established by the industry. Nine regional reliability organizations were formalized under the NERC umbrella, with regional planning coordination guides and operating criteria.

For almost 40 years there were no major outages in the eastern US, until August 2003, when 50 million people lost power in Northeastern and Midwestern US and Ontario. As a direct consequence of this blackout, in 2007, compliance with NERC standards, which had been voluntary, was made mandatory by the FERC. These standards primarily relate to short-term system operation and transmission system planning, with little reference to generation adequacy, which largely is left to RTOs, states and other entities.

Importantly, the two major eastern outages were not due to a lack of generation resources; both were triggered by transmission failures. The 1965 Northeast Blackout began when an improperly set protective relay shut off power after a small surge in upstate New York. The 2003 blackout occurred when high-voltage transmission lines in Ohio contacted overgrown trees. In its 2003 summer assessment, NERC reported that the NERC subregion where the transmission outage was triggered had a 28.3% reserve margin, which meant that available reserve generating capacity was significantly more than adequate.

It is possible to have a robust transmission system but have less than adequate reliability because of inadequate generation. Although resource shortages have rarely led to load shedding, it did occur in California in late 2000 and early 2001. Despite an installed capacity target in California, there was no mandate to maintain a required level of capacity. When California restructured its generation sector in 1996, it was assumed that energy prices would rise to the level needed to support new entry by independent power producers in time to maintain planning margins. While the California economy boomed, electricity demand grew rapidly, but little new generation was built because energy prices remained low and there was no other mechanism to provide ample revenue to support new entry. In fact, prices (unmitigated) would have had to rise to the high levels seen in the 2000-2001 crisis period to have provided sufficient revenue for a generator. But prior to May 2000, the California ISO market price signals were well below what a new entrant needed, and the futures markets for power were also quite weak. As a result, by 2000, available generation was well below what was required to maintain reliable service, and brownouts and blackouts occurred. Figure 5 below, which is from the FERC testimony of Dr. William Hieronymus of CRA, makes this point quite forcefully. The chart shows that energy prices both before and after the April 2000–March 2001 period were well below the $105-142/kW-year mark needed to finance an efficient new combined-cycle unit. Consequently, most merchant plant investors avoided California, and the merchant capacity that was added did not come online until after the crisis.

Figure 5. Margins Earned by Hypothetical New Combined-Cycle Unit Based on Unmitigated Prices ($1998/kW)



Source: Testimony of William H. Hieronymus in El03-180-00, *et al,* May 13, 2005.

As discussed in the report, unlike in California, mechanisms do exist in the Eastern Interconnection —namely, capacity markets and state regulation—to ensure that ample capacity will be available to maintain reliability. Consequently, a California-type crisis triggered by inadequate supply resources is far less likely in the Eastern Interconnection, provided that unit retirements are foreseen with sufficient notice to bring any required replacement resources into service.

The Eastern Interconnection consists of a large portion of the US and Canadian transmission system east of the Continental Divide, with the exception of a large portion of Texas, which is a separate interconnected system (see Figure 3). Today, the Eastern Interconnection consists of six NERC regional reliability organizations and five RTOs. All Eastern Interconnection transmission and generation is in one of the NERC regions, but only a portion of the generation and transmission is in an RTO. Although the NERC regions have responsibility for monitoring and enforcing NERC reliability standards in practice, the RTOs are ultimately responsible for taking the actions needed to ensure reliability in their control areas.

The RTOs conduct reliability impact studies for all units that announce retirement, and can offer RMR agreements to those units needed to temporarily operate past their planned retirement date to maintain reliability. For example, on December 2, 2009, Exelon Generation submitted a notice to retire four coal units at its Cromby and Eddystone stations in Pennsylvania. PJM studied the transmission system impact and determined that these retirements would adversely affect reliability until certain upgrades to the transmission system were made. PJM asked Exelon Generation to continue to operate one unit at each station beyond May 31, 2011. PJM and Exelon negotiated an RMR rate under the PJM Tariff, and FERC approved the RMR rate subject to hearing.[49]

Additionally, three of the RTOs (ISO New England, the New York ISO, and PJM) have established capacity markets to ensure that adequate capacity is online, and the Midwest ISO and SPP are moving to establish their own capacity markets as well.[50]

These capacity markets are designed to ensure that adequate capacity is online to meet load and that new entry occurs when and where needed. These payments can be substantial. For example, for the 2013/2014 period, a capacity resource in PJM outside of MAAC[51] will receive $27.73/MW-day ($10.12/kW-year), while resources in MAAC will receive from $226.15/MW-day ($82.54/kW-year) to $247.14/MW-day ($90.21/kW-year), depending on the location within MAAC. Because this forward market provides a signal three years in advance developers can see the need and capacity revenues they will receive early enough to develop new resources or, conversely, if capacity revenues will be inadequate to support existing resources, allowing for an orderly deactivation of these uneconomic resources.

