UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure — **Docket No. AD15-4-000**

STATEMENT OF JOHN MOORE, THE SUSTAINABLE FERC PROJECT

On behalf of the Sustainable FERC Project (Project),[1] I am pleased to provide views on the U.S. Environmental Protection Agency's (EPA) proposed Clean Power Plan (CPP) and the bulk electric power system.[2] The Project and its coalition partners have participated in nearly 20 years of Commission rulemakings, and we also participate extensively in planning, reliability, and markets initiatives in most grid regions of the country. We also have deep knowledge of state and federal environmental and energy standards and other factors influencing grid design and operation.

In considering the questions posed for this conference, we emphasize that fuel prices, technology shifts, the economy, increasing use of demand-side management, and other changes have shaped the power sector far more significantly than environmental standards. The grid does face reliability challenges due to aging infrastructure, lack of investment, and greater climate

---

[1] The Sustainable FERC Project is a coalition of environmental and other public interest organizations throughout the United States. The Project and its partner organizations engage in Commission proceedings involving transmission grid planning, operations and markets. The Project and its coalition members also are active stakeholders in RTOs, ISOs, and other FERC-jurisdictional entities throughout the country. See www.sustainableFERC.org for more information.

[2] EPA, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, 79 Fed. Reg. 34,830 (2014) (Proposed Rule), available at: http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13725.pdf.

extremes. Transitioning to a lower carbon electric system is an opportunity both to reduce air pollution and to build a more reliable, modern energy system based on flexible generating technologies, smart grid technologies, and more efficient energy use. As more than two decades of Commission involvement in these issues attests, this process is iterative and dynamic.

RESPONSES TO QUESTIONS

Since I am participating on the first panel of the technical conference scheduled for February 19, 2015, in Washington, DC, this statement focuses primarily on the questions for the first panel. However, I also address the infrastructure and markets topics of the second and third panels.

I. Electric Reliability Considerations

In developing compliance approaches to the proposed Clean Power Plan, it will be important to consider potential implications for electric reliability. This session will discuss how to sustain reliability as states and regions develop their plans to comply with the proposed rule. This panel will focus on how state, regional, and federal plans for compliance could affect grid operations, the tools available to identify potential reliability impacts, and how reliability planning processes and compliance planning efforts can be coordinated to address potential issues. This session should include a discussion of the Commission's role in this area.

1. ***What operational issues could arise under different compliance approaches? Are there operational issues that could arise if neighboring states adopt different methods of compliance?***

Fundamental to the CPP is its compliance flexibility. It allows states and generators to meet the targets using a wide range of resource choices, including state clean energy and energy efficiency standards, shared regional compliance strategies, multi-year averaging, and other options. No other Clean Air Act standard affecting electric generating units has offered this degree of flexibility. When coupled with more than a decade-long period available to meet the final standards, and the relatively modest target levels, the CPP will not create unusual or unique operational challenges for grid operators.

Grid Design and Operation Evolves to Accommodate New Requirements

From an operational perspective, experience shows that the system is capable of accommodating a range of environmental standards and requirements while maintaining reliability. There are numerous examples of individual electric generating units—within the same ISO/RTO market region—that are able to maintain grid reliability despite being subject to different fuel use restrictions, operational limitations, environmental standards, energy policies, and regulatory approaches. For example:

- In MISO, eight states have mandatory renewable energy standards (RES), and seven states have none. Of those states with RES policies, nearly all have different timing, target levels, and eligibility requirements. Moreover, most states in MISO are not exclusively within that RTO's footprint.
- PJM includes both states that are part of the Regional Greenhouse Gas Initiative (RGGI) program, which subjects generation units to carbon pricing, and states that are not part of RGGI.
- The NO_x and SO_2 trading markets, which have operated successfully for years, cross ISO/RTO boundaries.
- Emissions standards for conventional air pollutants in power plant operating permits vary depending on a variety of factors, including local air quality designations.
- Hydroelectric facilities have operating limitations at different times of the year.
- Municipal and investor owned utilities have different energy efficiency programs and policies.

