EPA's Clean Power Plan and Reliability

Assessing NERC's Initial Reliability Review

PREPARED FOR

Advanced Energy Economy Institute

PREPARED BY

Jurgen Weiss, PhD

Bruce Tsuchida

Michael Hagerty

Will Gorman

February 2015

THE Brattle GROUP

This report was prepared for *Advanced Energy Economy Institute*. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or its clients.

Acknowledgement: We acknowledge the valuable contributions of many individuals to this report and to the underlying analysis, including Marc Chupka, Ryan Hledik, Kathleen Spees, Mike Kline, Ira Shavel, Sam Newell, and other members of The Brattle Group for peer review.

Table of Contents

Executive Summary

The United States ("U.S.") power system is undergoing a fundamental transformation, largely driven by advances in technology and low natural gas prices. This transformation is putting significant pressure on existing coal-fired and even nuclear generation, increasingly leads to renewable energy resources being cost-competitive with fossil-fired generation,[1] and results in myriad choices for consumers that promise to permanently alter the role of demand in the power system. As a consequence, the fuel mix and associated emissions of the U.S. power system are changing rapidly, as are the actions taken by system operators to manage the quickly evolving electric system.

Against this backdrop the U.S. Environmental Protection Agency ("EPA") released in June 2014 the proposed Clean Power Plan ("CPP") as a means of implementing Section 111(d) of the Clean Air Act to regulate carbon dioxide ("CO_2") emissions from existing power plants and has since received over four millions comments on the CPP.[2] In November 2014, the North American Electric Reliability Corporation ("NERC") released an Initial Reliability Review ("IRR") of the CPP.[3] In this review, NERC questions several assumptions in the CPP and identifies elements of the CPP that it suggests may lead to potential reliability concerns. Several Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") have issued their own reports and submitted comments highlighting their concerns about how the CPP might impact reliability in their areas.[4]

---

1 In several recent procurements in the United States renewable energy sources were chosen over both coal and natural gas-fired generation. For example, it was reported that Austin Energy signed a 20-year contract with a solar PV project at a cost below 5 cents/kWh, which it estimated to be cheaper than either natural gas (7 cents/kWh) or coal (10 cents/kWh). See http://www.greentechmedia.com/articles/read/Austin-Energy-Switches-From-SunEdison-to-Recurrent-For-5-Cent-Solar (accessed February 3, 2015). Prices of wind PPAs executed in 2013 were at the low end of average wholesale prices and often below $30/MWh; see U.S. Department of Energy, 2013 Wind Technologies Market Report, August 2014.

2 The proposed Clean Power Plan regulations are available on the EPA's website at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule

3 NERC, Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review, November 2014.

4 MISO, MISO comments RE: Docket ID No. EPA-HQ-OAR-2013-0602 to the EPA, November 2014; SPP, SPP assesses Clean Power Plan, says more time is needed to implement, October 2014; NYISO, Comments of the NYISO on the Carbon Pollution Emission Guidelines for Existing Stationary sources: Electric Utility Generating Units; SNL, ISOs, RTOs agree: EPA must include 'reliability safety valve' in CO2 rule, December 2013.

Maintaining reliability is the primary focus of system planners and operators. At a high level, NERC recommends in the IRR, and we agree, that further in-depth analysis should be conducted as the EPA finalizes the CPP so that any emerging reliability issues can be managed.[5]

Following a review of the reliability concerns raised and the options for mitigating them, we find that compliance with the CPP is unlikely to materially affect reliability. The combination of the ongoing transformation of the power sector, the steps already taken by system operators, the large and expanding set of technological and operational tools available and the flexibility under the CPP are likely sufficient to ensure that compliance will not come at the cost of reliability.

NERC's IRR identifies several issues with the methodologies used by the EPA to estimate the four "building blocks" that make up the Best System of Emissions Reductions ("BSER"), which in turn is used to set state-level emissions rate standards between 2020 and 2029. NERC also discusses the potential reliability concerns of implementing the building blocks as suggested by the EPA's analysis. Some RTOs/ISOs have gone further in their own reports and statements, being at least suggestive that the CPP, if implemented as proposed, will cause reliability problems.[6]

NERC's concerns with the EPA's assumptions in constructing the BSER should conceptually be separated from NERC's arguments about potential reliability issues that could arise from the states' approaches to complying with the CPP. We look at these two issues in order below.

Table ES-1below summarizes NERC's main concerns with the assumptions underlying the EPA's development of BSER and provides our view of these concerns and a description of the set of tools available to address each concern where appropriate. NERC is concerned that overstating the potential for emissions reductions from some of the BSER building blocks may challenge the reliability of the system. It is concerned that in the short term, emissions rate reductions will have to come from increases in the use of natural gas-fired plants, which NERC believes could be difficult to accomplish due to pipeline constraints and resulting reliability issues due lack of natural gas supply. In the longer term, NERC believes that the CPP could require increased deployment of Variable Energy Resources ("VERs") such as wind and solar photovoltaic ("PV") capacity, which could challenge operation of the power system.

The assumptions underlying the construction of achievable emissions reductions in each of the four building blocks comprising BSER are likely all subject to some level of debate. As indicated in Table ES-1, we agree that in several areas the methodology used by the EPA to derive BSER is likely a simplification. However, we also show that legitimate arguments exist to counterbalance NERC's concerns in each building block and that, as a result of these arguments (and the

5 "NERC should continue to assess the reliability implications of the proposed CPP and provide independent evaluations to stakeholders and policy makers." NERC, 2014, p. 3.

6 See Section III in the main report for a summary of the comments submitted by regional entities to the EPA.

additional tools we outline as options to counteract the issues raised by NERC) NERC's reliability concerns could be partially or entirely mitigated.

Table ES-1
Summary Analysis of NERC's Building Block Concerns

NERC Building Block Concern	Response to NERC Concern	Solutions Not Considered by NERC
Projected coal heat rate improvements may be difficult to achieve	Plant-level heat rate improvements may be harder to achieve than BSER assumes, but fleet-level heat rates would likely improve due to retirement and re-dispatch. Also, some plant level emission reduction strategies that are not considered in BSER could help.	- Fleet level heat rate improvements due to Mercury and Air Toxics Standards ("MATS") retirements and re-dispatch or retirements as a result of CPP - Co-firing with biomass - Waste heat recovery - Co-generation
Regional gas pipeline issues may limit coal-to-gas switching	Potential constraints in some regions are offset by additional coal-to-gas switching within regional electricity markets elsewhere.	- Regional coal-to-gas switching - Use of LNG and gas storage - Gas demand response
Expansion of renewable capacity does not account for differences amongst state-level Renewable Portfolio Standard ("RPS") mandates	The EPA methodology for developing regional renewable penetration rates has shortcomings, but in many regions existing state-level targets exceed BSER levels and significant additional potential exists.	- Renewable energy solutions not relying on additional transmission infrastructure, such as distributed wind and solar PV - Operational changes to managing transmission to increase transfer capacity - Merchant transmission projects in addition to ongoing transmission improvements can increase access to renewables over time
Assumed EE growth exceeds achievable reductions in load	The EPA's BSER methodology may be over-simplified and the ability to maintain high levels of Energy Efficiency ("EE") growth in leading states is unproven to date, but EPA's BSER also omits several important drivers of EE that could help states meet or exceed BSER.	- Program experience in leading states helps identify untapped EE potential - New EE technologies continue to shift boundary of EE potential - Adoption of best practices by lagging states will facilitate ramp-up - Options exist beyond BSER, including Energy Service Companies ("ESCOs"), changes to codes and standards, and other non-utility EE efforts - Regional cooperation to overcome current limit on EE credit to in-state generation

Table ES-2 below provides a summary of NERC's primary reliability concerns as well as our comments and suggested tools to address those concerns.

Table ES-2
Summary Analysis of NERC's Reliability Concerns

NERC Reliability Concern	Response to NERC Concern	Solutions Not Considered by NERC
Maintaining resource adequacy within the constrained time period due to potential coal and oil/gas steam unit retirements	Coal plants required to maintain adequate reserve margins can continue operating at a lower capacity levels. Not all retirements need to be replaced due to excess capacity in many regions. Several capacity resources can be deployed in less than 2 years; longer term planning processes, such as capacity markets and integrated resource planning are capable of adapting to the CPP requirements.	- Gas and electric demand response - Energy efficiency - Natural gas-fired combustion turbines - Energy storage
Obtaining sufficient natural gas service during high-use periods due to pipeline constraints and other gas and electric interdependencies	Market rules are adapting to ensure sufficient resources are available during constrained operation periods. Gas storage and demand response can help manage gas demand during constrained periods.	- Market incentives to improve performance (such as ISO New England's Pay for Performance rules) - Natural gas storage - Gas demand response - Gas and electric energy efficiency
Increased generation from renewable VERs will create operational challenges and require transmission build out	Current levels of renewable generation in many regions exceed penetration levels assumed by the EPA without negatively impacting operational reliability. Transmission planning processes are adequate due to the significant build out expected regardless of CPP standards. Many tools exist for managing high levels of VERs and studies show significant integration is possible without reliability issues.	- Non-VER renewables - Improved scheduling of energy and ancillary services markets, including participation by VERs - Balancing system with non-traditional technologies - Cooperation/increased transmission between balancing areas - Flexible operation of transmission network - Energy Storage - Improved VER forecasting
Limited timeframe for compliance and the potential for reliability issues require EPA include a "reliability back-stop" in the final rule	EPA provides states significant flexibility in achieving standards that can be utilized prior to considering a "reliability back-stop".	- Interim 10-year average standard - Emission reductions beyond BSER - Option to pursue market-based strategies - Multi-state compliance options

Even if one accepted NERC's concerns that CPP compliance may require more reliance on natural-gas fired generation in the short run and on more variable generation from non-hydro renewables in the longer run than what is assumed under BSER, this would not imply a significantly increased risk to reliability.

Shifting electricity production from coal to natural-gas fired generation during periods without gas pipeline constraints will likely contribute significantly to reducing emissions rates, since even in the short term, gas pipeline bottlenecks only occur during relatively short periods of combined high heating and electric demand. The CPP does not require coal to natural gas switching during such periods, so that traditional resources as well as other options (such as gas storage, localized gas and electric energy efficiency measures, gas and electric demand response) can continue to provide the services necessary to ensure reliability. In addition, gas supply shortages have already been increasing due to relatively low natural gas prices, and significant efforts are underway to address those issues. Therefore, it is likely that short-term gas supply bottlenecks will be at least partially overcome in the next few years.

There is also ample evidence that power systems can and are already operating at levels of VER penetration significantly above what would be necessary to achieve the CPP emissions reduction goals even if contributions from other building blocks are less than those embedded in BSER. The EPA's modeling of least-cost compliance with the CPP (as opposed to constructing BSER) assumes that nation-wide non-hydro renewable energy production would likely rise to 8% by 2020 as opposed to 7% without the CPP. Under BSER assumptions the share of intermittent renewables would need to reach 13% nationally by 2029 assuming full contributions from the other BSER building blocks.[7] Even if emissions reductions from other building blocks were lower, national VER penetration rates would likely be both achievable and below the levels where serious integration challenges may emerge.

Ample evidence indicates that a nation-wide increase of the renewables share from 7% under a business as usual scenario without the CPP to 8% with the CPP would not lead to any reliability concerns. Many states and countries are operating at much higher levels of renewable energy today without any negative impact on reliability. The same holds true for a 13.5% average national renewables share by 2029. More importantly, even under very pessimistic assumptions about the availability and cost-effectiveness of emissions reductions from other building blocks (or measures not included in building blocks), national renewable energy shares that could become necessary to meet the CPP targets remain below 30% and thus below levels already managed in some states and countries today, using existing tools and technologies. For example, California is on target to meet its 33% 2020 Renewable Portfolio Standard ("RPS"), which is not expected to lead to serious reliability concerns.[8] Germany already reached close to 30%

---

7 EPA, Goal Computation, Technical Support Document for the CAA Section 111(d) Emission Guidelines for Existing Power Plants, Docket ID No. EPA-HQ-OAR-2013-0602, June 2014.

8 California Public Utility Commission, Renewable Portfolio Standard Quarterly Report: 3rd Quarter 2014, Issued to Legislature October 10, 2014. Available at: http://www.cpuc.ca.gov/NR/rdonlyres/CA15A2A8-234D-4FB4-BE41-05409E8F6316/0/2014Q3RPSReportFinal.pdf

renewable energy generation in 2014, also without reliability concerns.[9] In both regions, the mix of tools used to manage a system with a high share of intermittent renewables includes expanded use of the current set of operational practices (re-dispatch, occasional curtailment of renewable generation, additional reserves) as well as increasingly relying on newer technologies such as storage and demand response. It is likely that over the coming decade the availability of various options to manage intermittency will increase while their cost will decrease.[10] Given the fact that much higher VER penetration is likely a longer term issue, both developments will further help mitigate any reliability concerns.

Assuming regional rather than national implementation,[11] regionally required renewables shares would be higher in some regions, but in very few regions would renewable generation need to approach or exceed 30% by 2029, even assuming zero contribution from other building blocks.[12]

Furthermore, aside from the four building blocks, EPA has also provided states with considerable flexibility, allowing them to employ emission reduction technologies not included in the BSER. These technologies include co-firing coal with biomass, demand response, combined heat and power ("CHP"), and non-utility energy efficiency measures. Incorporating these and other emission reduction options will lower the emission reductions that states need to achieve under the four building blocks, thereby ameliorating possible reliability concerns that may result from the strict application of BSER.

In addition to allowing states to reduce emissions by going beyond BSER, the CPP provides flexibility options that further reduce the chances of reliability issues emerging. The EPA designed the CPP to provide the states options in choosing how to comply with the CO_2 standards. The compliance options provided to the states include (1) allowing states to create their own approaches in their state implementation plans ("SIPs") for meeting the standards, including the use of a market-based approach, and as described above, the option to incorporate

---

9 In Germany, renewable energy represented 28.4% of total electricity consumption in the first half of 2014. See http://www.germany.info/Vertretung/usa/en/__pr/P__Wash/2014/07/30-Energy-record.html.

10 We note that Germany has a renewable energy target of 40-45% by 2025 and of 55-60% by 2035. See http://www.mondaq.com/x/329922/Renewables/German+Renewable+Energy+ActChanges+In+2014 for an English language summary of the law including targets. German transmission service operators ("TSOs") have to file annual reports with the national regulator (Bundesnetzagentur). The latest set of reports has identified the costs of managing intermittency through curtailment and re-dispatch at a few hundred million Euros per year, when annual payments under feed-in tariffs exceed 20 billion Euros. Also, Germany has a stricter reliability standard and continues to achieve very high levels or reliability. For a more detailed discussion of integration costs in Germany, see Weiss, Solar Energy Support in Germany: A Closer Look, The Brattle Group, July 2014.

11 The CPP's flexibility options could allow states to cooperate in ways that could, de facto, lead to states fully leveraging the ability to build VERs more easily and cheaply in some rather than in other regions. We discuss the options for cooperation in some detail in our main report.

12 EPA Goal Computation, 2014. See the main report for more details on renewable penetration.

measures not included in the BSER, (2) allowing for the proposed rate-based standards to be converted to mass-based standards, (3) allowing for states to cooperate with each other to meet their standards, and (4) setting the interim goal as an average over a ten-year period rather than as annual requirements. Individually and in combination these flexibility options likely lead to both lower compliance costs and lower reliability risks associated with the CPP.

The absence of predictable reliability concerns does not mean that unpredictable reliability concerns may not appear during implementation of the CPP. However, there is some historic evidence that the EPA allows for flexibility in compliance so that reliability can be maintained, as long as states provide contingency plans in their SIPs for just such cases and implement those contingency measures to ensure that overall regulatory goals are attained or nearly so over time.[13] This approach ensures that incentives to comply with environmental regulations are maintained, while allowing for reliability concerns to trump short-term emissions goals and for overall long-term emissions reductions to be achieved. Should the timeline of approving and implementing the CPP prove particularly tight – for example because SIPs and the required actions contained therein will only be known with certainty as late as 2018 with compliance with the interim emissions rate target starting in 2020 – we expect EPA to allow the flexibility it has shown in the past. To this end, the EPA could make more explicit how it intends to measure compliance or what enforcement options it would use in situations where SIPs include contingency provisions for dealing with unexpected reliability situations, but where following those contingency plans lead to emissions not on a path to meet with interim targets or even exceeding overall average targets over the 2020-2029 compliance period.

---

13 In the past, the EPA has recognized the need to balance reliability needs and compliance with environmental regulations. For example, the EPA clarified that when MATS compliance would create local reliability issues, a one-year extension to compliance with MATS can be granted and that long-term reliability issues would be dealt with on a case by case basis in consultation with FERC, RTOs and ISOs. (EPA, Memorandum, The Environmental Protection Agency's Enforcement Response Policy For Use of Clean Air Act Section 113(a) Administrative Orders In Relation to Electric Reliability And The Mercury And Air Toxics Standard, December 16, 2011). See also Jonas Monast et al, Regulating Greenhouse Gas Emissions From Existing Sources: Section 111(d) and State Equivalency, Environmental Law Reporter, 3-2012, which points to the ability to use established rules under NAAQS to allow contingency plans as backstop measures.

I. Introduction

Advanced Energy Economy Institute asked consultants at The Brattle Group to provide a critical review of North American Electric Reliability Corporation's ("NERC") Initial Reliability Review[14] ("IRR") of the Environmental Protection Agency's ("EPA's") proposed rule under Section 111(d) of the Clean Air Act, also known as the existing source rule or the proposed Clean Power Plan ("CPP"). The CPP regulates carbon dioxide ("CO_2") emissions from existing fossil-fired power generation sources and the EPA estimates that it would reduce total power sector CO_2 emissions by 30% by 2030 relative to 2005 emissions levels.[15] The EPA received over four million comments on the proposed CPP and expects to finalize its rule by July 2015.

In its IRR, NERC raises several concerns about assumptions made by the EPA for setting the emissions rate standards and about potential resulting reliability impacts of the CPP. Maintaining the reliability of the electric grid over time is, of course, a major priority not just for NERC, but for electric power system operators and planners across the United States ("U.S."). Consequently, it is important that the Final Rule under Section 111(d) of the Clean Air Act, the "final" Clean Power Plan, not create any requirements that lead to unacceptable declines in reliability of the U.S. power system.

The changes in the generation mix required to reduce CO_2 emissions rates and comply with the CPP could have a wide range of impacts on the power system. The extent of the impacts will depend on how the final CPP is structured, how states choose to comply, and how utilities, generators, and system operators adapt. As these changes occur, system reliability will be tracked closely to ensure the reliability standards set by NERC and its regional entities are maintained.[16]

The physical reliability of the power system requires that certain electrical properties be maintained. The most important aspect of maintaining these properties is to balance generation

---

14 NERC, Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review, November 2014. ("NERC, 2014") Available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf

15 The proposed Clean Power Plan regulations are available on the EPA's website at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule.

For a summary of the CPP, see: Celebi, et al., EPA's Proposed Clean Power Plan: Implications for States and the Electric Industry, Policy Brief, June 2014. ("Celebi, et al. 2014") Available at:

http://www.brattle.com/system/publications/pdfs/000/005/025/original/EPA's_Proposed_Clean_Power_Plan_-_Implications_for_States_and_the_Electric_Industry.pdf

16 For details on NERC's reliability standards, see: http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States

and load.[17] Failing to do so, in a purely physical sense, creates an imbalance in the system that, if not corrected, will cause loss of service to electricity consumers (e.g., black-outs and brown-outs). For this reason, the reliability of the system is constantly monitored by operators and studied by system planners to ensure that resources in the system can handle expected operational conditions and potential system disruptions.

In the *short run*, the balance between supply and demand is primarily achieved by forecasting load and committing and dispatching generation resources (and, increasingly, demand resources) to meet the total load. In addition to energy production, a number of ancillary service products ensure significant short term reserves exist on the system in case of unexpected changes in supply or demand due to an unforeseen change in production from an intermittent renewable facility, the sudden loss of a major generator, or sudden and unforeseen changes in load. Ancillary services for the purpose of discussion in this report include regulation service for the real time changes of load within the normal operations, contingency reserves (e.g., spinning and non-spinning reserves) for addressing a sudden loss of generation resources, reactive power and voltage support to ensure delivery of power through transmission lines, and inertia to keep the system immune to external shocks, among others.

Operators are using a range of options to accomplish this task today, including dispatching fossil generation (coal, natural gas- and occasionally oil-fired), demand resources and increasingly energy storage devices and renewable generation equipped with advanced technology (such as smart inverters). Operators have also begun to establish protocols for utilizing flexibility in the transmission system, but such actions are generally limited. Finally, under extreme situations, operators use additional tools such as the curtailment of renewables and, as a last resort, the selective shedding of load so as to avoid system-wide power failures.

In the *longer run,* "resource adequacy" for a given system is typically achieved by setting reserve margin requirements or targets that ensure there will be enough capacity to minimize the chance of having insufficient capacity to meet peak demand. Planning to meet reserve margins generally occurs several years ahead of expected future peak load conditions and is accomplished through different processes across the U.S., including utility planning processes often referred to as "integrated resource planning" and state or regional capacity markets. Capacity for meeting the reserve margins can come from both generation and load resources. If system operators identify that a generation facility that is potentially retiring for economic reasons is required to maintain reliability, they will often provide additional payments to maintain operation of the unit through short term arrangements known as "reliability must run" ("RMR") contracts until alternative solutions can be implemented.

The remainder of this report provides an in-depth discussion of NERC's concerns outlined in the IRR, including an assessment of NERC's critique of EPA's assumptions underlying state-specific

---

17 Maintaining the proper balance between supply and demand requires maintaining the quality of electricity, including voltage and frequency, within narrow bounds. When we refer to 'supply and demand balance' in this paper, we are including these necessities of power delivery.

CPP emissions rate standards and an analysis of the possible reliability impacts identified by NERC In addition to critically reviewing NERC's preliminary findings in the IRR, this report also discusses the options available for mitigating those potential impacts, should they occur, using technical, operational, and market-based approaches. The report is organized as follows: Section II provides a brief overview of the CPP; Section III provides an overview of NERC's IRR and comments provided by various ISOs and RTOs; Section IV critically assesses the IRR's individual reliability concerns and provides an overview of the available mitigation options; and Section V provides a regional perspective on how the CPP will impact different markets across the country. Section VI provides some concluding remarks.

II. Summary of Proposed Clean Power Plan

In this section we provide a brief summary of the Clean Power Plan, highlighting areas relevant to the main points in NERC's IRR.

Announced in June 2014, the CPP requires each state to reduce CO_2 emission rates from existing fossil fired plants with capacity greater than 25 megawatt ("MW") to meet state-specific rate standards (in pounds per megawatt-hour, or lbs/MWh) starting in 2020. For each year from 2020 to 2029, the EPA has proposed state-specific emissions rate targets. To be in compliance, states have to meet the average of the standards set for 2020 to 2029, known as the "interim goal." In 2030 and thereafter, the states will need to comply with the "final goal" on an annual basis.

For setting state-specific CO_2 emissions rate standards, the EPA identified a Best System of Emissions Reductions ("BSER") based on four "building blocks" for reducing CO_2 emissions rates.[18] As shown in Table 1, the four building blocks are (1) increasing the efficiency of fossil fuel power plants, (2) switching generation to lower emitting fossil power plants, (3) building more low and zero emissions generation, and (4) using electricity more efficiently. EPA's estimated costs of CO_2 emissions reductions for each building block and the percentage of emissions reductions relied upon to derive overall reduction targets are also shown in the table.