Forward capacity markets, like those in PJM and ISO New England, therefore serve a dual purpose with respect to existing unit retirements. Existing units facing high costs, including capital costs related to environmental upgrades, may find themselves priced out of the market if that capacity is no longer needed for reliability; consequently, these "at risk" generators may choose to retire rather than earn capacity payments insufficient to cover their costs. If that capacity *is* needed for reliability, however, the capacity market provides a transparent price signal, set by the going-forward costs of existing units (including, when needed, capital expenses for environmental upgrades). If the all-in, levelized cost of new capacity resources is below the going-forward costs of these

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[49] http://pjm.com/~/media/documents/ferc/2010-filings/pjmmotion.ashx

[50] The Midwest ISO already conducts monthly capacity auctions through which it enforces resource adequacy standards, pursuant to Module E of its tariff.

[51] MAAC is the portion of PJM that corresponds to what used to be the NERC Mid-Atlantic Area Council. The term MAAC is still used by PJM to describe the eastern part of the PJM system.

highest-cost existing generators, then the older resources will be displaced by the more economic new units.

The New England ISO, the New York ISO, and PJM capacity markets selectively draw from a common set of objectives:

- Price signals for new capacity that are observable or reasonably predictable several years in advance of actual need.[52]
- Demand curves or other mechanisms that provide stability and lead to price formation that will set the price at the net cost of new entry (Net CONE) when capacity levels are at the target reserve margin, but will be higher than Net CONE if capacity is below the target reserve margin and less than Net CONE if capacity is above the target reserve margin.[53]
- Locational price signals.

The locational aspect is quite important since in order to maintain reliability, capacity must be deliverable to load. Given limitations of the transmission system, some amount of capacity typically must be located near load centers.

In PJM there are 24 load delivery areas (LDAs), each of which can be a separate zone in PJM's RPM capacity market. The zones (consisting of LDAs) are determined by the level of imports needed to maintain a predetermined level of reliability. Capacity prices are then set at levels in each LDA that ensure not only that the overall regional planning reserve margin is met, but that the locational resource requirement of each LDA is also satisfied. Consequently, it has generally been the case that capacity prices along the Eastern seaboard, from New York City to Washington, are much higher than capacity prices in the Midwest, reflecting both the constrained west-to-east transmission system and the higher going forward-costs of generators in the east—in some cases, costs directly attributable to compliance with state air emissions regulations.[54]

Non-RTO regions, primarily in the Southeast, as well as many states in RTO areas, particularly the Midwest ISO and SPP, are served by vertically integrated utilities, municipal systems, cooperatives, and federal systems. State public utility commissions (or other regulators) set rates and allow regulated utilities to include new capacity in rate base after a demonstration that this new capacity is needed and a prudent investment. To

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[52] Although the NYISO does provide the same three-year forward pricing as the PJM and ISO-NE markets, the relative price stability and predictability created by the administrative demand curve used in the capacity market provides greater guidance to investors than, for example, the month-to-month pricing in the Midwest ISO.

[53] The ISO-NE Forward Capacity Market does not have an administrative demand curve *per se*, but has other design features intended to stabilize the capacity price near the Net CONE value.

[54] The PJM Independent Market Monitor noted that the high capacity prices in Southwest MAAC were linked to bids that included capital cost recovery for compliance with Maryland emissions laws.

establish the need and prudency of the investment, regulated utilities typically prepare IRP forecasts. These forecasts include future load growth and capacity online that together specify the need for investment in generation and transmission, and preferred solutions. State regulators then act to approve major capital projects and set regulated retail rates to cover direct costs plus a return on invested capital. While this centralized approach to capacity expansion has generally ensured that the utility maintains sufficient capacity reserve margins, many states' legislators and regulators found that the technological and other risks placed onto ratepayers would be better borne by independent power producers.