Coal retirements, expanded use of energy efficiency and demand response, declining energy intensity in most regions, and more renewable energy will continue to produce changes in dispatch and operational practices to optimize efficiency and maintain reliability. But these changes can without doubt be accommodated, particularly with advance planning. Already grid operators are engaged in the process of identifying potential issues and planning and implementing measures to accommodate the changing characteristics of the system.

<u>FERC Should Encourage State Coordination on Compliance Strategies</u>

The two primary state plan regulatory structures under consideration are a rate-based credit trading system and a mass-based trading system. Either approach will reveal a price of carbon which can be reflected in market bids, just as other operating costs are reflected in the bids of electric generating units. Under a mass-based trading system, covered sources are required to hold an emissions allowance for every ton of CO_2 released to the atmosphere. Under a rate-based trading system, generators that operate above the target emission rate need credits to cover their excess emissions, while units operating below the target rate earn credits.

While experience has demonstrated that the system is capable of accommodating different regulatory structures, we would also emphasize that significant cost savings are achievable if states coordinate their plans within and across regions. EPA and others have modeled the CPP assuming both state-by-state compliance, with no averaging or trading across state borders, and through regional approaches. As logic would dictate, regional compliance—with greater geographic flexibility for compliance—reduces total compliance costs by allowing each region to take advantage of the most cost-effective compliance solutions, whether it is redispatch, renewable energy development, or other measures to reduce the carbon intensity of the fleet. EPA should continue to encourage regional cooperation, for example, by facilitating linkage and trading between states with the same policy approach, such as mass-based cap and trade. FERC could also be an important voice in support of regional compliance approaches which achieve all or a portion of the CPP-required emissions reductions.

2. ***What tools are available to address these potential issues and ensure that electric reliability is maintained as states and regions comply with the proposed rule?***

States and regions that have moved forward with clean energy policies in advance of CPP implementation have found that improved technologies and operational practices completely mitigate the concerns implicit in this question. Maintaining grid reliability requires a synergistic and evolving combination of resource adequacy, planning, operations, and markets. When systems have encountered reliability problems such as large scale blackouts, it generally has been the result of human error, poor planning, accidents, or poor maintenance. We are unaware of any environmental policies ever causing a blackout or other significant reliability issue. As noted above, much higher levels of clean energy can be accommodated on electric systems than will be necessary to comply with the CPP.

<u>Planning and Operations Tools Evolve to Maintain Reliability</u>

As the grid has evolved over time, with changes in regional resource mix, growth rates, fuel costs, and other changes, the tools available to assess and respond to reliability challenges also have evolved and changed. ISOs and RTOs have grown in size and experience over the years, resulting in more efficient planning and operations, and greatly improved communications. The continuing successful integration of variable energy resources into the grid (with far lower grid integration costs than initially estimated), demonstrates the value of these system tools.

For the resource adequacy component of reliability, the key for weather driven resources like wind and solar power is the extent to which they can be relied on during periods of maximum demand. Grid operators use the effective load carrying capability (ELCC) to help answer this question. ELCC statistically evaluates whether wind and solar power are coincident with peaking electric demands and forced or unforced outages of conventional units. The ELCC method and tools are relatively well established as standard practice when evaluating the capacity value or capacity credit for wind and solar power portfolios. Regional grid operators and the Department of Energy's National Renewable Energy Laboratory maintain locationspecific historic wind and solar resource data, and power output predictions can be matched against historic electric demand and conventional resource availability and outage rates.

