

# **Electric System Reliability and EPA's Clean Power Plan: Tools and Practices**

**Analysis Group**

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## **Acknowledgments**

This report provides a primer on various reliability issues facing the electric industry as it looks ahead to implementation of the Clean Power Plan, as proposed by the U.S. Environmental Protection Agency on June 2, 2014.

Taking into consideration the many comments of various parties filed on EPA's proposal, the report addresses issues that the nation and the electric industry need to address in order to simultaneously meet electric system reliability and carbon-emissions reduction obligations.

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The report, however, reflects the analysis and judgment of the authors only.

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Analysis Group provides economic, financial, and business strategy consulting to leading law firms, corporations, and government agencies. The firm has more than 600 professionals, with offices in Boston, Chicago, Dallas, Denver, Los Angeles, Menlo Park, New York, San Francisco, Washington, D.C., Montreal, and Beijing.

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## Executive Summary

**Since the U.S. Environmental Protection Agency (EPA) proposed its Clean Power Plan last June, many observers have raised concerns that its implementation might jeopardize electric system reliability.**

Such warnings are common whenever there is major change in the industry, and play an important role in focusing the attention of the industry on taking the steps necessary to ensure reliable electric service to Americans. There are, however, many reasons why carbon pollution at existing power plants can be controlled without adversely affecting electric system reliability.

**Given the significant shifts already underway in the electric system, the industry would need to adjust its operational and planning practices to accommodate changes even if EPA had not proposed the Clean Power Plan.**

In the past several years, dramatic increases in domestic energy production (stemming from the shale gas revolution), shifts in fossil fuel prices, retirements of aged infrastructure, implementation of numerous pollution-control measures, and strong growth in energy efficiency and distributed energy resources, have driven important changes in the power sector. As always, grid operators and utilities are already looking at what adjustments to long-standing planning and operational practices may be needed to stay abreast of, understand, and adapt to such changes in the industry.

**The standard reliability practices that the industry and its regulators have used for decades are a strong foundation from which any reliability concerns about the Clean Power Plan will be addressed.**

The electric industry's many players are keenly organized and strongly oriented toward safe and reliable operations. There are well-established procedures, regulations and enforceable standards in place to ensure reliable operations of the system, day in and day out.

Among other things, these "business-as-usual" procedures include:



<http://imgkid.com/checklist-icon.shtml>

- Assigning specific roles and responsibilities to different organizations, including regional reliability organizations, grid operators, power plant and transmission owners, regulators, and many others;
- Planning processes to look ahead at what actions and assets are needed to make sure that the overall system has the capabilities to run smoothly;
- Maintaining secure communication systems, operating protocols, and real-time monitoring processes to alert participants to any problems as they arise, and initiating corrective actions when needed; and
- Relying upon systems of reserves, asset redundancies, back-up action plans, and mutual assistance plans that kick in automatically when some part of the system has a problem.



<http://www.bls.gov/ooh/installation-maintenance-and-repair/line-installers-and-repairers.htm>

**As proposed by EPA, the Clean Power Plan provides states and power plant owners a wide range of compliance options and operational discretion (including various market-based approaches, other means to allow emissions trading among power plants, and flexibility on deadlines to meet interim targets) that can prevent reliability issues while also reducing carbon pollution and cost.**

EPA's June 2014 proposal made it clear that the agency will entertain market-based approaches and other means to allow emissions trading within and across state lines. Examples include emissions trading among plants (e.g., within a utility's fleet inside or across state lines), or within a Regional Transmission Organization (RTO) market. In this respect, the Clean Power Plan is fundamentally different from the Mercury and Air Toxics Standard (MATS) and is well-suited to utilize such flexible and market-based approaches. Experience has shown that such approaches allow for seamless, reliable implementation of emissions-reduction targets. In its final rule, EPA should clarify acceptable or standard market-based mechanisms that could be used to accomplish both cost and reliability goals.

Moreover, EPA has stated repeatedly that it will write a final rule that reflects the importance of a reliable grid and provides the appropriate flexibility.<sup>1</sup> We support such adjustments in EPA's final rule as needed to ensure both emissions reductions and electricity reliability.

**Some of the reliability concerns raised by stakeholders about the Clean Power Plan presume inflexible implementation, are based on worst-case scenarios, and assume that policy makers, regulators, and market participants will stand on the sidelines until it is too late to act. There is no historical basis for these assumptions. Reliability issues will be solved by the dynamic interplay of actions by regulators, entities responsible for reliability, and market participants with many solutions proceeding *in parallel*.**

Some of the cautionary comments are just that: calls for timely action. Many market participants have offered remedies (including readiness to bring new power plant projects, gas infrastructure, demand-side measures, and other solutions into the electric system where needed).<sup>2</sup> Indeed, this dynamic interplay is one reason why a recent survey of over 400 utility executives nationwide found that more than 60 percent felt optimistic about the Clean Power Plan and either supported EPA's proposed current emissions reduction targets or would make them more stringent.<sup>3</sup>

We note many concerns about electric system reliability can be resolved by the addition of new load-following resources, like peaking power plants and demand-side measures, which have relatively short lead times.<sup>4</sup> Other concerns are already being addressed by ongoing work to improve market rules, and by infrastructure planning and investment. A recent Department of Energy (DOE) report found that while a low-carbon electric

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<sup>1</sup> See, for example, the January 6, 2015 blog post of Janet McCabe, EPA's Acting Administrator for Air and Radiation, "Time and Flexibility: Keys to Ensuring Reliable, Affordable Electricity," <http://blog.epa.gov/epaconnect/2015/01/time-and-flexibility/>. Also, see EPA's October 2014 Notice of Data Availability (NODA) that sought comments on, among other things, the potential to change the phase-in of emissions reductions to accommodate, for example, any constraints in natural gas distribution infrastructure, or how states could earn compliance credits for actions taken between 2012 and 2020.

<sup>2</sup> Although we think it is ultimately a good thing that the industry is paying close attention to reliability issues – so that any potential problems can be avoided through planning and infrastructure – we do note that serious questions have been raised about the assumptions used in recent reliability assessments performed by the North American Reliability Corporation (NERC). For example, Brattle Group's February 2015 report found that NERC failed to account for how industry is likely to respond to market and operational changes resulting from the Clean Power Plan. See Jurgen Weiss, Bruce Tsuchida, Michael Hagerty, and Will Gorman, "EPA's Clean Power Plan and Reliability: Assessing NERC's Initial Reliability Review," The Brattle Group, February 2015.

<sup>3</sup> The same survey found that utility executives believe that distributed energy resources offer the biggest growth opportunity over the next five years, and more than 70 percent expect to see a shift away from coal towards natural gas, wind, utility-scale solar and distributed energy. Utility Dive and Siemens, "2015 State of the Electric Utility Survey Results," January 27, 2015. The survey included 433 U.S. electric utility executives from investor-owned and municipal utilities, and electric cooperatives.

<sup>4</sup> Our report provides typical timelines for various types of resource additions in Section II.

system may significantly increase natural gas demand from the power sector, the projected incremental increase in natural gas pipeline capacity additions is modest (lower than historic pipeline expansion rates), and that the increasingly diverse sources of natural gas supply reduces the need for new pipeline infrastructure.<sup>5</sup>

Some other comments raise the reliability card as part of what is – in effect – an attempt to delay or ultimately defeat implementation of the Clean Power Plan. We encourage parties to distinguish between those who identify issues and offer solutions, and those who (incorrectly) suggest that reducing carbon pollution through the Clean Power Plan is inconsistent with electric system reliability.

In the end, because there are such fundamental shifts already underway in the electric industry, inaction is the real threat to good reliability planning. Again, there are continuously evolving ways to address electric reliability that build off of strong standard operating procedures in the industry.

**There are many capable entities focused on ensuring electric system reliability, and many things that states and others can do to maintain a reliable electric grid.**

First and foremost, states can lean on the comprehensive planning and operational procedures that the industry has for decades successfully relied on to maintain reliability, even in the face of sudden changes in industry structure, markets and policy.

Second, states should take advantage of the vast array of tools available to them and the flexibility afforded by the Clean Power Plan to ensure compliance is obtained in the most reliable and efficient manner possible. Given the interstate nature of the electric system, we encourage states

Entities with roles to play as part of ensuring electric system reliability and timely compliance with EPA’s Clean Power Plan	
Electric Reliability Entities	Federal Energy Regulatory Commission (FERC)
	North American Electric Reliability Corporation (NERC)
	Regional Reliability Organizations
	Electric System Operators and Balancing Authorities
Other public entities	Environmental Protection Agency (EPA)
	States (air agencies, public utility commissions, energy offices, state legislatures)
	Other federal agencies (Department of Energy, Energy Information Administration)
Entities involved with markets, resource planning, procurements	Wholesale market administrators
	Electric utilities (investor-owned, municipal utilities, cooperatives, joint action agencies)
Other organizations that have a role to play	Non-utility generating companies and providers of other technologies
	Interstate natural gas pipeline companies (and storage suppliers)
	North American Energy Standards Board (NAESB)
	Energy efficiency program administrators
	Others

<sup>5</sup> U.S DOE, “Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector,” February 2015.

to rely upon mechanisms that facilitate emission trading between affected power plants in different states. Doing so will increase flexibility of the system, mitigate many electric system reliability concerns, and lower the overall cost of compliance for all.<sup>6</sup>

In this report we identify a number of actions that the Federal Energy Regulatory Commission (FERC), grid operators, states, and others should take to support electric system reliability as the electric industry transitions to a lower-carbon future. We summarize our recommendations for these various parties in tables at the end of our report.

**In the end, the industry, its regulators and the States are responsible for ensuring electric system reliability while reducing carbon emissions from power plants as required by law. These responsibilities are compatible, and need not be in tension as long as all parties act in a timely way and use the many reliability tools at their disposal.**

We observe that, too often, commenters make assertions about reliability challenges that really end up being about cost impacts. Although costs matter in this context, we think it is important to separate reliability considerations from cost issues in order to avoid distracting attention from the actions necessary (and feasible) to keep the lights on. There may be “lower cost” options that reduce emissions some part of the way toward the target reductions, but that fail to meet acceptable reliability standards. We do not view such ‘solutions’ as the lowest cost solution precisely because they fail to account for the cost of unacceptable system outages to electricity consumers.

Any plan that starts with consumer costs and works backward to reliability and then to emission reduction is one that fails to consider the wide availability of current tools that have served grid operators for more than a decade to meet reliability needs. There is no reason to think that cost and reliability objectives cannot be harmonized within a plan to reduce carbon pollution.

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<sup>6</sup> As we will discuss in a series of regional reports, others have already identified that regional strategies will minimize overall compliance costs. For example, the Midcontinent Independent System Coordinator (MISO) estimated that a regional carbon constraint approach could save up to \$3 billion annually relative to a sub-regional or individual state approach. MISO, “Analysis of EPA’s Proposal to Reduce CO<sub>2</sub> Emissions from Existing Electric Generating Units,” November 2014. See also, “Statement of Michael J. Kormos, Executive Vice President – Operations, PJM Interconnection, FERC Docket No. AD15-4-000, Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure,” February 19, 2015.



This paper is designed to:

- Describe the changes underway in the industry which set the stage for the continued evolution of reliability tools and practices;
- Provide a “reliability 101” primer to describe what “electric reliability” means to system planners and operators, and why specific standard practices are so important to assuring electric reliability;<sup>7</sup>
- Summarize reliability concerns expressed by various stakeholders;
- Explain the ways that standard operating procedures can address these concerns; and,
- Recommend actions that can be taken by various actors in the electric industry to assure that the Clean Power Plan's goals do not undermine reliable power supply.

**Our recommendations can be found in tables following the Executive Summary.**

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<sup>7</sup> This report also includes a glossary of acronyms used in our report.

## Recommendation Tables

**Table 1**  
**Key Players in the Clean Power Plan and Available Tools**

Entities	Roles and Responsibilities
<b>Entities with direct responsibility for electric system reliability</b>	<ul style="list-style-type: none"> <li>- FERC (under the Federal Power Act (FPA))</li> <li>- NERC (as the FERC-approved Electric Reliability Organization under the FPA)</li> <li>- Regional Reliability Organizations (RROs)</li> <li>- System operators and balancing authorities (including Regional Transmission Organizations (RTOs) and electric utilities)</li> <li>- States (for resource adequacy)</li> </ul>
<b>Other public agencies with direct and indirect roles in the Clean Power Plan</b>	<ul style="list-style-type: none"> <li>- U.S. Environmental Protection Agency (EPA)</li> <li>- State executive branch agencies:                             <ul style="list-style-type: none"> <li>- Air offices and other Environmental Agencies</li> <li>- Public Utility Commissions (PUCs)</li> <li>- Energy Offices</li> <li>- Public authorities (e.g., state power authorities)</li> </ul> </li> <li>- State governors and legislatures</li> <li>- U.S. Department of Energy (DOE)</li> <li>- Energy Information Administration (EIA)</li> </ul>
<b>Owners of existing power plants covered by 111(d) of the Clean Air Act</b>	<ul style="list-style-type: none"> <li>- Electric utilities                             <ul style="list-style-type: none"> <li>- investor-owned utilities</li> <li>- municipal utilities</li> <li>- electric cooperatives</li> <li>- joint action agencies</li> </ul> </li> <li>- Non-utility power plant owners</li> </ul>
<b>Markets and Resource Planning/ Procurement Organizations</b>	<ul style="list-style-type: none"> <li>- Organized markets administered by RTOs (CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, SPP).</li> <li>- Electric utilities with supply obligations &amp; subject to least-cost planning processes:                             <ul style="list-style-type: none"> <li>- Many utilities (including joint action agencies) operate under requirements to use a combination of planning and competitive procurements (with or without self-build opportunities)</li> <li>- Transmission owners also have transmission planning requirements</li> </ul> </li> <li>- Private investors (including non-utility companies) responding to market signals and seeking to develop/permit/construct/install/operate new resources (including new power plant projects, demand-response companies, merchant transmission companies, rooftop solar PV installation companies, etc.)</li> </ul>
<b>Others</b>	<ul style="list-style-type: none"> <li>- North American Energy Standards Board (NAESB) for setting electric &amp; gas standards</li> <li>- Administrators/Operators of CO<sub>2</sub> allowance-trading systems</li> <li>- Administrators/Operators of energy efficiency programs</li> <li>- Fuel supply and delivery companies (gas pipeline and/or storage companies; gas producers; coal producers; coal transporters)</li> <li>- Energy marketing companies</li> <li>- Emerging technology providers – including, e.g., storage system providers, companies providing advanced communications and “smart” equipment, etc.</li> </ul>