Appendix B: Modeling and Methodology

Estimating Retirements

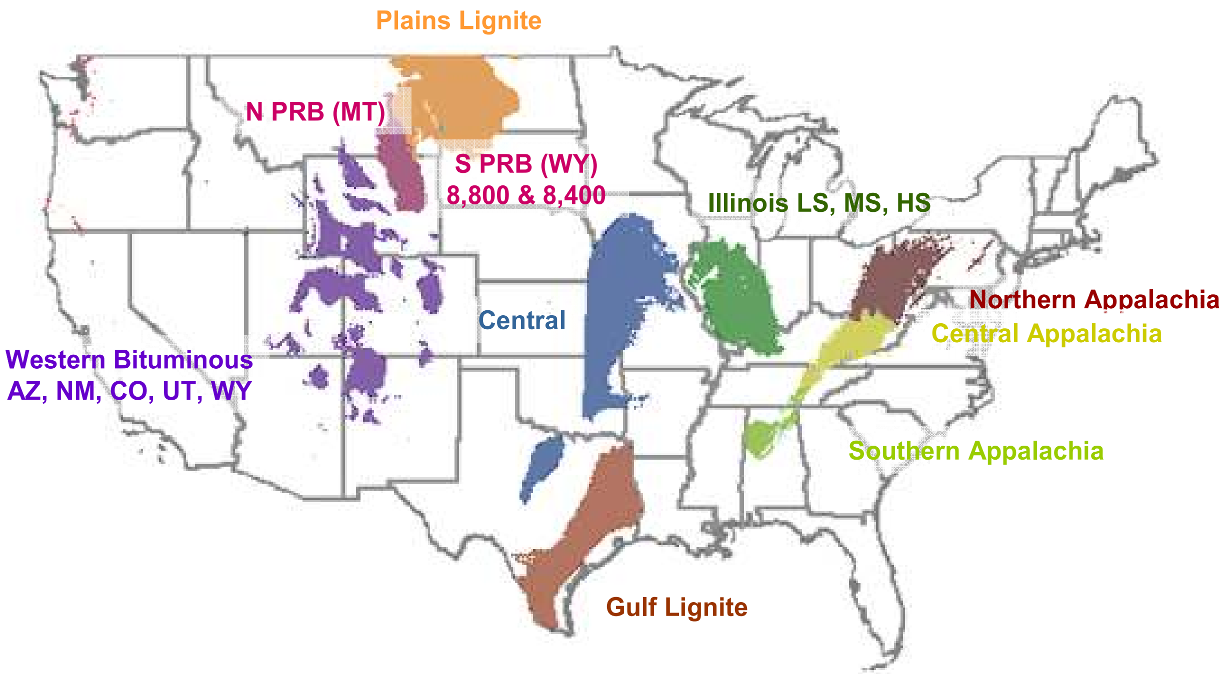
CRA used its NEEM model to estimate coal unit retirements under the utility MACT/CAIR NO_x policy representation described in the main body of this paper. NEEM optimizes generation operation in each major region in the US, taking into account power transfer limits among regions. NEEM optimizes retirements, unit environmental retrofits, and new capacity additions by region over a 60-year period, taking into account the operating and cost characteristics of existing capacity and the capital and operating costs of potential new capacity.

NEEM models the North American electric system as 39 regions that are connected by a network of transmission lines with region-to-region limits and, in some cases, joint import and export limits as shown in Figure 6.

Figure 6. NEEM Regions

Coal Supply - NEEM models coal supply from 23 individual curves representing distinct domestic production areas, Latin American imports, and different coal qualities (sulfur and Btu). See Figure 7 for a description of NEEM's coal supply regions.

Figure 7. NEEM Coal Supply



Pollution Control Retrofits - Coal units in NEEM can install pollution control retrofits based on economics. Control technologies are available for SO_2 (FGD), NO_x (SCR, SNCR), and mercury (ACI + fabric filter, or simply ACI if the unit already has a fabric filter). Each coal unit in NEEM is given a base Fixed O&M (FOM) cost, which is a function of its age and the combination of any existing emissions controls on the unit.[55]

Future retrofits (planned or economically determined by NEEM) result in emissions rate reductions, additional capital expenditures, an incremental FOM adder, an incremental VOM adder, and possibly heat rate and capacity penalties. The capital costs and incremental FOM for FGDs are based on Sargent & Lundy (August 2010).[56] Capital costs and incremental FOM for mercury controls are based on Cichanowicz (July 2006;

[55] EPA IPM Base Case Assumptions, EPA IPM Base Case v4.10, Chapter 4: Generating Resources, Table 4-9. (Based on FERC Form 1.)