18 The EPA identified the building blocks following a review of recent experience at the plant and state-level for reducing CO_2 emissions rates and quantified the potential impact of each building block based on its evaluation of best practices in each area of potential emissions reductions. The purpose of the building blocks is to create a standardized approach for identifying the extent to which emissions rate reductions could be reasonably achieved in each state.

Table 1
EPA's Proposed System of Emissions Reductions for Carbon Dioxide

BSER Building Block	EPA Basis for BSER Determination	EPA Estimated Average Cost	% of BSER CO_2 Reductions
1. Increase efficiency of fossil fuel power plants	EPA reviewed the opportunity for coal-fired plants to improve their heat rates through best practices and equipment upgrades, identified a possible range of 4–12%, and chose 6% as a reasonable estimate. BSER assumes all coal plants increase their efficiency by 6%.	$6–12/ton	12%
2. Switch to lower-emitting power plants	For re-dispatching gas instead of coal, EPA determined that the average availability of gas CCs exceeds 85% and that a substantial number of CC units have operated above 70% for extended periods of time, modeled re-dispatch of gas CCs at 65–75%, and found 70% to be technically feasible. BSER assumes all gas CCs operate up to 70% capacity factor and displace higher-emitting generation (*e.g.*, coal and gas steam units).	$30/ton	31%
3. Build more low/zero carbon generation	EPA identified 5 nuclear units currently under construction and estimated that 5.8% of all existing nuclear capacity is "at-risk" based on EIA analysis. BSER assumes the new units and retaining 5.8% of at-risk nuclear capacity will reduce CO_2 emissions by operating at 90% capacity factor.	Under Construction: $0/ton "At-Risk": $12–17/ton	7%
	EPA developed targets for existing and new renewable capacity in 6 regions based on its review of current RPS mandates and calculated regional growth factors to achieve the target in 2030. BSER assumes that 2012 renewable generation grows in each state by its regional growth factor through 2030 (up to a maximum target) to estimate future renewable generation.	$10–40/ton	33%
4. Use electricity more efficiently	EPA estimated EE deployment in the 12 leading states achieves annual incremental electricity savings of at least 1.5% each year. BSER assumes that all states increase their current annual savings rate by 0.2% per year starting in 2017 until reaching a maximum rate of 1.5%, which continues through 2030.	$16–24/ton	18%

Source: Celebi, et al., 2014.

The EPA derived intermediate and final CO_2 emissions rate standards by estimating the potential for emissions reductions from each building block in each state through 2030. In calculating BSER the EPA assumed that building *new* fossil generation sources, which are subject to Section 111(b) of the Clean Air Act, could not contribute to lower emissions from *existing* sources.[19] With this important constraint, the EPA expects the majority of emissions reductions to be achievable in Building Blocks 2 and 3, which replace generation from higher emitting resources, such as coal and gas/oil steam units, with generation from existing natural gas combined cycle ("NGCC") plants, new and "at-risk" nuclear plants, and new and existing non-hydro renewable capacity.[20]

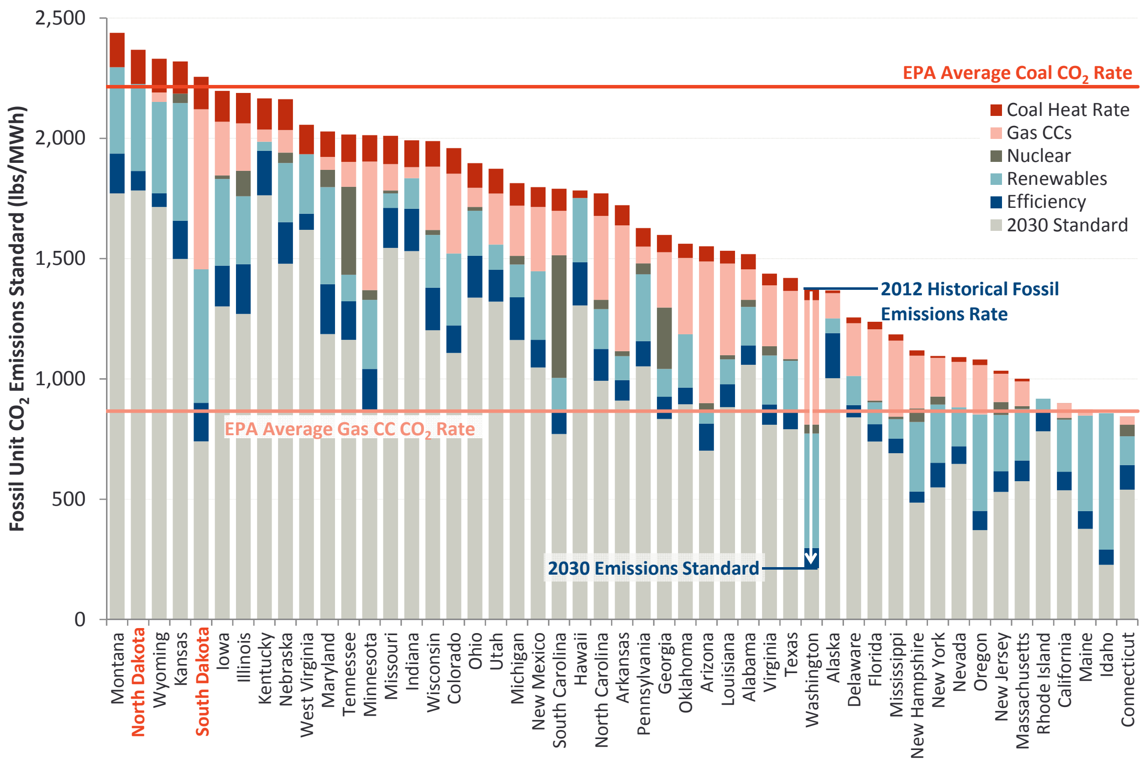
---

[19] It may nonetheless be possible for states to include new NGCCs in their SIPS as a mechanism for meeting the CPP targets. Based on private analysis by VanNess Feldman LLP. Also, if states choose to convert the rate-based standard into a mass-based standard, they have the option of either setting the mass-based standard on just existing generation or both existing and new generation. In states that choose this option new natural-gas fired generation can contribute to meeting CPP targets. See: http://www.gpo.gov/fdsys/pkg/FR-2014-11-13/pdf/2014-26900.pdf

[20] U.S. nuclear plants are already operated at a capacity factor around 90% (Nuclear Energy Institute shows approximately 90.9% in 2013) and therefore the potential for increasing generation from existing nuclear plants is limited without uprates. In addition, new nuclear facilities can take well over

Continued on next page

Figure 1
Application of BSER for 2030 CO_2 Emissions Rate Standards by State



Source: Celebi, et al., 2014.

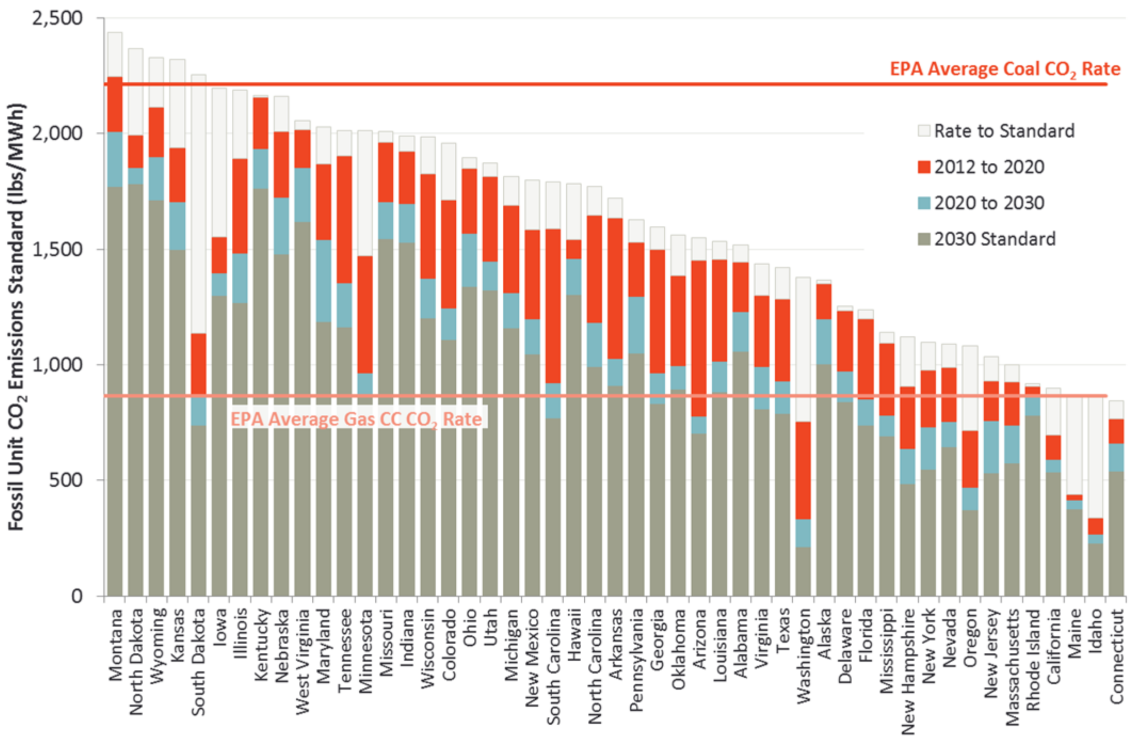
Because the BSER considers state-specific availability of the resources in the four building blocks and because emissions rates from existing fossil generation sources differ by state, Figure 1 shows how the application of the BSER building blocks across the states results in a wide range of emissions rate standards.[21]

Continued from previous page

10 years to develop, permit, and build such that they are not likely to contribute to meeting the 2020 – 2030 compliance requirements. See: http://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/US-Nuclear-Capacity-Factors. Should states choose to convert to a mass-based emission standard, new hydro resources could also contribute to emissions reductions.

21 For example, North and South Dakota have similar 2012 fossil fuel generation emissions rates (as demonstrated by the relative total height of the bar), but have very different 2030 standards (represented by the light grey area of the bars).

Figure 2
Phase-In of BSER from 2012 Fossil Rates to 2030 Standards



Source and notes: EPA, Goal Computation, Technical Support Document for the CAA Section 111(d) Emission Guidelines for Existing Power Plants, Docket ID No. EPA-HQ-OAR-2013-0602, June 2014. ("EPA Goal Computation, 2014") The Rate to Standard area of each state's column accounts for the existing renewable and nuclear generation as of 2012 that counts towards compliance.

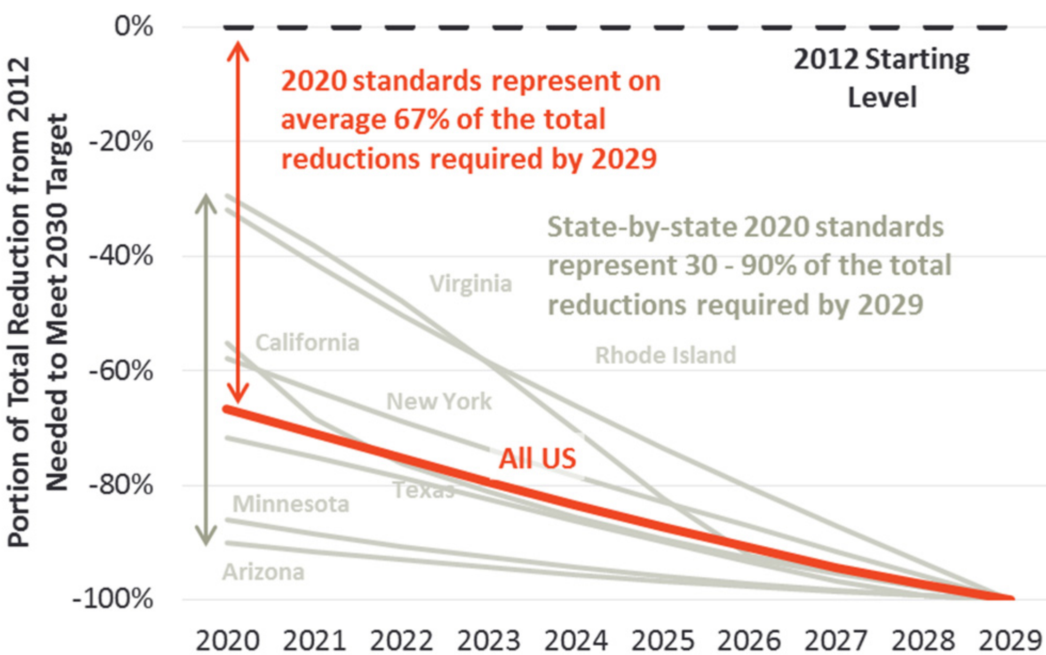
Figure 2 shows how the emissions rate standards are phased in over time for each state. Due to the EPA's approach for calculating the CO_2 emissions rates standards using all existing non-hydro renewable and 5.8% of its existing nuclear generation, the states' 2012 emissions rates, as calculated by the EPA for purposes of developing BSER, may be significantly lower than the average fossil unit emission rates, as shown by the light grey bar.[22] Based on the EPA's formula, these "reductions" in the emissions rates have already been achieved and count towards achieving 2020 and 2029 emissions rate targets. For setting 2020 emissions rate targets, the EPA assumes that emissions reductions from coal heat rate improvements (Building Block 1) and switching from higher to lower emitting resources (Building Block 2) can occur by 2020 and are maintained going forward. These reductions are shown by the red bar in Figure 2. Further annual reductions in the emissions rates between 2020 and 2029 are assumed to be driven by the

22 The CPP emissions standards are neither fossil generation emissions rates nor state-wide emissions rates, but instead a calculation of total fossil emissions spread across the generation included in the BSER, including all fossil generation, existing and new non-hydro renewables, new and "at-risk" nuclear, and the avoided generation due to new energy efficiency measures. In the calculation of the standards, states will thus get credit for the existing generation from renewable and nuclear capacity, which reduces their burden in meeting the standards starting in 2020.

adoption of renewable generation (Building Block 3) and energy efficiency (Building Block 4), as shown by the light blue bar.

Due to the different assumptions about the timing of achievable emissions reductions in each building block, the assumed path of emissions reductions required to meet the final 2030 goals is not linear, but rather assumes that significant reductions are achievable by 2020. As previously noted, states are in compliance as long as they meet the average 2020-2029 emissions rates targets over the ten year period. Figure 3 shows that on average the emissions reductions required to achieve the 2020 standards represent 67% of the total reductions necessary to meet the 2030 standard, although there is significant variation among states.[23]

Figure 3
Percent of Total Mass-Based Emissions Reductions Required to Meet CPP Standards



Source: EPA, Translation of the Clean Power Plan Emission Rate-Based CO2 Goals to Mass-Based Equivalents, Technical Support Document for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR-2013-0602, November 2014.

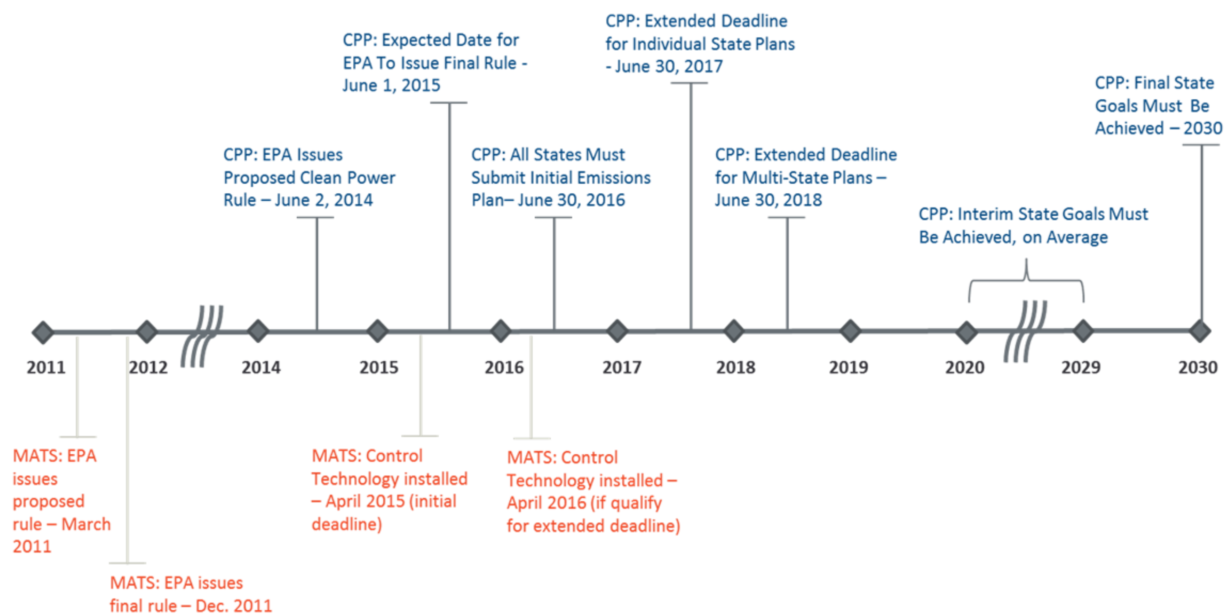
Since different types of emissions reductions require different lead times for the planning and approval of state-level measures as well as changes in electric power system infrastructure (e.g., transmission lines and new capacity), the timing of steps between the release of the final CPP

---

[23] Due to the likely changes in emissions between 2012 and 2020, the actual amount of reductions required by 2020 will differ from what is demonstrated here. We have not attempted to project how emissions will change in the years between 2012 and 2020 in this analysis. The amount of reductions required for 2020 may be higher if emissions increase in the years prior to the standard or lower if emissions decrease over that time.

and the start of the compliance period is also a relevant feature of the CPP. As shown in Figure 4, the final CPP will be promulgated in the summer of 2015 after which states will have a year to submit their initial compliance plans, known as state implementation plans ("SIPs"). Deadlines for individual state plans and multi-state plans may be extended upon request and review by either a year (to 2017) or two years (to 2018), respectively. Compliance with the interim goal therefore could begin either one or two years following approval of the SIPs. Thus, to the extent market participants' investment decisions are dependent on the content of final SIPs and states decide to meet 2020 interim targets rather than the average target between 2020 and 2029, lead times for required investment decisions will matter. States will be required to submit compliance updates every two years during the initial 10 year period and potentially adjust their SIPs if they are not on target to meet the interim or final goals.

Figure 4
Timing of CPP and MATS Compliance



Source: EPA Proposed MATS Timeline taken online from the EPA website: http://www.epa.gov/mats/actions.html and EPA proposed Clean Power Plan Timeline taken online from the EPA website: http://www2.epa.gov/carbon-pollution-standards/fact-sheet-clean-power-plan-carbon-pollution-standards-key-dates

Figure 4 shows the timing for finalizing and complying with the CPP as well as the Mercury and Air Toxics Standards ("MATS"). As noted by NERC, the CPP is proposed to be implemented following the MATS regulations, which has initial deadlines in 2015 and extended deadlines in 2016. The MATS timeline is included due to the potential for significant coal retirements to occur as a result of MATS compliance. While there is a perception that the cumulative retirements of MATS and incremental potential retirements to comply with the CPP targets could create challenges (further discussed below), it is important to emphasize that while MATS will force coal-plant retirements unless certain capital investments are made by a specific date, the CPP alone will not force the retirement of any fossil generation source; instead, units required to maintain resource adequacy can remain operational and lower emissions by operating at a reduced capacity factor.

Both interim and final CO_2 emission rate standards are derived based on what EPA assumes can be achieved using the four building blocks. However, the EPA does not require that the states achieve emissions reductions similar to the BSER building blocks in its SIPs or achieve actual emissions reductions corresponding to the assumed emissions reductions in each block. The CPP also does not require that the annual intermediate emissions rate targets are met as long as average emissions rates between 2020 and 2029 are equal to those implied by the targets.[24]

Several important flexibility features are available for states in choosing how to comply with the CPP standards.

1. First, states can use multiple means for lowering emissions intensity, deviating both from the set of compliance options comprised in the BSER building blocks and/or using different amounts of particular measures to achieve overall target emissions rate reductions.[25]
2. Second, states are not required to meet annual intermediate emissions rate standards as long as the average emissions rate between 2020 and 2029 is not higher than the average emissions rate standards over this time. Adopting a mass-based system would therefore create a total emissions budget for the entire compliance period and states will be free to choose among multiple compliance strategies over a ten year period to keep total emissions within this budget.
3. Third, states have discretion to convert emissions rate standards into mass-based standards, which in essence would create emissions budgets and thus provide greater flexibility in achieving emissions reductions than an emissions rate standard.[26] Mass-based standards however may be more difficult to achieve within states that experience higher than expected growth in electricity demand.

---

24 See section 2(b), State Goals and Flexibility, of the proposed rule in the Federal Register, available at: http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf

25 Among the options not included in the BSER building blocks but mentioned in the CPP as potential opportunities are biomass co-firing of coal generation, carbon capture, and new nuclear. There are likely other options to reduce emissions not explicitly mentioned in the CPP. Under a mass-based approach, they include in particular the construction of new gas-fired generation, which EPA's modeling assumes will be an important component of ultimate emissions reductions, but also CHP, non-utility energy efficiency measures, and other options further discussed below.

26 The CPP does not prevent the development of emissions rate-based trading schemes. However, doing so would likely be more complex than developing mass-based trading systems.

4. Finally, the asymmetry amongst states in the stringency of both intermediate and final targets provides ample opportunities for compliance through multi-state or regional cooperation, which the CPP specifically allows and encourages.[27]

The EPA modeled the CPP for its Regulatory Impact Analysis ("RIA"), allowing its model to identify the lowest cost approaches for meeting the standard, except for EE.[28] Through its modeling, the EPA estimated the costs of complying with the CPP to be $8.8 billion in 2030 resulting in 594 million metric tons of CO_2 emissions avoided, such that the average cost of emissions reductions under the CPP is $15/ton in 2030.[29] The average costs were found to be $2/ton lower when the EPA modeled the case in which states comply on a regional basis.[30]

III. Reliability Issues Identified by NERC and Regional Planners

In this section, we briefly summarize the IRR released by NERC in November 2014. The IRR discusses the EPA's assumptions for setting the BSER building blocks and assesses how those assumptions may impact reliability. In the IRR NERC states that it expects to continue to assess the reliability issues of the CPP over the next two years following the final release of the rule and as state implementation plans are proposed and finalized.[31]

Subsequently, several RTOs/ISOs have also released reports outlining each entity's concerns with the CPP related to regional reliability. While NERC's IRR simply raises potential reliability issues that it suggests will require ongoing study, several of the RTO/ISO studies make stronger statements about the potential/likely impact of the CPP on regional reliability. Before providing a critical assessment of the IRR and some of the statements made by RTOs/ISOs on the same issues, we summarize the primary reliability concerns that have been raised by NERC and by regional entities in this section.

---

27 "The agency also recognizes, as many states have, the value of regional planning in designing approaches to achieve cost-effective GHG reductions." Proposed Rule, Federal Register, Vol. 79, No. 117, June 18, 2014, p. 34850 – 34851. Available at: http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf

28 The EPA modeling assumed that the amount of energy efficiency assumed in the BSER is achieved. The remaining reductions are optimized in the model.