**Table 2**  
**FERC, NERC, and RROs’ Potential Actions to Address Reliability Issues**

<b>Electric Reliability Entities (with some of the their Standard Tools)</b>	<b>Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)</b>
<p><b>FERC:</b></p> <ul style="list-style-type: none"> <li>- Adoption of federally-enforceable reliability requirements and standards</li> <li>- Oversight of NERC and all bulk power system operators</li> <li>- Oversight of interstate natural gas pipeline owners/operators, with authority to approve interstate pipeline expansions</li> <li>- Authority over transmission planning, tariffs, open-access</li> <li>- In organized markets, authority over market rules (including capacity markets, provision of ancillary services providing various attributes to system operators)</li> <li>- Interagency coordination with EPA, DOE</li> </ul>	<p><b>Consider:</b></p> <ul style="list-style-type: none"> <li>- Requiring NERC, RROs, and system operators/balancing authorities to periodically assess potential reliability impacts of CPP with geographic scope appropriate to the reliability entity. The assessments could identify specific concerns, and develop backstop solutions                             <ul style="list-style-type: none"> <li>– Preliminary assessments starting at end of 2015/early 2016, to inform state action taking into account known policy, practices, resources in the relevant area</li> <li>– Reliability assessments at the time of proposed state plans</li> <li>– Reliability assessments annually up through early 2020s</li> </ul> </li> <li>- Continuing to evaluate the adequacy of current FERC gas/electric coordination policies in light of <i>incremental</i> changes resulting from CPP relative to trends already underway in the industry</li> <li>- Eliciting filings from RTOs and other transmission companies about any new planning tools, notice provisions for potential retirements, information reporting, new products, minimum levels of capability with various attributes</li> <li>- Inquiring into new natural gas policies to support wider interdependence with electric system reliability (e.g., incentives for development of gas delivery/storage infrastructure)</li> <li>- Working with states to consider mechanisms to afford bulk-power system grid operators’ greater visibility into generating and demand-side resources on the distribution system</li> <li>- Providing guidance outlining compliance strategies that would require approvals of the FERC under the FPA (versus approaches that might not require such)</li> </ul>
<p><b>NERC</b></p> <ul style="list-style-type: none"> <li>– Reliability Standards, compliance assessment, and enforcement</li> <li>– Annual &amp; seasonal reliability assessments</li> <li>– Special reliability assessments</li> </ul>	<p><b>Consider:</b></p> <ul style="list-style-type: none"> <li>– Continuing to conduct special assessments of impact of CPP on reliability (as it periodically does for other developments in the industry)                             <ul style="list-style-type: none"> <li>– Preliminary assessments in parallel with final rule development,(in 2015) and development of State Plans (2015/2016)</li> <li>– Final assessments upon finalization of State Plans (2016+)</li> </ul> </li> <li>– Assess whether any new standards relating to Essential Reliability Services need to be modified in light of electric system changes occurring as part of the industry’s response(s) to CPP</li> </ul>
<p><b>Regional Reliability Organizations</b></p> <ul style="list-style-type: none"> <li>– Annual &amp; seasonal reliability assessments</li> <li>– Special reliability assessments</li> <li>– Coordination with neighboring RROs</li> </ul>	<p><b>Consider:</b></p> <ul style="list-style-type: none"> <li>– Conducting special assessments of impact of CPP on reliability                             <ul style="list-style-type: none"> <li>– Preliminary assessments in parallel with final rule development,(in 2015) and development of State Plans (2015/2016)</li> <li>– Final assessments upon finalization of State Plans (2016+)</li> </ul> </li> </ul>

**Table 3  
Grid Operators’ Potential Actions to Address Reliability Issues**

<p align="center"><b>Electric Reliability Entities (with some of the their Standard Tools)</b></p>	<p align="center"><b>Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)</b></p>
<p><b>System Operators and Balancing Authorities</b></p> <ul style="list-style-type: none"> <li>- On-going annual &amp; seasonal reliability assessments, including transmission planning</li> <li>- Special reliability assessments</li> <li>- Coordination with neighboring systems</li> </ul> <p><i>Note: Some of these entities also fulfill market, resource planning and procurement functions (described further below)</i></p>	<p><b>Consider</b></p> <ul style="list-style-type: none"> <li>- Conducting special assessments of impact of CPP on system reliability                             <ul style="list-style-type: none"> <li>- Preliminary assessments in parallel with final rule development (in 2015) and development of State Plans (2015/2016)</li> <li>- Final assessments upon finalization of State Plans (2016+)</li> </ul> </li> <li>- Identifying specific areas of concern (e.g., notice period for potential unit retirements; need for more routine anticipatory analyses in transmission planning to explore “what if” changes occur on the system; identification of zones with violations of reliability requirements and any specific units needed for reliability pending resolution of the violation)</li> <li>- Working with stakeholders (including environmental agencies in relevant states) to develop proposals for reliability safety value to ensure mechanism to fully offset CO<sub>2</sub> emission impacts when use of a safety valve is triggered</li> <li>- Working with counterparts in natural gas industry to harmonize business practices, develop improved inter-industry forecasting tools, coordinate operating days/market timing, share information, identify specific natural gas infrastructure needs</li> <li>- Refreshing policies and practices to assure technology-neutral and competitively neutral means for providing reliability services (both resource adequacy and system operations)                             <ul style="list-style-type: none"> <li>- Technology neutrality should recognize the different attributes needed for essential reliability services, but be supportive of generation, transmission and demand-side solutions for providing such attributes</li> </ul> </li> <li>- Working with state officials and distribution utilities within their relevant geographies to explore ways to expand the visibility (e.g., through communications and information systems) of the system operator into distribution system resource operations (i.e., distributed variable resources such as solar PV); incorporate into planning activities</li> <li>- Continuing to improve meteorological forecasting capabilities</li> </ul>

**Table 4  
Other Federal Agencies’ Potential Actions to Address Reliability Issues**

Other Public Entities (with some of the their Standard Tools)	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)
<p><b>EPA</b></p> <ul style="list-style-type: none"> <li>- Issuing the final Clean Power Plan regulation</li> <li>- Responsibility for finalizing standards for new power plants (Section 111(b))</li> <li>- Responsibility for administering federal air, water, and waste pollution standards</li> </ul>	<p><b>Consider:</b></p> <ul style="list-style-type: none"> <li>- Clarifying acceptable standard market mechanisms that could be used to accomplish emission-reduction and reliability goals in economically efficient ways</li> <li>- Providing guidance on allowing one or more forms of a reliability safety valve, <i>with the condition</i> that overall emissions over the interim period (e.g., 2020-2029) are equal to or better than the plan without a triggering of the reliability safety valve. Examples might include:               <ul style="list-style-type: none"> <li>- Allowing the reliability safety valve as proposed by the RTO/ISO Council (with the noted CO<sub>2</sub> emissions offset condition)</li> <li>- Requiring/allowing temporary exemptions/modifications of timing/quantity requirements in State Plans</li> <li>- Providing guidance about how states may propose to alter compliance deadlines/requirements where needed for reliability, should such issues arise over time</li> </ul> </li> <li>- Requiring States to include reliability assessments in final State Plans (not for EPA to review/approve, but rather to ensure that such studies are conducted)</li> </ul>
<p><b>Other federal agencies</b></p> <ul style="list-style-type: none"> <li>- DOE</li> <li>- EIA</li> </ul>	<p><b>Consider:</b></p> <ul style="list-style-type: none"> <li>- Investigating additional reporting requirements by members of the industry</li> <li>- Conducting studies and analyses that examine physical capabilities of more integrated gas and electric system</li> <li>- Identifying CPP compliance issues as qualifying for DOE Critical Congestion Areas and Congestion Areas of Concern, and/or “national interest electric transmission corridors” under the Energy Policy Act of 2005</li> </ul>

**Table 5**  
**States’ Potential Actions to Address Reliability Issues**

Other Public Entities (with some of the their Standard Tools)	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)
<p><b>States</b></p> <ul style="list-style-type: none"> <li>- Air agency:               <ul style="list-style-type: none"> <li>- obligation to submit State Plans to EPA</li> <li>- reviewing/approving any modification to air permits of affected generating units</li> </ul> </li> <li>- Executive and legislative responsibility for energy, environmental laws and regulations</li> <li>- Oversight over regulated electric and natural gas utilities (public utility commissions) – including ratemaking, planning and resource procurement</li> <li>- Coordination with neighboring states</li> <li>- Engagement in regional planning, operational, and market rules and procedures</li> <li>- Siting/permitting of electric energy infrastructure and local gas distribution facilities</li> </ul>	<p><b>Consider:</b></p> <ul style="list-style-type: none"> <li>- Proactively (i.e., now) engaging with state utilities and state/regional system operators in evaluation of potential CPP reliability impacts, and identification of reliability solutions (including supporting preliminary assessments in parallel with development of State Plans (2015/2016), and final assessments upon finalization of State Plans (2016+))</li> <li>- Establishing as part of the State Plan an annual state reliability evaluation, and identification of/commitment to take steps and measures in the future in response to any identified reliability concerns. This could include a framework for allowing compliance waivers and extensions in the early years in the event that reliability issues arise circa 2020, combined with requirements on state and/or compliance entities for provisional CO<sub>2</sub> reductions over transition period to make up for waivers/extensions in early years (e.g., to arrive at same cumulative emissions over the period)</li> <li>- Incorporating conditions in air permits to reflect operating limits (e.g., total emissions within an annual period)</li> <li>- Creating flexible implementation plans (e.g., mass-based models) and multi-state programs (e.g., regional cap/trade) to mitigate potential reliability impacts and operational flexibility across regions that reflect the normal operations of interconnected electric system               <ul style="list-style-type: none"> <li>- State or regional cap and trade programs</li> <li>- “Bubbling” of requirements across units owned by common owner (e.g., within one state or across states through bilateral state agreements/MOUs)</li> </ul> </li> <li>- Developing statewide policies and measures for compliance that support reliability (energy-efficiency/renewable energy programs, including measures beyond Investor Owned Utility funded programs), for example:               <ul style="list-style-type: none"> <li>- Clean energy standards</li> <li>- Investment in emerging or early-stage technologies (e.g., storage), public-private partnerships, tax and investment credits</li> <li>- Protocols for counting Energy Performance Savings Contracts in State Plans</li> </ul> </li> <li>- Reviewing need to modify permitting/siting regulations to accommodate dual-fuel capability of gas-fired power plants</li> <li>- Reviewing need to modify administrative or procedural measures to expedite siting, zoning, permitting of needed energy infrastructure (renewables, other power plants, transmission, LNG storage)</li> <li>- Instituting new entities (e.g., natural-gas buying authorities) to serve as contracting entity to support long-term commitments that may be necessary for gas system expansion</li> <li>- Requiring longer advance notice of power plant retirements</li> </ul>

**Table 6**  
**Organized Markets’ & Electric Utilities Potential Actions to Address Reliability Issues**

Entities Involved with Markets, Resource Planning, and Procurements	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)
<p>Wholesale Market Administrators (Generally, Bulk Power System (BPS) Operators in Competitive Market Regions)</p> <ul style="list-style-type: none"> <li>- <b>Markets designed and administered to minimize costs <i>subject to the constraint that all reliability requirements of the system are met</i></b></li> </ul>	<p><b>Consider:</b></p> <ul style="list-style-type: none"> <li>- Adding technology-neutral and competitively neutral market rules/products to add incentives for new reliability attributes.                             <ul style="list-style-type: none"> <li>- Local (zonal/load pocket) capacity and energy market pricing; changes to scarcity pricing</li> <li>- Reliability attributes for system security (greater quantities of spinning or non-spinning reserves; AGC; ramping/load-following; reactive power; on-site fuel; frequency response; black start capability)</li> </ul> </li> <li>- Establishing or clarifying, where necessary, expectations around unit performance during shortage or scarcity conditions</li> <li>- Clarifying how normal dispatch processes incorporate current restrictions on unit operations (including emissions limits, ramping periods, etc.), and how similar operational restrictions (if any) resulting from Clean Power Plan compliance would be incorporated in system operations</li> <li>- Establishing or clarifying, where needed, provisions for the creation of reliability must run (RMR) contracts for generators needed for reliability that would otherwise retire – conditioned upon permit restrictions that account for CO<sub>2</sub> emissions offsets</li> <li>- Establishing or clarifying, where needed, procedures to minimize duration of RMR contracts through development of utility or market responses (generation, transmission)</li> <li>- Identifying any changes in forward capacity markets for the period starting in 2020</li> </ul>
<p>Vertically-Integrated Utilities, Cooperatives, Municipal Light Companies</p> <ul style="list-style-type: none"> <li>- <b>Long-term resource planning</b></li> <li>- <b>Obligation and opportunity to develop and obtain cost recovery for necessary demand, supply, and transmission investments and expenses</b></li> <li>- <b>Obligation to maintain power system reliability</b></li> <li>- <b>In some states, integrated resource planning and/or resource need/procurement processes</b></li> <li>- <b>Coordinated operation of systems with neighboring utilities</b></li> </ul>	<p><b>Consider:</b></p> <ul style="list-style-type: none"> <li>- Conducting forward-looking assessments of potential impacts on system reliability of CPP implementation                             <ul style="list-style-type: none"> <li>- Preliminary assessments prior to and during final rule development and SIP implementation</li> <li>- Final assessments upon finalization of SIP</li> </ul> </li> <li>- Developing or expanding long-term integrated resource planning processes for timely and practical incorporation of CPP compliance requirements</li> <li>- Incorporating all potential short- and long-term measures (supply and demand; generation and transmission) to address significant changes during CPP transition period</li> <li>- Engaging in coordination with neighboring utilities around local reliability concerns tied to CPP implementation</li> </ul>

**Table 7  
Other Organizations’ Potential Actions to Address Reliability Issues**

Other Organizations that have a Role To Play in Assisting in Reliable and Effective Industry Compliance	Potential Additional Actions to Address Reliability Issues Relating Directly or Indirectly to Clean Power Plan (CPP)
Non-Utility Generating Companies	<p><b>Consider:</b></p> <ul style="list-style-type: none"> <li>- Responding to signals in organized wholesale markets and in response to competitive solicitations by electric utilities</li> </ul>
<p>Interstate Natural Gas Pipeline Owners/Operators</p> <ul style="list-style-type: none"> <li>- Coordination among NGP owners/operators</li> <li>- Coordination with BPS operators</li> <li>- Development of new pipeline capacity</li> </ul>	<p><b>Consider:</b></p> <ul style="list-style-type: none"> <li>- Improving coordination with system operators – e.g., harmonize standards and practices, coordinate operating days/market timing, share information, etc.</li> </ul>
<p>NAESB</p> <ul style="list-style-type: none"> <li>- Working with industry stakeholders to develop standards for operations in electric and gas industry</li> </ul>	<p><b>Consider:</b></p> <ul style="list-style-type: none"> <li>- Periodically convening industry sector discussions about continuing need to harmonize standards in the electric and gas industries</li> </ul>
Administrators of Allowance Trading Programs (e.g, RGGI, California, new ones)	<p><b>Consider:</b></p> <ul style="list-style-type: none"> <li>- Establishing new “plug and play” programs that allow states to join with relatively administrative ease</li> </ul>
Administrators of Energy Efficiency Programs	<p><b>Consider:</b></p> <ul style="list-style-type: none"> <li>- Establishing products to offer to generating companies to ‘purchase’ program credits to offset emissions, subject to strict measurement and verification</li> </ul>
Energy Service Companies (ESCOs)	<p><b>Consider:</b></p> <ul style="list-style-type: none"> <li>- Working with State agencies to develop mechanisms to incorporate energy-savings-performance contracts into State Plans</li> </ul>



## I. Context

In June 2014, the U.S. Environmental Protection Agency (EPA) issued its proposed Clean Power Plan, designed to reduce carbon dioxide (CO<sub>2</sub>) emissions from existing fossil-fuel power plants in the United States. The final rule, which is now anticipated to come out in mid-2015, will require each of the 49 states with covered power plants to prepare and submit plans for how they propose to reduce emissions from the plants in their state. Although the features of the final regulation will undoubtedly change in light of the many comments filed, EPA’s current proposal requires states and affected electric generating units (EGUs) to demonstrate progress to reduce emissions starting in 2020, with subsequent reductions thereafter. This new policy will eventually affect over half of the nation’s generating capacity and all but the smallest fossil fuel generating units.<sup>8</sup>

In light of the broad scope of the regulation, many stakeholders have raised concerns about whether EPA’s proposal will jeopardize the reliability of the electric system. In Washington, in state capitols, in media alerts, in comments filed at the EPA, and elsewhere, many public officials, electric utilities, industry reliability organizations, and others have been demanding