[56] Sargent & Lundy, "IPM Model - Revisions to Cost and Performance for APC Technologies: Wet FGD Cost Development Methodology," August 2010, Table 1.

January 2010).[57] The incremental VOM for new and existing retrofits are also based on the aforementioned documentation.

Load Forecast - NEEM is a load-duration curve model. Load forecast assumptions in NEEM are derived from a combination of 2009 FERC 714 filings and 2010 ISO load forecasts (PJM, MISO, ISO-NE); minor adjustments were made for non-filing entities and some cooperatives. Load forecasts at the planning area level are aggregated to the NEEM-regional level and sorted into three seasons and 20 load blocks. Peak energy forecasts are similarly aggregated and peak coincidence factors are based on 2006 FERC 714 hourly data and 2006 ISO hourly reporting.

Fuel Prices - Natural gas and fuel oil delivered-price forecasts are based on a combination of NYMEX futures and AEO 2010 price forecasts. August 2010 NYMEX Henry Hub futures prices are blended into a longer-term AEO 2010 forecast before 2015. Delivered prices for generating units in each NEEM region are estimated using historically estimated basis differentials. Natural gas prices in NEEM vary seasonally and fuel oil prices vary annually.

New Capacity - In addition to simulating retirement of existing generators, NEEM simulates the deployment of new generating capacity to replace retirements and to meet growth requirements. New generating technologies available in 2015 include fossil units such as advanced conventional coal, natural gas combustion turbine, natural gas combined-cycle, and coal integrated gasification combined-cycle (IGCC). Renewable units such as wind turbines, solar – photovoltaic, solar – concentrated solar power, landfill gas, biomass, and geothermal are also built by the model based on economics and local and regional renewable electricity standards. Capital costs and operating characteristics for new generating capacity are primarily based on EIA Annual Energy Outlook 2009 with some CRA adjustments (e.g., transmission adders). As discussed below, we do not use NEEM's economic new builds directly in our reliability analysis.

Estimating Reliability Impacts

CRA used the following approach to estimating reliability impacts by NERC region:

1. We started with the NERC 2010 Summer Assessment's Total Internal Demand. We also calculated the difference between Total Internal Demand and Net Internal Demand as an estimate of demand side resources (in 2010 and 2015).

2. Using the 2010 Total Internal Demand, we applied growth factors to obtain the 2015 Total Internal Demand estimates by NERC region. We then subtracted the demand-side resource estimates obtained above to arrive at 2015 Net Internal

[57] J. Edward Cichanowicz, "Testimony of J. E. Cichanowicz to the Illinois Pollution Control Board: A Review of the Status of Mercury Control Technology," July 28, 2006; J. Edward Cichanowicz, "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies," January 2010.

Demand. The growth factors applied to Total Internal Demand are based on the 2010–2015 growth in Total Internal Demand from the 2009 NERC Electricity Supply & Demand (ES&D).

3. The 2015 capacity online estimate was calculated by taking the certain-existing capacity from the NERC 2010 Summer Assessment and adding planned new builds and subtracting planned retirements. The data source for new builds and retirements is Energy Velocity. The new build status categories considered were, conservatively, "under construction" or "testing." For retirements, conservatively, all status categories were considered except for "canceled."

4. Net firm transactions were then deduced from the NERC 2010 Summer Assessment and added to the 2015 capacity online estimate.

5. The 2015 resource adequacy surplus (or shortfall) was then calculated using the capacity online estimate and the Net Internal Demand estimate. This resource adequacy surplus (or shortfall) estimate is prior to the inclusion of our coal retirement estimates.

6. We then included modeled coal unit retirement estimates from NEEM and recalculated the 2015 resource adequacy surplus (or shortfall). We did not add in NEEM's economic new additions.