29 Total costs reported in EPA RIA, p. ES-8. Average costs from Celebi, et al., 2014.

30 The EPA's cost estimates differ sharply from the alleged additional annual $284 billion in combined electricity and gas expenditures by 2020 claimed in a recent study by EVA (Energy Market Impacts of Recent Federal Regulations on the Electric Power Sector, EVA, November 2014). It should be noted that EPA's estimates are relative to an assumed "business as usual" ("BAU") case, while EVA's estimates simply compare actual 2012 expenditures to 2020 expenditures under the CPP and MATS and thus also include the impacts of assumed higher natural gas prices and assumed higher increases in electricity demand.

31 NERC, 2014, p. 4.

A. NERC's Building Block Analysis

NERC begins its review of the CPP by assessing the EPA's assumptions for setting the BSER building blocks and the issues that may prevent each building block from achieving its assumed impact on CO_2 emissions rates. We summarize their main points here:

1. **Building Block 1 (Increased Efficiency of Coal Plants):** NERC claims that improving the efficiency of the coal fleet by 6% on average "may be difficult" to achieve and criticizes the lack of consideration by the EPA of several characteristics of coal plants, including post-combustion environmental controls, boiler technology and unit size and age.[32] NERC suggests that overstating this potential may lead to increased reliance on coal-to-gas switching and renewable generation to meet the targets and thus exacerbate the reliability concerns NERC finds associated with those changes.
2. **Building Block 2 (Switching to Lower Emissions Fossil Generation)**: NERC claims that there may be regional issues with natural gas pipeline capacity that may limit the amount of coal-to-gas switching that is assumed in Building Block 2. In addition, NERC finds that additional gas generation may lead to increased retirements of less-efficient coal units, require the development of new pipeline capacity in a short timeframe, and make the power system susceptible to supply disruptions, similar to the 2014 polar vortex.[33]
3. **Building Block 3 (Building Additional Zero Emission Generation)**: NERC claims that the EPA's assumptions about "at-risk" nuclear capacity will "add pressure to states that will need to retire nuclear units."[34] For renewable growth, NERC finds that the EPA's approach to be too simplistic as it does not account for the different resources allowed under each state's Renewable Portfolio Standard ("RPS"), especially the role of new versus existing hydropower, the ability to use out-of-state resources to comply, and the economic aspects of renewable resources.[35]
4. **Building Block 4 (Using Electricity More Efficiently)**: NERC claims that the EPA does not "reasonably reflect energy efficiency achievability" and, consequently, underestimates the evolution of total demand between now and 2030.[36] Overstating the potential expansion of energy efficiency could lead to higher load and therefore the need to increase other approaches for cutting emissions.

32 NERC, 2014, p. 8.

33 Ibid, p. 10.

34 Ibid, p. 11.

35 Ibid, p. 12.

36 Ibid, p. 16.

B. NERC's Reliability Concerns

Based on its concerns about the EPA's assumptions in deriving the BSER and state-level emissions rate targets, NERC identifies the following concerns about how reliability may be affected:

1. NERC suggests that the **retirement of coal and gas/oil steam capacity** (combined with lower than expected energy efficiency gains) may result in accelerated reductions in reserve margins. NERC suggests that it may be difficult to replace the generation capacity in the short time period between when the multi-state implementation plans are finalized, potentially as late as 2018, and when the compliance period begins in 2020.
2. NERC suggests that the assumed amount of **coal-to-gas switching** due to the CPP will further challenge existing electric-gas interdependency issues, natural gas pipeline constraints, and coal plant retirements. NERC raises the possibility that gas-electric interdependency issues, especially the real-time availability of gas, could lead to short-term reliability issues. NERC also suggests that coal plant retirements could become more likely due to the extra costs of operating less efficiently and as a result of additional wear and tear due to the need to follow load rather than continuing to operate primarily as base load.
3. NERC believes that **increased renewable generation capacity** will require additional transmission investment for connecting geographically constrained resources. In particular, NERC suggests that difficulties and delays of transmission expansion needed to interconnect the new renewable resources could lead to potential supply shortages in the longer term. NERC also suggests that integrating large amounts of new renewable resources, which NERC and EPA assume to be dominantly solar, wind, and other variable energy resources ("VERs'), will become challenging in the longer term.
4. Finally, NERC raises the concern that, due to the time provided by the EPA for states to submit their implementation plans and for the EPA to approve them, there may be **insufficient time for compliance** between the final approval of implementation plans and the compliance period to implement all of the potential changes (e.g., transmission lines and new generation facilities) required for compliance. NERC suggests that this could limit the time for advanced planning and that the EPA should consider including mechanisms in the rule for ensuring reliability.

C. Reliability Concerns Identified by Regional Planners

In addition to NERC, various regional entities have submitted comments to the EPA that raise reliability concerns associated with the CPP. In these comments, the regional planners point to specific details of the CPP which they suggest lead to reliability concerns in their specific area. Their comments are more specific and in several cases worded more strongly than NERC's IRR.

For instance, the main concern addressed by the Midcontinent ISO ("MISO") and the Southwest Power Pool ("SPP") is the feasibility of retiring significant portions of the coal fleet by 2020. MISO's initial analysis estimates that 11 GW of coal capacity will have to retire due to the CPP.[37] SPP estimates that 6 GW of coal and gas steam units will have to retire due to the CPP on top of the 3 GW of expected retirements due to MATS.[38] In their comments submitted to the EPA, these groups emphasize that it can take five years for natural gas pipeline projects to be installed and that it could take eight and a half years to study, plan, and construct transmission lines.[39] These entities are concerned that the CPP timelines are not realistic and propose that the interim performance requirement be eliminated or at least extended.[40]

Other regions worry more about the reliability of the natural gas infrastructure, which could be strained due to significant expected coal-to-gas switching. New York ISO ("NYISO"), for example, describes their current system that uses dual-fuel oil/gas steam EGUs to hedge against potential gas supply shortages.[41] NYISO argues that the EPA's BSER building blocks will reduce the output from these facilities by up to 99%, significantly impacting reliability of providing power to the population-dense region of New York City.[42]

Most regions express an overall concern that uncertainty about state plans could affect the reliability of the electricity grid. Therefore, most of the comments submitted to the EPA by the regional planning organizations request the adoption of a reliability safety valve that can be used as a potential relief mechanism that those involved in the reliable operation of the grid can evoke to adjust/postpone some of their emission targets in emergency situations.[43]

---

37 See 'MISO comments RE: Docket ID No. EPA-HQ-OAR-2013-0602 to the EPA,' November 25, 2014, p. 3. ("MISO, 2014")

38 See Press Release, 'SPP assesses Clean Power Plan, says more time is needed to implement,' October 9, 2014.

39 See 'SPP comments RE: Docket ID No. EPA-HQ-OAR-2013-0602 to the EPA,' December 1, 2014, p. 2. ("SPP, 2014")

40 MISO, 2014, p. 1.

41 See 'Comments of the New York Independent System Operator on the Carbon Pollution Emission Guidelines for Existing Stationary sources: Electric Utility Generating Units,' Docket ID No. EPA-HQ-OAR-2013-0602, p 7. ("NYISO, 2014")

42 Ibid.

43 Eric Wolff, 'ISOs, RTOs agree: EPA must include 'reliability safety valve' in CO2 rule,' SNL Financial, December 4, 2013.

IV. Assessing NERC's Initial Reliability Review

At a high level, NERC is concerned that in the short run existing pipeline capacity constraints could impede gas-fired generation from contributing to both resource adequacy and to integrating increasing levels of VERs and that assumed emissions reductions in Building Blocks 1, 2 and 4 might be overstated so that the CPP would require significant expansion of the use of VER in the longer run, creating reliability challenges and that both could be problematic, individually and in combination.

In this section, we critically discuss NERC's concerns regarding each of the four building blocks. In sum, we conclude that while it may be the case that individual contributions from Building Blocks 1, 2 and 4 could fall short of EPAs assumptions, deviations are likely smaller than NERC suggests. At the same time, the structure of the CPP allows states to use mitigation options beyond the building blocks, mitigating the impact of underachieving under any particular block. However, even if NERC's preliminary assessment were correct and only building block compliance measures were considered, the increased reliance on VERs is unlikely to create significant and unavoidable reliability concerns. We will discuss in this section historical evidence that higher levels of VER penetration have not come at the price of reduced reliability, and will later lay out several technical and operational strategies to integrate the resulting increase in VERs over the next 5 to 15 years without sacrificing reliability (Section IV.B.3).

A. Review of NERC's Building Block Analysis

1. Coal Fleet Heat Rate Improvements

While we have not performed a detailed analysis of the extent to which heat rates could be improved through upgrades and operations practices at individual plants, we do find that, even in the absence of any BSER heat rate improvements at individual units, fleet level heat rate improvements are likely possible due to the potential shift of energy production from less efficient to more efficient coal plants.[44] There may also be other means for reducing emissions rates from coal plants not considered by the EPA in developing BSER.

BSER assumes a 6% reduction in average fleet-wide heat rates relative to 2012 emissions through operational changes and certain plant-level investment. BSER does therefore not reflect fleet-level heat rate effects due to MATS retirements. Table 2 below illustrates the potential decrease in the average fleet-level heat rate for the remaining coal fleet if 50 GW of the least efficient coal

---

[44] For a discussion of the advantages of providing flexibility to achieve emissions rate reductions at the fleet rather than at the individual plant level, see Dallas Burtraw and Matt Woerman, Technology Flexibility and Stringency for Greenhouse Gas Regulations, Resources for the Future, July 2013. Available at: http://www.rff.org/RFF/Documents/RFF-DP-13-24.pdf For example, modeling of a 4% heat rate improvement target applied across the entire coal fleet results in both investments in heat rate improving technology and switching to more efficient coal, as well as natural gas-fired generation (page 20).

plants retire due to current pressures (e.g., MATS and low gas prices), finding that the average heat rate could be reduced by 1.7% due to this affect alone.[45]

While the CPP does not require physical retirement of coal units, the capacity factor of the least efficient coal units could drop significantly as a result of this shift in utilization, whether or not coal-plants retire as a consequence of the CPP. If we assume that the capacity factor of another 50 GW of coal plants drops to (near) zero as a consequence of the assumed BSER re-dispatch, a hypothetical removal of energy production of 100 GW of coal has the potential of improving the average fleet heat rate by 3.1% or approximately half the assumed coal heat rate improvements under BSER.[46]

Table 2
Coal Generator Fleet-wide Heat Rate Change by Retirements and CPP Re-Dispatch

		Weighted Average	
Scenario	**Coal Capacity** *GW*	**Avg. Heat Rate** *Btu/kWh*	**Heat Rate Reduction** *%*
Current Fleet	319	10,360	---
50 GW Retired	269	10,182	**1.7%**
50 GW Retired + 50 GW with CF = 0	269*	10,038	**3.1%**

Source: Ventyx Energy Velocity Suite using the 2014 CEMS dataset. Coal plants with the highest fully loaded heat rates were assumed to retire first.

* EPA's modeling suggests that an additional 50 GW of coal fired capacity may retire. However, since the CPP does not require retirement, we estimate the equivalent effect of 50 GW of coal fired capacity with a capacity factor approaching zero. Therefore, total coal capacity remains unchanged.

The assumption that all of the least efficient units would retire as a result of MATS and that the next least efficient 50GW of coal units would either retire or see their capacity factor drop to near zero provides an upper bound to the potential fleet-level heat rate improvements. In reality, some more efficient units may retire while some less efficient units may not. Nonetheless, our analysis shows that fleet-level effects due to retirements alone could contribute substantially to the coal heat rate improvements assumed under BSER.

---

45 The EPA estimated 50 GW of coal plant retirements occur by 2016 in the Base Case results from their Integrated Planning Model (IPM) in their Regulatory Impact Analysis (RIA) of the proposed rule. Details posted at: http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html

46 Clearly, coal plants with a capacity factor of zero would require significant revenues unrelated to output to avoid retirement. As we discuss below in more detail, the CPP does not require retirements and hence coal plants can continue to contribute to reliability if they are properly compensated for the services they provide. In reality, the capacity factor of the least efficient coal plants may approach zero in cases where such plants are only used during peak demand conditions, i.e. as capacity reserves.

The above analysis assumes only shifts from retiring to non-retiring coal units. Further fleet-wide reductions in average heat rates may occur due to re-dispatch from less efficient to more efficient plants of the remaining coal fleet. This effect would at least partially offset any increases in heat rates caused by more frequent cycling and startups of the remaining coal-fired generation fleet, which NERC has identified as potential drivers of higher heat rates for coal units as their place in the merit order shifts.[47]

Beyond fleet-level heat rate improvements due to both MATS related retirements and re-dispatch from coal to natural gas and among remaining coal plants, there are also some unit-level options for reducing emissions rates from coal plants not considered by the EPA. While not strictly improving heat rates, they could contribute to emissions reductions from existing/remaining coal-fired power plants. The options include altering the fuel mixture burned at primarily coal-fired facilities and identifying opportunities for waste heat recovery and co-generation. Coal generation facilities can reduce emissions by switching to fuel with lower carbon content, including co-firing with biomass,[48] or fuel oil.[49] Coal generation facilities can also improve heat rates through effective use of waste heat or through cogeneration applications. Even though the potential for converting existing covered coal-fired generation to combined heat and power ("CHP") may be limited,[50] there may be individual coal-fired generators already operating in CHP-mode, and additional opportunities for recognizing the greenhouse gas savings of those units have been suggested.[51]

---

47 It is indeed likely that lower fleet-wide capacity factors for coal plants will tend to result in more start-ups and cycling and hence higher fleet-level heat rates. However, how important this effect is will depend on the specific changes of individual plants in the merit order. For example, the most efficient coal plants may see their capacity factor unaffected, with cycling provided by a relatively smaller number of less efficient coal plants.

48 We recognize the ongoing discussions about the impact of biomass co-firing on total greenhouse gas emissions. However, there is some evidence that co-firing with biomass is both an available option and could lead to significant emissions rate reductions (See for example U.S. Department of Energy, Biopower Factsheet, DOE/GO-102000-1055, June 2000, which highlights that 15% co-firing with biomass results in 18% reductions in greenhouse gas emissions).

49 The impact of co-firing with oil would likely be limited, given the cost differential between coal and oil. There are some dual-fuel generators who are contributing to local reliability, notably in New York. These units can use either natural gas or oil, so that fuel switching to oil would increase emissions. However, the effect would likely be small given that oil use would likely be limited to short periods of time when access to natural gas is limited.

50 To convert existing coal-fired generation to CHP would require finding appropriate steam hosts as well as in most cases significant incremental capital investments since existing coal-fired generators are likely designed for optimal electric generating efficiency, which may preclude the production of high quality steam for secondary applications absent significant investments.

51 Comments filed with the EPA by various supporters of CHP suggest that crediting for steam related emissions could be improved and the credit for avoided losses for local electricity production could be increased. (Comments on Proposed Rule, Carbon Pollution Emission Guidelines for Existing

Continued on next page

In sum, we recognize that both the amount and cost of achieving higher plant-level efficiency of coal-fired generation are uncertain. Our analysis suggests that even ignoring any BSER heat rate improvements that could be made at the plant level, other options exist to achieve emission reductions from coal-fired units, including:: a) fleet level heat rate improvements could by themselves lead to average fleet-wide heat rate improvements similar to those assumed by the EPA in developing BSER; and b) options to lower emissions rates not specifically addressed by the EPA, which could partially offset any limitations to efficiency improvements that have been identified.

2. COAL TO GAS SWITCHING

For Building Block 2, NERC claims that there may be insufficient gas pipeline capacity to provide the gas required to replace coal generation with gas generation. In the short term, NERC warns that this could limit the ability to meet emissions rate reductions from coal to gas switching assumed by the EPA under Building Block 2. Also, if those constraints persist, the ability to integrate larger amounts of VERs could be jeopardized. We discuss the second issue in detail in Section IV.B.3. As to the short-term concern, gas pipeline capacity constraints tend to occur during peak gas demand periods so that during most of the year gas pipeline bottlenecks should not constrain switching from coal to gas-fired generation even inside a given state. This means that strategies for relieving potential pipeline capacity constraints do not need to be permanent, year-round solutions, but rather can include flexible solutions employed only during times of peak demand; several such options are explored in Section IV.B.2.

Aside from solutions to the potential bottleneck issue identified by NERC, in reviewing how the EPA calculated the emissions reductions from this building block, we find that the EPA's approach does not capture the significant potential for interstate switching between coal and gas generation that is likely to occur within regional markets. The EPA limited the extent to which coal may be replaced by gas generation to the amount of unused gas generation capacity available within each state.[52] However, as generation facilities operate in regional markets, where a coal plant in one state can be re-dispatched for a gas plant in another state, the EPA estimates of coal-to gas switching available in each state as a basis for developing state-level emissions rate targets likely understate the amount of emissions reductions that could and likely would occur from coal-to-gas switching, especially if states pursued coordinated regional actions. The opportunity for interstate coal-to-gas switching is largest in the northwest where Montana and Utah have

Continued from previous page

Stationary Sources: Electric Utility Generating Units, Docket EPA-HQ-OAR-2013-0602, signed by Paul Cauduro, Director, WADE Cogeneration Industries Council)

52 As stated in Table 1, the EPA assumes that NGCC plants can be re-dispatched up to 70% capacity factors. The extent of re-dispatch considers the current output of both gas and coal capacity within each state.

significant coal generation and limited NGCC capacity.[53] If the same assumptions made by the EPA within each state are applied regionally we find that regional coal-to-gas switching in the northwest could more than double the potential emissions reductions from this building block.[54] While we would not expect complete switching to occur due to transmission constraints between balancing areas, the regional nature of electricity markets provides an opportunity for it if states choose to do so. So while the ability to reach the amounts of coal to gas switching embedded in EPA's Building Block 2 could in individual cases be constrained by insufficient pipeline capacity in some locations, any such issue could be partially offset by increasing regional coal to gas switching to plants that are not pipeline constrained. Also, over the entire compliance period additional pipeline capacity needed to allow significant coal to gas switching, while substantial, is likely smaller than comparable pipeline expansions in the past.[55] We discuss the impact of temporary gas delivery bottlenecks on short-term reliability in more detail in Section IV.B.2.

3. RENEWABLE ENERGY

We find that the renewable capacity that the EPA assumes can or will be built is achievable and, as discussed in detail below, can be integrated while maintaining reliability. In its IRR, NERC questions the methodology used by EPA to calculate BSER targets for renewable energy. However, when discussing reliability implications of this building block, the important consideration is not the underlying methodology, but the final BSER target. In this section, we therefore discuss the renewable energy penetration expected by EPA under BSER.[56] The EPA assumptions result in 2020 renewable generation levels remaining below 20% of total generation

---

53 We included Montana, Idaho, Utah, Nevada, Washington, and Oregon in our regional analysis of the northwest reflecting the Northwest Power Pool sub-region within WECC. See: https://www.wecc.biz/Reliability/2014LAR_MethodsAssumptions.pdf

54 Using the EPA's spreadsheet for calculating the state-specific emissions rate standards, we calculated regional totals based on the states listed above and applied the same formulas for re-dispatching across the region. On a state-by-state basis, coal-to-gas switching as estimated by the EPA results in 13 million metric tons of CO2 emissions reductions. Allowing for regional coal-to-gas switching increases the emissions reductions to 30 million metrics tons, which is 2.4 times more than the state-by-state calculation? The primary cause for this increase is that under state-specific BSER coal-to-gas switching is limited by in-state coal and/or in-state NGCC generation and capacity. BSER for a state with no coal but ample NGCC capacity assumes no coal to gas switching, as does the BSER for a state with coal but no NGCC capacity. However, across the two states combined the same calculation would identify coal to gas switching opportunities, subject to transmission being available.

55 See U.S. Department of Energy, Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector, February 2015.

56 We agree that the EPA's approach for determining renewable capacity potential in each state based on a relatively simple aggregation of state level renewable portfolio standards is too simplistic by ignoring both political drivers behind state RPS goals and substantial definitional differences that make adding state-level RPS goals complicated. Also, a substantial amount of RPS compliance arises from out-of-state renewables, which are not meaningfully accounted for in EPA BSER calculations.

in the majority of states.[57] The maximum renewables penetration of 25% occurs in Maine, which, according to the EPA, already receives 28% of its generation from renewables. Other states have also achieved high levels of renewable penetration; in 2013, the three investor-owned utilities in California served 23% of their retail load with renewable energy.[58]

On average across the U.S., the renewable generation assumed by Building Block 3 represents a 7% overall penetration of renewables in 2020[59] rising to 13% in 2030.[60] NERC claims that other building blocks may not be able to meet their assumed emissions reductions, which may require additional renewable capacity to be installed. We find the impact of such a scenario would be limited. For example, if renewable generation compensates for the lack of coal heat rate improvements, the total U.S. wide average penetration of renewables would need to increase by 3% to 10% in 2020 and to 16% in 2030, using the EPA's methodology. These overall levels of renewable penetration have already been achieved in several states and at least some even have significantly higher 2030 RPS targets.[61]

More specifically, Table 3 below compares the EPA estimate of renewable penetration achievable in 2020 in Building Block 3 with the renewable penetration levels as of 2012 and current RPS requirements in 2020.[62] This table indicates that a majority of states will have a surplus of renewable generation at the start of the compliance period if they meet established RPS targets;

---

57 EPA TSD, GHG Abatement Measures, June 2, 2014, p. 4-27 – 4-28. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

58 California Public Utility Commission, California Renewables Portfolio Standard (RPS), http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm. Although approximately 25% of the renewable generation is from base load geothermal, the remaining renewables serve 17% of the retail load and the amount served by non-geothermal renewables is projected to increase significantly from 2013 to 2016. See: California Public Utility Commission, Renewable Portfolio Standard Quarterly Report: 3rd Quarter 2014, Issued to Legislature October 10, 2014. Available at: http://www.cpuc.ca.gov/NR/rdonlyres/CA15A2A8-234D-4FB4-BE41-05409E8F6316/0/2014Q3RPSReportFinal.pdf

59 As mentioned above, the EPA's modeling of most likely compliance finds a 2020 renewables share of 8%, slightly higher than its BSER assumption.

60 We calculated the national renewable penetration as a percentage of total load, similar to how RPS mandates are structured. EPA Goal Computation, 2014.

61 For example, California is currently exploring an increase of its RPS to 50% by 2030 (See http://www.powermag.com/california-governor-wants-to-raise-states-2030-rps-target-to-50/). Several states have climate goals or legislation requiring an 80% or higher reduction in greenhouse gas emissions by 2050, which would likely require renewables shares significantly in excess of those assumed to contribute to CPP compliance by 2030.