<sup>8</sup> An affected electric generating unit (EGU) is defined broadly, as any boiler, integrated gasification combined cycle (IGCC), or combustion turbine (in either simple cycle or combined cycle configuration) that (1) is capable of combusting at least 250 million Btu per hour; (2) combusts fossil fuel for more than 10 percent of its total annual heat input and (3) sells the greater of 219,000 MWh per year and one-third of its potential electrical output to a utility distribution system (Proposed Rule, Federal Register, Vol. 79, No. 117, June 18, 2014, page 34854). Generating units estimated to be subject to EPA’s Clean Power Plan:

SNL Financial (as of 2-2015)	Generating Units Likely to be Directly Covered by Section 111(d)*		Total Grid-Connected Generating Capacity in the U.S. (GW)	111(d) Capacity as Share of Total Capacity (%)
	(# Units)	Summer Capacity (GW)	Summer Capacity (GW)	Summer Capacity (GW)
Coal	922	300	303	99%
Gas	2,137	334	464	72%
Oil	62	17	39	44%
Total Fossil	3,121	651	806	81%
All Capacity			1,151	57%
* Includes all existing or under development steam turbines and combined cycle units greater than 25 MW, and any natural gas combustion turbines with generation greater than 219,000 MWh. Source: SNL Financial, Power Plant Unit Database.				

that the changes introduced by the Clean Power Plan not come at the expense of electric reliability.<sup>9</sup>

For many decades, such cautions have appeared whenever major events – such as major new environmental regulations affecting power plants or structural changes to introduce competition in the electric industry – occur that could affect electric system reliability.<sup>10</sup>

Indeed, well before the EPA issued its proposal, various reliability organizations had already begun to anticipate how changes underway in the electric industry would necessitate modifications in traditional ways to plan for and operate the electric system. For example, the North American Electric Reliability Corporation (NERC) – the nation's electric reliability standards organization – issued a “concept paper” in October 2014, in which NERC describes the many ways that today's reliability procedures will need to evolve to keep ahead of the changing character of the electric “resources” that connect with the grid.<sup>11</sup>

NERC's paper, which was in development well before the EPA issued its Clean Power Plan (and is different from NERC's November 2014 assessment relating to the EPA proposal), begins by recognizing that the

North American BPS [bulk power system] is experiencing a transformation that could result in significant changes to the way the power grid is planned and operated. These changes include retirements of baseload generating units; increases in natural gas generation; rapid expansion of wind, solar, and commercial solar photovoltaic (PV) integration; and more prominent uses of Demand Response (DR) and distributed generation.... As the overall resource mix changes, all the aspects of the ERSs [Electric Reliability Services] still need to

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<sup>9</sup> See discussion in Section III and the Appendix to this paper. Note that even the leadership of the EPA and the President of the United States have insisted upon design and implementation of the Clean Power Plan in ways consistent with electric system reliability. See, for example: President Obama's Presidential Memorandum (“Power Sector Carbon Pollution Standards,” June 25, 2013), in which the President directed the EPA to issue regulations to control CO<sub>2</sub> emissions from the power sector, and included the following instructions: “In developing standards, regulations, or guidelines ... [EPA] shall ensure, to the greatest extent possible, that you: ... (v) ensure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power for consumers and businesses...” Available at: <http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards>

Also, see: Statement of Gina McCarthy, Nominee for the Position of Administrator of the EPA, Before the Environment and Public Works Committee, U.S. Senate, April 11, 2013; and the January 6, 2015 blog post of Janet McCabe, EPA's Acting Assistant Administrator for Air and Radiation, “Time and Flexibility: Keys to Ensuring Reliable, Affordable Electricity,” <http://blog.epa.gov/epaconnect/2015/01/time-and-flexibility/>.

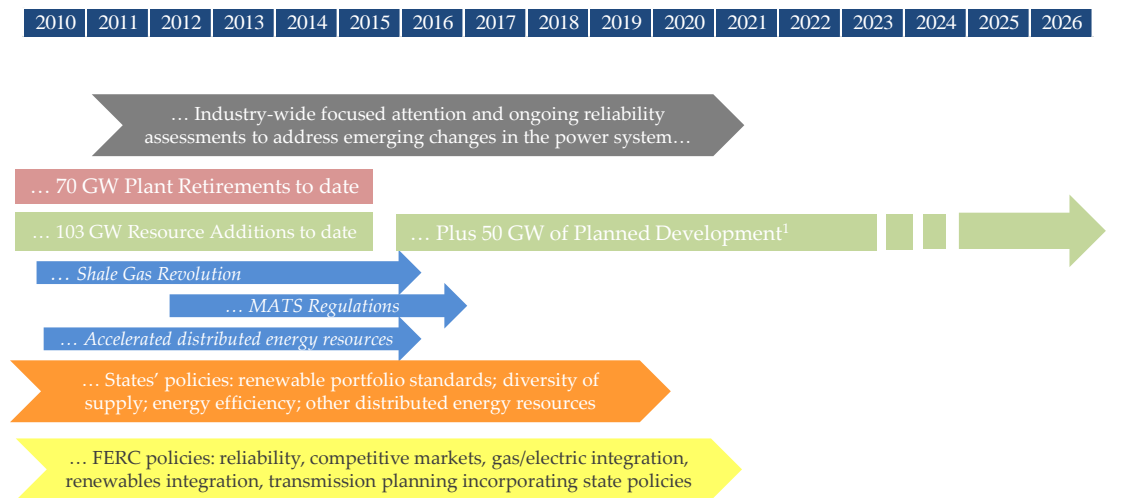
<sup>10</sup> Notably, this has occurred in conjunction with: the EPA “NO<sub>x</sub> SIP call” which affected 23 states in the 1990s; state and federal policies related to electric industry restructuring in the 1990s: the Cross-State Air Pollution Rule (CSAPR) and MATS rule; and with on-going increases in the amount of distributed energy resources and intermittent/non-dispatchable resources on the grid.

<sup>11</sup> NERC, “Essential Reliability Services Task Force: A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability,” October 2014. Hereinafter referred to as “NERC Essential Reliability Services Report”.

be provided to support reliable operation. ERSs are technology neutral and must be available regardless of the resource mix composition.<sup>12</sup>

Those transformations have been in the works for years – in part as a result of the shale gas revolution, changes in the relative prices of fossil fuels, state policies and federal laws encouraging greater use of renewable energy and energy efficiency, declines in wind and solar technology costs, retirements of old and highly polluting coal plants, retirements of a handful of nuclear plants (in some cases for safety reasons, and others for economic reasons), and strong interest by many customers in exploring ways to better manage their own energy use.<sup>13</sup> We depict these changes occurring in parallel in Figure 1, below.

**Figure 1**  
**Timeline of Changes Underway in the Electric Industry**



<sup>1</sup> Includes retirements/additions announced for 2015 and units that are mothballed or out of service. Planned units include those under construction or in advanced development. Source for MW of retirements and planned additions: SN Financial, Accessed February 2015

As always, grid operators and utilities have implemented and adjusted long-standing planning and operational practices to stay abreast of, understand, and adapt practices to address reliability issues related to such changes in the industry. Given the multiple pressures on the electric power sector, such actions would be needed today even if EPA had not proposed to control carbon pollution in the Clean Power Plan.

<sup>12</sup> NERC Essential Reliability Services Report, page iii. The scope of work for this report was adopted by NERC in March of 2014, before the EPA Clean Power Plan was issued in proposed form in June, 2014.

<sup>13</sup> See, for example: Susan Tierney, "Greenhouse Gas Emission Reductions From Existing Power Plants Under Section 111(d) of the Clean Air Act: Options to Ensure Electric System Reliability," May 8, 2014, pages 23-46.

Indeed, many organizations besides NERC have also been flagging the need to address reliability issues as the industry undergoes significant change. For example:

- The Federal Energy Regulatory Commission's (FERC) attention to gas-electric coordination as the two industries become increasingly dependent on each other,<sup>14</sup> and transmission companies and Regional Transmission Organizations (RTOs) plan for integration of variable generating resources and transmission requirements driven by public policies of state and local governments;<sup>15</sup>
- Studies by the Midcontinent ISO (MISO) of gas infrastructure,<sup>16</sup> and MISO's support for policies addressing transmission implications of the region's growing quantities of wind and other renewable resources;<sup>17</sup>
- ISO-New England's (ISO-NE) continuing analysis of that region's deepening reliance on gas-fired generating facilities, near-term generator retirements, and need to integrate deepening amounts of renewable resources;<sup>18</sup>

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<sup>14</sup> FERC Commissioner Philip Moeller first requested comments on gas-electric coordination in February 2012. Since that time, the FERC has held nine regional conferences to address the issue. See FERC "Natural Gas – Electric Coordination." Available: <http://www.ferc.gov/industries/electric/indus-act/electric-coord.asp> for additional detail. In 2013, FERC Chairman Cheryl LaFleur and Commissioner Moeller testified before Congress on "The Role of Regulators and Grid Operators in Meeting Natural Gas and Electric Coordination Challenges". The Commissioners noted that gas-electric coordination was and is a growing and important trend due to falling natural gas prices and substantial domestic supplies. FERC receives quarterly updates from its staff on the status of developments in the industry regarding gas/electric coordination issues. <http://www.ferc.gov/industries/electric/indus-act/electric-coord.asp>. Note too that in response to a directive from FERC, the North American Energy Standards Board (NAESB) undertook a process to develop some new standards for both electric and natural gas industries, which were described in a report submitted to FERC on September 29, 2014.

<sup>15</sup> On July 21, 2011, FERC issued Order 1000 (Docket No. RM10-23-000), in which the agency required, among other things, that each public utility transmission provider: (1) participate in a regional transmission planning process that produces a regional transmission plan; and (2) consider transmission needs driven by public policy requirements established by state or federal laws or regulations. Each public utility transmission provider must establish procedures to identify transmission needs driven by public policy requirements and evaluate proposed solutions to those transmission needs. FERC Fact Sheet, Order 1000, <http://www.ferc.gov/media/news-releases/2011/2011-3/07-21-11-E-6-factsheet.pdf>. On June 22, 2012, FERC issued the final rule in its docket (RM10-11-000) on Integration of Variable Energy Resources, in which it ordered a number of changes in interconnection agreements, transmission tariffs and cost recovery for regulation reserves to better accommodate renewables reliably and efficiently. 139 FERC ¶ 61,246, FERC Order No. 764.

<sup>16</sup> MISO released its first gas-electric interdependence study in February 2012; it reviewed existing gas pipeline capacity to serve existing electric generation and additional capacity that could be added in the future, and signaled to the MISO and stakeholders that an increase in gas-fired generation will require an "improved collaborative process between pipelines, power generators, and regulators to coordinate natural gas infrastructure projects." Gregory L. Peters, "Gas and Electric Infrastructure Interdependency Analysis," Prepared for the Midwest Independent Transmission System Operator, February 22, 2012, page. 12.

<sup>17</sup> MISO's "Multi-Value Project Portfolio Analysis" of transmission projects will support delivery of up to 41 million MWh of wind energy. Available: <https://www.misoenergy.org/PLANNING/TRANSMISSIONEXPANSIONPLANNING/Pages/MVPAnalysis.aspx>

<sup>18</sup> ISO-NE first identified these issues in 2010. In 2013, ISO-NE's Chief Executive Officer, Gordon van Welie, stated: "It is clear that resolving these challenges will not be simple, and it will take several years to realize the benefits of the solutions... It is important to remember that, often, the best ideas are born out of necessity. Today the power system faces significant and formidable obstacles. But tomorrow, it will be smarter, stronger, and more environmentally sound because of our collective efforts." ISO-NE, "2013 Regional Electricity Outlook," January 31, 2013, page 8.

- Starting in 2010, calls by the American Public Power Association (APPA) to pay greater attention to the impacts of distributed generation and increased natural gas demand for power generation;<sup>19</sup>
- The Electric Reliability Council of Texas' (ERCOT) ongoing analysis of wind integration as part of its bi-annual Long Term System Assessment;<sup>20</sup>
- The review by the five major electric utilities in California of the implications of a potential significant increase in the state's renewable portfolio standard,<sup>21</sup> and the California ISO's (CAISO) solicitation of more flexible resources to support integration of renewables;<sup>22</sup>
- PJM Interconnection's (PJM) recent capacity performance proposal, in response to concerns raised by unavailable conventional generation capacity during the 2013-2014 polar vortex;<sup>23</sup> and
- New York ISO's (NYISO) ongoing evaluation of reliability needs, including scenarios that account for environmental regulations, increasing penetration of renewable resources, and natural gas fuel availability.<sup>24</sup>

These studies and activities – and others like them – illustrate that our electric system operators, planners, regulators, and others are stepping up to the plate (as they typically do) to grapple with ways to make sure that the future electric system is as reliable as the one we count on today. And their analyses reflect the reality that these trends are occurring as a result of economic, policy and regulatory forces that are independent of EPA's Clean Power Plan.

The value of such “reliability alerts” is that they identify ways in which changes in policy, economics, technology, and law affecting the electric industry intersect with the physics and engineering of interconnected electric systems. All parts of the system must pay attention to certain imperatives of the others.

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<sup>19</sup> See, for example, Aspen Environmental Group, “Implications of Greater Reliance on Natural Gas for Electricity Generation,” prepared for American Public Power Association, July 2010.; and American Public Power Association, “Distributed Generation: An Overview of Recent Policy and Market Developments”, November 2013.

<sup>20</sup> See, for example, ERCOT, “Long-Term System Assessment for the ERCOT Region,” December 2012, which examined the implications of introducing significant wind generation and new gas-fired power plants on to the ERCOT Texas system.

<sup>21</sup> Energy+Environmental Economics, “Investigating a Higher Renewables Portfolio Standard in California,” January 2014.

<sup>22</sup> California Independent System Operator Corporation Reply Comments on Workshop issues, before the Public Utilities Commission of the State of California, In the Matter of “Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations.” Rulemaking 11-10-023, April 5, 2013.

<sup>23</sup> PJM Staff Proposal, “PJM Capacity Performance Proposal”, August 20, 2014.

<sup>24</sup> NYISO conducts a detailed “Reliability Needs Assessment” every two years. See, for example, NYISO, “2014 Reliability Needs Assessment,” Final Report, September 16, 2014.

Certainly, the shale gas 'revolution' has introduced significant quantities of domestically supplied natural gas at prices which compete with coal, the historically dominant domestic fossil fuel for power generation. This new reality presents economic opportunities to the power system, with cost and environmental benefits for households and businesses. At the same time, however, lower-cost natural gas introduces new issues that must be addressed in the standards, business practices and regulation of both the electric and gas industries: for example, there are new issues surrounding ensuring adequate fuel-transportation and storage arrangements. States' policies to rely more heavily on domestic wind and solar generation also introduce new challenges: grid operators must plan to operate their systems reliably with greater reliance on less dispatchable resources (or in some cases resources that cannot be 'seen' on the system by grid operators, when the resources are behind the meters of customers).

Reliability organizations and grid operators (including NERC, Regional Transmission Organizations (RTOs), electric utilities, and others) are already facing the implications of these trends. They are doing what we count on them to do: looking ahead to see what's on the horizon and identifying reliability-related issues that require adjustments to planning, markets, or operations. They are identifying issues that arise from economic, technological, legal or policy changes. They are developing new analytic tools to better understand how factors like the weather (or wind or sun/cloud-cover conditions) affect power system operations. They are identifying possible, if not likely, changes in power supplies, and indicating where and when new resources might be needed in the years ahead. They are working with transmission owners, power plant companies, government regulators, reliability coordination organizations, consumer representatives, and others to identify changes that may be required in operating standards, market products, and practices.