7. We then included planned additions that are less conservative, including those in the "permitted" or "site prep" status categories. These are new additions that are less certain than those under construction but nevertheless could occur fairly quickly as they face no significant regulatory hurdles. We recalculated the 2015 resource adequacy surplus (or shortfall).

8. Finally, we reported the forecasted number of percentage points above or below reserve margin in 2015.

Appendix C: PJM RPM Market Example

To illustrate how retrofit and replacement decisions for existing coal units will be guided by the RPM market, CRA has examined how the LDAs that have been modeled in recent RPM auctions would be affected by the retirements identified in the analysis described earlier in this report. Specifically, the analysis estimates the reliability requirements and available resources in each LDA for the BRA for the 2015/16 Delivery Year, which is the first auction for which regulations would be expected to affect capacity resource offers.

Table 5[58] shows the reliability requirements and available resources for the PJM RTO and each LDA that was included in the most recent BRA, conducted in May 2010 for the 2013/14 delivery year. The reliability requirements for 2013/14 are shown, along with the quantity of resources that were offered into the BRA. The projected supply and demand for 2015/16 is also shown, assuming that the reliability requirements will escalate with projected load growth and that the coal-fired capacity will be retired as projected under our analysis of the utility MACT/CAIR NO_x policy.

The expected retirements from the utility MACT/CAIR NO_x policy includes 7,529 MW (on a UCAP basis, which reduces the capacity of each resource to reflect the forced outage rate) of coal-fired capacity within the PJM RTO footprint. Of the total PJM capacity, 1,744 MW is located in the AEP zone, which does not participate in the RPM market, leaving 5,785 MW of planned retirements that will affect the RPM market clearing directly.

[58] Table 5 shows the supply and demand balance in terms of the unforced capacity (UCAP) metrics used by PJM. In addition, the planned retirements shown are only those from the 2013/14 auction to the 2015/16 auction.

Table 5. Impact of Projected PJM Coal Retirements 2015/16 Base Residual Auction

	2013/14 Capability Year			Retirements		2015/16 Capability Year		
LDA	Available Resources	Reliability Requirement	Surplus/ (Shortfall)	Planned	Economic	Available Resources	Reliability Requirement	Surplus/ (Shortfall)
RTO (with AEP)	186,588	169,799	16,789	825	7,061	178,703	174,843	3,860
RTO (excluding AEP)	160,898	146,239	14,659	69	5,425	155,404	150,583	4,821
MAAC	72,798	71,451	1,347	-	1,503	71,295	73,538	(2,243)
SWMAAC	18,493	17,502	992	-	294	18,199	18,038	162
PEPCO	9,772	9,250	522	-	152	9,620	9,460	160
EMAAC	40,102	39,472	630	-	302	39,800	40,573	(773)
PSEG	13,902	13,099	803	-	-	13,902	13,421	480
PS-North	6,743	6,208	535	-	-	6,743	6,361	383
DPLS	3,735	2,933	802	157	15	3,563	3,016	547

All values in MW (UCAP)

Overall the PJM RTO has sufficient capacity to replace retirements, but the impact varies by subzones within the broader PJM region: in 2015/16, given current transmission limits,[59] more resources than are required to meet the LDA reliability requirement are available for each LDA except MAAC and Eastern MAAC. As long as the policy is known with sufficient lead time to allow new resources to be offered into the BRA, RPM will provide a transparent market signal for new entry. In fact, for the MAAC LDA, which would need just over 2,000 MW of new capacity under the retirement scenario, 3,700 MW of new capacity is already under development, of which just over 1,000 MW is permitted and another 600 MW is in the permitting process. Additional projects could be developed if needed between now and the time of MACT implementation.

In addition to identifying need, RPM provides a price mechanism to support resource adequacy. In the Eastern MAAC and MAAC LDAs, RPM prices will, by design, rise to levels that can support new entry, or if it is more cost-effective, support retrofitting existing coal-fired capacity to be compliant with the utility MACT.

[59] Planned new transmission such as the PATH, MAPP and Susquehanna–Roseland projects may well impact the locational capacity requirements. In addition, transmission projects can participate in the RPM market and respond to the same price signals.