62 This is a simplified high level comparison because the definition of renewables (what qualifies), enforcement (mandatory, voluntary, penalties for not complying, etc.), accounting (preferential treatment for in-state resources or certain types of renewables etc.) and year of effectiveness differ, sometimes significantly by state.

these states will therefore not face any planning or infrastructure constraints because they have ample lead-time to prepare for the build-out of new renewable generation. Only when 2020 BSER renewable penetration levels are not achieved already or 2020 RPS targets fall short of corresponding BSER levels would the introduction of the CPP potentially create a new concern. However, as indicated by the table, these concerns are likely minimal. Given the complexity and variation of today's RPS requirements (all but 16 states have an RPS), we provide only a high level comparison by looking at two cases, one that excludes hydro resources and another that includes hydro resources.[63]

As Table 3 shows, only three states (New Hampshire, North Dakota, and Oklahoma) out of the 34 states with RPS requirements show renewable penetration levels required under BSER in excess of these states' 2020 RPS or current penetration levels if hydro resources are not being considered. When hydro resources are included, four western states (Arizona, Montana, Oregon, and Washington) show renewable penetration levels required by CPP that are higher than the states' RPS in 2020 or current renewable penetration levels. However, the potential shortages of renewable resources for these states are very small and the CPP requirement could be achieved by increasing the renewable penetration levels by 4% or less.[64] Oregon, which requires the largest incremental increase in renewable penetration out of these four states, has an RPS goal to achieve a 25% penetration level by 2025. This goal exceeds the CPP needs and indicates that the CPP requirements can easily be achieved by accelerating (or front-loading) the RPS.[65] Washington, with its proximity to Canada, and abundance in small scale hydro has multiple options.

In the 16 states without RPS requirements, Wyoming, which shows that a 6.4% increase in renewable penetration level is needed to achieve the CPP needs, is the only state where the CPP requirements could potentially be seen as causing a concern. All other states either have a higher penetration level today (Iowa), or a fairly low difference between the CPP needs and existing renewable penetration levels. In most cases the need to increase renewable penetration by 2020 from the 2012 level is less than 3%, smaller than what many states have achieved in recent

---

63 EPA, in its technical document titled "Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units - GHG Abatement Measures" (Docket ID No. EPA-HQ-OAR-2013-0602, available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf), has included estimates of renewable penetration achievable in 2020 in Building Block 3 for both with and without hydro resources.

64 Renewable penetration level here is calculated using the 2012 load by state shown in Table 3. Using 2012 loads will underestimate actual renewable generation relative to RPS assuming future load growth. This is because RPS requires renewable penetration as a percentage of actual load rather than 2012 load.

65 For this simple analysis, we assumed 20% penetration level for 2020 by interpolating Oregon's 25% requirement for 2025.

years.[66] These gaps would be even smaller when a regional approach is taken, as discussed in Section V.[67]

Confirming this general observation, EPA's RIA modeling found that the total renewable generation in 2020 is only slightly greater in the case with the CPP (8%) than the case without the CPP (7%).[68] This indicates that the incremental growth in renewable capacity needed to meet the emissions standards beyond what is already expected is small. This is especially important since NERC raises the concern that significant increases in renewable generation may require a transmission build out that will be challenging due to the constrained timeframe between final approval of SIPs and the beginning of the compliance period in 2020. Since there is limited renewable capacity added due to the CPP relative to the base case in EPA's modeling, building transmission for such levels of renewables should not be a significant issue since transmission planners will already have to plan for similar quantities of renewables in either case and will have sufficient time to do so.[69] Also, there are multiple ongoing projects to build new transmission including merchant high voltage direct current ("HVDC") line specifically designed to allow for more renewable generation.[70] In addition, there are various options to increase transfer capability of existing transmission paths through changes in operation procedures and limited amounts of investments. These options are discussed further in Section IV.B.3.

---

66 The 3% increase is required by 2020, resulting in approximately 0.4% increase per year if spread evenly over the 8 years between 2012 and 2020, or 0.6% per year if spread evenly over the 5 years between 2015 and 2020. By comparison, the Massachusetts RPS for example has been requiring the state to increase its renewable penetration level by 1% per year.

67 The last column of Table 3shows the aggregate regions that we use later in our analysis.

68 EPA Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, June 2014, p. 3-27. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-regulatory-impact-analysis

69 Texas has been expanding its transmission to access more renewable resources. The Competitive Renewable Energy Zones ("CREZ") project is partially completed and will allow increasing Texas wind capacity to 18.5 GW, a 50% increase relative to today. See http://www.texascrezprojects.com/overview.aspx.

70 For example, Clean Line Energy Partners is developing at least five merchant HVDC lines that are designed to increase the ability to deliver renewable energy. The Plains & Eastern Clean Line would allow transporting the electricity of up to 3,500 MW of wind energy from Oklahoma to Tennessee and other states in the Southeast. The current construction timeline suggests a potential completion by 2018, ahead of the beginning of the CPP interim compliance period. See http://www.plainsandeasterncleanline.com/site/page/schedule.

Table 3
State RPS Policies and CPP Compliance Requirements

State	2012 EPA Load Basis (GWh)	2012 EIA Renewable Generation without Hydro (GWh)	2020 RPS Renewable Generation Goal (GWh)	2020 EPA BSER Renewable Generation Goal (GWh)	Shortfall (-) or Surplus (+) Relative to the BSER without Hydro (GWh)	2012 EIA Renewable Generation with Hydro (GWh)	2020 EPA BSER Renewable Generation Goal with Hydro (GWh)	Shortfall (-) or Surplus (+) Relative to the BSER with Hydro (GWh)	Region Name
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Alabama	92,655	2,777	0	4,597	-1,820	10,212	12,032	-1,820	Southeast
Arizona	80,701	1,698	5,649	2,151	3,498	8,415	8,868	-453	Desert Southwest
Arkansas	50,379	1,660	0	2,288	-628	3,858	4,487	-629	MISO/SPP
California	279,029	29,967	92,080	37,968	54,112	56,804	64,805	27,275	California
Colorado	57,717	6,192	17,315	7,845	9,470	7,689	9,343	7,972	Rocky Mountain
Connecticut	31,707	667	6,341	1,071	5,270	979	1,383	4,958	ISO-NE
Delaware	12,384	131	2,198	248	1,950	131	248	1,950	PJM
Florida	237,247	4,524	0	7,490	-2,966	4,675	7,640	-2,965	Southeast
Georgia	140,815	3,279	0	5,428	-2,149	5,515	7,664	-2,149	Southeast
Idaho	25,493	2,515	0	3,186	-671	13,455	14,126	-671	NWPP
Illinois	154,320	8,373	23,210	10,563	12,647	8,484	10,674	12,536	MISO/SPP
Indiana	113,072	3,546	11,307	4,474	6,833	3,980	4,908	6,399	MISO/SPP
Iowa	49,142	14,183	0	8,566	5,618	14,949	9,332	5,617	MISO/SPP
Kansas	43,320	5,253	8,664	7,239	1,425	5,263	7,249	1,415	MISO/SPP
Kentucky	95,736	333	0	551	-218	2,695	2,913	-218	Southeast
Louisiana	91,094	2,430	0	3,349	-919	3,110	4,029	-919	MISO/SPP
Maine	12,429	4,099	1,243	3,612	487	7,832	7,344	488	ISO-NE
Maryland	66,456	898	10,633	1,698	8,935	2,555	3,355	7,278	PJM
Massachusetts	59,467	1,843	8,920	2,962	5,958	2,755	3,875	5,045	ISO-NE
Michigan	112,690	3,785	11,269	4,776	6,493	5,000	5,991	5,278	MISO/SPP
Minnesota	73,094	9,454	21,928	7,889	14,040	10,015	8,450	13,478	MISO/SPP
Mississippi	52,022	1,509	0	2,499	-989	1,509	2,499	-990	Southeast
Missouri	88,626	1,299	8,863	1,638	7,224	2,013	2,353	6,510	MISO/SPP
Montana	14,905	1,262	2,236	1,599	637	12,545	12,882	-337	NWPP
Nebraska	33,143	1,347	0	1,856	-509	2,604	3,113	-509	MISO/SPP
Nevada	37,822	2,969	7,822	3,761	4,060	5,409	6,202	1,620	NWPP
New Hampshire	11,687	1,381	1,227	2,220	-838	2,670	3,509	-839	ISO-NE
New Jersey	80,689	1,281	12,934	2,421	10,512	1,292	2,432	10,502	PJM
New Mexico	24,919	2,574	3,987	3,261	726	2,797	3,484	503	Desert Southwest
New York*	153,914	5,192	11,697	8,344	3,353	29,844	32,997	7,871	New York
North Carolina	137,704	2,704	13,495	4,477	9,018	6,432	8,205	5,290	Southeast
North Dakota	15,822	5,280	1,582	5,460	-180	7,757	7,937	-180	MISO/SPP
Ohio	163,906	1,739	10,228	3,287	6,941	2,153	3,701	6,527	PJM
Oklahoma	63,797	8,521	9,570	11,743	-2,173	9,667	12,888	-3,221	MISO/SPP
Oregon	50,195	7,207	10,039	9,132	907	46,617	48,542	-1,925	NWPP
Pennsylvania	155,577	4,459	10,979	8,430	2,548	6,701	10,672	307	PJM
Rhode Island	8,287	102	1,326	164	1,162	106	168	1,158	ISO-NE
South Carolina	83,622	2,143	0	3,549	-1,405	3,563	4,969	-1,406	Southeast
South Dakota	12,615	2,915	1,262	1,819	1,096	8,896	7,800	1,096	MISO/SPP
Tennessee	103,620	836	0	1,385	-548	9,132	9,681	-549	Southeast
Texas	392,523	34,017	0	46,880	-12,863	34,601	47,464	-12,863	Texas
Utah	31,956	1,100	6,391	1,393	4,998	1,848	2,141	4,250	NWPP
Vermont	-	-	-	-	-	-	-	-	-
Virginia	115,890	2,358	17,384	4,459	12,925	3,402	5,503	11,881	PJM
Washington	99,271	8,214	14,891	10,408	4,483	97,678	99,872	-2,194	NWPP
West Virginia	33,132	1,297	8,283	2,451	5,832	2,728	3,883	4,400	PJM
Wisconsin	73,988	3,223	7,081	4,066	3,014	4,745	5,589	1,492	MISO/SPP
Wyoming	18,246	4,369	0	5,536	-1,167	5,262	6,429	-1,167	Rocky Mountain

Notes: 2012 Penetration numbers based on EIA Renewable generation numbers and EPA estimates are based on the BSER renewable generation numbers. In both cases, the 2012 load numbers provided by the EPA are used as the total load for each state. * New York 2020 RPS projections do not include existing Hydro resources. To calculate column [9], we use RPS data including existing hydro for NY.

Also, if transmission constraints are encountered in some regions, distributed generation, such as distributed solar PV, could provide an alternative until transmission capacity to bring other forms of renewable capacity is built. Given the nature of distributed solar PV technology and developed global supply chains, solar PV and other low- or no emissions distributed generation sources could likely be ramped up rapidly if expected contributions from other renewable sources, such as large scale onshore or offshore wind, cannot be accomplished due to transmission issues. To illustrate the potential dynamics of solar PV deployment, several European countries have been able to rapidly increase annual solar PV installations. Germany's annual solar PV installations, almost all connected to the distribution network, increased from less than 1 GW per year until 2005 to above 7 GW per year by 2010.[71] This demonstrates the ability to ramp up distributed renewable capacity generally not constrained by the absence of transmission infrastructure over a very short timeframe.[72]

Finally, the EPA's approach for calculating the extent to which renewable generation can be deployed in each state to reduce emissions rates does not capture all of the likely renewable generation that is expected to enter the system over the next 15 years. As explained in Table 1 above, the EPA set the BSER target of renewable penetration for the states in each region based on annual growth rates required to meet the simple average of existing RPS mandates within the region. States with 2012 renewable penetration levels below the calculated regional average are expected to increase their generation according to this regional growth rate, such that states with low historical renewable generation will never reach the regional target while states with higher historical renewable generation are expected to reach—but not exceed—the regional target prior to 2029. Renewable generation in excess of the regional average therefore either makes meeting CPP rate targets easier in these higher performing states (since the excess renewable generation offsets BSER emissions reductions in other building blocks) or could contribute to meeting BSER renewable targets in other states if states choose to cooperate.

4. ENERGY EFFICIENCY

Estimating the potential, feasible, or likely contributions of energy efficiency to reducing emissions by curbing demand growth is a complex task. It is made more complex because of the many underlying changes to demand and efficiency of energy use unrelated to policy action and because, unlike power generation, energy efficiency effects are not directly observable. For this reason, a detailed evaluation of the potential for energy efficiency measures to contribute to emissions reductions under the CPP is beyond the scope of this report. However, on balance we do not equally share NERC's concerns that lower than expected gains in energy efficiency are likely. While we agree that EPA's methodology for developing state-by-state targets may be

---

71 See Bundesministerium für Wirtschaft und Energie – Zeitreihen zur Entwicklung der erneuerbaren Energien in Deutschland, August 2014.

72 There is a significant ongoing debate about the costs and reliability and resource adequacy impacts of rapid renewable deployment in Germany and its implications for the United States. For an overview, see Weiss, Solar Energy Support in Germany: A Closer Look, The Brattle Group, July 2014. See also Ebinger, Banks and Schackmann, Transforming the Electricity Portfolio: Lessons from Germany and Japan in Developing Renewable Energy, Energy Security Initiative at Brookings, Policy Brief 14-03, September 2014.

oversimplified and may overstate the potential additional energy efficiency savings in some states or under some programs included in the calculation of BSER, there is also substantial evidence that the BSER as calculated by the EPA omits important potential sources for additional energy efficiency and that certain factors not explicitly considered by the EPA could help increase energy efficiency. These options are ignored by NERC's IRR. We do not claim that achievable emissions reductions through enhanced energy efficiency measures will likely exceed or fall short of the assumptions embedded in the BSER. However, the energy efficiency potential not included or not fully reflected in the BSER could be as large as or larger than the potential shortfalls that have been identified.

More specifically, NERC is concerned with the EPA's assumption that states with a positive track record of energy efficiency will be able to continue to improve energy efficiency at historic high rates. NERC has also been noted that EPA's estimates are based on a single year's worth of estimated efficiency gains and that it is unclear whether single year gains can be sustained over 15 years or longer.[73] All else equal, maintaining higher annual rates of energy efficiency can be argued to become more challenging in states that have pursued aggressive energy efficiency strategies for a while, as "low hanging fruit" opportunities are exhausted. However, there are several factors potentially offsetting this effect. Some are counteracting effects inside energy efficiency measures explicitly part of BSER, while others include effects potentially outside BSER, which would still contribute to energy efficiency gains.[74]

Among factors inside the BSER measures, the following issues should be considered:

1. New technology continuously provides new opportunities for energy savings. For example, significant energy savings from switching from incandescent lighting to compact fluorescent lighting may have provided early "low hanging fruit", but ongoing progress in light emitting diode ("LED') lighting may provide opportunities for similarly large additional energy savings in lighting going forward. Also, the cost of many new energy saving technologies (such as LEDs) continues to decline.

---

73 See U.S. EPA, Technical Support Document: GHG Abatement Measures, pages 133 – 137 and pages 149 to 150. While the EPA did benchmark its 1.5% annual energy efficiency target against other studies, it did ultimately rely on a single year's energy efficiency data even though it had access to a longer time series.

74 To what extent energy efficiency measures can help meet CPP targets may depend to some extent on how states choose to implement the CPP. States have the flexibility to propose measures outside of the BSER building blocks in their SIPs. Also, if states choose converting to mass-based targets, declines in emissions irrespective of their origin could contribute to meeting targets.

2. At least in terms of goals, leading energy efficiency states are maintaining relatively high incremental savings goals, in at least some cases above the rates assumed to be achievable under BSER.[75]

3. Leading energy efficiency states have likely managed to gain experience over time that allows the identification of additional untapped pools of energy efficiency.[76]

4. While states with limited experience with implementing energy efficiency measures likely have an experience gap, those states could learn quickly from the experience of leading states and potentially ramp up their energy efficiency savings relatively rapidly, especially since significant "low hanging fruit" likely remains uncollected. Energy efficiency programs run by utilities have been increased rapidly, suggesting that the ability to ramp up energy efficiency efforts will likely not be significantly constrained by the organizational capacity to expand energy efficiency programs.[77] The existence and maturing of consultancies engaged in operating utility energy efficiency programs and firms implementing efficiency solutions in the field on a national scale will allow states historically "underperforming" states to ramp up their efforts rapidly.

There are also several potential contributors to energy efficiency gains not included in BSER. The assumptions in Building Block 4 are limited to the effect of utility efficiency programs. However, a significant portion of end-use efficiency improvements occur outside and independent of utility efficiency programs.[78] Continuously evolving building codes and appliance standards, as well as private sector energy efficiency efforts outside of utility programs, such as those conducted by Energy Service Companies ("ESCOs") and other companies implementing energy efficiency solutions can continue to deliver energy efficiency progress.[79] For example, as of 2013, the

---

75 For example, the Massachusetts utilities' energy efficiency plans targeted efficiency gains of 1.0% in 2009, increasing to 2.4% by 2012. In their second three-year plan, annual efficiency targets have been further increased to 2.6% by 2015 (See www.aceee.org)

76 This experience related effect is difficult to demonstrate empirically, but could be one explanation why leading states in terms of energy efficiency have been able to maintain or increase their energy efficiency targets.

77 Between 2006 and 2011, utility spending on electricity efficiency programs increased from $1.9 billion per year to $7.2 billion per year, an almost four-fold increase in five years (Bloomberg New Energy Finance and The Business Council for Sustainable Energy, Sustainable Energy in America 2013 Factbook, January 2013 revised July 2013, Figure 86).

78 See for example Steven Nadel and Rachel Young, Why Is Electricity Use No Longer Growing? February 2014, page 6, which cites evidence that utility programs can explain between approximately 30% and 40% of total reductions in residential electricity demand between 2007 and 2012.

79 In 2012, non-utility ESCO spending on energy efficiency was approximately equal to utility spending (Bloomberg New Energy Finance and The Business Council for Sustainable Energy, Sustainable Energy in America 2014 Factbook, PowerPoint presentation, page 12)

percentage of U.S. floor space covered by any kind of state or local building benchmarking was around 7%. Even though it is not clear that all cost effective energy efficiency measures have been implemented on those 7%, this indicates that large opportunities likely remain.[80]

Since these non-utility programs represent roughly 50% of total energy efficiency spending[81] and are not reflected in BSER, their contribution could partially or fully compensate – or even exceed- any shortfalls of utility programs assumed to be achievable under BSER.[82]

Finally, due to the constraint of having to derive emissions rate targets for each state, the EPA likely underestimates the potential for energy efficiency improvements to contribute to emissions reductions. This is because EPA's formula for calculating the contribution of Building Block 4 to the BSER limits energy efficiency to in-state emissions. A state that reduces end-use consumption by 10% gets credit for a 10% reduction in in-state emissions. If a state imports power from other states, the EPA gives no credit for the emissions reductions that would occur in the exporting states as a consequence of these efficiency measures. This result depends critically on the need for the EPA to derive state-level targets. At the regional or national level, it understates the impact of energy efficiency measures on total emissions. We estimate that this simplification limits the extent to which energy efficiency reduces states standards by approximately 10%, such that the approach the EPA implemented more closely represents an annual growth of 1.3%.[83] While it is unclear how the final CPP will address this issue in a rate-based standard setting, converting to a mass-based standard in combination with multi-state collaboration would create emissions reductions above those that EPA has used to develop the BSER.

On balance we therefore do not share NERC's concerns that lower than expected gains in energy efficiency are likely. Even though there are risks to fall short of the energy efficiency gains assumed under BSER in some areas, there are also opportunities to exceed the savings assumed under BSER in other areas. In addition, significant additional energy efficiency gains outside the

---

80 Ibid, page 13.

81 Ibid, page 13.

82 It is not entirely clear how much energy efficiency improvements independent of utility programs are embedded in the business as usual forecast developed by the Energy Information Administration and used by the EPA to develop BSER. In general EIA includes existing programs in its projections. These would include changes to building and appliance codes either already in effect or passed into law, even if they come into effect in the future. It is clear however that non-utility programs can be used to meet CPP targets (if properly verified). See U.S. EPA, Technical Source Document: GHG Abatement Measures, page 5-31.

83 We calculated the additional potential for energy efficiency to reduce emissions on imports based on the unaccounted for energy efficiency in the spreadsheet the EPA provided for calculating state-by-state goals, available at: http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-state-goal-data-computation_1.xlsx Although we just report the sustained annual growth rate here, the initial ramp-up rate of 0.2% per year would also be proportionally lower.

measures considered under BSER exist and those measures could more than offset any shortfall of energy efficiency progress under utility programs,

B. Review of NERC's Reliability Concerns

We generally agree with NERC that changes in the electric power generation mix that lower CO_2 emissions due to the CPP will affect how reliability is maintained and that further modeling of the power system will continue to be necessary to properly manage any potential reliability impacts.[84] Ensuring reliability will, and should, remain the primary focus of the planning and operation of the electric power system.

However, the changes required to comply with the CPP will not occur in a vacuum—rather, they will be met with careful consideration and a measured response by market regulators, operators, and participants. We find that in its review NERC fails to adequately account for the extent to which the potential reliability issues it raises are already being addressed or can be addressed through planning and operations processes as well as through technical advancements.

We directly address NERC's reliability concerns in the following sections.

1. CPP Unlikely to Force Declines in Reserve Margins Below Requirements

NERC states that "developing suitable replacement generation resources to maintain adequate reserve margins levels may represent a significant reliability challenge, given the constrained time period."[85] To support its concern, NERC highlights the trend in tightening reserve margins in its recent Long Term Reliability Assessments and the additional coal retirements in the EPA's modeling of the CPP. As noted by NERC, the EPA modeling resulted in an additional 21 GW of new NGCC capacity being developed to compensate for the retirements and maintain resource adequacy. However, NERC remains concerned that such an amount of new capacity may be difficult to build under a constrained timeframe. In the regional comments, SPP and MISO in particular were concerned about the CPP resulting in lower reserve margins than they have historically maintained.[86] NYISO noted that maintaining oil and gas steam units necessary for reliability purposes within New York City may be challenging due to the reduced output assumed by the BSER.[87]

---

84 NERC's first two General Recommendations are "NERC should continue to access the reliability implications of the proposed CPP" and "Coordinated regional and multi-regional industry planning and analysis groups should immediately begin detailed system evaluations to identify areas of concern." NERC, 2014, p. 3.

85 Ibid, p. 2.

86 SPP, 2014 and MISO, 2014.

87 NYISO, 2014.

We find that the concern raised by NERC and the RTOs/ISOs is likely overstated for the following reasons:

1. Although generation from higher CO_2 emitting generation resources, such as coal plants, is likely to decline due to the CPP, retirements will depend on whether there are sufficient total revenues for a plant to remain profitable and whether other resources can provide capacity at lower cost.
2. There is currently significant excess capacity in some regions so that retiring capacity will not need to be replaced with an equal quantity of capacity from other capacity resources.
3. Regions with capacity markets have shown that many types of capacity resources can be added to the system in response to significant coal plant retirements due to environmental regulations (e.g., MATS), including resources that can be constructed and commissioned in less than two years.
4. If a large number of coal plants will ultimately retire but other resources cannot come online to replace their capacity quickly, those coal plants can be maintained on a capacity-only basis with minimal energy dispatch for a transition period of a few years until replacement capacity can be developed. Existing capacity market and IRP mechanisms will enforce that the reserve margin requirement is maintained through this transition.
5. States that choose to comply on their own will have at least two and a half years prior to the beginning of the compliance period to ensure sufficient capacity resources are available, which is sufficient time for several types of capacity resources such as combustion turbines, demand response, and energy efficiency to be developed.
6. Although states that choose to comply through regional cooperation may have less time to respond to retirement announcements, they will have additional flexibility in meeting its targets through cooperation with states that are able to achieve near-term standards more easily.
7. In many regions, system operators can offer out of market payments to facilities needed for resource adequacy (or shorter term reliability) purposes if market revenues are insufficient to prevent retirement. Reliable Must Run ("RMR") contracts are one option widely used as a temporary measure.
8. The existing planning processes for developing the necessary infrastructure are expected to be sufficient to ensure reserve margins are maintained in the later years of the compliance period.