This is standard operating procedure in an industry with a history with strong legal, cultural, and organizational incentives to do what it takes to make sure that a world-class reliable electric system remains a bedrock of the American economy and society. Recent calls for action to ensure that the Clean Power Plan does not jeopardize electric system reliability should be viewed in that context: people are doing their jobs, not necessarily trying to impede the Clean Power Plan.

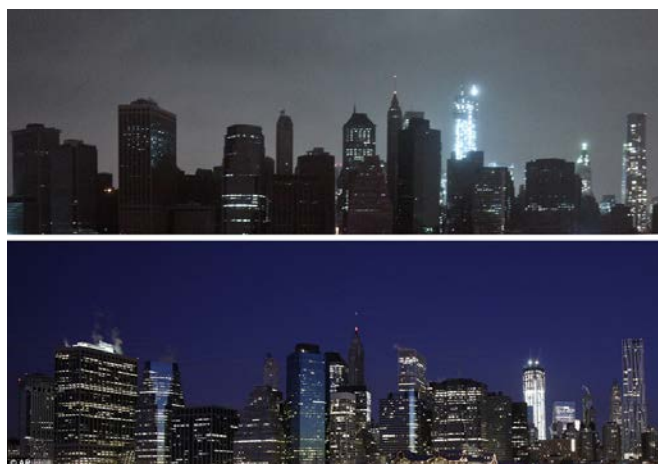
## II. What Do We Mean by “Electric System Reliability”?

### What is reliability, and why does it matter?

Most electricity users think of reliability in terms of how often their power shuts off and how long it takes to get it back on. These familiar reliability annoyances typically result from events affecting the local distribution system, such as a snowstorm or hurricane knocking out power lines or a car hitting a power pole.

While critically important to electricity users,<sup>25</sup> such events are not the main concern of observers considering the implications of EPA's Clean Power Plan. What they worry about is whether the overall electric system can do its job, day in and day out, even if one neighborhood or another loses its power.

This other kind of reliability is known as “bulk power system”<sup>26</sup> reliability (and what we call “system reliability” and what insiders sometimes call “BPS” reliability). Outages due to system failures differ from local outages in fundamental ways: in how they can arise; in the geographic scope of power interruptions; in the process and timing of power restoration; in the magnitude of adverse consequences; and, in terms of the parties responsible to fix the problems. The sheer scale of potential human health, safety, and economic impacts is what separates system reliability from local reliability, and dictates a high degree of vigilance on the part of regulators and the industry to avoid system-reliability failures.<sup>27</sup>



<http://www.dailymail.co.uk/news/article-2226399/Sandy-Vast-majority-ConEd-wont-power-10-days--Manhattan-hopes-lit-Saturday.html>

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<sup>25</sup> Electricity consumers are acutely aware of how inconvenient and costly outages can become, and of course may not care whether an outage is local or system-wide, in terms of the disruptive impacts on their lives. At the state level, maintaining reliable service is a fundamental obligation of every local utility, and state public utility commissions (PUCs) measure the performance of local utilities in maintaining local reliability over time through measurements that track the frequency and duration of outages. In many states, utilities can be fined heavily for poor reliability performance tied to local distribution-system outages. In contrast, system power failures – which are far less common – generally involve events affecting power plants and transmission lines and a wider geographic area of the grid, with reliability enforcement subject to the jurisdiction of FERC under then Federal Power Act (FPA).

<sup>26</sup> A Bulk Power System (BPS) generally covers a wide geographic region, and includes the generating resources, transmission lines, and associated equipment and systems used to operate the integrated electric system within the region. BPSs generally do not include the lower-voltage distribution systems of local utilities, which deliver power from the BPS to end-use customers.

<sup>27</sup> This is not to say that local distribution system circumstances can never create system reliability challenges. Given that the electric system has to maintain customer demand (load) and supply in balance at all times, a major storm that causes local lines to

For this reason, multiple entities (including those in Table 8) constantly monitor conditions on the overall power system to assure that the overall system operates with a high degree of reliability. System planners, reliability organizations, power companies and regulators look many years ahead, to analyze changing conditions and flag issues on the horizon that need attention. From one season to the next, they review whether there will be enough resources

to meet peak demand. Closer to real time, system operators monitor whether power plants are out for maintenance, whether temperature conditions will produce higher than expected demand, and myriad other conditions so that they can get ready for the next day’s operations. And in real time, on a second-by-second basis, grid operators have to monitor, and manage the “balance” of the system so that supply equals demand within tolerable operating limits (i.e., “frequency”). Thus, across very different time frames, many actors in the industry work to assure that the system performs with impeccable reliability levels.

Those responsible range from: the federal regulators at the FERC, which has statutory authority relating to system reliability; to NERC, the nation’s “Electric Reliability Organization” (ERO), authorized by FERC to set reliability standards for grid operators, utilities and other power companies; to Regional Reliability Organizations (RRO) which ensure that the system is reliable, adequate and secure within the geographic footprint for which they’re responsible; to grid operators (also known as “balancing authorities” or “system operators”) with the operational responsibility in smaller areas.<sup>28</sup> Each

<b>Table 8 Entities Responsible for Electric System Reliability</b>	
<b>Organization</b>	<b>Roles and Responsibilities</b>
<b>Federal Energy Regulatory Commission (FERC)</b>	- Federal agency responsible for enforcement of electric sector reliability requirements, including oversight of the ERO (NERC)
<b>North American Electric Reliability Corporation (NERC)</b>	- Designated as the Electric Reliability Organization (ERO) by FERC; responsible for developing, assessing and enforcing reliability standards
<b>Regional Reliability Organizations (RROs)</b>	- Members of the NERC that ensure regional operations are reliable, adequate and secure. Includes: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability First (RF), SERC, Southwest Power Pool (SPP), Texas Reliability Entity (TRE), and Western Electric Coordinating Council (WECC)
<b>Grid and System Operators, and Balancing Authorities</b>	- Responsible for the reliability functions in specific geographic areas. In addition to many electric utilities, there are other organizations serving this function in wide geographic areas, including Regional Transmission Organizations (the New York System Operator (NYISO), PJM Interconnection, New England Independent System Operator (ISONE), Midcontinent Independent System Operator (MISO), California Independent System Operator (CAISO), and Electric Reliability Council of Texas (ERCOT)

go down can cause a rapid loss of demand with the immediate need to address that big imbalance on the overall system in order to avoid a bigger problem affecting many other areas of the grid. Similarly, high penetrations of distributed resources (e.g., rooftop solar panels on customers’ premises) connected to the local distribution system are emerging as a reason to increase the BPS grid operator’s “visibility” into what is happening at the distribution system level because of the interrelationships between the two systems. In fact, several areas with significant current or expected installation of distributed resources (e.g., Hawaii, California) have begun to evaluate potential system-wide challenges associated with such developments.

<sup>28</sup> NERC’s Glossary of Terms formally defines the various entities, along with various terminologies that described their responsibilities. NERC, “Glossary of Terms Used in NERC Reliability Standards,” January 29, 2015, available: [http://www.nerc.com/pa/stand/glossary%20of%20terms/glossary\\_of\\_terms.pdf](http://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf)



one has different responsibilities, as shown in Table 8.

These entities monitor system reliability using time-tested, well-developed industry analytic tools. For longer-term assessments, the standard methods take into consideration a vast array of potential future infrastructure scenarios and system operational contingencies (e.g., sudden loss of generation, transmission or load). Annually and seasonally, system operators and reliability planners conduct reliability assessments to evaluate system changes, flag areas of concern that need to be addressed within different time frames, and identify plans to address any reliability concerns that may arise over the planning period. In addition, special assessments are periodically carried out in response to any industry or policy changes that have the potential to affect system reliability.

Thus it should not be surprising that EPA's proposed Clean Power Plan is being (and will continue to be) evaluated for potential reliability impacts in future years. We have seen such reliability evaluations exercised regularly over decades in the face of other major industry changes, as noted previously.<sup>29</sup> In every case, the prospect of change has led to reliability assessments and the waving of cautionary flags to call attention to the new challenges ahead.

### **How could electric system reliability be affected by the Clean Power Plan?**

The Clean Power Plan will not lead to more cars hitting distribution poles, nor will it affect the frequency, location, or severity of storms that lead to local outages. The more relevant questions are how controls on power plant CO<sub>2</sub> emissions will affect power system components and operations. As highlighted in Section III (which summarizes stakeholder concerns around the Clean Power Plan's potential impacts on system reliability), concerns primarily relate to impacts these pollution controls will have on availability of existing power plants. Will plants

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<sup>29</sup> There are many examples where changes in conditions have led to questions about whether the electric industry (and its supply chains) could respond in a sufficiently timely and effective way to avoid reliability problems. This occurred, for example, with: (1) prior EPA and state regulations governing human health and environmental impacts, including the CAA Title IV sulfur dioxide cap-and-trade program contained in the 1990s; the changes in National Ambient Air Quality Standards (NAAQS) and Clean Water Act (CWA) requirements; the more recent CSAPR and MATS regulations; and the proposals under 316(b) of the CWA. (2) Changes to the structure of the electric industry over the past several decades, involving major changes in the regulation of and the incentives for investment and operation; transfers of ownership and management of existing generation and transmission system elements; and the formation of RTOs and associated wholesale markets for energy, capacity and ancillary services. (3) Fundamental shifts in the economics of generating power from coal or from natural gas, driven initially by changes in technology costs (e.g., large-scale steam generators versus combined-cycle technologies) and more recently by the emergence of low-priced domestic shale gas resources; the growing strain in some regions on the capacity of interstate natural gas delivery and storage systems to meet combined demand from heating and electricity generation uses during peak winter conditions; and different business practices, and operational protocols and standards in two industries (the natural gas industry and the electric industry) that might need to be better aligned as the two industries become more interdependent. (4) The ongoing displacement of traditional generation resources by grid-connected and customer-sited variable renewable resources, in some cases dramatically changing the shape of net load that must be followed by system operators. (5) Questions about the ability of some wholesale electricity markets to provide sufficient financial incentives for suppliers to continue to operate and/or to enter the market.

retire and, if so, which ones and when? Which new ones will be added, over what time period? Will gas pipelines and other fuel-delivery infrastructure be in place in time to fuel a power system that depends more upon natural gas? Will the electric transmission system be capable of moving power generated in new locations relative to customer demand?

Insights and answers to these various questions fall into two basic categories, differentiated by time scales. One focuses on long-term planning considerations, and is called “resource adequacy”: Will there be enough (adequate) resources in place when system operators need to manage the system to meet demand in the future? The other focuses on short-term operations, and is called “system security”: Will the operators be able to run the system in real time in a secure way to keep the system in balance, with all that that entails technically?<sup>30</sup>

### Resource Adequacy

First, the interconnected electric grid must have resource adequacy – that is, there must be sufficient electric supply to meet electric demand at the time of annual peak consumption, taking into account the expectation that some parts of the system will not be able to operate for one reason or another. The system must have some additional quantity of capacity above the annual peak load value (the reserve margin) to cover the possibility that in highest-demand hours some resources may be out of service due to planned or unplanned outages.<sup>31</sup> In some regions and sub-regions (or “zones”), constraints on the ability of the transmission system to move power from one location to another mean that some portion of the demand within the zone must be met by generating resources within that same zone.

Ensuring resource adequacy is generally accomplished through two steps. First, the expected system peak demand and energy requirements over a long-term period (e.g., ten years) are established through a comprehensive forecasting effort. Forecasting processes for this purpose use well-established economic and industry modeling tools and data, are conducted frequently, and typically involve input by utilities, grid operators, public officials, consumer advocates, and

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<sup>30</sup> The U.S. Energy Information Administration (EIA) defines electric system reliability as the “degree to which the performance of the elements of the electrical system results in power being delivered to consumers within accepted standards and in the amount desired. Reliability encompasses two concepts, adequacy and security. Adequacy implies that there are sufficient generation and transmission resources installed and available to meet projected electrical demand plus reserves for contingencies. Security implies that the system will remain intact operationally (i.e., will have sufficient available operating capacity) even after outages or other equipment failure. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service.” U.S. EIA, “Glossary,” available at <http://www.eia.gov/tools/glossary/index.cfm?id=E>.

<sup>31</sup> Reserve margins are generally in the range of 10 to 20 percent of system peak load. The actual reserve margin varies from region to region as a function of many factors (e.g., the mix and expected performance of assets on the system, operational and emergency procedures, the availability of demand response/load curtailment, and contributions that may come from neighboring regions).

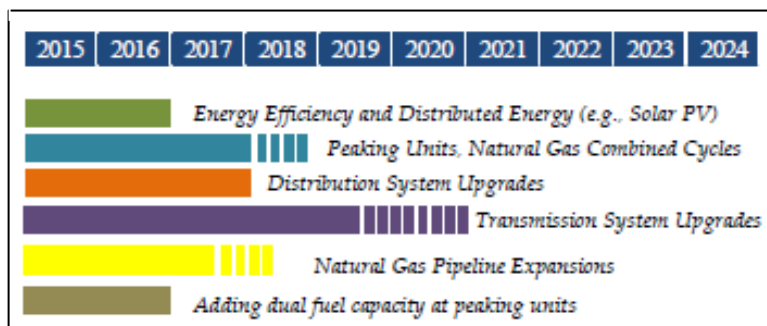
many other market participants and stakeholders. This step occurs in both wholesale energy markets and through integrated resource planning conducted by electric utilities.

Second, to the extent that identified long-term needs exceed resources expected to be on the system (due, for example, to growth in demand over time, and/or the retirement of existing resources), the deficit is met through the addition of new infrastructure (power plants or transmission lines) and/or demand resources (such as energy efficiency or demand-response measures). The ways in which new resources are added varies around the country, depending on the structure of the electric industry and the regulatory approach in place in a given state, along with other aspects of the market (including FERC-regulated RTOs in many regions). In wholesale market regions like PJM and NYISO, identified needs are met through market structures designed to provide financial incentives for investment in new capacity. In other regions (like most of the West), vertically integrated utilities, cooperatives and municipal electric companies add needed capacity by proposing and building their own project and/or through soliciting offers from other competitive suppliers. In any event, the overall resource need is forecasted (and, if relevant, a local/zonal requirement is further identified), and some combination of regulated and/or market process brings forth proposals to satisfy the need.

These processes are designed to accommodate the lead times necessary to bring a new project or resource into operation. They typically involve sufficient advance notification of need to allow for: (1) initial development stages and associated studies around project feasibility, interconnection, etc.; (2) administration of the markets or competitive procurement processes (and regulatory approvals of them); (3) zoning, permitting, and siting approvals for specific facility projects; (4) construction of the power plant and associated infrastructure (e.g., transmission interconnection/upgrades and – if needed – fuel delivery such as natural gas pipeline connections). Lead times

for implementing peaking generating units and demand-side actions (e.g., programs leading to installation of energy efficiency measures; equipping buildings with automated capability to control demand when signaled to do so by the system operator; adding solar PV panels) are much shorter than those for large power plants and transmission upgrades.

**Figure 2**  
Typical Lead Times for Different Electric Resources



Source: Analysis Group

Figure 2 provides a conceptual depiction of lead times for planning, developing and installing

different types of infrastructure to support electric resource options.

The processes outlined above rarely occur in a sequential fashion.<sup>32</sup> Ten-year assessments take into account time periods that extend well beyond the number of years it typically takes to develop, permit, finance, and construct a new power plant.<sup>33</sup> As one developer is starting to scope out where to site a new power plant in anticipation of hoping to get approvals and enter the market four years in the future, another already has its approvals and has commenced construction. Installation of demand-response measures take much shorter time periods altogether. Many steps occur concurrently across many different types of resources that are being planned and put in place to meet resource adequacy requirements.