More sophisticated, normal-operations reliability questions are addressed through sophisticated power flow modeling, day ahead and real-time generation ramping (up or down), real time grid updates in state-of-the-art control rooms (monitoring demand, generation output and outages, transmission constraints, etc.) and hourly production cost modeling tools. Wind and solar power profiles similar to those used for ELCC are necessary, as well as detailed conventional unit operational and economic parameters. Security-constrained, unit commitment and economic dispatch optimization modeling can evaluate key items such as operational costs due to ramping, impacts of load forecast uncertainty, limitations of contractual power provisions, transmission constraints, and reserve practices. Regions such as MISO already have developed the markets and operations products to dispatch wind, improve forecasting, and improve ramping capabilities.[3]

As levels of variable energy resources increase, modeling practices evolve to answer more sophisticated questions. Key areas of analytical capability and data evolution include:

- Ensuring renewable resource geographic diversity is properly represented;
- Capturing *sub-hourly* renewable variations and conventional power ramp characteristics;
- Considering use of dynamic rather than static reserve values; and
- Using renewable forecasting in commitment and dispatch decision frameworks.[4]

---

[3] See MISO, *Wind Integration*, available at: https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/WindIntegration.aspx (unit commitment and dispatch advances).

[4] For example, see 2013 International Energy Agency report on best practices for modeling systems with high penetrations of wind power, available at: http://www.ieawind.org/index_page_postings/100313/RP%2016%20Wind%20Integration%20Studies_Approved%20091213.pdf.

One of the new tools that has been used in many recent studies examining operational issues at high renewable energy penetration is Plexos, a commercial production cost model from Energy Exemplar. The availability and widespread use of this tool shows that the industry and regulators have methods, available data, and study examples to inform questions arising from CPP implementation options. In addition, the use of production cost modeling can help identify specific at-risk generation under different scenarios/assumptions, and power flow modeling can help identify transmission upgrades that may be needed if retirements occur.

Size Matters

In addition to developing better analytical capacity, it is also important to focus on the breadth of resource use and access. Broad access to larger pools of supply and demand will strengthen reliability and flexibility. In an analogous context, PJM reported in 2013 that, due largely to its nearly doubling in size in the last decade, the need for synchronized reserve calls decreased from once every three days to once every 12 days. Given the additional resources under PJM's economic dispatch, and that the largest single unit contingency has increased only from 1150 MW to 1300 MW, PJM now has more resources that can respond economically to a unit loss without resorting to reserves.[5]

Renewable Energy Is Reliable Energy

We emphasize that significantly expanding the level of renewable energy on the grid – far more than EPA and most grid regions have modeled to date in CPP analyses – can be accomplished over time while maintaining and even strengthening reliability. There is more renewable energy flowing through the power grid today than ever before. At times, wind has

[5] PJM presentation, Markets and Reliability Committee (Aug. 29, 2013); communications with PJM staff.

supplied more than 60 percent of the electricity on some utility systems without reliability problems.[6] *(See attached Exhibit A for a map of wind generation records as of late 2014; some levels have increased since then.[7])* Solar power now routinely contributes 10–15 percent of midday electricity demand in California.[8]

Due to more precise weather forecasts and sophisticated technologies, grid operators increasingly can predict and control wind and solar generation levels. Using advanced and often automatic control systems, grid operators can both increase and decrease power output, which helps to stabilize its electrical frequency and maintain reliability.

Numerous studies from grid operators, utilities, and others confirm that the grid is capable of handling high levels of renewable power. Among those conducting the studies are public and investor owned utilities, the Electric Reliability Council of Texas,[9] PJM,[10] the Minnesota Department of Commerce and Utilities and Transmission Companies in Minnesota,[11] the U.S. Department of Energy,[12] and the International Energy Agency.[13] Consultants conducting the

---

[6] *E.g.*, *Xcel Colorado sets U.S. record with over 60% wind*, available at: http://www.aweablog.org/blog/post/xcel-colorado-sets-us-record-with-over-60-wind (accessed February 5, 2015).

[7] Data courtesy American Wind Energy Association, from ISO and utility sources.

[8] California ISO, *Today's Outlook: Renewables*, available at: www.caiso.com/Pages/TodaysOutlook.aspx#Renewables (accessed November 25, 2014).