In discussing resource adequacy issues, it is important for policymakers to understand that generation facilities serve two purposes: they generate *energy* to meet hourly load throughout the year and *capacity* to meet the annual peak load. The CPP is intended to shift *energy generation* towards lower emitting resources. As coal plants produce the most CO_2 emissions per unit of electricity generated, the CPP will likely result in reduced generation from coal plants and replace it with generation from lower emitting resources, such as natural gas-fired plants, renewables, and energy efficiency.

However, decisions on whether to retire coal-fired *capacity* do not depend solely on the hours of operation for each plant and the revenues received from generating energy; rather, retirement decisions depend on whether there are sufficient total revenues for a plant to remain profitable. While the most efficient coal plants are expected to remain in operation with the CPP and provide fairly cheap capacity, less efficient coal plants (many of which are already under pressure to retire due to sustained low natural gas prices and other environmental regulations) may be at risk for retirement if their production and energy revenues are decreased significantly. Whether inefficient coal plants retire will depend on whether other capacity resources can provide capacity at lower cost.

Historically, older fossil fuel-fired generation plants have maintained operations for capacity purposes despite only operating for a limited number of hours. For example, in 2012 there was over 15 GW of oil/gas steam turbine operating capacity in California with an average capacity factor of 8% and 10 GW in New York with an average capacity factor of 12%.[88] Further reduced output of oil/gas steam units in New York City, as noted by NYISO, may put additional pressure on the plants to retire, but similar to coal plants they would only be expected to do so if lower cost capacity solutions become available.[89]

The need to meet reserve margin requirements under the CPP tends to be an *economic* question rather than a reliability concern as NERC has framed it.[90] While there are may be additional costs imposed to maintain reserve margins in the near term as CPP is implemented, we do not view these as material risks to system reserve margins. If a coal plant's energy dispatch is reduced so materially that is no longer an economic supply resource, then there are many alternative ways

---

88 The oil/gas steam turbine capacity and capacity factor in California and New York were calculated using data provided by the EPA in the Clean Power Plan Technical Support Document Data File: 2012 Unit-Level Data Using the eGRID Methodology, available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents The national average capacity factor for oil/gas steam units is 11%. The EPA assumes that the annual fixed costs of oil/gas steam capacity is $32/kW-year, which is lower than the corresponding value for a typical coal plant.

89 NYISO, 2014.

90 In some cases, retirements may be seen to create local reliability issues and lead to the need for additional transmission facilities. These local reliability issues, should they occur, could potentially lead to local capacity requirements, or the creation of a new reserve margin zone. However, as discussed later in this section, many of these local issues can be avoided through the various operational options to increase the transfer capability of the existing transmission system without large capital investments.

to meet the reserve margin by retiring without replacement, replacing the resource with an alternative supply resource, drawing on capacity resources from neighboring regions, or maintaining the coal plant on a capacity-only basis for an interim period until replacements can come online.

It is also important to contrast the relative flexibility of the CPP with the more stringent plant-specific nature of other regulations such as MATS, which required each individual plant to comply or retire by a specific date. Under MATS, localized reliability concerns such as needing a specific plant for local transmission stability or voltage support could materialize if the specific retirement is not known sufficiently in advance to identify an alternative solution. In contrast under the CPP, no specific plant needs to retire at any given time. In that case, plant retirements can be delayed if necessary for months or years while alternative means of meeting the CPP requirements through additional fuel switching, EE, RE, or regional cooperation are pursued in the interim.

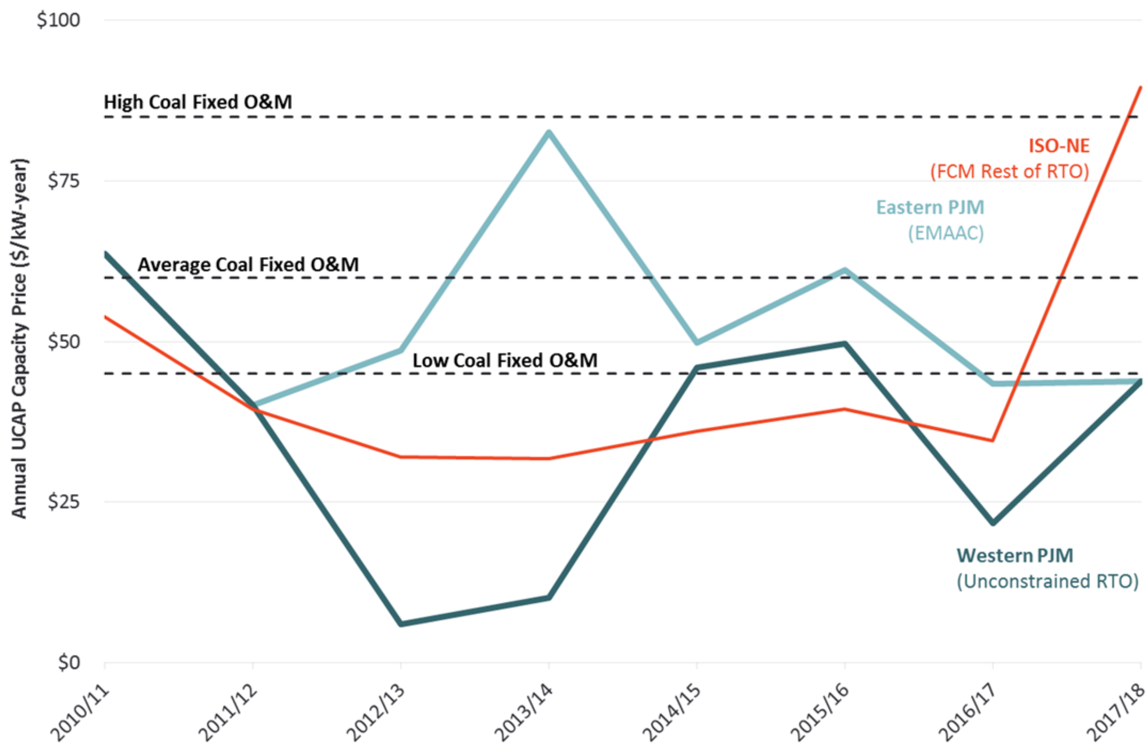
Capacity prices in the northeast and mid-Atlantic capacity markets provide an indication of the value of capacity and a point of comparison with the annual costs of maintaining operations of coal plants. Figure 5 shows recent capacity market prices in PJM, the largest electricity market in the U.S., and ISO New England ("ISO-NE") against coal plants fixed operation and maintenance costs. Comparing the coal plant costs to the potential capacity revenues, we find that the lowest cost coal units are likely to remain valuable capacity resources even if energy margins significantly decline, while higher cost plants remain viable only if energy margins are able to keep the plants profitable or capacity prices rise (if, for example, lower cost alternatives are not available going forward).[91] The majority of existing coal generation facilities is projected to have going-forward fixed operation and maintenance (O&M) costs between $45 and $85 per kilowatt-year with the average close to $60/kW-year.[92]

---

91 The 2013 PJM State of the Market Report finds that in 2013 the average sub-critical coal plant earned $30/kW-year and the average super critical coal plant earned $55/kW-year. Monitoring Analytics, LLC., State of the Market Report for PJM, Volume II, March 13, 2014, p. 231. ("Monitoring Analytics, 2014")

92 EPA Analysis of Clean Power Plan, IPM Run Files: EPA Base Case for the proposed Clean Power Plan, RPE Report, June 2, 2014. Available at: http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html

Figure 5
Coal Fixed O&M Costs versus Recent Capacity Market Prices



Source and notes: ISO-NE and PJM market prices are based on auction results posted on their respective websites. Coal plant fixed O&M costs are based on EPA assumptions in its RIA modeling. Coal plant energy margins, which in 2013 were on average $30/kW-year for sub-critical units and $55/kW-year for supercritical units, reduce the capacity revenues required for coal plants to remain financially viable. (Monitoring Analytics, 2014)

Since many regions of the U.S. still experience non-trivial levels of excess capacity, coal-plant retirements (should they occur) by themselves do not automatically require new capacity to be added to the system to maintain reserve margins.[93] Regions that remain at or above its required reserve margin after accounting for retirements will not be impacted; regions that currently have excess capacity will not need to replace all of the retired capacity to maintain its reserve margin.

For example, in the 2014 NERC Long-Term Reliability Assessment, SPP is projected to see a decline in its reserve margin over the next decade from the current level of over 35% to approximately 20% in 2022 without considering the CPP.[94] With a target reserve margin of 13.6%, SPP would not need to replace all of the capacity that may retire due to the CPP to maintain its reserve margin. While lower reserve margins do increase the probability of loss of load, as suggested by MISO, RTOs set their reserve margin requirement to meet an acceptable

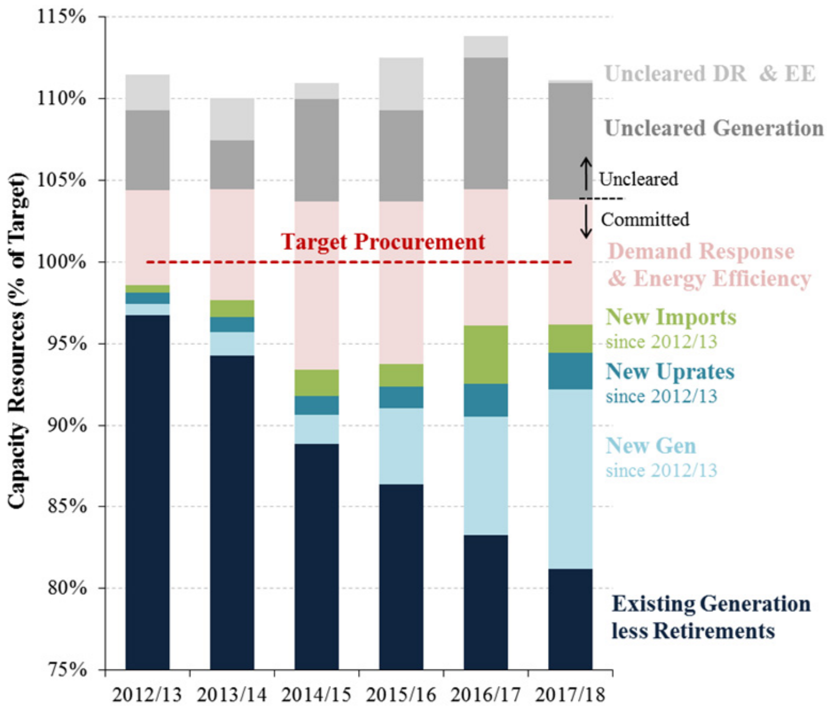
---

93 NERC, 2014 Long-Term Reliability Assessment, November 2014, available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf, p. 4.

94 Ibid, p. 82.

loss of load expectation ("LOLE").[95] Declining reserve margins will increase LOLE only up to the standard that is used to establish its requirement.[96] If RTOs wish to ensure that they achieve a higher level of reliability, then a higher reserve margin requirement would be needed regardless of whether or how CPP is implemented.

Figure 6
New Resources Cleared in PJM Capacity Market since 2012/2013



Source: PJM, RPM Auction User Information, available at: http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx. The data is from the Base Residual Auction results for each delivery year.

For coal-fired capacity that does retire and require replacement, recent experience with capacity markets demonstrates how significant coal-fired capacity retirements have led other capacity resources to enter the market to maintain adequate reserve margins. Figure 6 shows the resources that cleared in the past six PJM capacity auctions. Over this time more than 28 GW of coal plants

---

95 For example, in its comments MISO noted that they expect "resource availability will remain close to the planning reserve margin for the foreseeable future. This erosion of the reserve margin increases the likelihood that MISO will need to manage high electricity demand situations by use of emergency operation procedures. The probability of a loss of load event becomes greater than the MISO region has ever experienced." MISO, 2014, p. 3.

96 The most common LOLE standard used for setting reserve margin targets and requirements is the 1-in-10 standard, which targets sufficient capacity for just one hour in ten years in which load cannot be met.

retired.[97] This demonstrates how the gap between existing generation (dark blue bar) and the targeted level of procurement (red line) has been filled by new capacity resources over this time. The new capacity resources include both new generation resources, including new plants and uprates of existing plants, and new load resources, including demand response and energy efficiency.

Demand response ("DR") and energy efficiency ("EE") have on average accounted for 8% of the total capacity procured in PJM during this time, or approximately 12 GW of capacity.[98] In New England, DR and EE has accounted for 9% of capacity resources (3 GW) over the past three capacity auctions.[99] While DR and EE capacity tends to be lower in regions without capacity markets, a Federal Energy Regulatory Commission ("FERC") assessment of the potential for growth of DR resources projected that with "achievable participation" up to 138 GW of DR capacity could be developed, or 14% of total U.S. peak load.[100]

Demand-side capacity resources like DR and EE are therefore expected to play an important role in maintaining resource adequacy in the future if coal plant profitability is threatened by the CPP changes and provide an alternative to adding new generation facilities, which tend to require longer time periods to be developed.[101] States that submit single-state SIPs for complying with the CPP will have at least two and a half years (30 months) between the time when their plans are finalized and when the compliance period begins in 2020. Several types of capacity resources can likely be added in that timeframe to maintain reserve margins. Natural gas-fired combustion turbine capacity can be constructed and commissioned in less than two years.[102]

---

97 http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-base-residual-auction-report.ashx, Table 7.

98 PJM, RPM Offers and Commitments by Fuel Type, dated May 29, 2014, available at: http://pjm.com/~/media/markets-ops/rpm/rpm-auction-info/rpm-commitment-by-fuel-type-by-dy.ashx

99 ISO-NE, FCM Auction Results, available at: http://iso-ne.com/isoexpress/web/reports/auctions/-/tree/fcm-auction-results The percentage of EE and DR was calculated for the past three auctions based on the Auction Results published by ISO-NE for the past three auctions.

100 FERC, 2009 National Assessment of Demand Response Potential, Staff Report, June 2009. Available at: https://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf

101 There is a risk of DR not being able to participate as fully in wholesale markets pending the current review by the U.S. Supreme Court of FERC Order 745 on *EPSA v. FERC.* This discussion of DR assumes that states and RTOs will identify alternative mechanisms to maintain DR capacity commitments even if some historical mechanisms become infeasible.

102 The time required for adding new, green field combustion turbine facilities is assumed to be 20 months in the recent cost of new entry studies completed for PJM and ISO-NE. See: http://www.brattle.com/system/publications/pdfs/000/005/010/original/Cost_of_New_Entry_Estimates_for_Combustion_Turbine_and_Combined_Cycle_Plants_in_PJM.pdf Early stage development often requires additional time however many projects are developed in preparation of need and can quickly begin construction if there is a sufficient economic signal to do so.

Demand response and EE can also be installed within this timeframe, with a new portfolio of DR resources expected to take 4 months to 18 months to develop depending on the extent to which DR aggregators have existing capabilities in a given region.[103]

New energy storage technologies are also starting to play a role in meeting capacity requirements. In 2013 the California Public Utility Commission mandated that its investor owned utilities procure 1,315 MW of storage capacity by 2020.[104] In a recent procurement for capacity resources, Southern California Edison selected 262 MW of storage capacity including battery and thermal storage technologies.[105] In Texas, an Oncor proposal suggested installing up to 5,000 MW of distributed battery storage capacity state-wide beginning in 2018.[106] Due to its relatively shorter installation period, battery capacity could potentially provide another alternative capacity resource if its costs continue to decrease.

States that may face potential resource adequacy issues in the first few years of the compliance period due to coal plant retirements can benefit considerably from the flexibility provided by the CPP through regional cooperation. Even though many types of capacity resources (such as DR, EE and storage) can likely be deployed in the shorter time period (18 months) between when multi-region SIPs will be finalized and the beginning of the compliance period, a lower cost near-term compliance approach may be to cooperate with other states.

In cases where plants facing retirement risks are necessary to maintain reliability, either for providing capacity, for meeting reserve margins or an essential reliability service such as voltage support, system operators will often offer contracts for the plants to remain in operation until a lower cost alternative is identified. The contracts are often termed as reliability must run or RMR contracts. Such contracts are generally offered on a short term basis and are meant to provide a temporary solution to remaining reliability. For example, the California ISO offered AES' Huntington Beach Generation Station a RMR contract for the 2013 and 2014 contract years to provide voltage support following the retirement of the San Onofre Nuclear Generation Station.[107]

---

103 The estimate of 4 to 18 months is based on our previous experience evaluating demand response resources and input from DR developers.

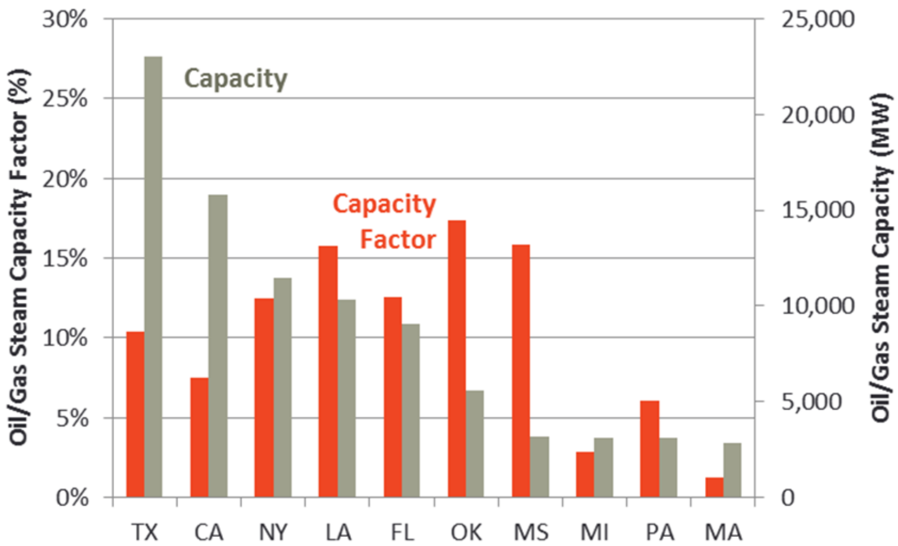
104 http://www.cpuc.ca.gov/PUC/energy/electric/storage.htm

105 https://www.sce.com/wps/portal/home/procurement/solicitation/lcr

106 http://www.dallasnews.com/business/energy/20141108-oncor-proposes-giant-leap-for-grid-batteries.ece

107 http://www.caiso.com/Documents/Apr12_2013_InformationalFiling-ReliabilityMust-RunAgreement-AESHuntingtonBeachER13-351.pdf

Figure 7
Oil/Gas Steam Capacity Factors and Capacity



Source: EPA, Technical Support Document Data File: 2012 Unit-Level Data Using the eGRID Methodology, June 2014. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents

As mentioned above, existing fossil fuel-fired generation facilities can continue to provide capacity to the system despite a relatively few hours of operation. Figure 7 shows the ten states with the most oil/gas steam capacity and the capacity factors of the plants in those states. The capacity factors of 1 – 17% are similar to simple cycle combustion turbines, operating mostly to meet peak load during only a few hours per year. As this figures show, substantial generation capacity provides energy and capacity at very low annual capacity factors. This implies that even if the CPP were to lead to significant reductions in the capacity factors of coal- or oil-fired power plants, this does not mean that their capacity could not be available to provide reserves and thus help maintain reliability and resource adequacy.

2. Gas Constraints May Increase, But Unlikely to Introduce Reliability Concerns

NERC claims in its IRR that the BSER will "accelerate the ongoing shift towards greater use of natural-gas-fired generation and VERs."[108] NERC is concerned that reliability issues may occur if "pipeline constraints and growing gas and electric interdependency challenges impede the electric industry's ability to obtain needed natural gas service, especially during high-use horizons."[109] Individual states and utilities have expressed more urgent concern about gas

[108] NERC, 2014, p. 2.

[109] Ibid.

pipeline constraints. In their comments, Dominion notes a similar challenge of maintaining reliability with additional natural gas capacity, which they term as "just-in-time" resources.[110]

Natural gas generation has increased significantly in recent years due to low prices and the development of new natural gas capacity across the country.[111] We agree that additional natural gas pipeline capacity may need to be built to provide sufficient capacity as the amount of generation continues to grow and that additional analysis will be necessary to understand how a combination of coal retirements and cold weather could introduce additional constraints and test the system. However, we believe that many of the issues noted by NERC are already being resolved in response to the increased reliance on natural gas generation over the past several years as well as the polar vortex of 2014.[112] Other approaches for managing short-term gas supply constraints are also available for limiting the potential for reliability impacts. More importantly, since gas-supply bottlenecks tend to occur during a limited number of days, they are unlikely to significantly impede the ability to switch average energy production over the course of the year from coal to natural-gas fired power generation, even in the near term before new pipeline developments are completed. During periods of peak natural gas demand, short-term solutions are available to compensate for possible constraints early in the compliance period.

Gas-electric coordination issues tend to focus on gas pipeline capacity shortages, leading to generators not being supplied with fuel during periods of peak, non-electric gas usage. This issue arises since gas pipelines have historically not been developed based on the fuel needs of the power system. Instead, most of the existing gas pipeline infrastructure is built based on the demand from local gas distribution companies and primarily used to meet heating related demand. As a result, most of the firm pipeline capacity today is not available for gas fired power generation, which instead tends to rely on non-firm capacity. The relatively low utilization of gas generation historically combined with an electricity market that focuses on short term marginal costs have also discouraged gas-fired generation from seeking long term firm pipeline contracts. There is evidence that natural gas generation is more likely to seek firm gas contracts on pipelines in which fuel supply is unreliable.[113] Furthermore, the switch from coal to gas

---

110 Dominion Resources Services, Inc., Re: Comments to the Environmental Protection Agency on the Carbon Pollution Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rules (79 Fed. Reg. 34830; June 18, 2014), Docket ID No. EPA-HQ-OAR-2013-0602, November 25, 2014.

111 Natural gas generation increased from 19% of total generation in 2002 to 30% in 2012. EIA, Annual Energy Outlook 2014, April 2014, MT-16.

112 For a discussion of the responses of ISO New England to gas supply shortages during cold winter events, see Mark Babula and Kevin Petak, The Cold Truth: Managing Gas-Electric Integration: The ISO New England Experience, IEEE power and energy magazine, November/December 2014

113 For example, new combined cycle plants in PJM's SWMAAC region are expected to sign firm gas transportation service contracts due to operational issues created for such facilities that rely on natural gas supply from the existing pipeline without a contract. Newell, et al., Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM with June 1, 2018 Online Date, Prepared

Continued on next page

generation will increase the utilization of gas units (the IRR does not suggest that a 70% capacity factor for NGCCs is not achievable, but emphasizes instead that NGCCs have traditionally been used as cycling units).[114] Increased capacity factors should entice at least some gas generation owners to sign long term firm pipeline contracts.