In practice, there are exceptionally few instances where industry has failed to provide for resource adequacy, where – due to a lack of installed capacity – the grid operator had to implement emergency protocols (such as lowering voltage (sometimes known as rolling brownouts) or curtailing service to customers (sometimes known as rolling blackouts)).<sup>34</sup> Although there have been rare occasions where a relatively near-term resource adequacy problem has been identified, regulators, market participants, grid operators, customers and reliability organizations have taken the steps needed to assure that the lights stayed on. There are well-known examples from around the country where the industry (including its regulators) did what was necessary to keep power flowing to consumers.<sup>35</sup> In large part, this track record

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<sup>32</sup> For example, often initial market development of a new generating resource – e.g., site identification and control, technology selection, fuel and transmission infrastructure studies, fatal flaw analyses, even some initial siting and permitting efforts – happen in advance of or concurrent with resource need specification or market/utility procurement. Similarly, engineering, construction, and fuel contracts may be established (on a contingent basis) prior to final resource selection or final regulatory approval. Successful resource development teams effectively manage the flow of steps needed to take a new power plant from concept to operation so as to balance the stages of investment risk against the process of procurement and approval.

<sup>33</sup> Typically, lead times for a new natural gas power plant involve 2 years for development and permitting and another 2 years for construction. A peaking unit typically takes less time: from 2 to 3 years. Demand-response and other distributed energy resources can be brought to market in 1 to 2 years. Some generating additions may further require transmission or distribution system upgrades. These can range in time from as little as 2 to 3 years for local distribution upgrades to 5 to 6 years or longer for more extensive transmission system upgrades, but such permitting and construction activities are carried out coincident with power plant permitting and construction. Lead and development times are in part, flexible, depending on the system need and critically, it is possible to move faster when needed. For example, following the California Energy Crisis in the early 2000's, the state added thousands of MWs of new generation using a set of emergency 21-day, 4-month, and 6-month citing procedures. These emergency responses helped establish a set of best practice siting procedures that can be used by other states in similar situations. Susan F. Tierney and Paul J. Hibbard, "Siting Power Plants: Recent Experience in California and Best Practices in Other States," Hewlett Foundation Energy Series, February 2002.

<sup>34</sup> A notable exception is the well-known California electricity crisis of 2000-2001, which resulted from a combination of actions (including market manipulation through actions in the electric and natural gas markets, as well as caps on retail electricity prices). To our knowledge, there has never been a resource adequacy event (e.g., a brownout or blackout) due to implementation of an environmental regulation.

<sup>35</sup> Examples include:

- ERCOT's slim reserve margins in recent summers, including for example, in 2012, when nearly 2,000 MW of mothballed capacity was returned to service. Commissioner Anderson Jr., Public Utilities Commission of Texas, "Resource Adequacy in

reflects the existence of the many resource-adequacy processes outlined above, the presence of multiple early warning systems, the ability of policy makers to take action to address challenges when urgent action is needed,<sup>36</sup> and a strong mission orientation of the industry and its regulators.<sup>37</sup>

### System Security

Even assuming that these resource adequacy processes end up ensuring there are enough megawatts of capacity in place when needed to meet aggregate load requirements, actual

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ERCOT," Update #4, January 30, 2013. Available:

[https://www.puc.texas.gov/agency/about/commissioners/anderson/pp/analysis\\_ercot\\_capacity\\_reserve\\_margin\\_013013.pdf](https://www.puc.texas.gov/agency/about/commissioners/anderson/pp/analysis_ercot_capacity_reserve_margin_013013.pdf).

- Reliability must run (RMR) contracts to keep plants operating, for example:
  - o The retention of operations of the Potomac Generating Station until completion of the Pepco transmission lines; see, Paul J. Hibbard, Pavel G. Darling, and Susan F. Tierney, "Potomac River Generating Station: Update on Reliability and Environmental Considerations," July 19, 2011);
  - o A delay in Exelon's proposed retirement of the Eddystone and Cromby generating stations in Pennsylvania after PJM determined that in the absence of transmission upgrades, retirements of those units would lead to violations of security standards, with a reliability must run agreement between PJM and Exelon and state air regulators so that the plant could remain on line pending those transmission upgrades, but with limits on the units' dispatch to only those times when the units were needed for operational reliability purposes. Prepared Testimony of Kathleen L. Barrón, Vice President of Federal Regulatory Affairs and Policy, Exelon Corporation, before the FERC, Reliability Technical Conference Docket No. AD12-1-000 (etc.), November 11, 2011.
- Construction of peaking units on a fast-track basis by the New York Power Authority: "We increased our generating capacity by about 450 megawatts during summer 2001 when we began operating small, clean natural gas-powered generating plants at six sites in New York City and one on Long Island. We had launched a crash program in late August 2000 to install these PowerNow! plants in response to warnings from officials in the public and private sectors that the New York City metropolitan area could face power shortages in the summer of 2001. Similar warnings were repeated throughout the 10 months it took to obtain, site, design and install the units—a process that normally would require more than two years." New York Power Authority, "Small Clean Power Plants," Available: <http://www.nypa.gov/facilities/powernow.htm>.
- Requests by ISO-NE for demand-response resources in Connecticut on a fast-track basis: "On December 1, 2003, ISO New England Inc. (ISO-NE) issued a Request for Proposals (RFP) soliciting up to 300 MW of temporary supply and demand resources for Southwest Connecticut (SWCT) for the period 2004 to 2008. The purpose for acquiring these resources was to improve the electric system reliability in SWCT through the summer of 2007, when the 345 kV transmission loop is planned for completion." J.E. Platts, ISO-NE, "Final Report on Evaluation and Selection of Resources in SWCT RFP for Emergency Capability, 2004-2008," October 4, 2004, page iii.
- New York State's contingency planning efforts (including consideration of new transmission projects) to prepare for a possible shutdown of the Indian Point nuclear plant, shutdown as early as 2018, depending on the outcome of its re-licensing with NRC. See the New York Department of Public Service Commission Case No. 12-E-0503, "Proceeding on Motion to Review Generation Retirement Contingency Plans." Available: <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=12-e-0503&submit=Search+by+Case+Number>

<sup>36</sup> Susan F. Tierney, and Paul J. Hibbard, "Siting Power Plants: Recent Experience in California and Best Practices in Other States," Hewlett Foundation Energy Series, February 2002.

<sup>37</sup> For example, FERC/EPA processes under the MATS regulation introduced a Reliability Safety Valve and related procedures to ensure that identified reliability challenges could be addressed, while allowing some flexibility with the eventual MATS timeline. As discussed below, the ISO/RTO council has proposed a similar reliability safety valve for the Clean Power Plan and the EPA has also acknowledged potential reliability concerns in its most recent Notice of Data Availability memorandum.

'delivered' reliability also depends on making sure that the system operates in real time with high technical integrity.

System reliability is affected in real time by several things:

- The mix of attributes of the resources on the system – their location, their fuel source, and the operating characteristics of the supply and demand resources;
- The variations in system conditions (e.g., building lights turned on, or a power plant tripping off line unexpectedly, or sudden storm-related outages, or shifts in windiness) that change on a second-to-second, minute-to-minute, hour-to-hour, and day-to-day basis; and
- The system operator's practices and procedures for managing the changing conditions on the system at all times and in all places under that operator's responsibility, to assure that the system stays in balance.

System security describes the ability of the system to meet ever changing system conditions, and to do so with enough redundancy in operational capabilities to manage and recover from a variety of potential system events – or “contingencies” – such as sudden and unexpected loss of generation, transmission, or load.<sup>38</sup> System planners and operator must ensure that the mix of resources on the system is capable of responding in real time to normal load changes and contingency events. This is needed to avoid the catastrophic wide-area failure of the bulk power system – such as a cascading outage covering one or more regions – that can come from unacceptable variations in system voltage and frequency. Blackouts can damage electrical equipment on the grid and on customers' premises, and create wide-ranging safety and health impacts.

To assure system security, the system as a whole must have certain attributes allowing it to provide “essential reliability services,” as summarized in Table 9. These include two functional categories:

- *Voltage support*, meaning the ability of system resources to maintain real power across the transmission grid, through the use of reactive power sources such as generators connected to the system, capacitors, reactors, etc. Voltage on the system must be

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<sup>38</sup> NERC describes certain features of the bulk power system needed to meet system security requirements – e.g., voltage control, frequency control – as Essential Reliability Services, or ERS. NERC Essential Reliability Services Report.

maintained within an acceptable voltage bandwidth in normal operations and following a contingency on the system.<sup>39</sup>

- *Frequency Management*, meaning the ability of the system to maintain a system frequency within a technical tolerance at all times.<sup>40</sup> Frequency is a function of the match between generation output and load on the system, and requires constant balancing, or following of load by resources that can increase and decrease output instantaneously.

Importantly, system security, or operational reliability, is not a “yes” or “no” condition. To maintain it, system operators use a combination of strategies, tools, procedures, practices, and resources to keep the entire system in balance even as conditions change on a moment to moment basis.<sup>41</sup> The difficulty of this task largely results from several things. First, the

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<sup>39</sup> Voltage support is local in nature, can change rapidly, and depends in part on the type and location of generators connected to the transmission system. Typically, voltage control is maintained by system planners and operators. Acceptable power factors for voltage support are maintained, in part, through the use of reactive power devices (or power factor control) that inject or absorb reactive power from the bulk power system. Reactive power can be provided by synchronous thermal generators and through capacitors and other devices, as well as by ‘adequately designed’ variable energy resources (including wind and solar) and storage technology. Voltage disturbance performance is the ability to maintain voltage support and voltage control after a disturbance event. NERC Essential Reliability Services Report, pages 1, 10-11.

<sup>40</sup> Frequency must typically be maintained within tens of mHz of a 60 Hz target. Higher frequencies indicate greater supply, while lower frequencies typically indicate greater demand. Frequency management includes: (1) Operating reserves, which are used to balance minute to minute differences in load and demand, load following capabilities to respond to intra- and inter-hour changes in load fluctuations, and reserves, which are used to restore system synchronization following generator or transmission outages; (2) Active Power Control, including ramping capability to quickly bring generators online in response to operator needs, often in ten minutes or less; (3) Inertia, or stored rotating energy that is used to arrest declines in frequency following unexpected losses. Historically, inertia has been supplied by large coal-fired generators, although NERC notes that new ‘synthetic’ inertia is available through the operation of variable energy resources supported by energy storage devices; and (4) Frequency Distribution Performance, which similar to voltage distribution performance, is the ability to maintain operations during and after an unplanned disturbance. NERC Essential Reliability Services Report, pages 3-5, 8-9.

<sup>41</sup> System operators manage voltage and frequency as load changes over time, and in response to contingency events, through the posturing and management of the resources on the system across several time scales:

- On a second-by-second basis through automatic generation control (AGC) systems on resources that will automatically adjust generation up or down in response to system frequency signals.
- On the time scale of minutes through tens of minutes through accessing “spinning reserves,” including operating resources with the ability to ramp output up or down quickly, and resources that can connect to the system within several minutes.
- On the timescale of tens of minutes through accessing longer-term reserve resources that can turn on and connect to the system in less than an hour (typically on the order of 15 to 30 minutes).
- On the time scale of hours or days by committing sufficient operating and reserve resources to manage *expected* swings in net system load (that is, system load net of variable resource output). Note that load varies in relatively ‘normal’ ways over the course of the days, weeks, and months, and is predictable with a relatively high degree of accuracy by system operators. This allows for the commitment and availability of enough system resources to meet reliability objectives. However, the proliferation of distribution-level, behind-the-meter (BTM) generation with variable output (e.g., distributed wind and solar PV) complicates the forecasting of “net load” visible to system operators – that is, the normal variation in load net of variable BTM output that comes and goes with the sun and wind.
- On an as-needed basis for voltage control by adjusting reactive power injected into or absorbed from the system by on-line generators, capacitors, reactors, and system var compensators.

Source: NERC Essential Reliability Services Report, generally.

operator has, in effect, a particular set of assets on the system at any time, which reflects the operational attributes of the various resources on the system at that time. These include things like: power plants with different operating profiles (e.g., start-up time, limits on output under different temperature conditions, availability to fuel supply); transmission systems that allow or limit power flows in various directions; ‘smart’ controls and communications devices that allow (or not) visibility into and/or management of power flows; demand response; storage systems; and so forth.

**Table 9**  
**System Security Needs and “Essential Reliability Services”**

Services	Components	Description	Consequences of Failure	
<b>Voltage Support</b>	<i>Voltage Control</i>	Support system load; maintain transmission system in a secure and stable range	· Loss of Load	
	<i>Voltage Disturbance Performance</i>	Ability to maintain voltage support after a disturbance	· Equipment Failure · Cascading Losses	
<b>Frequency Management</b>	<i>Operating Reserves</i>	Regulation	Minute-to-minute differences between load and resources	
		Load Following	Intra- and inter-hour load fluctuations	
		Reserves	Includes Spinning, Non-Spinning, and Supplemental; Used for synchronization and respond to generator or transmission outages in 10 min or greater time frames	
	<i>Inertia</i>		Stored rotating energy; Used to arrest decline in frequency following unexpected losses	· Loss of Generation · Load Shedding · Interconnection Islanding · Overload Transmission Facilities
		<i>Frequency Distribution Performance</i>	Ability of a plant to stay operational during disturbances and restore frequency to BPS	· Damage Equipment and lead to Power System Collapse
		<i>Active Power Control</i>	Frequency Control	Real-time balance between supply and demand
			Ramping (Curtailment) Capability	Ability to increase/decrease active power, in response to operator needs. Measured in MW/min basis

**Notes and Sources:**  
 [1] Adapted from NERC (2014) "Essential Reliability Services Task Force: A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability".  
 [2] NERC (2014) notes that these Essential Reliability Services are functionally equivalent to the Interconnected Operations Service (IOS) definitions, with Voltage Support covering Reactive Power Supply from Generation Sources and Frequency Support covering Frequency Response, Regulation, Load Following, and Contingency Reserves.  
 [3] NERC notes that many of these ESRs are already defined as ancillary services in the OATT of many system operators. Ancillary services are "those services necessary to support the transmission of electric power from seller to purchaser", considering reliability needs. Therefore, NERC considers ancillary services to be a subset of ESRs.

Second, the operator must maintain frequency and voltage on the system at all times. This means, for example, starting up plants as backup resources (“reserves”) to quickly replace another plant that trips off line or dips in its output (e.g., due to changes in wind conditions or power plant failure), or adjusting power output up and down with little notice to meet swings in load.

Third, the operator maintains and draws on a diverse set of operational procedures to manage system performance – such as committing or “posturing” resources that may be needed, allowing minor variations in system voltage, calling on resources from neighboring regions,



disconnecting variable generation, signaling to 'demand-response' providers to curtail their loads within short periods of time, and other procedures (including, as a last resort, isolated involuntary disconnection of load – or “rolling blackouts”).

Reliability is by nature a technology-neutral concept. That said, not all of a system's resources are equal when it comes to the attributes they provide to system operators to manage system security. Historically, power systems' needs for voltage support, inertia, frequency control, and contingency-response capability have been met through operator actions in conjunction with their commitment of the types of technologies on the system: traditional thermal steam units (e.g., coal, nuclear, oil plants, natural gas and combined heat and power units) providing baseload service around the clock; cycling and load-following technologies (e.g., combined cycle plants operating on natural gas); quick-start fossil-fired peaking plants; and dispatchable hydro power supplies.