[9] Brattle Group, *Exploring Natural Gas and Renewables in ERCOT, Part II: Future Generation Scenarios for Texas* (2013), available at: http://www.texascleanenergy.org/TCEC_Report%20Final%20Clean%2012%203%2013.pdf.

[10] GE Energy Consulting, *PJM Renewable Integration Study: Executive Summary* (2014), available at: http://pjm.com/~/media/committees-groups/task-forces/irtf/postings/pris-executive-summary.ashx.

[11] GE Energy Consulting, *Minnesota Renewable Energy Integration and Transmission Study* (2014), available at: http://mn.gov/commerce/energy/images/final-mrits-report-2014.pdf.

studies include Brattle Group, GE Energy Solutions, KEMA, and Energy and Environmental Economics. The technical experts supporting the studies include many who reside at research institutions such as Lawrence Berkeley National Laboratory, National Renewable Energy Laboratory, Pacific Northwest National Laboratory, and Massachusetts Institute of Technology.

Renewable Energy Can Supply Ancillary Services

The shift in generation mix does not mean ancillary services needed for grid reliability will suffer. Utility-scale wind and solar energy resources can provide many essential reliability services, including:

- *Reactive Power*: +/- 0.95 power factor;
- *Ride Through*: zero voltage ride through;
- *Frequency Response*: available from wind and utility-scale solar if needed; and
- *Inertial Response*: available from most new wind plants if needed.[14]

NERC agrees that variable energy resources can provide other ancillary services, explaining that:

> As variable resources, such as wind power facilities, constitute a larger proportion of the total generation on a system, these resources may provide voltage regulation and reactive power control capabilities *comparable to that of conventional generation*. Further, wind plants may provide dynamic and static reactive power support as well as voltage control in order to contribute to power system reliability.[15]

---

[12] EnerNex Corporation, *Eastern Wind Integration and Transmission Study* (2011), available at: http://www.nrel.gov/docs/fy11osti/47078.pdf.

[13] International Energy Agency, *Wind, Sun, and the Economics of Flexible Power Systems* (2014), available at: http://www.iea.org/Textbase/npsum/GIVAR2014sum.pdf.

[14] *See* Federal Energy Regulatory Commission, *Standard Interconnection Agreements for Wind Energy and Other Alternative Technologies*, available at: http://www.ferc.gov/industries/electric/indus-act/gi/wind.asp (reactive power and ride through); National Renewable Energy Laboratory, *Active Power Controls from Wind Power: Bridging the Gaps* (Jan. 2014), available at: http://www.nrel.gov/docs/fy14osti/60574.pdf (frequency and inertial response).

[15] NERC, *Accommodating High Levels of Variable Generation*, at 22 (April 2009) (emphasis added), available at: http://www.nerc.com/files/ivgtf_report_041609.pdf.

Looking ahead, the extent to which continuing changes in resource mix characteristics will affect electric system operations depends on the nature of the local electric system. Flexible, modernized electric systems will have less difficulty accommodating resource shifts than inflexible, dated electric systems. Modeling will help to identify the need,[16] and proven technologies and changes in operational practices are available to provide the required services.[17] For example, newer resources can reduce the need for system inertia by responding more quickly and accurately to frequency excursions than traditional central station generating options. FERC's "pay for performance" rules on Order No. 755 were implemented to promote just this type of improved system operations.[18]

3. How will entities responsible for electric system planning (e.g., reliability entities, state public utility commissions, grid operators) coordinate with entities responsible for developing state and regional plans to comply with the proposed rule?

Grid planning processes, including the regional transmission planning initiatives required by FERC Order 1000, are currently in place in every FERC-jurisdictional planning region of the United States. These forums are well-suited to help states select the best mix of strategies to meet or exceed the CPP's final emissions standards, and to coordinate their implementation plans with regional grid planners.