Appendix D: Detailed Calculation Tables

Table 2. Loads and Resources by 2015, RTO Level

	(NID)	(RRM)	(n)	(p)	(q) Resource Increase	(r) Resource Decrease	(x) = (p) + (q) - (r)	(y) Resource Increase	(z) = (x) + (y)	(A) = (z) - (n)	(d) Resource Decrease	(e) = (z) - (d)	(B) = (e) - (n)	(f) Resource Increase	(C) = (B) + (f)	= [(e) + (f)] / NID - 1 - RRM
RTO	***2015 Net Internal Demand Estimate (MW)**	**Required Reserve Margin (%)**	**Required Capacity (MW)**	****Certain-Existing Capacity (MW)**	*****Planned New Additions by 2015 (derated MW), Energy Velocity**	**# Planned Retirements by 2015 (MW), Energy Velocity**	**Projected Capacity in 2015 (MW)**	**++ Net Firm Transactions in 2010 Summer Assess. (MW)**	**Projected Capacity PLUS Net Firm Transactions (MW), 2015**	**(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)**	**Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)**	**## Retirement-Adjusted Projected Capacity PLUS Net Firm Transactions (MW), 2015**	**(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)**	**+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity**	**(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)**	**Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)**
PJM	146,441	15.3%	168,846	176,362	5,154	3,454	178,061	-	178,061	9,215	7,529	170,532	1,686	2,350	4,036	2.8%
MISO	91,001	15.4%	105,015	123,821	3,470	203	127,088	-	127,088	22,073	7,074	120,014	14,999	435	15,434	17.0%
New England	26,180	15.0%	30,107	32,229	213	100	32,342	288	32,630	2,523	370	32,260	2,153	1,094	3,247	12.4%
New York	31,803	15.0%	36,573	36,668	1,386	743	37,312	1,580	38,892	2,318	348	38,543	1,970	192	2,162	6.8%
SPP	45,284	13.6%	51,442	49,777	2,407	-	52,184	1,225	53,409	1,966	664	52,745	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment" (for New England, New York, and SPP). For PJM, the PJM 2013/14 RPM Base Residual Auction Planning Parameters, total RTO load net of load management. For MISO, 2015 Coincident Net Internal Demand, Midwest ISO Transmission Expansion Plan (MTEP) 2009.

** NERC 2010 Summer Assessment for New England, New York, and SPP. PJM: 2013/14 RPM Model existing resource parameters net FERC 411 purchases and sales; MISO: 2009 Summer Assessment Total July 2009 capacity net of imports/exports.

*** This includes the "under construction" and "testing" categories in Energy Velocity. Renewables have been derated.

This includes all categories of retirements in Energy Velocity except for "cancelled."

++ Firm net imports that count toward reserve margin.

Assume no change in net firm transactions through 2015.

+ Planned new additions that are in the "permitted" or "site prep" status categories.

Table 3. Loads and Resources by 2015, NERC Regional Level

	(NID)	(RRM)	(n)	(p)	(q) Resource Increase	(r) Resource Decrease	(x) = (p) + (q) - (r)	(y) Resource Increase	(z) = (x) + (y)	(A) = (z) - (n)	(d) Resource Decrease	(e) = (z) - (d)	(B) = (e) - (n)	(f) Resource Increase	(C) = (B) + (f)	= [(e) + (f)] / NID - 1 - RRM
NERC Region	***2015 Net Internal Demand Estimate (MW)**	**Required Reserve Margin (%)**	**Required Capacity (MW)**	**Certain-Existing Capacity (MW), NERC 2010 Summer Assess.**	****Planned New Additions by 2015 (derated MW), Energy Velocity**	**# Planned Retirements by 2015 (MW), Energy Velocity**	**Projected Capacity in 2015 (MW)**	**++ Net Firm Transactions in 2010 Summer Assess. (MW)**	**Projected Capacity PLUS Net Firm Transactions (MW), 2015**	**(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)**	**Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)**	**## Retirement-Adjusted Projected Capacity PLUS Net Firm Transactions (MW), 2015**	**(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)**	**+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity**	**(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)**	**Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)**
FRCC	47,330	15.0%	54,429	52,989	1,550	804	53,735	2,025	55,760	1,331	1,335	54,425	(4)	2,550	2,546	5.4%
MRO	42,681	15.0%	49,083	48,750	885	83	49,553	265	49,818	735	3,640	46,178	(2,905)	377	(2,528)	-5.9%
NPCC	60,894	15.0%	70,028	68,897	1,599	843	69,653	1,868	71,521	1,494	718	70,803	776	1,286	2,062	3.4%
RFC	186,008	15.0%	213,909	217,700	5,175	3,495	219,380	1,900	221,280	7,371	10,306	210,974	(2,935)	2,351	(583)	-0.3%
SERC	213,891	15.0%	245,975	246,535	9,019	3,525	252,029	91	252,120	6,145	12,716	239,404	(6,571)	5,934	(638)	-0.3%
SPP	45,284	13.6%	51,442	49,777	2,407	-	52,184	1,225	53,409	1,966	664	52,745	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment."