As the technologies on the system change – which is happening to different extents in different regions as a result of various forces, with or without the Clean Power Plan (as described above in Section I) – steps are being taken to ensure that the suite of essential reliability services is available to supply the frequency/voltage control and contingency-reserve needs of the system. NERC has characterized the challenge as one of filling gaps in services as they arise or widen over time.

Notably, system planners across the country are dealing constantly – and so far successfully – with the new and emerging reliability challenges from changing technology mixes. For example, the CAISO and California electric utilities have identified the need to add greater ramping capability to handle an increased variability in intra-day loads introduced from increasing amounts of 'variable energy resources' (VERs) necessary to meet increasingly higher renewable portfolio standards.<sup>42</sup> In general, load following is typically accomplished through the dispatch of fast-ramping combustion turbines and natural gas combined cycle (NGCC), although load following can also be met through well-designed and cost-effective storage, optimized energy efficiency programs, demand response, and devices (such as smart inverters) being added to wind farms.

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<sup>42</sup> California is on track to meet its renewables portfolio standard target, such that by 2020, 33 percent of its total energy comes from renewable resources. The state is considering whether to adopt a 50-percent goal by 2030. Behind-the-meter solar and wind supplies are projected to significantly decrease net load during the middle of the day, while leaving significant shoulder peaks in the morning and evening, resulting in what is commonly called the “duck curve.” A recent analysis found that this will require a significant increase in fast ramping, flexible dispatchable generation resources (along with other technologies, including storage). See Energy+Environmental Economics (E3), “Investigating a Higher Renewables Portfolio Standard in California,” January 2014.

### III. What Concerns are Commenters Raising About Reliability Issues Associated with EPA's Clean Power Plan?

#### Summary of comments

To date, the EPA has received more than 3 million comments on the proposed Clean Power Plan. Many comments have raised concerns about electric system reliability. These comments have come from a wide range of stakeholders, including: owners of affected power plants (including vertically integrated utilities, merchant generators, municipal electric utilities, cooperatives); state officials, including public utility commissions, air pollution regulators, energy offices, as well as governors, attorneys general, and consumer advocate offices, and associations representing these various groups of public officials; system operators, regional reliability organizations; trade associations with business, public health, environmental, fossil-fuel supply and delivery organizations; members of the public; and others.<sup>43</sup>

The many comments received on reliability issues reflect the importance of thinking clearly about the potential impacts of the Clean Power Plan on system reliability. We summarize the types of reliability-related comments in Table 10, below, and provide more information about these public comments in the Appendix. Notably, EPA has made it clear that system reliability needs to be maintained as the Clean Power Plan is finalized and implemented.<sup>44</sup>

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<sup>43</sup> Among the latter include various electric industry organizations (e.g., the Edison Electric Institute; the APPA; the National Rule Electric Cooperative Association; the Electric Power Supply Organization; the Clean Energy Group); business associations (e.g., the Chamber of Commerce); gas industry organizations (e.g., the Interstate Natural Gas Association (INGAA)); coal-industry groups (e.g., the Coal Utilization Research Council); non-energy trade groups (e.g., Water Associations such as the American Water Works Association, National Association of Water Companies and the National Association of Clean Water Agencies), and environmental organizations (e.g. Natural Resources Defense Council and Environmental Defense Fund); NERC; various individual RTOs (MISO, PJM, NYISO); FERC Commissioner Philip Moeller; Senator Dan Coats and 22 other senators. This is not intended to be a comprehensive or exhaustive list of comments or commenters, but rather represent the broad cross-section of types of organizations with an interest in Clean Power Plan reliability issues. Regulations.gov Docket Folder Summary, Docket No. EPA-HQ-OAR-2013-0602, "Standards of Performance for Greenhouse Gas Emissions from Existing Sources: Electric Utility Generating Units," available at <http://www.regulations.gov/#!docketDetail;rpp=100;so=DESC;sb=docId;po=0;D=EPA-HQ-OAR-2013-0602>.

<sup>44</sup> For example, see both the Proposed Rule, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Federal Register, Vol. 79, No. 117, June 18, 2014. Available at: <http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf>, and the Technical Support Document: Resource Adequacy and Reliability Analysis. Available at: <http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-resource-adequacy-and-reliability-analysis>

**Table 10**  
**Summary of Reliability Concerns Raised in Public Comments and Which Need to be Addressed as the EPA’s Proposed Clean Power Plan is Implemented**

Summary of Comments Submitted on Reliability Issues Related to the EPA Clean Power Plan		
Category	Description	Potential Reliability Considerations – Which Need to be Addressed
Resource Adequacy	Retirements of baseload power plants are presenting on-going challenges in some regions	May tighten planning reserve margins in some regions and require timely replacement of capacity on a 1-to-1 basis
		Requires additional transmission planning and analyses, with transmission solutions typically having longer lead times (~10 years) than generation additions
Resource Mix and Operational Security	Retirement of coal-fired capacity and restrictions on output at coal plants, combined with greater use of gas-fired capacity, will result in less fuel diversity in various regions	Some coal units will/may be cycled more frequently, ending up with lower overall capacity factors and adversely impacting relevant heat rates (and emissions per MWh)
		Operating gas plants at higher output will depend upon having adequate gas delivery capability, including firm supply and delivery contracts
		Increased reliance on variable and non-dispatchable resources (like wind and solar) will mean the need for greater quantities of operating reserves and ramping capability
		Loss of baseload generation requires additional voltage and frequency support, including Inertia
Planning and Regulatory Coordination	The interim goals established in the Clean Power Plan do not provide adequate time for planning and development of adequate resources, for state and regional coordination, or for market solutions	Lead times for new transmission and power plants (including planning, siting, permitting, and construction time lines) extend beyond 2020 and the interim deadlines)
		Successful resolution of various gas-electric coordination issues will be needed to support greater reliance on natural gas in many regions
		RTO/ISO rules and practices regarding security-constrained economic dispatch may need to be reviewed and/or updated, depending upon how states design their plans to incorporate emissions controls
		Greater reliance on demand response and energy efficiency may require new rules and forecasting capabilities in wholesale energy and capacity markets
		Allocation (or reassignment) of transmission rights may be needed to accommodate changing power flows following power plant retirements or to accommodate greater reliance on underutilized gas-fired capacity and/or renewable resources.
Market Impacts and Market Responses	Uncertainty surrounding final regulations and state plans make it hard for markets to respond with concrete proposals in timely fashion	Uncertainty surrounding the regulatory treatment of new gas-fired combined cycles (under 111(b)) may chill development.
		Increased reliance on gas-fired power plants may depend upon new investment in pipeline capacity, with need for new mechanisms to support long-term commitments in some regions (e.g., organized markets)
		Increased reliance on natural gas may accelerate retirements of nuclear units prior to the end of their operating licenses.
		Reliability must-run contracts may be needed to retain some units needed for reliability, but with potential adverse impacts on wholesale market efficiency
		Uncertainty surrounding how states will plan for ensuring new capacity additions in regional organized markets, in light of buyer-side mitigation and other federal wholesale market rules

Many observers’ concerns that the Clean Power Plan could jeopardize *resource adequacy* are tied primarily to questions around timing: Does the sequence of steps implied by EPA’s proposal – starting with the June 2014 proposal, then taking into account the timing of EPA’s final rule, the development of State Plans, the approval of plans by the EPA, and then through compliance

decisions and actions by owners of affected power plants – allow sufficient time for everything that needs to be done by states, reliability planners, grid operators, planning and procurement processes, market responses, and so forth to ensure resource adequacy? Or, where that is not assured, do the final EPA and state compliance provisions and administrative procedures allow sufficient flexibility to ensure proper administration of Clean Power Plan without jeopardizing resource adequacy?

Concerns voiced about whether Clean Power Plan implementation could jeopardize *system security* are tied primarily to anxiety over how and when state compliance activity will alter the diversity of resources on the system, and thus the mix of resource capabilities needed to meet system security requirements. In particular, will the economic signals and compliance obligations provided through state implementation of the Clean Power Plan cause the retirement of resources that are needed for system security, and/or will replacement capacity provide the needed operational capabilities? If a significant portion of existing coal-fired capacity retires and is replaced (in part) by gas-fired capacity, will regional interstate pipeline systems be robust enough to ensure reliable delivery of fuel in all hours of the year? If state compliance activities significantly increase the proliferation of grid- and distribution-level variable resources, how much more difficult will it be for system operators to manage the variability in net load on a real-time basis? Or, where this is not assured, do the final EPA and state compliance provisions and administrative procedures allow sufficient flexibility to ensure proper administration of Clean Power Plan without jeopardizing system security concerns?

Other commenters portray the readiness of the industry to step up with solutions to these reliability issues. For example, INGAA described the capability of the natural gas pipeline industry to add new infrastructure.<sup>45</sup> Calpine stated its readiness (along with other market participants) to add new gas-fired generation (and to offer under-utilized capacity already existing on the system).<sup>46</sup> The Clean Energy Group provided suggestions about how the design of policies supporting flexibility and market-based approaches can substantially mitigate reliability concerns.<sup>47</sup> State energy offices (through their national association (NASEO)) noted the ability of a wide variety of well-tested energy efficiency measures (beyond utility-provided programs) to avoid CO<sub>2</sub> emissions from power plant operations.<sup>48</sup> The National Association of Regulatory Commissioners (NARUC) pointed to the ability to reap cost-effective savings in the

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<sup>45</sup> Comments of INGAA, filed December 1, 2014.

<sup>46</sup> Comments of Calpine Corporation, filed November 26, 2014.

<sup>47</sup> Comments of the Clean Energy Group (CEG), filed December 1, 2014.

<sup>48</sup> Comments of the National Association of State Energy Officials (NASEO), filed December 1, 2014.

electricity used for water treatment and delivery by introducing measures on the water utility system – thus affording water savings and avoiding CO<sub>2</sub> emissions on the power system.<sup>49</sup>

We also point out many ways to address the reliability issues raised in comments in Section IV of our report, with our suggestions organized around the different entities with some direct or indirect role to play in system reliability.

### **Reliability safety value concept**

The ISO/RTO Council (IRC) has proposed that EPA include a “Reliability Safety Valve” provision as part of the final rule, to help with resolve multi-state issues that may arise due to the Proposed Rule and impact grid reliability.<sup>50</sup> In the view of the IRC, a Reliability Safety Value would provide a regulated and reviewed backstop solution with a defined process for modifying State Plans to ensure reliability against unforeseen issues. As part of this process, the IRC has recommended that the EPA include a specific requirement in the final rule that State Plans must include a detailed reliability assessment. By requiring reliability assessments ahead of final plans, according to the IRC, the Reliability Safety Valve would only be used in situations that could not be addressed ahead of time and that arise solely from dynamic, unplanned changes in the grid. As proposed by the IRC, a Reliability Safety Value would allow relief from compliance schedules if specific units are deemed necessary for reliability considerations.<sup>51</sup> The Reliability Safety Value has been supported by numerous organizations and RTOs, who point out that the concept has been successfully implemented as part of the MATS compliance policy.

We note – as an important element in considering the particular Reliability Safety Valve proposed by the IRC – that there are key differences between the regulatory frameworks of Clean Power Plan and the MATS rule. In particular, the latter assigns emissions-reductions targets on each affected fossil-fuel generating unit, and does not allow any emission averaging across generating stations or across time. As we noted previously in this report, there is much more flexibility in the design of the Clean Power Plan.<sup>52</sup> In particular, the opportunity for states

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<sup>49</sup> Comments of the National Association of Regulatory Utility Commissioners (NARUC), filed November 19, 2014.

<sup>50</sup> For example, see comments filed by the ISO/RTO Council (IRC), December 1, 2014.

<sup>51</sup> This process is analogous to RMR contracts that are often available in organized ISO/RTO markets. These contracts provide for time-limited, out-of-market payments to generators that have provided notification of retirement but are necessary for reliability reasons (e.g., local voltage support). Once alternative resources (transmission or generation) solving the reliability need are in place, the RMR contracts cease and the units may retire. By way of example, the IRC suggests that the Reliability Safety Value and a mandatory reliability assessment could help identify reliability issues arising from an individual State Plan, such as a state requirement for reduced utilization at a fossil unit needed for transmission security and voltage support on a transmission network that crosses a state line. ISO/RTC Comments, filed December 1, 2014.

<sup>52</sup> EPA is relying on a portion of the Clean Air Act– Section 111(d) – in its Clean Power Plan. “Section 111(d)’s regulatory framework creates an entirely different and potentially much wider set of compliance and implementation options compared to

to rely upon market-based mechanisms that allow emission trading across power plants within states and across wide regions is a compelling basis for thinking differently about the need for a reliability safety value in this instance. The wider the region in which emission trading might occur, the less likely that reliability issues will be introduced by the Clean Power Plan.

### **NERC's initial reliability assessment of the Clean Power Plan**

NERC published its own "Initial Reliability Review" of the Proposed Rule in November 2014.<sup>53</sup> NERC flagged a number of "significant reliability challenge[s], given the constrained time period for implementation" and that "Essential Reliability Services may be strained by the proposed [Clean Power Plan]."<sup>54</sup> NERC notes that the primary purpose of the paper was to "provide the foundation for the range of reliability analyses" that will be required for stakeholders to work together. Notably, NERC recommended that coordinated regional and multi-regional planning and analysis should start immediately to identify specific areas of concern and that the EPA should consider a more timely approach to resolving any known reliability concerns.

NERC noted that the accelerated retirement of fossil units will stress already declining reserve margins, and that time will be a major constraint, particularly for facility planning, permitting, and construction. NERC identifies transmission upgrades as potentially being needed to successfully integrate variable energy resources anticipated as part of various states' plans, as well as to support reliability concerns regarding voltage and frequency support associated with extensive re-dispatch of NGCC. NERC also suggested that pipeline capacity constraints will

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other recent federal regulatory initiatives applicable to the electric industry.... In the recent MATS rule, for example, EPA set uniform national standards to reduce emissions from different categories of existing coal- and oil-fired power plants. No trading or averaging is allowed across different generating stations. There is no possibility of purchasing credits resulting from over-compliance at other sources, or to credit emissions reductions resulting from end-use efficiency or zero-carbon energy sources. By contrast with MATS, Section 111(d) inherently allows greater opportunities for different pathways to compliance... And in its [State Plan], each state will have flexibility to propose its own preferred actions to accomplish the targeted reductions, as long as the plan provides reductions across the facilities in the state that are at least as effective as EPA's approach. This language "supports the use of market-based mechanisms" and other alternatives in ways that are not possible under the statutory language governing MATS, which required each affected generating station to have emissions at or below the allowed emissions rates. If a state has concerns about the reliability implications of compliance with EPA guidance, the state can take that fact into account as it designs its SIP and its schedule/timetable for individual units' compliance so long as the overall emission reduction required by the guideline has a firm deadline and is achieved. For example, a state could propose plan elements that enable early action/compliance at some Section 111(d) generating units in exchange for allowing more time for others, or that allow for deeper reductions at one unit in exchange for lighter reductions at another." Source: Susan F. Tierney, "Greenhouse Gas Emission Reductions From Existing Power Plants Under Section 111(d) of the Clean Air Act: Options to Ensure Electric System Reliability," May 2014, pages 3-4.

<sup>53</sup> NERC has stated that its November report, "Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review," November 2014 (Hereinafter referred to as "NERC CPP IRR") is the first in a series of reliability assessments that NERC plans to conduct. NERC says it plans to release two additional studies in 2015 that will include a detailed evaluation of generation and transmission adequacy and a preliminary assessment of state SIPs.