Development of gas pipelines has already increased to support the growth of natural gas production from shale formations and demand by power generation. The current investment trend shows that with proper market signals and adequate lead time the pipeline industry could accommodate the increased gas demand projected under the CPP. For example, there are currently several new pipelines proposed in New England that will increase capacity into the region.[115] The Interstate Natural Gas Association of America expressed confidence that the industry would be able to respond to increased demand if the CPP necessitates additional pipeline capacity.[116] On the other hand, the Natural Gas Supply Association has emphasized the importance of structural barriers that inhibit the construction of new gas pipelines, including the limited interest from gas generation plants to sign long term contracts mentioned above.[117] A study just released by the Department of Energy also concludes that the challenges of building additional natural gas pipeline infrastructure are manageable and, due to the increased geographic diversity of natural gas resources, less significant than historic gas pipeline expansion.[118]

The typical timeline for developing a new gas pipeline is approximately three to five years, and therefore gas shortages are likely avoidable in the longer term if proper incentives for building pipelines to support natural gas generation are in place.

In the short run, market rules are changing to account for the possibility of real-time gas shortages in regions that are expected to be particularly tight, especially during cold weather. For overcoming the issues with increasing dependence on natural gas capacity, ISO-NE developed

Continued from previous page

for PJM Interconnection, May 15, 2014, p. 14. Available at: http://www.brattle.com/system/publications/pdfs/000/005/010/original/Cost_of_New_Entry_Estimates_for_Combustion_Turbine_and_Combined_Cycle_Plants_in_PJM.pdf

114 NERC, 2014, p. 9. Also, others have pointed out that there are no technical limits to operating NGCCs at 70% capacity factor. The average U.S. fleet wide capacity factor represents a wide range of capacity factors among more and less efficient NGCCs. See for example http://www.rff.org/centers/energy_and_climate_economics/Pages/3-Utilization-of-Natural-Gas.aspx

115 Spectra Energy is developing the Algonquin Incremental Market and Atlantic Bridge pipelines to increase capacity into New England. See: http://www.spectraenergy.com/Operations/New-Projects-and-Our-Process/New-Projects-in-U.S./Atlantic-Bridge/

116 Sarah Smith, "Pipe industry can respond to Clean Power Plan gas needs, groups say," SNL Financial, December 3, 2014.

117 Ibid.

118 U.S. Department of Energy, Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector, February 2015.

market-based performance incentives, called Pay for Performance, in its market rules, which award facilities that operate during scarcity events and penalizes those that do not.[119] By doing so, ISO-NE is not mandating any single approach for ensuring capacity but allowing for the owners of natural gas-fired capacity, as well as all other resources, to identify the lowest cost approaches to ensuring their availability, including among other options the addition of dual fuel capability.

While issues around natural gas dependence have been a concern in New England for a while, the cold weather caused by the 2014 polar vortex led to similar concerns in other markets. Over the past year, PJM adjusted its own market rules to institute an approach similar to what the ISO-NE developed to provide the proper incentives for ensuring future availability of gas-fired capacity.[120]

In addition to changing market rules there are also several technology options to address short-term limits of natural gas deliveries to gas-fired power generators. These technology options will allow system operators to have increased flexibility in dispatch (and not rely too much on certain select units), leading to a lower probability of real-time gas supply shortage. This section discusses other options available to address the potential gas supply shortage issue.

Use of Existing LNG and Natural Gas Storage Options

Prior to the shale gas boom significant investments were made in infrastructure to support the import of liquefied natural gas ("LNG"). This infrastructure can deliver additional gas supplies to at least some of the potentially supply-constrained regions such as New England.[121] In addition, existing natural gas storage capacity exists and could potentially be used more efficiently to supply natural gas to power generators during short durations, when gas shortage has reliability impacts.

Gas Demand Response

While *electric demand response* has recently gained substantial visibility as a likely key future component of a more flexible electricity system, the notion that there may also be significant latent flexibility in demand for gas, in particular from outside the electricity sector, is just beginning to be discussed.[122] The most established form of *gas demand response* is the use of

---

119 For information on the ISO-NE Forward Capacity Market Performance Incentives see: http://www.iso-ne.com/committees/key-projects/fcm-performance-incentives

120 For information on the PJM Capacity Performance proposal, see: http://pjm.com/~/media/documents/reports/20141007-pjm-capacity-performance-proposal.ashx

121 See ICF, Options for Serving New England Gas Demand, prepared for GdF Suez Gas North America, October 22, 2013, which concludes that for gas supply constraint periods of 30 days or less, the use of LNG may be more cost effective than the construction of additional pipeline capacity.

122 See for example Faruqui and Weiss, Gas Demand Response, SPARK, available at: http://spark.fortnightly.com/fortnightly/gas-demand-response. See also Jaquelin Cochran, Owen

Continued on next page

interruptible contracts with industrial customers, which have existed for some time in New York and typically involves switching to a back-up fuel.[123] Industrial gas demand may be the easiest source of incremental gas demand response, but there are at least two additional sources. With low gas prices and concerns about greenhouse gas (and other) emissions more broadly, there has been an increase in compressed natural gas ("CNG") fueled transportation fleets. The operator of these fleets have significant demand for natural gas, but also significant potential for flexibility of demand given that CNG can be stored onsite. In addition, with the advent of smart thermostats, the residential sector emerging as a potential target for temporary reductions in gas demand during periods of tight gas supply for the power sector. Some gas demand response options, such as the increased use of interruptible gas supply contracts with industrial customers, could be implemented in a relatively short time frame and could thus contribute to mitigating short-term concerns about gas supply shortages. Others will require more time to be developed and hence will likely only contribute to mitigating longer-term concerns.[124]

3. Increased Variable Energy Resources Unlikely to Cause Operational Reliability Challenges

NERC's IRR indicates that renewable generation, especially wind and solar capacity, may increase significantly under the assumed state-by-state increases in the BSER.[125] Further, NERC states that an "increased reliance on VERs can significantly impact reliability operations and requires more transmission and adequate ERSs to maintain reliability." In addition to these issues, NERC is concerned that if other sources of emissions reductions are unable to meet their targeted goals in the BSER, additional VERs may need to enter the system.

We find that NERC's concerns related to integration challenges caused by the growth of renewables are exaggerated for two reasons. First, as indicated in our discussion of Building Block 3 in Section IV.A.3., many states already have RPS mandates that are higher than what would be required to comply with the CPP. Therefore the introduction of the CPP will not lead to any new concerns about higher renewable penetration levels and in these states renewable generation will reduce the need for other emission reductions to meet their goals.[126]

Continued from previous page

Zinaman, Jeffrey Logan, and Doug Arent, Exploring the Potential Business Case for Synergies Between Natural Gas and Renewable Energy, NREL, February 2014.

123 Kathreen Tweed, Enernoc moves into natural gas demand response, April 18, 2012, available at: http://www.greentechmedia.com/articles/read/enernoc-moves-into-demand-response-for-natural-gas.

124 For a summary of issues discussed during a gas demand response workshop, see http://www.brattle.com/system/news/pdfs/000/000/667/original/Gas_DR_Summit_2014.pdf

125 NERC, 2014, p. 25.

126 Alternatively, if states choose to cooperate on CPP compliance, renewable energy generation above BSER requirements in one state can also help achieve CPP compliance in other states.

The costs of integrating renewable generation while maintaining reliability have recently been found to be relatively modest. For example, Electric Reliability Council of Texas ("ERCOT") notes that the integration of 11,000 MW in its system (or 11% of total generation) has required a "minimal increase" in ancillary services due to the introduction of its nodal market with 5-minute dispatch.[127] The National Renewable Energy Laboratory ("NREL") Western Wind and Solar Integration Study Phase 2 studied three scenarios with 33% renewables and found that the additional costs to the system of cycling fossil plants in response to intermittent output is $0.14 – 0.67 per MWh of renewable generation.[128] The study finds that the system-wide cycling costs per MWh of renewable generation tend to decline with increased renewable generation.[129]

Looking further ahead, several states are likely to exceed the EPA's assumed renewable growth values over the next several years, including California which, independently of the CPP, is on track to reach its RPS target of 33% renewables by 2020.[130] Renewable integration studies of the PJM Interconnection ("PJM") and ERCOT markets analyzing VER penetration levels of 30% and above have shown to have limited impact on reliability. The PJM study notes that "no insurmountable operating issues were uncovered over the many simulated scenarios of system-wide hourly operation and this was supported by hundreds of hours of sub-hourly operation using actual PJM ramping capability." The study found that additional regulation services, similar in scale to what is already procured to respond to uncertain load, will be required to respond to changes in VER output.[131] Analysis by The Brattle Group of the ERCOT market, which included several scenarios above 30% and one at 43%, found "no technical difficulties accommodating much higher levels of variable wind and solar energy, while fully preserving reliability" but did

---

[127] ERCOT, Future Ancillary Services in ERCOT, ERCOT Concept Paper, Draft Version 1.1, November 1, 2013, p. 8. Available at: http://www.ercot.com/committees/other/fast. ERCOT reports that 10.6% of its energy came from wind generation in 2014. ERCOT, 2014 Demand and Energy Report: Energy by Fuel Type for 2014, January 7, 2015. Available at: http://www.ercot.com/content/news/presentations/2015/ERCOT2014D&E.xls

[128] Debra Lew and Greg Brinkman, The Western Wind and Solar Integration Study Phase 2: Executive Summary, Technical Report, NREL/TP-5500-58798, September 2013, p. 17. Available at: http://www.nrel.gov/docs/fy13osti/58798.pdf

[129] The scenario with 13% renewables (TEPPC) resulted in higher additional cycling cost due to renewables of $0.41 – 1.05 per MWh of renewable generation compared to $0.14 – 0.67 per MWh of renewable generation for the 33% scenarios.

[130] CPUC, Renewables Portfolio Standard Quarterly Report: 3rd Quarter 2014, Available at: http://www.cpuc.ca.gov/NR/rdonlyres/CA15A2A8-234D-4FB4-BE41-05409E8F6316/0/2014Q3RPSReportFinal.pdf

[131] GE Energy Consulting, PJM Renewable Integration Study: Executive Summary Report, Revision 05, March 31, 2014, p. 7. Available at https://www.pjm.com/committees-and-groups/task-forces/irtf/pris.aspx. "The 30% scenarios, which added over 100,000 MW of renewable capacity, required an annual average of only 1,000 to 1,500 MW of additional regulation compared to the roughly 1,200 MW of regulation modeled for load alone. No additional operating (spinning) reserves were required."

require changes to the ancillary services products, which ERCOT is currently reviewing, and additional natural gas capacity.[132]

Second, recent experiences provide insights into how the system may adapt with increasing generation from VERs. There are multiple options for minimizing the reliability challenges associated with additional renewable energy generation. In this section, we discuss those options in detail.

Incorporating Non-Variable Renewable Energy Sources

Additional renewable generation does not necessarily have to be generated by VERs. A number of renewable technologies beyond solar PV and wind can be used to lower CO_2 emissions and several of them have properties that either pose less of an intermittency problem or might even be used to balance the intermittency of wind and solar PV resources. Biomass and biogas-fired generation tends to be dispatchable or at least not subject to the intermittency of wind and solar generation, and therefore poses essentially no risk to reliability. While the use of biomass in power generation is a subject of active debate, some additional biomass or biogas based renewable generation could likely be used, based on the relatively large theoretical potential.[133] A second potential source of renewable energy that lacks the intermittency features of wind and solar PV is small scale hydroelectric generation. Estimates suggest that the technically suitable sites for small scale hydro generation could provide 100 GW capacity, of which 13 GW could be

---

132 Shavel, et al., Exploring Natural Gas and Renewables in ERCOT Part II: Future Generation Scenarios for Texas, Prepared for the Texas Clean Energy Coalition, December 10, 2013. Available at: http://www.brattle.com/system/publications/pdfs/000/004/970/original/Exploring_Natural_Gas_and_Renewables_in_ERCOT-_Future_Generation_Scenarios_for_Texas.pdf "Remarkable as it may seem, our modeling indicates that this level of variable generation [43%] can be integrated with full reliability with properly structured ancillary services markets and a fleet of about 57 GW of CC capacity, 25 GW of which are newer, faster-ramping units, plus 12 GW of conventional steam gas plants."

133 Estimates of the sustainable feedstock for biomass and bio-gas fired power generation differ significantly. A recent report by the Union of Concerned Scientists estimates the 2030 potential to be 677 million dry tons, which in turn could generate 732 billion kWh of electricity annually, or 19% of 2010 total U.S. power consumption. See Union of Concerned Scientists, The Promise of Biomass: Clean Power and Fuel – If Handled Right; 2012. A 2011 update to a 2005 study by the U.S. Department of Energy comes to similarly sized estimates of potentially more than a billion try tons of agricultural and forest biomass, although at various price points and with potentially more than half the potential coming from energy crops (See U.S. Department of Energy, U.S. Billion Ton Update, August 2011). Crop and forest residues are particularly plentiful in the Midwest and Southeast, regions with states that under the proposed rule require significant CO_2 reduction. See biomass resource maps at http://www.nrel.gov/gis/biomass.html (accessed January 5, 2014). The benefits of using biomass in power generation for the purpose or limiting greenhouse gas emissions have also been questioned. See for example Manomet Center for Conservation Sciences, Biomass Sustainability and Carbon Policy Study, June 2010.

cost effective.[134] Untapped large hydro power would also provide the same benefits and, since more often associated with reservoirs (or at least some storage behind dams). In the United States, the majority of suitable sites for large scale hydro power production have been developed. However, Canada has significant untapped hydro power potential from both existing and undeveloped sites. The ability for Canadian large scale hydro generation to contribute to meeting CPP emissions reductions goals will depend on the availability of transmission infrastructure to access U.S. markets and on how such large hydro resources are accounted for under EPA-approved SIPs.[135] Geothermal generation is another renewable resource that can provide base load generation. Geothermal resources currently account for almost 25% of the generation used to meet California's 33% RPS.[136]

Optimizing the Mix of VERs

In addition to including non-variable renewable generation, states can minimize the impact of variable resources by incorporating a mix of VERs. The impact of VERs on the short-run operations of the electric system depends significantly on both technology mix and location. For any VER technology there are significant geographic diversity benefits. Wind conditions tend to be highly location-specific, so that the total output from wind facilities spread over a broad geographic area is less variable than the electricity produced by any single wind turbine.[137] The same is true for solar PV, where the effects of cloud cover differs significantly even across

---

[134] Lea Kosnik, The potential for small scale hydropower development in the US, Energy Policy, Volume 38, 2010. The study includes a discussion of both the technical potential and an analysis of the amount of cost effective small scale hydro resources.

[135] The potential use of imports of hydro power from large hydro projects as a means of meeting state level greenhouse gas reduction targets is actively being discussed in several states, notably in New England. For example, the Northern Pass transmission project would bring additional hydro resources from Quebec to New England. (http://www.utilitydive.com/news/northern-pass-line-can-help-solve-new-england-energy-issues/285415/)

[136] California Public Utility Commission, Renewable Portfolio Standard Quarterly Report: 3rd Quarter 2014, Issued to Legislature October 10, 2014. Available at: http://www.cpuc.ca.gov/NR/rdonlyres/CA15A2A8-234D-4FB4-BE41-05409E8F6316/0/2014Q3RPSReportFinal.pdf

[137] Several studies have examined the diversity benefits from wind located in different states. See for example Jonathan Naughton, Thomas Parish, and Jerad Baker, Wind Diversity Enhancement of Wyoming/California Wind Energy Projects, Final Report Submitted to the Wyoming Infrastructure Authority, January 2013, which concludes that the co-variation of wind across sample sites in Wyoming and California is relatively low, which in turn would lead to significant reduction of wind variability across these sites (see for example Figure 10). See also Jonathan Naughton, Thomas Parish, and Jerad Baker, Wind Diversity Enhancement of Wyoming/Colorado Wind Energy Projects, Final Report Submitted to the Wyoming Infrastructure Authority, April 2013 for a similar analysis of diversity benefits between Wyoming and Colorado.

relatively limited geographic areas.[138] Apart from creating incentives to achieve a mix of technologies and locations that not only maximizes production but also minimizes the impact of intermittency on reliability, the benefits of diversified renewable energy resources increases with the size of the area, in which VERs are balanced. From a market design perspective, increasing the size of balancing areas, either through cooperation between balancing areas or through combinations of existing balancing areas into larger ones, provide significant and relatively inexpensive means of reducing the balancing costs of systems with high shares of VERs.[139]

Options also exist for making wind and solar generation more flexible. The use of more advanced wind and solar PV technologies themselves can alleviate intermittency-related reliability concerns by allowing for direct control of their output as necessary. For example, wind turbines have been advancing from early models that could only operate at constant speed to more advanced models that can operate at variable speed and provide frequency control and voltage regulation.[140]

The approaches that could be used to reduce the intermittent impact of solar and wind generation also include a transition of revenue mechanisms away from output-based compensation (through long-term contracts for energy without time or locational components, feed-in tariffs, etc.) to more market-based prices as well as allowing solar and wind resources to participate in ancillary services and capacity markets.[141] Such mechanisms would likely lead to changing patterns in installation and operation of wind and solar facilities, with the effect of reducing reliability concerns. For example, as of today the vast majority of solar PVs installed today in the U.S. are facing south or southeast because it provides the highest energy production

---

[138] See for example Andrew Mills and Ryan Wiser, Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power, LBNL, September 2010.

[139] See for example Milligan, Kirby, King and Beuning, Benefit of Regional Energy Balancing Service on Wind Integration in the Western Interconnection of the United States, NREL, October 2010, which also enumerates benefits from balancing area coordination without consideration of VERs. For an update with cost savings estimates for an Energy Imbalance Market in the WECC, see Milligan et al., An Analysis of the Impact of Balancing Area Cooperation on the Operation of the Western Interconnection with Wind and Solar Generation, NREL, 2011, which estimates significant cost savings and approximately 50% reductions in various ancillary service requirements from an Energy Imbalance Market (pages 9-12).

[140] Wind turbines are typically categorized as one of the four types: Type I is a conventional induction generator that operates at constant speed not having the ability to slip wind. Type II is a variable rotor resistance generator that can operate at variable speed. Types I and II cannot provide voltage regulation. Type III is a doubly-fed asynchronous generator that can operate at variable speed. Type IV is a full-converter unit (with conventional, induction, or permanent magnetic generators) that can operate at variable speed. Types III and IV have full pitch control and can provide both frequency control and voltage regulation.

[141] For example, Xcel Energy already uses wind resources to provide ancillary services in real time operation. See Presentation by Drake Bartlett (Xcel Energy Colorado) at the Utility Variable Generation Group 2012 Forecasting Workshop.

level. However, production from these south facing solar PVs will not coincide with peak load needs that typically occur in late afternoon to early evening. Having solar panels facing west, while not optimal from a pure production perspective and hence reducing the contribution to emissions reductions, would better match the PV production with peak demands, potentially reducing the ramp needs from conventional resources. It should be noted that the need to provide incentives for solar PV sites to face more west rather than just south has been identified as a goal in Germany, where solar PV capacity exceeds 35 GW and represents in excess of 5% of total power generation.[142]

Improved Forecasting and Scheduling of VER output

Although VER generation is intermittent, its output can be forecasted so that standard unit commitment and economic dispatch methods can respond to the majority of the swings in their output. There are several ways in which these processes can be improved to better account for VER output. As a starting point, shortening the dispatch cycle helps reduce the uncertainty brought by increased VERs. Implementing a five minute dispatch cycle, as already completed in several of the structured markets today (including ISO-NE, NYISO, PJM, MISO, SPP, ERCOT, and California ISO), significantly reduces the need for ancillary services compared to dispatching units on an hourly basis, as still practiced in some regions. For example, MISO, by including 80% of its wind capacity in the 5 minute dispatch as Dispatchable Intermittent Resources,[143] improved system reliability "through better congestion management by replacing manual curtailments with automated real-time dispatch." [144] In its recent review of potential changes to its ancillary services market, ERCOT notes that "resource-specific dispatch with 5-minute resolution allows ERCOT to closely follow net load variations and is one of the main reasons why ERCOT has been successful in integrating renewables with minimal increase in [ancillary service] capacity."[145] The reduced amount of ancillary service needs leaves the system with increased flexibility since not all available flexibility is used up for managing VER output fluctuations.

---

142 See Agora Energiewende, Erneuerbare-Energien-Gesetz 3.0, October 2014 (in German) For a discussion of the impact of the mix of solar PV and wind on the potential need for electricity storage, see Judy Chang, Kathleen Spees and Jurgen Weiss, Renewables and Storage – Does Size Matter? Presented at the 15th annual POWER Conference on Energy Research and Policy, University of California at Berkeley Energy Institute, March 2010.

143 See MISO, MISO 2013-2014 Winter Assessment Report, Information Delivery and Market Analysis, June 2014, page 10.

144 Minnesota Department of Energy Resources, Minnesota Renewable Energy Integration and Transmission Study, September 13, 2013, p. 21. Available at : http://mn.gov/commerce/energy/images/MN_RE_Integration_Study_2014_pres_Stakeholder_Mtg_091313.pdf. The study notes that two-thirds of curtailments in MISO occur through the economic dispatch with the other third occurring still from manual curtailments.

145 ERCOT, Future Ancillary Services in ERCOT, ERCOT Concept Paper, Draft Version 1.1, November 1, 2013, p. 8. Available at: http://www.ercot.com/committees/other/fast

Similarly, unit commitment cycles could be improved. In many parts of the country unit commitment is still being performed on a day-ahead or even longer basis. While the day-ahead unit commitment has performed well in the past, the short-term variation in output caused by increased levels of VERs, combined with newer generation and load resources that require relatively shorter start-up times may allow for shorter term unit commitment periods. Further enhancement of the intra-day unit commitment processes already implemented by several of the U.S. RTO/ISOs could better address the increased variability concern.[146] For both unit commitment and economic dispatch, shorter cycles allow system operators to take in more up-to-date information, which typically includes smaller forecast errors, leading to reduced variability and less of a need for flexibility.

Ancillary service markets are also evolving to provide incentives for faster responding resources that can provide better performance. For example, PJM provides "mileage payments" which account for how well resources respond to the regulation signal for controlling frequency.[147] In Texas, ERCOT is currently working on updating its ancillary services design so that fast responding resources can be incentivized to provide improved performance.[148]

In addition to shortening the unit commitment and dispatch cycles, a process that incorporates forecast into both processes should be considered. For example, currently many regions will make dispatch decisions based on current rather than on anticipated system conditions of the near future (5 or 10 minutes from now). Given improvements in forecasting techniques, including the forecasts (and range of errors) in unit commitment and dispatch decisions can provide additional flexibility. MISO has started developing and partially implementing a look-ahead unit commitment and dispatch process.[149] Stochastic unit commitment, while still in its infancy, has been gaining traction as another tool for dealing with uncertainty.[150]

---

[146] For example, PJM is changing the intra-day unit commitment process to better address the coordination between gas and electric. See: http://pjm.com/~/media/committees-groups/committees/mrc/20140918/20140918-item-16-gas-unit-commitment-coordination-proposal.ashx

[147] See http://www.pjm.com/markets-and-operations/ancillary-services/mkt-based-regulation/fast-response-regulation-signal.aspx

[148] http://www.ercot.com/committees/other/fast/index.html

[149] See MISO press release discussing how look-ahead tool improves efficiencies while reducing costs, available at: https://www.misoenergy.org/AboutUs/MediaCenter/PressReleases/Pages/Look-AheadTool.aspx Further materials for the look-ahead tools are available at: https://www.misoenergy.org/WhatWeDo/MarketEnhancements/Pages/LookAhead.aspx

[150] For examples of stochastic unit commitment studies, see presentation from NREL and EPRI at: http://uvig.org/wp-content/uploads/2014/10/Ela-Stochastic.pdf and http://uvig.org/wp-content/uploads/2014/10/Tuohy.pdf

Storage, Demand Response and other Flexible Distributed Resources

Another option for securing operational flexibility is through the usage of non-traditional resources to balance the system. Today, most of the flexibility is being provided by hydro and fossil generation units. Using demand response as a source for ancillary services, such as practiced in ERCOT today, is a proven option to implement.[151] Dynamic pricing and other forms of demand response are quickly emerging as new and often cheaper tools for providing flexibility.[152] Thermal energy storage of loads, such as controlling residential electric hot water heaters or commercial refrigeration systems, may also be able to provide ancillary services, including regulation, to the system operators by adjusting the power usage from thermal storage systems a few minutes at a time.