** This includes the "under construction" and "testing" categories in Energy Velocity. Renewables have been derated.

This includes all categories of retirements in Energy Velocity except for "cancelled."

++ Firm net imports that count toward reserve margin.

Assume no change in net firm transactions through 2015.

+ Planned new additions that are in the "permitted" or "site prep" status categories.

Table 4. Loads and Resources by 2015, NERC Subregional Level

	(NID)	(RRM)	(n)	(p)	(q) Resource Increase	(r) Resource Decrease	(x) = (p) + (q) (r)	(y) Resource Increase	(z) = (x) + (y)	(A) = (z) - (n)	(d) Resource Decrease	(e) = (z) - (d)	(B) = (e) - (n)	(f) Resource Increase	(C) = (B) + (f)	= [(e) + (f)] / NID - 1 - RRM
NERC Sub-Region	***2015 Net Internal Demand Estimate (MW)**	**Required Reserve Margin (%)**	**Required Capacity (MW)**	**Certain-Existing Capacity (MW), NERC 2010 Summer Assess.**	****Planned New Additions by 2015 (derated MW), Energy Velocity**	**# Planned Retirements by 2015 (MW), Energy Velocity**	**Projected Capacity in 2015 (MW)**	**++ Net Firm Transactions in 2010 Summer Assess. (MW)**	**Projected Capacity PLUS Net Firm Transactions (MW), 2015**	**(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)**	**Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)**	**## Retirement-Adjusted Projected Capacity PLUS Net Firm Transactions (MW), 2015**	**(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)**	**+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity**	**(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)**	**Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)**
FRCC	47,330	15.0%	54,429	52,989	1,550	804	53,735	2,025	55,760	1,331	1,335	54,425	(4)	2550	2,546	5.4%
MRO	42,681	15.0%	49,083	48,750	885	83	49,553	265	49,818	735	3,640	46,178	(2,905)	377	(2,528)	-5.9%
NPCC - New England	26,180	15.0%	30,107	32,229	213	100	32,342	288	32,630	2,523	370	32,260	2,153	1094	3,247	12.4%
NPCC - New York	31,803	15.0%	36,573	36,668	1,386	743	37,312	1,580	38,892	2,318	348	38,543	1,970	192	2,162	6.8%
RFC	186,008	15.0%	213,909	217,700	5,175	3,495	219,380	1,900	221,280	7,371	10,306	210,974	(2,935)	2351	(583)	-0.3%
SERC - Central	44,956	15.0%	51,699	49,345	1,871	-	51,216	2,046	53,262	1,563	4,329	48,933	(2,766)	1363	(1,403)	-3.1%
SERC - Delta	30,167	15.0%	34,692	40,172	886	227	40,831	(720)	40,111	5,419	343	39,768	5,077	513	5,590	18.5%
SERC - Gateway	19,883	11.9%	22,250	24,369	1,600	-	25,969	(2,150)	23,819	1,569	641	23,178	929	62	991	5.0%
SERC - Southeastern	52,889	15.0%	60,822	61,779	399	758	61,420	1,007	62,427	1,604	4,407	58,020	(2,802)	2121	(681)	-1.3%
SERC - VACAR	67,838	15.0%	78,014	70,870	4,263	2,540	72,593	221	72,814	(5,200)	2,997	69,817	(8,197)	1874	(6,322)	-9.3%
SPP	45,284	13.6%	51,442	49,777	2,407	-	52,184	1,225	53,409	1,966	664	52,745	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment."

** This includes the "under construction" and "testing" categories in Energy Velocity. Renewables have been derated.

This includes all categories of retirements in Energy Velocity except for "cancelled."

++ Firm net imports that count toward reserve margin.

Assume no change in net firm transactions through 2015.

+ Planned new additions that are in the "permitted" or "site prep" status categories.