---

[16] As an example of the type of system disturbance study that can be performed, see NREL's Western Wind and Solar Integration Study Phase 3, which examines the Western Interconnection large-scale stability and frequency response with high wind and solar penetration, and identifies means to mitigate any adverse performance impacts via transmission reinforcements, storage, advanced control capabilities, or other alternative means, available at: http://www.nrel.gov/docs/fy15osti/62906.pdf

[17] For example, synchronous condensers can provide system inertia if the loss of inertia proves to be a problem and advanced wind control capabilities, advanced solar inverter capabilities, demand response, and storage can provide very fast frequency response.

[18] *Frequency Regulation Compensation in Organized Wholesale Power Markets*, 137 FERC ¶ 61,064 (2011).

Regional Planning Can Facilitate CPP Implementation *and* Strengthen Reliability

Grid operators are empowered under Order 1000 to use their planning processes to support state implementation of the CPP. The planning process required under Order 1000 creates forums for states, utilities, and other stakeholders to bring CPP compliance strategies for discussion and critical review. Working together, the grid planner and states can identify conflicts among different state plans, and the grid planner can then create a regional transmission plan (updated on an annual basis) that helps to meet the states' CPP goals.

Critically, the regional planning process also provides a framework for assessing how well the state or regional plan can accommodate reliability in the face of potential unexpected grid challenges. Currently, regional (and utility-specific) planning considers precisely the kinds of issues that can cause unforeseen reliability impacts, including for example: (i) the unplanned retirement of a generating unit; (ii) permitting delays associated with new or upgraded infrastructure; and (iii) a lack of participation in demand side management programs. Sound planning, with significant input from states whose policies drive system needs, is the foundation for ensuring reliability.

Broadly speaking, FERC-jurisdictional grid planners have at least two important roles related to CPP plan development and implementation. First, they can provide technical and analytical support to help states craft and implement the most effective state plans. Given the wide range of compliance options in the CPP, states may want to evaluate several potential compliance scenarios. Regional grid planners already are beginning to provide meaningful guidance to states to help them assess options – guidance that otherwise is not readily available to the states.[19]

---

[19] For example, last September the Organization of PJM States asked PJM to assess the costs and impacts of several different potential compliance scenarios for the CPP. *See OPSI Data*

Second, these FERC-jurisdictional bodies have the independent responsibility to plan and operate a reliable and cost-effective grid. Acting under Orders 890, 1000, and other FERC authorities, they regularly assess how state public policy requirements (*e.g.*, state renewable energy and energy efficiency standards) will affect system needs. Coordinated planning by states and the FERC-jurisdictional regions will help achieve the CPP's environmental benefits at lower cost to consumers. The compliance timeline established under the CPP should provide states and planning regions with more than enough time to utilize Order 1000-compliant frameworks to identify and agree on cost-effective compliance solutions.

Using regional planning to support CPP compliance while minimizing reliability challenges is not a novel idea. For example, in its September 2014 preliminary assessment of the CPP, the Western Electricity Coordinating Council (WECC) identified ways in which it could support state compliance activities while also furthering its reliability goals, including:

- "Work with states and other stakeholders to continue to refine and adjust the underlying data sources that provide the analytical foundation for this report and future analyses;
- Provide data and information useful to the development of state compliance plans;
- Investigate potential reliability issues by conducting cross-functional analyses on potential or conceptual compliance plans using WECC's production cost model and powerflow model capabilities;
- Compare impacts of emission rate compliance with mass-based emission methods;
- Analyze possible multistate compliance options;
- Investigate how state compliance plans could interact and impact one another; and
- Convene groups of stakeholders, such as impacted utilities and state officials, to inform them of analyses related to any of the above topics and discuss regional impacts of state compliance plans."[20]

Request for Section 111(d) Modeling, available at: http://www.opsi.us/filings/2014/DATA-REQUEST-SEPT-2.pdf.

[20] WECC, *EPA Clean Power Plan: Phase I – Preliminary Technical Report* (Sept. 19, 2014), at 31, available at: https://www.wecc.biz/Reliability/140912_EPA-111(d)_PhaseI_Tech-Final.pdf.