Storage of electric power is often seen as a technological solution to the perceived reliability threat posed by the uncertainty caused by VERs and the lack of appropriate transmission and pipeline infrastructure. Storage comes in many forms, and a detailed description of the many options is beyond the scope of this report. Generally speaking, all storage technologies are capable of addressing some element of any reliability concern resulting from VERs or any other mismatches between supply and demand. Extremely short-term storage technologies such as fly wheels help balance very short term fluctuations in the balance between power supply and demand. Batteries of various types help with similar fluctuations, but are also capable of smoothing mismatches on an hourly and sometimes up to a multi-day basis. Electrolyzers allow the conversion of electricity into hydrogen, which can be stored for long periods of time and reconverted into electricity with the help of a fuel cell or used as an additive to natural gas supply.[153] Progress of storage in terms of performance and cost has been quite rapid such that storage may be cost effective in an increasing number of applications over the next few years. In addition, several storage technologies are relatively mature and can be deployed and scaled rapidly. The "billion dollar battery factory" currently under construction in Nevada is an indicator of the dynamics of the storage segment. [154]

---

151 See http://www.ercot.com/services/programs/load/laar/index

152 These forms of demand response will also contribute to reducing the peak demand, which will help alleviate the supply shortage concern of the Planning Timeline.

153 The idea of using very low cost electricity, for example during off-peak periods with large amounts of wind generation, to split water into hydrogen and oxygen and then to either store the hydrogen for future electricity generation with a fuel cell or inject hydrogen into existing natural gas pipeline infrastructure is relatively new, but is being tested with various pilot programs in Germany. For an overview of German pilots see http://www.engerati.com/article/germanys-power-gas-pilots-real-world-solution.

154 See http://www.nytimes.com/2014/02/27/automobiles/tesla-plans-5-billion-battery-factory-for-mass-market-electric-car.html?_r=0 (accessed January 22, 2015)

The increase in storage leads to an increase in demand response potential. Utilities in California and Hawaii have already started utilizing electric vehicles as part of their resource portfolio. It can be expected that storage "behind the meter" will evolve in a particularly dynamic fashion over the next few years. Essentially all U.S. households already have some form of behind the meter distributed storage in their houses and apartments, as parts of their mobile phones, electric shavers, UPS systems, etc. It is likely that many more options for small scale storage of this kind will emerge quite rapidly. This in turn further facilitates an already rapid increase in demand response, which will likely continue to evolve towards "DR 2.0", i.e. demand response that no longer primarily relies on the ability to participate in wholesale markets, but rather is capable of adjusting behind-the-meter rapidly to wholesale and/or retail price signals. The rapid increase in smart meter penetration rates, wifi-enabled thermostats and other controllable home equipment and a regulatory environment increasingly aware of the need to integrate demand-side flexibility options likely creates potential for a significantly increased role of DR in managing the electric supply and demand balance in the future.

Demand response and storage are just two of a large set of options for system operators to secure flexibility to manage increasing levels of variability in the electric system. Other options include those related to operational rules, such as providing flexibility through transmission operations, and through change in unit commitment and dispatch. These options are discussed next.

Another technology trend that can be observed in regions with significant heating demands and greenhouse gas reduction goals is the emergence of small scale combined heat and power systems. Often small enough to provide heat and electricity for individual homes or commercial buildings, these systems increase the overall efficiency of combined heat and power production and thus free up gas supplies locally. They can also respond quickly to market price signals and increase or decrease electricity production depending on market prices. By doing so, they can help integrate increasing levels of VERs. Often, heating systems include a thermal storage unit, which allows for a complete decoupling of electricity and heat production, which increases the ability of such systems to integrate with high levels of VERs. Various power generation technologies are being used for these applications, including reciprocating engines, Stirling engines and increasingly also fuel cells.[155]

Flexible Use of Transmission Infrastructure

Flexibility in transmission operation can reduce congestion, which has two important benefits for system with high VER penetration. First, it can partially eliminate the market segregations (pre-established reserves zones of the RTO/ISOs are based on anticipated transmission congestion), which allows a larger pool of resources to provide the energy and ancillary services. Second, in the longer term it can reduce the need to build critical new lines.

---

155 For an overview of the current US micro-CHP market, see ARPA-E Workshop on Small Engines; Case Study: Marathon Engine Systems, May 28, 2014. For an earlier evaluation of micro-CHP systems see United Technologies Research Center, Micro-CHP Systems for Residential Applications Final Report, 2006.

Flexibility in transmission operation comes from increasing transfer limits, which under today's operational schemes are assumed fixed. Traditionally, increasing transfer capability was addressed by upgrading existing lines or adding new lines, both of which require intense capital expenditure, multiple years of planning, various regulatory hurdles, and managing stakeholder issues. However, options with lower cost and faster turn-around to increase the transfer capability of transmission systems have been developed in recent years.

There are three potential options to increase transfer limits.

- The first is dynamic line ratings ("DLR"), which increases the transfer limits based on ambient conditions of the physical transmission line, such as temperature, wind, and humidity, or based on the direct measurement of line sag. Lower temperature and higher wind will help cool the physical wires and therefore the wires can transfer increased amount of power without sagging as much from the heat produced by the current flow. This is particularly relevant for transmission build-outs that are for harnessing wind. Oncor Electric Delivery and other utilities have been testing DLR application.[156]
- The second option is adaptive line ratings ("ALR"). ALR update emergency ratings based on system response capability, effectively determining how quickly a constraint could be relieved by system re-dispatch should a contingency happen, and then employing the relief time for the calculation of the emergency limit. ALR can be very effective in relieving congestion due to thermally limited contingency constraints. Since most transmission constraints tend to be contingency constraints, increasing post-contingency transfer capabilities can be very effective in reducing congestion and associated renewable curtailments. ALR were proposed by ISO-NE in 2008 and tested and prototyped subsequently, although they have not yet been implemented in the ISO-NE market because of the lack of significant thermal constraints in the market.[157]
- The third option, transmission topology control ("TC"), reconfigures the system to maximize the transfer capacity from areas with transmission-constrained low-cost generation to load centers. By opening or closing transmission circuits, a fraction of the flows is routed away from the congested elements and forced to go through other facilities that are more lightly loaded. TC can be very effective in relieving thermal congestion in areas where there is sufficient redundancy in the transmission system. A recent ARPA-E study estimated congestion cost reductions

---

156 See Oncor West Texas Dynamic Line Rating (DLR) Project presentation, dated March 26, 2013, available at: http://www.ercot.com/content/meetings/rpg/keydocs/2013/0326/Oncor_W_Texas_Dynamic_Line_Rating_Presentation_for_ERCOT_032.pdf

157 See Prototyping and Testing Adaptive Transmission Rates for Dispatch presentation by ISO-NE and Alstom Grid, available at: http://www.ferc.gov/CalendarFiles/20120626080541-Monday_SessionA_Maslennikov.pdf

> of about 50% for PJM.[158] TC can also be effective for increasing system reliability by relieving overloads and for simplifying transmission maintenance scheduling. Topology control has been used in the past, but has been based solely on operator experience and not part of a formulated operational procedure. Recent developments of topology control focus on software that allows the system operator to systematically open and close lines to control topology.

The technical options listed above indicate that there are many ways to address the potential reliability concerns raised by NERC due to increased VER penetration. In many instances, the technology options described above will alleviate short-term reliability concerns without corresponding changes to market rules or regulatory frameworks. In other cases and in addition, market and/or regulatory-rules can and should be adjusted to further increase their beneficial contributions to system reliability.

The incentives for renewable resources to provide value other than energy discussed above should be addressed through these adjustments. While adjusting the rules may require some time, many of these options exist to a significant degree today or likely have to be developed and deployed over the next few years given the relatively quick increase of VERs in the United States even before the effect of the CPP is taken into account. As with some of the other options discussed above, many of the market and regulatory rule changes are "no-regret" options, i.e. they improve the market and regulatory framework in general. Consequently, they can be implemented today and hence will improve the chances that the electricity system will evolve in ways that make complying with the CPP easier.

Together, they will likely provide enough additional flexibility to avoid increased physical reliability issues due to the CPP in the short-run operational timeframe, even if the role of VERs should increase significantly. These various measures, especially those that change operational procedures, also function as an insurance policy during the transition period. In general, these options will increase the flexibility that is available to the system operator, making it easier for system operators to handle real time contingencies.

4. Timing of CPP Implementation Likely Sufficient to Assure Reliability

Because of the relatively short period of time for planning between the final approval of multi-state plans (June 2018) and the beginning of the compliance period (January 2020) and NERC's concerns about potential reliability impacts of the CPP, NERC suggests that the EPA should consider allowing states or regions to develop a "reliability back-stop."[159] NERC argues that incorporating such a mechanism will give states a way out of meeting the standards in cases where they can prove that doing so will impact reliability.

---

158 See http://www.topologycontrol.com/impacts.html

159 NERC, 2014, p. 3.

Based on our review of the reliability issues identified by NERC, we find that the combination of the ongoing transformation of the power sector, the steps already taken by system operators, the large and expanding set of technological and operational tools available, and the flexibility under the CPP are likely sufficient to ensure that compliance with the CPP can be planned by states in ways that will not materially affect reliability.

The CPP provides the states options in choosing how to comply with the CO_2 standards. As explained earlier in our summary of the CPP, these options include (1) allowing states to create their own approaches in their SIPs for meeting the standards (and not requiring the BSER), (2) allowing for the proposed rate-based standards to be converted to mass-based standards, (3) allowing for states to cooperate with each other to meet their standards, and (4) setting the interim goal as an average over a ten-year period rather than as annual requirements.

States will have the choice to take advantage of any combination of these options. The optimal approach to meeting the CPP targets may well differ from state to state. In general, however, the ability to comply with the CPP while maintaining high levels of reliability both in the short and in the longer run will be made easier (and likely less costly) by taking advantage of all the flexibility options in the CPP and by expanding the geographic region within which the CPP is implemented. Practically speaking, this means that success in implementing regional cooperation will likely reduce any potential pressure on reliability that might result if CPP implementation is more local. Concerns about the timeline for implementing the CPP while maintaining reliability will have less merit the more states take advantage of the existing flexibility options under the CPP.

For example, states can expand the tools for achieving CPP compliance beyond the four building blocks included in the CPP. Emission reduction options available to states but not included in BSER include, among others, co-firing coal with biomass, combined heat and power (CHP), distributed generation resources, demand response, energy storage, advanced metering infrastructure, and non-utility energy efficiency programs and technologies.

States also have the flexibility to achieve CPP targets through a variety of policies, including market-based compliance strategies. They can do so while maintaining rate-based emissions targets, which have the potential advantage of not creating overall emissions caps in regions expecting significant economic and/or population growth in the future. On the other hand, maintaining rate-based emissions standards, even if based on a broader set of emissions reductions options, still need to define how the rate-based standard is calculated and hence which options do and which do not contribute to lower emissions rates. Mass-based standards, on the other hand, do not require an ex-ante definition of how emissions reductions are achieved and hence probably achieve even more flexibility. Mass-based standards may also make it easier to cooperate with other states, especially if some states are likely to choose mass-based approaches to CPP compliance.[160] Each state can therefore choose between the relative advantages and disadvantages of a rate- versus mass-based compliance target, incorporating policies tailored to its own electricity system.

States can also choose to cooperate with other states. The EPA estimated that that the equivalent carbon price needed to achieve the CPP's emissions reductions is approximately \$2/ton of CO_2 lower under regional cooperation than under state-by-state implementation.[161]

The nexus between reliability and regional cooperation has further been stressed in comments made to the EPA, among others by Great River Energy and The Brattle Group, which emphasized that an implementation of the CPP through an ISO-administered carbon price would explicitly consider reliability issues in setting and adjusting carbon prices.[162] Also, it is likely that existing efforts to lower emissions, such as RGGI and potentially California's cap and trade program, will be used as the platform for CPP implementation and thus also contribute to alleviating reliability concerns.

The risk of short-term reliability issues emerging and the cost of maintaining reliability could therefore be further reduced by the EPA's explicit recognition of the full set of flexibility options including the ability to engage in regional cooperation.

States that choose not to enter into agreements with other states for regional cooperation will have an additional year (a total of 2 ½ years) to prepare for meeting all reliability requirements under their implementation plan since single state SIPs are due in June 2017. The extra year to plan for the 2020 interim target would likely make additional options such as the construction of natural gas-fired generation and demand response possible and thus significantly mitigate any concerns about reliability impacts of the CPP.[163]

In addition and as explained above, the CPP does not require compliance with the 2020 interim targets as long as average emissions rate targets over the 2020 to 2029 period are met. Therefore,

---

160 It seems highly likely that RGGI states will choose mass-based conversion to comply with the CPP. See for example Docket ID No. EPA-HQ-OAR-2013-0602–RGGI States' Supplemental Comments on Proposed Clean Power Plan, December 1, 2014, page 5, which states: "As previously stated, the RGGI states firmly believe that a mass-based approach represents the most cost-effective method to demonstrate compliance with the CPP." See Bruce Phillips, Alternative Approaches for Regulating Greenhouse Gas Emissions from Existing Power Plants under the Clean Air Act: Practical Pathways to Meaningful Reductions, February 27, 2014 for a discussion of some of the issues that arise when rate-based and mass-based systems interact.

161 Celebi, et al., p. 10. The average costs of compliance were calculated to be \$15/ton in the non-cooperation case and \$13/ton in the cooperation case.

162 See Judy Chang, Jurgen Weiss, Yingxia Yang, A Market-based Regional Approach to Valuing and Reducing GHG Emissions from Power Sector, The Brattle Group, April 2014.

163 Note that the standard timeframe for developing and building a merchant combustion turbine facility is assumed to be 20 months in PJM and ISO-NE.

even if SIPs propose measures to achieve 2020 interim targets, deviations from SIPs caused by unforeseen reliability related actions are possible while staying in compliance. The final CPP might benefit from further clarification for cases where SIPs demonstrate expected compliance and provide contingency plans in situations where unexpected reliability concerns force deviations from the main compliance path proposed, yet resulting emissions rate reductions risk being off-track relative to meeting either interim compliance targets or relative to ultimately meeting the average 2020-2029 emissions rate targets.

We conclude that the flexibility options included in the CPP itself provide substantial tools in addition to the available technology, market and operational options described earlier in the report provide sufficient opportunities to maintain reliability while meeting the CPP target emissions rates. Moving to compliance mechanisms beyond those included in defining BSER, taking advantage of the ability to choose a different emissions reductions timeline as long as average emissions rates (under a rate-based approach) or total emissions over the 2020-2029 timeframe (under a mass-based approach) are met, converting to a mass-based approach and, finally, cooperating on compliance across states and regions, should all individually facilitate compliance while maintaining reliability.

Since reliability issues could emerge in real time even if SIPs project compliance with the CPP while expecting to maintain reliability, confidence in the compatibility of the CPP with the maintenance of high levels or reliability could be further strengthened by making explicit how the EPA plans to act if SIPs are implemented as planned, contingency plans included in SIPs in response to unforeseen reliability issues are implemented and, as a consequence, emissions rate reductions fall short of CPP targets. Doing so might provide a de facto reliability back-stop and thus alleviate concerns about reliability being threatened in real time by the need to maintain compliance strategies in the short run. However, should regulatory precedent not be sufficient assurance to states that EPA will indeed take the approach just described, the final CPP could provide further clarity on how the EPA plans to assess non-compliance in cases where actual emissions reductions fall short of targets over the 2020-2029 timeframe in response to avoided short-term reliability issues and even though the corrective measures in SIPs were implemented.

V. Regional Compliance Options

In this section, we provide some comments on how regional cooperation may make CPP compliance easier. To the extent that the CPP will lead to significant changes in the resource mix of the U.S. power system, local or regional reliability issues, for example caused by the retirement of a significant amount of generation in a load pocket, could well arise even if the overall likelihood of such events from a national perspective are small.

Table 4
Regional Aggregation of States

Region Name	States
ISO-NE	CT, MA, ME, NH, RI
New York	NY
PJM	DE, MD, NJ, OH, PA, VA, WV
MISO/SPP	AR, IA, IL, IN, KS, LA, MI, MN, MO, ND, NE, OK, SD, WI
Southeast	AL, FL, GA, KY, MS, NC, SC, TN
Texas	TX
California	CA
NWPP	ID, MT, NV, OR, UT, WA
Desert Southwest	AZ, NM
Rocky Mountain	CO, WY
EIC	ISO-NE, New York, PJM, MISO/SPP, Southeast
WECC	California, NWPP, Desert Southwest, Rocky Mountain

The regional issues illustrated in this section assume that states choose to collaborate with other states in their region. However, states could also choose to cooperate beyond the regions defined here.[164] This type of cooperation would further reduce state-level reliability impacts. Furthermore, similar to our discussion of renewable penetration above, our analysis in this section uses the simplifying assumption that states will follow emissions reductions corresponding to the EPA's allocation of reductions across the four BSER building blocks, and therefore ignores additional flexibility that would help alleviate any potential reliability concerns.

For ease of presentation we have grouped states into regions following the existing market footprint because of existing generation dispatch practices, but which do not necessarily correspond exactly to the organization by states into regional reliability regions.[165] Table 4 above shows our grouping of states into regions for the purpose of discussion in this section of the

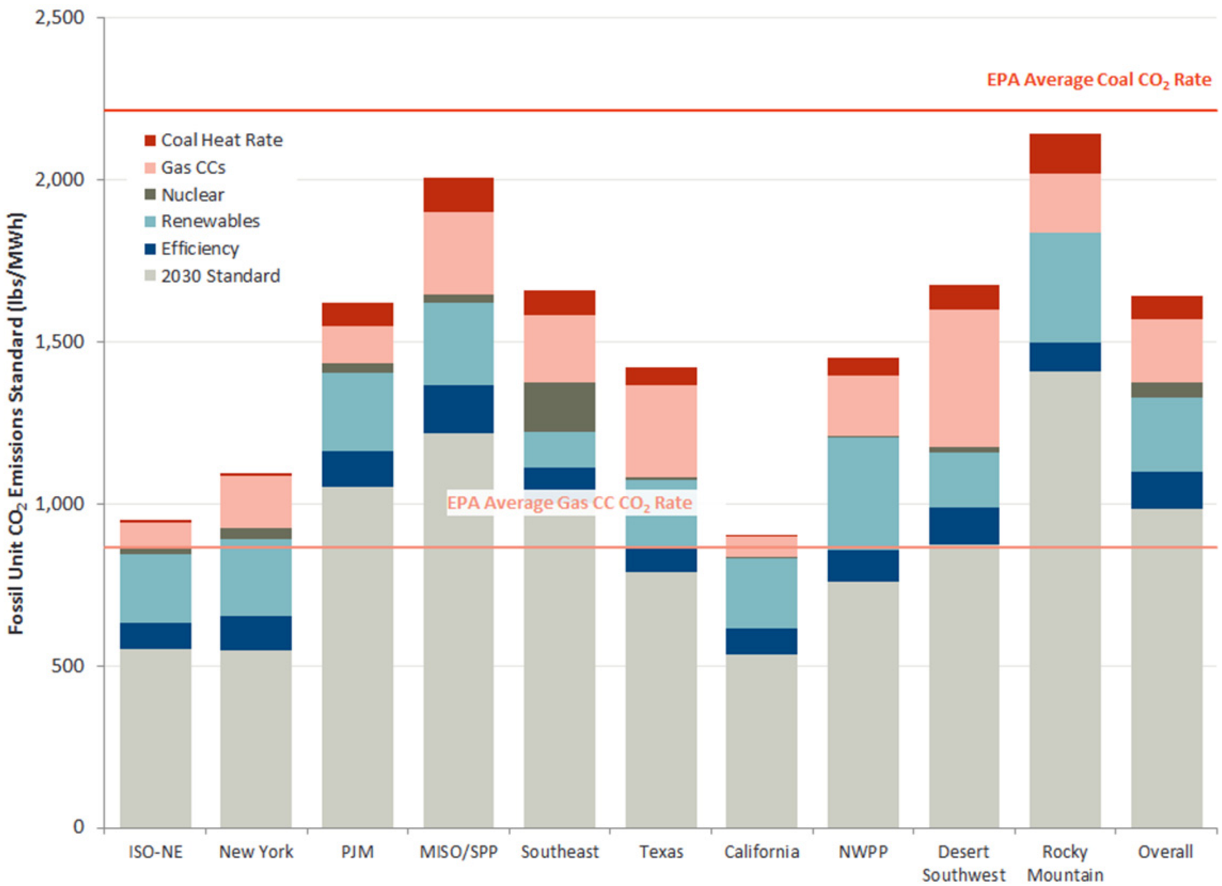
---

[164] In theory, cooperation could also occur between states that are geographically distant from each other, such as Washington and Florida. One recent example of such cooperation on greenhouse gas emissions reductions that does not follow electricity market boundaries is the joint auctioning of greenhouse gas emissions allowances in California and Quebec (recognizing of course that the province of Quebec will not be subject to the CPP). Tradable certificate systems lend themselves particularly well to cooperating without direct linkages between respective electricity markets. The states participating in the Regional Greenhouse Gas Initiative also do not make up a continuous geographic area with Maryland and Delaware separated from New York and the New England states.

[165] We recognize the difficulty of grouping states into relevant sets. Our choices are not meant to reflect precise existing groupings, but rather reflect likely similarities potentially facing states we group together.

report. Figure 8 below shows the compliance requirements under BSER for each of the regions defined above.[166]

Figure 8
Regional Compliance Requirements based on BSER without cross-regional cooperation



Source: EPA Goal Computation, 2014. Reflects Option 1 final rate for years2030 and later.

If states choose to collaborate on a regional (or national) basis, emissions reductions beyond those assumed under BSER may be possible in each region. The primary drivers of emissions rate reductions under the CPP will be a switch from coal (and to a lesser degree oil) to natural-gas fired generation and an increase in the power generation from renewable energy sources including VERs.

In Section IV.A.2., we described how the calculation of coal-to-gas switching under Building Block 2 of BSER at the state level may underestimate the ability for switching from existing coal to existing natural-gas fired generation across states. Table 5 below shows how emissions reductions from BSER Building Block 2 might increase if fuel switching to natural gas occurs at the regional level.