<sup>54</sup> NERC CPP IRR, page 2.

exacerbate the strain on essential reliability services from relying more heavily on gas. While a full review of the NERC study is beyond the scope of this paper, we note again that these issues have been emerging in markets for a number of years, well before the introduction of the Clean Power Plan. Indeed, NERC covered these “emerging trends” in California, Hawaii, ERCOT, and other regions in its October primer on “Essential Reliability Services.”

Many comments in turn, have cited and expanded on the NERC Review. While reliability has been a common theme of these comments, for the most part the NERC report and the public's comments on the Clean Power Plan do not point to specific, modeled reliability problems that have been identified at known points on the bulk power system. Rather, both the report and the comments focus on generalized concerns about potential reliability issues that may arise due to the operational challenge of meeting both the interim and final-goal targets, generally assuming little in the way of the compliance flexibility built into the proposed rule and available to states. While these are valid concerns, it is critical to recognize the numerous strategies, policies, markets and organizations in place that have successfully dealt with these similar operational challenges in the past, and will going forward, as we discuss further below.

Moreover, the Clean Power Plan proposed rule, like all proposed EPA rules, is a “first draft” that is designed to elicit data and comments. EPA has already signaled that it is evaluating stakeholder concerns about the timing and glide path for meeting interim and final targets, and will evaluate this information as it writes the final rule.

Although we think it is ultimately a good thing that the industry is paying close attention to reliability issues – so that any potential problems can be avoided and addressed in time through planning and infrastructure – we do note recent critiques (e.g., Brattle Group's February 2015 report) of the assumptions used in NERC's recent reliability assessments, which do not take into consideration industry responses to market and reliability signals. This is a significant reason to view the NERC as only having set the table with respect to potential reliability concerns, and to recognize that NERC and many other parties will step up with their important contributions to implementation of the CPP within the electric system reliability context.

## IV. Options for Assuring Electric System Reliability in Conjunction with Implementing the Clean Power Plan

### The reliability check list

The many comments on the proposed Clean Power Plan submitted to EPA serve as a reminder of the broadly-understood condition that pursuing CO<sub>2</sub> emission reductions in the power sector has to occur in an environment that respects the reliability rules of the game. Like the check list at the start of any endeavor, the comments point out a number of potential items to consider adding to the “to do” list that the electric industry routinely uses to ready itself for reliable system operations.



<http://imgkid.com/checklist-icon.shtml>

Fortunately, that check list is already robust. There are well-established procedures, regulations and enforceable standards in place to ensure reliable operations, placing the country in a good starting position as of the start of 2015. Many of the reliability issues identified in public comments are not new – the industry has responded successfully and effectively to similar challenges in the past. And for several years, some of the trends that commenters note must now be addressed in response to the Clean Power Plan are actually developments that have been underway for many years – and that are currently being addressed. Examples include the FERC’s policies addressing: transmission planning taking into account infrastructure needs arising from state-policy (such as renewable portfolio standards); integration of variable electric resources; market designs to assure efficient entry of capacity with attributes needed for reliable system operations; and directives to modify standards and policies so as to better harmonize operations of the electric and gas markets. Other examples include the many studies conducted by RTOs, electric utilities, national laboratories (like the National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory), research institutions (such as the Electric Power Research Institute, university research centers, and think tanks), and the Department of Energy.

These many studies are already pointing out that some of the tools and checklists needed for reliability may need to be enhanced as a result of the many changes underway in the industry. In many respects, the shift towards natural gas-fired generation (driven in large part by fundamental economic forces), the proliferation of variable resources due to economic and policy factors, and the growth in distributed resources in some regions will drive changes in industry planning and operations over a schedule largely coincident with implementation of the Clean Power Plan.



In the end, we think that even if sometimes exaggerated, the reliability “alerts” are actually a good thing: It is appropriate that people are paying attention to reliability issues, so that potential problems can be avoided – and they can be addressed in time through proper planning and appropriate responses. Even if some of the existing tools need to be sharpened or even new ones added, past experience, the capabilities of the industry, the attention of regulators, and the inherent flexibility of Clean Power Plan implementation strongly suggest that the task is manageable. As always, careful planning and advance work is necessary to make sure that there are not inefficient trade-offs between the two core objectives.

### **The Reliability Toolkit: Which ones to use here?**

The U.S. electric system performs so reliably because it includes both clearly defined and clearly assigned roles and responsibilities to particular actors, and also relies upon markets and regulated planning processes to provide an array of workable solutions. This is a very sturdy toolkit to build upon. Our suggestions aim to make it even better by pointing out some extra steps that responsible parties might take to make the toolkit as strong as possible for supporting the changes underway in the industry, including Clean Power Plan implementation.

For this reason, we organize our discussion of tools by identifying those in the hands of “reliability organizations” (like grid operators, FERC, NERC, the states, and others) and those in others’ hands (including power plant owners, the markets, and many additional players, including the EPA itself). While the latter may not be “reliability organizations” in the same ways that the institutions in the first group are, they still have significant opportunities (if not genuine responsibility) to take actions to help ensure reliable pathways to compliance with CO<sub>2</sub> emission reductions required from the power sector.

In Table 1 at the beginning of our report, we categorize parties into the following groupings:

- Entities with direct responsibility for critical reliability functions;
- Other public agencies with direct or indirect roles in the Clean Power Plan;
- Owners of existing power plants covered by Section 111(d) of the CAA;
- “Markets” and resource planning/procurement organizations; and
- Other entities with inevitable roles to play in ensuring a reliable system in conjunction with enabling effective and timely compliance with the Clean Power Plan.

Note that in some cases, some parties (e.g., a vertically integrated utility which is a balancing authority and also conducts resource/planning and procurements) may fall into one or more categories.

Then we use those groupings not only to identify the normal, business-as-usual responsibilities of those parties, but also to make a number of suggestions for things that those different players might do in anticipation of heading off potential reliability problems before they arise, or in mitigating impacts if they do. Table 2 makes suggestions for what FERC, NERC, the Regional Reliability Organizations, with Table 3 providing suggestions for System Operators/Balancing Authorities might do, in terms of institutionalizing new studies, reporting requirements, and so forth. Table 4 then focuses on things that other federal agencies can do, with Table 5 suggesting actions by state government entities. Table 6 identifies potential actions that might be considered/adopted as part of organized markets to send appropriate and timely signals for investment, and in parallel, what electric utilities might do within their own resource planning/procurement processes to accomplish reliable outcomes in their geographic footprint. Finally, Table 7 provides a number of suggestions about things that other players might do in their own zones of influence.

In the end, the industry, its reliability regulators and the States have a wide variety of existing and modified tools at their disposal to help as they develop, formalize, and implement their respective State Plans. These two responsibilities – assuring electric system reliability while taking the actions required under law to reduce CO<sub>2</sub> emissions from existing power plants – are compatible, and need not be in tension with each other as long as parties act in timely ways.

This is not to suggest that electricity costs to consumers do not also matter in this context; of course they do. But we observe that too often, commenters make assertions about reliability challenges that really end up being about cost impacts. We think that separating reliability considerations from cost consideration is important so as to avoid distracting attention from the actions necessary (and possible) in order to keep the lights on. There may be “lower cost” options that reduce emissions some part of the way toward the target reductions, but that fail to meet acceptable reliability standards. We do not view such ‘solutions’ as the lowest cost solution, precisely because they fail to account for the cost of unacceptable system outages to electricity consumers. Any plan that starts with consumer costs and works backward to reliability and then to emission reduction is one that fails to consider the wide availability of current tools that have served grid operators for more than a decade to meet reliability needs.

This array of tools is of course subject to important and beneficial social constraints and must be exercised to serve the interests of ratepayers. There is no reason to think that these dual objectives cannot be harmonized within a plan to reduce carbon pollution.

## V. Conclusion

In this report we identify the many rules, regulations, institutions, and organizations – in effect, the industry's *standard operating procedures* – for ensuring that EPA's design and administration of the Clean Power Plan in no way jeopardizes or compromises the high level of power system reliability we are used to. Such reliability is essential for the strength of our economy and the public health and safety of our citizens.

In the end, of course, it is a good thing that the industry is paying close attention to reliability issues, so that any potential problems can be avoided – and can be addressed in time through planning and appropriate responses. This is do-able, based on past experience and the capabilities of the industry. As always, careful planning and advance work is necessary to make sure that there are not trade-offs between the two.

Having reviewed the broad range of comments received by EPA with a focus on power system reliability, and the potential reliability challenges posed by Clean Power Plan administration, we find that many of these comments tend to assume inflexible implementation and present worst case scenarios, with an exaggerated cause-and-effect relationship. Moreover, many comments (including those from NERC itself) tend to assume that policy makers, regulators, and market participants will stand on the sidelines until it is too late to act. The history of the electric system and its ability to respond to previous challenges including industry deregulation and previous Clean Air Act regulations such as the NO<sub>x</sub> SIP call, SO<sub>2</sub> rule, CSAPR, and MATS prove that this is highly unlikely. These challenges will be solved by the dynamic interplay of regulators and market forces with many solutions proceeding *in parallel*.

Indeed, this dynamic interplay is one reason why a recent survey of more than 400 utility executives nationwide found that more than 60 percent felt optimistic about the Clean Power Plan and felt that EPA should either hold to its current emissions reduction targets or make them more aggressive.<sup>55</sup> Similarly, other market participants announced a willingness and ability to help meet system demand for new natural gas supplies<sup>56</sup> and gas-fired generation, in

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<sup>55</sup> The same survey found that those utility executives believed that distributed energy resources offered the biggest growth opportunity over the next five years, and more than 70 percent expect to see a shift away from coal towards natural gas, wind, utility-scale solar and distributed energy. Utility Dive and Siemens, 2015 State of the Electric Utility Survey Results, January 27, 2015. The survey included 433 U.S. electric utility executives from investor-owned, municipal, and electric cooperatives.

<sup>56</sup> See, for example, comments filed by INGAA, December 1, 2014. ("INGAA is confident that ... the natural gas pipeline industry can respond to demand for the natural gas pipeline capacity that may be necessary to enable compliance with the Clean Power Plan."). INGAA noted that the existing natural gas pipeline system is already supporting national gas-fired combined-cycle utilization rates of 60 percent during peak periods, which are the same periods when distribution constraints are most likely.

support of the Clean Power Plan.<sup>57</sup> This is in addition to the expanded and innovative solutions and strategies for incremental energy efficiency and distributed energy resources identified by State Regulators and Energy Officials.

There are a number of things states and others can (and, in our view, should) do as part of developing their State Plans to further ensure reliability. First and foremost, states can lean on the comprehensive planning and operational procedures that the industry has relied on to maintain reliability for decades – in the face of both normal operations and sudden changes in markets and policy. These procedures flow from a comprehensive set of laws, rules, protocols, organizations, and industry structures that focus continuously on what is needed to maintain electric reliability.

Second, states should give due consideration to the vast array of tools available to them and the flexibility afforded by the Clean Power Plan in order to ensure compliance is obtained in the most reliable and efficient manner possible. In particular, given the interstate nature of the electric system, we encourage states to enter into agreements with other states or add provisions to state plans that facilitate emission trading between affected power plants in different states; doing so will increase flexibility of the system, mitigate electric system reliability concerns, and lower the overall cost of compliance for all.

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<sup>57</sup>See, for example, the comments of Calpine Corporation, filed November 26, 2014. (“With our modern, flexible, and efficient generating fleet, Calpine is prepared to facilitate the successful implementation of the Proposed Clean Power Plan. We are confident that by working constructively with the states and EPA as we have always done, the Clean Power Plan can be a success.”)

## APPENDIX:

### Public Comments on EPA's Proposed Clean Power Plan: Summary of Concerns Relating to Electric System Reliability Issues

As of February 8, 2015, 3.83 million comments have been filed on the EPA's proposed Clean Power Plan.<sup>58</sup> Many organizations have compiled lists and summaries of comments filed by various parties.<sup>59</sup> Most of the comments focus on stringency of the proposed emissions reductions targets, the reasonableness of (and legal bases for) the "building block" methodology used by EPA is setting state targets, the timing of emissions reductions in two periods (interim: 2020-2029); and final (2030 and beyond); the ability of states to develop their State Plans with enough time; and other comments.<sup>60, 61</sup>

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<sup>58</sup> Regulations.gov Docket Folder Summary, Docket No. EPA-HQ-OAR-2013-0602, "Standards of Performance for Greenhouse Gas Emissions from Existing Sources: Electric Utility Generating Units," available at <http://www.regulations.gov/#!docketDetail;rpp=100;so=DESC;sb=docId;po=0;D=EPA-HQ-OAR-2013-0602>.

<sup>59</sup> See, for example: Bipartisan Policy Center ([http://bipartisanpolicy.org/wp-content/uploads/2015/02/Comments\\_Map\\_Static.pdf](http://bipartisanpolicy.org/wp-content/uploads/2015/02/Comments_Map_Static.pdf)); National Association of State Energy Offices (<http://111d.naseo.org/>); Advanced Energy Economy (<http://blog.aee.net/epa-ghg-regs-we-read-the-comments-so-you-dont-have-to-part-1-state-federal-regulator-association>); Institute for 21<sup>st</sup> Century Energy (U.S. Chamber of Commerce); (<http://www.energyxxi.org/eparule-stateanalysis>; <http://www.energyxxi.org/eparule-stateanalysis>).

<sup>60</sup> See, for example, comments filed by APPA, December 1, 2014; Business Roundtable, December 1, 2014; Class of '85 Regulatory Response Group, December 1, 2014; CEG, December 1, 2014; CURC, December 1, 2014; Coalition for Innovative Climate Solutions, December 1, 2014; Edison Electric Institute (EEI), December 1, 2014; Electric Power Supply Institute, December 1, 2014; ERCOT, November 17, 2014; Environmental Defense Fund, December 1, 2014; Georgetown Climate Center (with state officials from California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Minnesota, New Hampshire, New York, Oregon, Rhode Island, Vermont, and Washington), December 1, 2014; INGAA, December 1, 2014; NARUC, November 19, 2014; NASEO, December 1, 2014; NRDC, December 1, 2014; National Rural Electric Cooperative Association, July 29, 2014; Nuclear Energy Institute (NEI), December 1, 2014; NYISO, November 17, 2014; PJM Interconnection, December 1, 2014; RTO/ISO Council, December 1, 2014; Sierra Club, December 1, 2014; Southern States Energy Council, September 29, 2014; and Western Electricity Coordinating Council (WECC), November 25, 2014.

<sup>61</sup> Even before the final December 1<sup>st</sup>, 2014 deadline for filing comments, the EPA and other regulators had acknowledged these many public statements and the comments that had been submitted in advance of the deadline. Specifically, in October of 2014, EPA issued a Notice of Data Availability (NODA) that sought comments on three core issues, which we summarize below:

- Compliance trajectory of emissions reductions from 2020 to 2029, and in particular, if or how reductions related to building block 2 could be phased in over time (for example, to accommodate constraints in natural gas distribution infrastructure, or how the book life of existing assets could be used to define an alternative glide path) or how states could earn compliance credits for actions taken between 2012 and 2020;
- Technical assumptions in the building block methodologies for 2 and 3, including how to consider new gas-fired combined cycle (NGCC) units in state goals, the role of natural gas co-firing at coal plants as a compliance strategy, and if states with little to no existing NGCC capacity should achieve a minimum target of new NGCC generation; and with respect to renewable energy, how or if the EPA could consider alternative goal setting strategies that account for state or regional economic potential of renewables as opposed to relying on existing RPS; and the role of nuclear units in building block 3; and
- Methodologies for setting State-specific goals, including the feasibility of using a multi-year baseline (2010-2012) for goal setting, to what extent renewable and energy efficiency goals should be assumed to displace existing fossil generation – as opposed to displacing or avoiding future fossil generation.