---

166 State by state requirements are shown in Figure 1

Table 5
NGCC Re-Dispatch by State and by Region

Region	2012 NGCC Capacity Factor	State Re-Dispatch: Re-Dispatched NGCC Capacity Factor	State Re-Dispatch: Emissions Reduction	Regional Re-Dispatch: Redispatched NGCC Capacity Factor	Regional Re-Dispatch: Emissions Reduction
	%	*%*	*MMT*	*%*	*MMT*
ISO-NE	46%	50%	3	50%	3
New York	51%	70%	5	70%	5
PJM	53%	64%	25	70%	31
MISO/SPP	35%	70%	104	70%	105
Southeast	50%	69%	72	70%	76
Texas	45%	70%	53	70%	53
California	45%	49%	0	49%	0
NWPP	34%	47%	13	70%	30
Desert Southwest	29%	55%	19	63%	23
Rocky Mountain	30%	70%	10	70%	11

Source and notes: EPA, Goal Computation, 2014. Analysis based on EPA assumptions, but allowing for regional coal to natural gas switching to calculate achievable emissions reductions. MISO/SPP re-dispatching may be limited by transmission constraints between SPP and MISO. However, given the small effect of regional re-dispatch, this is not a significant issue.

As can be seen from Table 5, assuming that re-dispatching from coal to gas can occur across state boundaries provides some additional opportunities to reduce emissions while maintaining the assumption that NGCCs could (and can) be dispatched at 70%. The effects are generally small, with the exception of the NWPP, where emissions reductions from regional re-dispatch could more than double relative to state-by-state re-dispatching as assumed by the EPA for developing BSER. In PJM, emissions would decrease by about 20% as a result of regional coal to natural gas shifts. The main conclusion from this analysis is that if states collaborate regionally, achieving the emissions reductions from coal to gas switching under BSER Building Block 2 could be somewhat easier than BSER implies. This in turn could help address the concerns expressed by some regional entities about the limits of coal to gas switching.

The second primary source for emissions rate reductions is the addition of renewable energy resources. As mentioned above, a number of states have actual in-state renewable generation or RPS targets already exceeding the assumptions in BSER Building Block 3. Under regional cooperation, such excess renewable generation in one state can be used to meet BSER targets in other states in the region. Table 6 and Table 7 below show the likely evolution of regional renewable penetration in each region under a Business as Usual ("BAU") case, i.e. independent of the CPP, and compare this BAU case with the renewable penetration rates that would be necessary under BSER as well as under the assumptions that renewable generation has to make up for the complete absence of emissions reductions from one specific BSER building block.

Table 6
2020 Renewable Penetration under BAU, BSER and Sensitivity Cases

Region name	BSER Estimated Renewable Penetration Factors 2020					
	BSER Penetration	Exclude Coal Efficiencies	Exclude Coal Switching	Exclude New or 'At Risk' Nuclear	Exclude Enegy Efficiency	2020 Renewable Penetration BAU*
[1]	[2]	[3]	[4]	[5]	[6]	[7]
ISO-NE	8.1%	8.1%	14.3%	9.6%	12.0%	17.9%
New York	5.4%	5.4%	14.4%	7.0%	9.5%	7.6%
PJM	3.7%	7.0%	8.1%	5.2%	6.4%	11.6%
MISO/SPP	7.8%	11.8%	21.4%	9.0%	10.8%	13.3%
Southeast	3.2%	5.7%	18.4%	9.2%	4.9%	3.1%
EIC	**5.2%**	**8.2%**	**16.8%**	**8.1%**	**7.8%**	**9.4%**
Texas	**11.9%**	**14.4%**	**38.5%**	**12.5%**	**13.7%**	**8.7%**
California	13.6%	13.6%	16.2%	14.0%	17.1%	33.0%
NWPP	11.4%	12.4%	24.6%	11.5%	15.1%	16.9%
Desert Southwest	5.1%	6.0%	46.5%	6.8%	9.9%	9.1%
Rocky Mountain	17.6%	24.9%	33.5%	17.6%	20.7%	28.5%
WECC	**12.0%**	**13.3%**	**25.5%**	**12.4%**	**15.7%**	**23.2%**
Overall	**7.1%**	**9.5%**	**18.2%**	**9.3%**	**9.4%**	**9.9%**

*BAU scenario uses higher of current RPS standards or existing renewable penetration based on 2012 levels.
Additional Notes: To calculate penetration levels, the 2012 load is assumed to represent total consumption in the region. The RPS in some states includes resources not included in the BSER.

[1]: States mapped into regions as defined in Table 4

[2]: Renewable penetration with EPA BSER analysis for 2020.

[3]: Renewable penetration when renewable energy is substituted for CO2 reductions predicted from Coal efficiencies.

[4]: Renewable penetration when renewable energy is substituted for CO2 reductions predicted from coal to gas switching.

[5]: Renewable penetration when renewable energy is substituted for CO2 reductions predicted from new or continued 'At Risk' nuclear projects.

[6]: Renewable penetration when renewable energy is substituted for CO2 reductions predicted from EE.

Table 7
2029 Renewable Penetration under BAU, BSER and Sensitivity Cases

Region name	BSER Estimated Renewable Penetration Factors 2029					
	BSER Penetration	Exclude Coal Efficiencies	Exclude Coal Switching	Exclude New or 'At Risk' Nuclear	Exclude Enegy Efficiency	2029 Renewable Penetration BAU*
[1]	[2]	[3]	[4]	[5]	[6]	[7]
ISO-NE	16.7%	16.7%	24.6%	18.2%	27.0%	22.5%
New York	15.8%	15.8%	27.7%	17.3%	26.7%	7.6%
PJM	14.0%	18.0%	19.0%	15.5%	22.8%	13.7%
MISO/SPP	10.9%	15.5%	26.4%	12.2%	21.4%	15.1%
Southeast	8.6%	11.6%	25.9%	14.7%	17.6%	3.4%
EIC	**11.4%**	**14.8%**	**24.6%**	**14.3%**	**21.0%**	**10.8%**
Texas	**21.9%**	**24.8%**	**53.2%**	**22.5%**	**31.6%**	**8.7%**
California	14.7%	14.7%	17.3%	15.1%	23.0%	33.0%
NWPP	17.3%	18.5%	35.4%	17.5%	27.8%	18.3%
Desert Southwest	7.9%	8.9%	54.0%	9.7%	19.2%	11.8%
Rocky Mountain	26.7%	34.8%	44.2%	26.7%	36.5%	28.5%
WECC	**15.9%**	**17.4%**	**32.0%**	**16.4%**	**25.6%**	**24.1%**
Overall	**13.2%**	**16.0%**	**26.0%**	**15.4%**	**21.7%**	**13.0%**

*BAU scenario uses higher of current RPS standards or existing renewable penetration based on 2012 levels..

Additional Notes: To calculate penetration levels, the 2012 load is assumed to represent total consumption in the region. The RPS in some states includes resources not included in the BSER.

[1]: States mapped into regions as defined in Table 4
[2]: Renewable penetration with EPA BSER analysis for 2029.
[3]: Renewable penetration when renewable energy is substituted for CO2 reductions predicted from Coal efficiencies.
[4]: Renewable penetration when renewable energy is substituted for CO2 reductions predicted from coal to gas switching.
[5]: Renewable penetration when renewable energy is substituted for CO2 reductions predicted from new or continued 'At Risk' nuclear projects.
[6]: Renewable penetration when renewable energy is substituted for CO2 reductions predicted from EE.

Table 6 and Table 7 show that a regional level the BSER generation levels from renewable energy would likely be achieved even in the absence of the CPP. With the exception of New York, Texas and the Southeast, this is true for BSER assumptions both in 2020 and in 2029. This implies that with few exceptions any reliability issues that might arise from increasing penetration of renewable energy sources – even though unlikely for the reasons explained above - would arise in the absence of the CPP and thus cannot be attributed to the CPP. Since 2020 and 2029 BSER penetration levels are likely to be achieved under BAU for the entire Eastern Interconnection, inter-regional cooperation would likely permit meeting the levels of renewable generation implied by BSER without any (additional) difficulties due to the CPP.

This result also means that at least at the regional level emissions reductions in excess of BSER means that emissions reductions from other BSER building blocks could be lower and still allow for states to meet CPP targets.

Energy efficiency investments in any particular state will have an impact both on the generation within its borders and on imported electricity from generation in neighboring states. In the BSER, the amount of EE that is counted for setting the emissions rate standards was limited to the generation within each state. For that reason, if the states that are net importers of electricity are able to achieve the amount of load reductions assumed by the EPA, EE will be able to provide more emissions rate reductions than assumed. Table 8 shows how the impact of this in two ways: the first column shows the additional EE impact that can be achieved if imports had been considered in the BSER calculation. The second column shows the effective EE rate that is actually required by the BSER without considering the impact of imports. For example, in PJM, if states in this region all achieve the EE targets included in the BSER, they will generate 22% more MWh of load reductions than had been considered by the EPA in BSER, which will reduce the amount of emissions reductions required by other approaches. Alternatively, the amount of EE that would need to be achieved in PJM to meet BSER as currently calculated would need to 1.2% per year, instead of 1.5% per year.

Table 8
Impact of EE on Import Emissions

Region	Additional EE Impact if Imports Considered %	Effective EE Rate without Imports %
ISO-NE	14%	1.3%
New York	0%	1.5%
PJM	22%	1.2%
MISO/SPP	11%	1.3%
Southeast	6%	1.4%
Texas	0%	1.5%
California	0%	1.5%
NWPP	15%	1.3%
Desert Southwest	44%	0.8%
Rocky Mountain	30%	1.0%

Source and notes: EPA, Goal Computation, 2014. The reduction in the effective EE rate would also apply proportionally to the annual ramp-up rate that is assumed to be 0.2% per year.

The above discussion shows that regional cooperation would likely reduce the difficulty of achieving BSER emissions reductions from the BSER building blocks. States may be able to take advantage of similar potential additional emissions reductions by including those in their SIPs, even without formal regional cooperation. In either case, this section shows that achieving emissions rate reductions in addition to those in BSER as calculated by the EPA is possible and indeed likely for the reasons described in this section. This additional pathway for emissions reductions on a regional (or even national) level will likely contribute to further lowering any potential impact of the CPP on reliability.

VI. Conclusions

In this report, we provide a review of NERC's Initial Reliability Review of the CPP. While we generally agree that NERC should be concerned about the impact of any set of regulatory, legal or technological changes on the reliability of the electric system, we do not find, as NERC does in its preliminary analysis, that the CPP may be incompatible with sustaining reliability.

NERC's primary concerns are that in the relatively *short run,* high levels of coal (and oil) retirements, combined with lack of natural gas pipeline infrastructure, could make maintaining adequate reserve margins and achieving interim emissions rate targets incompatible. Over the *long run*, NERC is concerned that limits to achievable emissions reductions in Building Blocks 1, 2 and 4 will require significantly higher reliance on VERs, which, combined with potentially ongoing natural gas supply bottlenecks, could create reliability challenges related to VER integration.

Our primary conclusion is that the CPP is unlikely to cause such foreseeable reliability concerns. We find that current actions by system operators to respond to the ongoing fundamental transformation of the U.S. power system, a quickly expanding mix of technology options and available/possible changes to operational procedures, market and regulatory rules likely provide enough flexibility to maintain reliability, at least in expectation.

In the short-term, significant coal to gas switching can occur in dispatch during periods without gas supply constraints. The resulting lower capacity factor of coal generation will likely weaken the economic performance of coal generation, but since the CPP – unlike other environmental regulations such as MATS – does not require "retrofit or retire", states have the option to create mechanisms ensuring sufficient economic incentives to maintain coal-fired units sources required for resource adequacy early in the compliance period. At the same time, based on current market performance, we expect that in many cases lower cost alternatives to maintain resource adequacy will be available. There is understandable concern about the timing between final SIP approvals, which could happen as late as 2018, and the interim compliance period start year of 2020. However, it is important to emphasize that there is no requirement to meet a specific 2020 emissions rate target, nor is there a requirement to meet early requirements through building blocks 1 and 2 alone. Rather, states will be in CPP compliance as long as they meet average emissions rates equal to the targets set for 2020-2029. Any remaining concerns could be further reduced if the EPA clarified in its final CPP how and when it plans to react to states not being on track to meeting interim targets in response to having to take actions to respond to unforeseen reliability issues emerging in implementing EPA approved SIPs.

In the longer run, our analysis shows that the increase in VER penetration that may help meet the emissions rate reduction targets of the CPP will in all likelihood be very similar to the changes to VER penetration rates that would happen even absent the CPP. Driven by quickly declining technology costs and RPS statutes in many states, VERs at the regional level are for the most part on a growth path that is steeper than not only the BSER Building Block 3 assumption, but also steeper than would be necessary even if contributions to emissions reductions from other building blocks fell short of the EPA's assumption for calculating BSER. Consequently, system operators already have to prepare for a future U.S. electricity system characterized by significantly higher levels of VERs. Even those higher VER penetration levels, however, remain at levels that have shown to be manageable at reasonable incremental costs.

Finally, the proposed CPP itself recognizes the need for flexibility and provides various corresponding options. Apart from regional cooperation, which would likely help alleviate in particular concerns about the ability to manage larger amounts of VERs, the CPP also allows states flexibility to include in SIPs options for emissions reductions not included in BSER, to convert rate-based targets to mass-based targets, and to meet interim emissions reductions on average between 2020 and 2029. These flexibility options, especially with the addition of clarifying how EPA plans to react in cases of unexpected reliability events, should allow for the addition of infrastructure with non-trivial deployment times while preserving system reliability.

In addition to the flexibility incorporated into the CPP, the many technical, operational and market options are likely sufficient to allow states to meet the CPP emissions reduction targets while maintaining the high level of electric reliability enjoyed by U.S. electricity customers.

VII. Acronyms

ALR	Adaptive Line Ratings
BSER	Best System of Emissions Reductions
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CPP	Clean Power Plan
DLR	Dynamic Line Ratings
DR	Demand Response
EE	Energy Efficiency
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ESCO	Energy Service Company
FERC	Federal Energy Regulatory Commission
GW	Gigawatt
HVDC	High Voltage Direct Current
IRR	NERC's Initial Reliability Review
ISO	Independent System Operator
ISO-NE	ISO New England
lbs/MWh	Pounds per Megawatt-Hour
LED	Light Emitting Diode
LOLE	Loss of Load Expectation
LNG	Liquefied Natural Gas
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent ISO

MW	Megawatt
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combined Cycle
NREL	National Renewable Energy Laboratory
NYISO	New York ISO
PJM	PJM Interconnection
PV	Photovoltaic
RIA	Regulatory Impact Analysis
RMR	Reliability Must Run
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SIP	State Implementation Plan
SPP	Southwest Power Pool
TC	Topology Control
U.S.	United States
VER	Variable Energy Resource

VIII. Bibliography

Ahmad Faruqui, Jurgen Weiss, *Gas Demand Response*, Spark Fortnightly

Aidan Tuohy, *Challenges and Insights from Using Different Modeling Approaches*, EPRI UVIG Operating Impacts and Integration Studies, October 2014

Andrew Mills, Ryan Wiser, *Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power*, LBNL, September 2010

Bloomberg New Energy Finance and The Business Council for Sustainable Energy, *Sustainable Energy in America 2013 Factbook*, January 2013

Bruce Phillips, *Alternative Approaches for Regulating Greenhouse Gas Emissions from Existing Power Plants under the Clean Air Act: Practical Pathways to Meaningful Reductions*, February 2014

Bundesministerium für Wirtschaft und Energie*, Zeitreihen zur Entwicklung der erneuerbaren Energien in Deutschland*, August 2014.

California Public Utility Commission, *Renewable Portfolio Standard Quarterly Report: 3rd Quarter 2014*, October 2014

Dallas Burtraw, Matt Woerman, *Technology Flexibility and Stringency for Greenhouse Gas Regulations,* Resources for the Future, July 2013

Database of State Incentives for Renewables & Efficiency, Accessed December 2014 online at http://www.dsireusa.org/

Debra Lew, Greg Brinkman, *The Western Wind and Solar Integration Study Phase 2*, NREL, September 2013

Department of Energy Resources, *Massachusetts RPS & APS Annual Compliance Report for 2013*, December 2014

Ebinger, Banks, and Schackmann, *Transforming the Electricity Portfolio: Lessons from Germany and Japan in Developing Renewable Energy*, Energy Security Initiative at Brookings, September 2014

EIA, *Annual Energy Outlook 2014*, April 2014

EIA, *Electric Power Annual 2012,* December 2013

EPA, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,* June 2014.

EPA, Memorandum, *The Environmental Protection Agency's Enforcement Response Policy For Use of Clean Air Act Section 113(a) Administrative Orders In Relation to Electric Reliability And The Mercury And Air Toxics Standard*, December 16, 2011.

EPA, *EPA Technical Support Document: Goal Computation, Appendix 1*, June 2014

EPA, *EPA Technical Support Document: GHG Abatement Measures,* June 2014

Energy Ventures Analysis, *Energy Market Impacts of Recent Federal Regulations on the Electric Power Sector*, November 2014

EPA, *EPA Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants,* June 2014

ERCOT, *Future Ancillary Services in ERCOT, ERCOT Concept Paper, Draft Version 1.1*, November 2013

ERCOT, *ERCOT: Quick Facts*, accessed February 2015

Erik Ela, *Reliability, costs, and pricing impacts of stochastic scheduling*, NREL, October 2014

Eric Wesoff, "Austin Energy Switches From SunEdison to Recurrent for 5-Cent Solar," GTM, May 2014

FERC, *A National Assessment of Demand Response Potential,* June 2009

GE Energy Consulting, *PJM Renewable Integration Study*, March 2014

ICF, Options for Serving New England Gas Demand, prepared for GdF Suez Gas North America, October 22, 2013

Ira Shavel et al., *Exploring Natural Gas and Renewables in ERCOT Part II: Future Generation Scenarios for Texas*, December 2013

ISO-NE, 2014 Regional Electricity Outlook, January 2014

ISO-NE, *Monthly Market Operations Report December 2014*, January 2015

Jaclyn Trop, Diane Cardwell, "Tesla Plans $5 Billion Battery Factory for Mass-Market Electric Car," New York Times, February 2014

Jaquelin Cochran, Owen Zinaman, Jeffery Logan, Doug Arent, *Exploring the Potential Business Case for Synergies Between Natural Gas and Renewable Energy*, NREL, February 2014

Jonas Monast. Tim Profeta, Brooks Rainey Pearson, and John Doyle, *Regulating Greenhouse Gas Emissions From Existing Sources: Section 111(d) and State Equivalency*, Environmental Law Reporter, 3-2012

Jonathan Naughton, Thomas Parish, Jerad Baker, *Wind Diversity Enhancement of Wyoming/California Wind Energy Projects*, January 2013

Jonathan Naughton, Thomas Parish, Jerad Baker, *Wind Diversity Enhancement of Wyoming/Colorado Wind Energy Projects*, April 2013

Judy Chang et. al., *The Value of Distributed Electricity Storage in Texas*, November 2014

Judy Chang, Jurgen Weiss, Yingxia Yang, *A Market-based Regional Approach to Valuing and Reducing GHG Emissions from Power Sector*, The Brattle Group, April 2014

Judy Change, Kathleen Spees, Jurgen Weiss, *Renewables and Storage - Does Size Matter?*, Presentation at 15th annual POWER Conference on Energy Research and Policy, March 2010

Jurgen Weiss, *Solar Energy Support in Germany: A Closer Look*, The Brattle Group, July 2014

Kathreen Tweed, "Enernoc moves into natural gas demand response," GTM, April 2012

Lea Kosnik, *The potential for small scale hydropower development in the US*, Energy Policy, Volume 38 2010

Lopez et al., *U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis*, NREL, July 2012

Manomet Center for Conservation Sciences, *Biomass Sustainability and Carbon Policy Study*, June 2010

Mark Babula and Kevin Petak, The Cold Trurth: Managing Gas-Electric Integration: The ISO New England Experience, IEEE power and energy magazine, November/December 2014

Metin Celebi et al, *Policy Brief: EPA's Proposed Clean Power Plan, Implications for States and the Electric Industry*, The Brattle Group, June 2014

Milligan et al., *An Analysis of the Impact of Balancing Area Cooperation on the Operation of the Western Interconnection with Wind and Solar Generation,* NREL, 2011

Milligan, Kirby, King, Beuning, *Benefit of Regional Energy Balancing Service on Wind Integration in the Western Interconnection of the United States,* NREL, October 2010

Minnesota Department of Energy Resources, *Minnesota Renewable Energy Integration and Transmission Study*, September 2013

MISO, *Look-Ahead Tool Improves Efficiencies, Reduces Costs*, April 2012

MISO, *MISO 2013-2014 Winter Assessment Report*, *Information Delivery and Market Analysis*, June 2014

MISO, "MISO comments to the EPA," November 2014

Monitoring Analytics, LLC., State of the Market Report for PJM, Volume II, March 13, 2014

NERC, *Long-Term Reliability Assessment 2014,* November 2014

NERC, *Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review*, November 2014

NH Department of Environmental Services, *The New Hampshire Climate Action Plan*, March 2009

Nuclear Energy Institute, "US Nuclear Capacity Factors," update April 2014 at http://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/US-Nuclear-Capacity-Factors

NYISO, "Comments of the NYISO on the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units," 2014

Oncor, "West Texas Dynamic Line Rating (DLR) Project," Presentation in March 2013

Peregrine Energy Group, *Study on Long-Term Contracting Under Section 83 of the Green Communities Act,* December 2012

Samuel Newell, *Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM*, May 2014

Sarah Smith, "Pipe industry can respond to Clean Power Plan gas needs, groups say," SNL Financial, December 3, 2014.

SPP, "SPP assess Clean Power Plan, says more time is needed to implement," October 2014

Slava Maslennikov, Kwok Cheung, *Prototyping and Testing Adaptive Transmission Rates for Dispach*," ISO-NE, Presentation on June 25, 2012

Steven Nadel, Rachel Young, *Why Is Electricity Use No Longer Growing?*, February 2014

Thomas Berg, "Germany: German Renewable Energy Act—Changes In 2014," Jones Day, July 2014

Thomas Overton, "California Governor Wants to Raise State RPS Target to 50%," January 2015

Union of Concerned Scientists, *The Promise of Biomass; Clean Power and Fuel – If Handled Right*, 2012

United Technologies Research Center, *Micro-CHP Systems for Residential Applications*, 2006

U.S. Department of Energy, *2013 Wind Technologies Market Reports,* August 2014

U.S. Department of Energy, *Biopower Factsheet*, DOE/GO-102000-1055, June 2000

U.S. Department of Energy, Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector, February 2015.

U.S Department of Energy, U.S Department of Agriculture, *U.S. Billion Ton Update*, August 2011

U.S. Federal Register, Volume 29 No. 117 Part II: Environmental Protection Agency, June 2014, available at http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf

WADE Cogeneration Industries Council, "Comments of Proposed Rule, Carbon Pollution Emission Guidelines for Existing Stationary Sources"

WECC, *Loads and Resources Methods and Assumptions,* September 2014

CAMBRIDGE
NEW YORK
SAN FRANCISCO
WASHINGTON
LONDON
MADRID
ROME

THE Brattle GROUP