The formal NODA is available through Regulations.Gov in Docket No. EPA-HQ-OAR-2013-0602 and informally, through the EPA, here: <http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-notice-data-availability>.

Our own review of submissions from the public and various organizations has focused on issues related to system reliability. These commentaries include concerns raised about one or another aspect of the proposal's impact on the power system's performance. Many comments make suggestions for changes in EPA's proposal, and steps that other entities might take to address reliability issues in the context of compliance with the Clean Power Plan.

A common reliability-related comment is that the EPA did not consider – or seek out the expertise – for how the assumptions it used in setting states' emission reduction targets (i.e., the four “building blocks”) may change the operations of the electric grid and how those changes in turn can affect the ability to meet state targets.<sup>62</sup> A similar theme is that the individual state targets do not account for the regional nature of electric grid reliability. Finally, a common concern is that the proposed timeframes for compliance, combined with the interim targets for emissions reductions commencing in 2020, do not provide adequate time for states to develop regional compliance plans or for RTOs to incorporate State Plan provisions into the regional long-term planning frameworks or existing market rules for economic dispatch.

That said, a wide range of regulators and other organizations have committed to working with the EPA and the states to manage these challenges, and in turn, leverage their detailed knowledge of the electric system. As discussed later in this report, many regional coordinators and state regulators already have planning policies and procedures in place that can proceed in parallel with the development of SIPs to ensure the timely development of generation, transmission, and distribution infrastructure needs.<sup>63</sup>

Although the comments do not point to specific known, localized reliability problems identified by a specific commenter, many observers caution that if a state elects not to (or cannot, for one reason or another) accomplish the depth of emission reductions assumed by EPA in state

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<sup>62</sup> For example, the EEI noted that “a significant portion of [it's] comments is devoted to explaining how the system operates and how electric utilities, states and system operators engage in complex planning to maintain the reliability of the interconnected power system.” Comments filed December 1, 2014, at 12. Similarly, on December 22, 2014, Senator Murkowski (ranking member, Committee on Energy & Natural Resources), Representative Upton (Chairman, Committee on Energy & Commerce), and Representative Whitfield (Chairman, Subcommittee on Energy & Power) requested comment from the FERC Commissioners on their level of involvement and interaction with EPA staff when developing the Clean Power Plan and understanding reliability implications. Letter to FERC from Senator Murkowski, Representative Upton, and Representative Whitfield, December 22, 2014.

<sup>63</sup> Note for example, recent activities among the PJM states: the recent comments submitted to the FERC (Docket No. AD15-4-000: Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure, February 19, 2015) by Michael Kormos, Executive Vice President for Operations, PJM: “PJM has begun this coordination process by engaging state commissions, state environmental regulators responsible for implementing the Clean Power Plan, and EPA starting last year. Recently, PJM has undertaken detailed analyses of scenarios and alternatives that were provided to us by OPSI. Those results have been reviewed with our members and with the states and are posted on our website at <http://www.pjm.com/~media/committeesgroups/committees/mc/20150120-webinar/20150120-item-05-carbon-rule-analysis.ashx>.

targets, then the state will inevitably need to make additional cuts from other blocks which will increase the stress on remaining assets and strategies.

Comments on reliability issues thus tend to focus on challenges in system operation that may lead to reliability failures. The commentaries do, however, provide suggestions for how to mitigate the challenges for system reliability failures by building into State Plans alternative strategies for meeting those same targets beyond those incorporated into EPA's target-setting assumptions. For example, comments by both NARUC and NASEO discuss the extensive potential for additional CO<sub>2</sub> savings from energy efficiency projects at the interface of the energy-water nexus and other energy-efficiency initiatives outside of conventional programs administered by electric utilities. Additional guidance or clarification from the EPA on how to account for these programs in State Plans could unleash and incentivize a broad swath of carbon reduction strategies beyond the narrow four building blocks.

Many comments focused on the implications of greater utilization of natural gas-fired power plants on changes in system dispatch and the interdependence of interim and final state goals.<sup>64</sup> Achieving a system-wide 70-percent capacity factor for existing natural-gas combined cycle (NGCC) units, for example, would transition a set of power plants now used largely as intermediate and load-following resources to become base-load capacity resources. Baseload coal-fired generators in place at the end of the 2010s would feel the effects, through either greater cycling of these units, or retention of the units to operate only occasionally if needed to remain on the system for resource adequacy purposes, or retirements. Observers note that cycling such coal-fired units more frequently will decrease their efficiency (i.e., increase their heat rates), as plants use additional energy to overcome the inertia inherent in these units. Commenters' cautions that such impacts will increase the overall fleet average emission profile. The observation is that such interactions will mean that states will need to find additional carbon reductions elsewhere. To the extent that the shift includes greater reliance on renewable energy penetration, then the system operators will need to adjust how they operate the resources on their system to maintain reliability. These variable energy resources do not offer system operators the same level of control (e.g., some may be behind the meter and therefore not even "visible" to operator) for frequency or voltage support nor can they be relied upon to meet load in all hours of the day. In the absence of significant new storage capability on the system, this will increase the need for load-following, fast-ramping resources to respond to

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<sup>64</sup>The U.S. Chamber of Commerce Institute for 21st Century Energy reviewed and summarized State comments and found that 35 states raised issue with Building Block 2. This was more than any other category identified by the report. Institute for 21st Century Energy, U.S. Chamber of Commerce. "In Their Own Words: A Guide to States' Concerns Regarding the Environmental Protection Agency's Proposed Greenhouse Gas Regulations for Existing Power Plants", January 22, 2015, page 14.

sudden drops in renewable generation. Traditionally, gas-fired combined cycles or natural gas combustion turbines have met this need. But gas-fired plants that begin to operate more in baseload mode may not be able to perform that load-following function. As described in Section II, Figure 2 above, lead times for implementing peaking generating units and demand-side actions (e.g., programs leading to installation of energy efficiency measures; equipping buildings with automated capability to control demand when signaled to do so by the system operator; adding solar PV panels) are much shorter than those for large power plants and transmission upgrades.

These changes are already underway in part due to the shale gas revolution, state and federal policies supporting renewable energy, other environmental policies. According to some observers, the Clean Power Plan will accelerate such trends. Either way, grid operators will need to address the potential diminishing reservoir of voltage support and inertia that has historically been supplied by coal-fired thermal units with their rotating mass of equipment.

Also, the successful operation of natural gas combustion turbines to balance and integrate intermittent and variable renewable supplies will depend, in turn, on the availability and access to fuel when needed for dispatch. Commenters have suggested, and rightly so, that a significant increase in gas-fired generation will require new gas delivery infrastructure. (We note the recent report published by the U.S. DOE that found, among other things, that the amount of incremental gas infrastructure needed is less than what has been put in place by the industry in the recent past.<sup>65</sup>

Diverse sources of natural gas supply and demand will reduce the need for additional interstate natural gas pipeline infrastructure. The combination of a geographic shift in regional natural gas production—largely due to the expanded production of natural gas from shale formations—and growth in natural gas demand is projected to require expanded natural gas pipeline capacity. However, the rate of pipeline capacity expansion in the scenarios considered by this analysis is lower than the historical rate of natural gas pipeline capacity expansion. ...

(2) Higher utilization of existing interstate natural gas pipeline infrastructure will reduce the need for new pipelines. The U.S. pipeline system is not fully utilized because flow patterns have evolved with changes in supply and demand. ...

(3) Incremental interstate natural gas pipeline infrastructure needs in a future with an illustrative national carbon policy are projected to be modest relative to the Reference Case. While a future carbon policy may significantly increase natural gas demand from

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<sup>65</sup> U.S. DOE, "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector, February 2015, [http://energy.gov/sites/prod/files/2015/02/f19/DOE%20Report%20Natural%20Gas%20Infrastructure%20V\\_02-02.pdf](http://energy.gov/sites/prod/files/2015/02/f19/DOE%20Report%20Natural%20Gas%20Infrastructure%20V_02-02.pdf). After modeling interactions between the gas and electric industries, the report's key findings (at iv-v).



the electric power sector, the projected incremental increase in natural gas pipeline capacity additions is modest relative to the Reference Case.

(4) While there are constraints to siting new interstate natural gas pipeline infrastructure, the projected pipeline capacity additions in this study are lower than past additions that have accommodated such constraints.”

It will take time – in some cases several years – to build this infrastructure, and unlike transmission planning that is coordinated by a central planning authority, expansion of the gas delivery and storage system is driven by market economics. But significant amount of pipeline expansion is already in advanced planning and permitting. Thus, while typically, gas pipeline companies require long-term commitments from ‘anchor’ gas shippers before receiving permitting approval and proceeding to break ground, there is no reason to believe that the system will be short of capacity as a result of the Clean Power Plan. Indeed, such commitments have and can be made in many regions (notably, in Colorado, as part of the state’s approval of Xcel’s decision to replace parts of its coal fleet with gas-fired plants, or in the Midwest, where DTE Energy has committed to support pipeline expansion to access gas supplies in the Marcellus). In some organized wholesale electric markets, however, there may need to be changes in some market rules and/or new institutional commitments to induce new investment in firm pipeline expansion to make gas available to non-utility generators.

Another issue raised in many comments relates to the current uncertainty that exists with regard to how states may/should/will count *new* gas-fired combined cycle power plants in their overall planning. Because such new plants fall under a different part of the Clean Air Act (i.e., Section 111(b)) than existing power plants (i.e., Section 111(d)), EPA has suggested that states will have the option to determine whether to fold in new plants into their overall framework for controlling emissions of then-existing power plants, or to keep those new plants regulated under a separate regime. What states will do remains a critical unknown, and could affect the operations of the overall power system, as well as emissions from the plants now covered under the Clean Power Plan.<sup>66</sup>

Beyond regional concerns and detailed technical criticisms, the most frequent reliability-related comments focus on the implications of the interim targets and the timelines for compliance.<sup>67</sup>

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<sup>66</sup> For example, states with an emission rate goal less than 1,000 lbs/MWh may meet such a target through extensive renewable resources. The use and reliance on new NGCC units (with an emission rate equal to 1,000 lbs/MWh) to provide significant quantities of energy when renewables are off-line may actually increase net total emissions.

<sup>67</sup> The current rule includes two compliance options: a 2030 final goal with an interim compliance goal for average emissions between 2020 and 2029, and a second option, with lower total goals and no interim goals, to be achieved by 2025. Under option 1, States are required to file their SIP by June 30, 2016, with one year extensions available for single states and two years for multi-state plans. EPA has committed to reviewing and approving all SIPs within one year of receipt. Therefore, final SIPs will take effect

Commenters point out that the compliance timeline presents at least two challenges. The first is the added pressure on resource adequacy in light of pending retirements, particularly of economically marginal coal units facing difficult retrofit decisions for compliance with ongoing air regulations such as the MATS.<sup>68</sup> The second is the asserted lack of time for states to develop regional plans for compliance, which could easily require multi-year time frames to coordinate necessary staff in legislative departments, PUCs, and state energy and air offices.

Others have raised the issue that the timelines will result in significant stranded costs for ratepayers.<sup>69</sup> While not a reliability issue per-se, these stranded costs carry a true economic cost in that those monies may have been better spent on other programs in support of the Clean Power Plan project. However, as we discussed we observe that too often, commenters make assertions about reliability challenges that really end up being about cost impacts. We think that separating reliability considerations from cost consideration is important so as to avoid distracting attention from the actions necessary (and possible) in order to keep the lights on. There may be “lower cost” options that reduce emissions some part of the way toward the target reductions, but that fail to meet acceptable reliability standards. We do not view such ‘solutions’ as the lowest cost solution precisely because they fail to account for the cost of unacceptable system outages to electricity consumers. Any plan that starts with consumer costs and works backward to reliability and then to emission reduction is one that fails to consider the wide availability of current tools that have served grid operators for more than a decade to meet reliability needs.

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between June 30, 2017 and June 30, 2019. Interim compliance goals for each state are set for the 2020 to 2029 period, in what is commonly referred to as the “glide path” of emission reductions to the 2030 target. The interim compliance goals assume that states can achieve the full quantity of reductions equal to estimates from Building Block 1 and Building Block 2. The “glide” in the interim targets, then, is due to the steady increase in carbon reductions from avoided fossil fuel generation in the 2020-2029 period from increasing levels of renewable energy and energy efficiency deployment.

<sup>68</sup> For example, MISO estimated that between 10 -12 gigawatts of coal-fired capacity will retire by 2016 to meet the MATS rule. An additional 14 gigawatts of coal-fired generation (25 percent of the remaining supply) is further at risk of retirement by 2020. MISO conservatively estimates that it will take a minimum of six years for the necessary generation and transmission infrastructure to replace these retirements. Assuming that all state plans are finalized and approved by 2018, necessary infrastructure would not be in place until 2024 – leaving a four year gap of increased reliability risk. MISO, “Analysis of EPA’s Proposal to Reduce CO<sub>2</sub> Emissions from Existing Electric Generating Units,” November 2014.

<sup>69</sup> For example, Ameren estimated that the 2020-2029 interim timelines could cost Missouri ratepayers an additional \$4 billion compared to its existing Integrated Resource Plan (IRP). Ameren noted that its existing IRP assumes the full retirement of coal units at the end of their useful lives by 2034. The early retirements would move forward the in-service date for proposed NGCC and require additional capacity than would otherwise be needed by 2034. See Comments of Ameren, filed December 1, 2014, at 3.

## Acronyms

Acronym	Definition
<b>APPA</b>	American Public Power Association
<b>BPS</b>	Bulk Power System
<b>BTM</b>	Behind the Meter
<b>CAA</b>	Clean Air Act
<b>CAISO</b>	California Independent System Operator
<b>CPP</b>	Clean Power Plan
<b>CO<sub>2</sub></b>	Carbon Dioxide
<b>CSAPR</b>	Cross State Air Pollution Rule
<b>CURC</b>	Coal Utilization Research Council
<b>CWA</b>	Clean Water Act
<b>EI</b>	Edison Electric Institute
<b>EGU</b>	Electric Generating Unit
<b>EPA</b>	Environmental Protection Agency
<b>ERCOT</b>	Electric Reliability Council of Texas
<b>ERO</b>	Electric Reliability Organization
<b>ERSs</b>	Essential Reliability Services
<b>FERC</b>	Federal Energy Regulatory Commission
<b>FPA</b>	Federal Power Act
<b>IRP</b>	Integrated Resource Plan
<b>ISO</b>	Independent System Operator
<b>ISO-NE</b>	Independent System Operator – New England
<b>MATS</b>	Mercury and Air Toxics Standard
<b>MISO</b>	Midcontinent Independent System Operator
<b>NAAQS</b>	National Ambient Air Quality Standards
<b>NASEO</b>	National Association of State Energy Officials
<b>NARUC</b>	National Association of Utility Regulatory Commissioners
<b>NEI</b>	Nuclear Energy Institute
<b>NERC</b>	North American Electric Reliability Corporation
<b>NGCC</b>	Natural Gas Combined Cycle
<b>NODA</b>	Notice of Data Availability
<b>NYISO</b>	New York Independent System Operator
<b>OATT</b>	Open Access Transmission Tariff
<b>PJM</b>	PJM Interconnection
<b>PUC</b>	Public Utility Commission
<b>RPS</b>	Renewable Portfolio Standard
<b>RSV</b>	Reliability Safety Valve
<b>RRO</b>	Regional Reliability Organization
<b>RTO</b>	Regional Transmission Organization
<b>SIPs</b>	State Implementation Plans
<b>SPP</b>	Southwest Power Pool
<b>VER</b>	Variable Energy Resources (e.g., wind and solar)
<b>WECC</b>	Western Electric Coordination Council