In other words, regional planning entities and states can work together to meet each of their jurisdictional responsibilities: states develop cost-effective plans and regions maintain reliability.

Some may argue that Order 1000 is relevant only for planning the transmission system, and therefore is inadequate for facilitating CPP compliance while assuring state or regional resource adequacy. But Order 1000 is not properly viewed so narrowly: the process of considering what needs may arise from different state compliance plans will allow regional planning entities to provide useful information to state entities as they develop their compliance plans.[21] As WECC already is doing, grid entities can and should work with states to assess how different state compliance plans would affect grid reliability and resource adequacy while meeting state targets.

Account for All Demand-Side Resources

As the grid continues to evolve, grid planners must fully account for demand-side resources (energy efficiency, demand response, PV solar, combined heat and power, electric vehicles, and other storage) in load forecasting, modeling, and in the development of solutions to identified grid needs. These resources also will contribute, often significantly, to CPP compliance. Although some regions are making progress on accounting for these resources (*e.g.*, ISO New England), other regions lag in accounting and forecasting best practices. More accurate and locational accounting of these resources will improve reliability assessments. The Sustainable FERC Project looks forward to working with the Commission, regions, and states in the coming months and years to craft improvements to the forecasting process for these resources.

---

[21] For example, ISO New England's Regional System Plan considers the impacts of energy efficiency, demand response, distributed generation, and generation shifts, and also reviews all significant state and federal energy policy drivers affecting the grid.

4. Are additional tools or processes needed to address any potential operational issues or ensure coordination between relevant entities?

<u>Encourage Early Planning and Improve Modeling Approaches</u>

Although FERC-jurisdictional regional planning entities can facilitate better state compliance strategies, poorly-done regional grid planning can frustrate state efforts and undermine grid reliability assessments. Accurate modeling is the foundation of successful planning, and weak modeling can create challenges for states seeking optimal compliance strategies. For example, Southwest Power Pool's economic modeling of CPP compliance assumed that 9,000 MW of power plants would close by 2020, even though the interim target allows averaging over the years 2020-2029.[22] In contrast, PJM's economic modeling performed to date estimates power plant retirement decisions on plant economics under different compliance paradigms (*e.g.*, regional or state, mass- or rate-based), with the more realistic result that plants retire throughout the compliance period.[23] (Notably, PJM's economic modeling also found that higher renewable energy and energy efficiency levels resulted in fewer coal plant retirements, since more zero-carbon energy lowers the price of emission allowances and therefore reduces coal plant compliance costs.[24]) Compounding the problem is the lack, to our knowledge, of any significant inter-regional discussions on modeling the CPP, even though many states exist in more than one region's footprint and would benefit from more modeling consistency across regions.

---

[22] *SPP's Reliability Impact Assessment of the U.S. EPA's Proposed Clean Power Plan* (Oct. 8, 2014), available at: http://www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf.

[23] PJM, *Economic Analysis of Generation Retirement Potential due to the EPA's Clean Power Plan Proposal* (Jan. 7, 2015), available at: http://pjm.com/~/media/committees-groups/committees/teac/20150107/20150107-pjm-economic-analysis-of-generation-retirement-potential.ashx.

[24] *Id.* at 5.

Accurate modeling will be especially important after EPA issues final CPP rules and states begin to develop compliance strategies. Without realistic assumptions and inputs and an understanding of the final rule, grid planners should not claim to know or be able to model how the system will respond in order to achieve the state targets set by EPA.

To help improve modeling, grid planning, and reliability assessments, we encourage FERC to consider issuing an order to solicit more information on regional planning efforts in ensuring reliability while complying with the CPP and modeling best practices. The order would provide regional grid planning entities the opportunity to explain their modeling approaches and planning efforts. FERC's order could be similar to its 2014 order on fuel assurance directing the ISOs/RTOs to report on their efforts in ensuring adequate fuel, providing guidance on critical planning issues impacting reliability, and soliciting public comment on the ISO/RTO reports. As FERC explained in that order:

> *While the Commission could take action to impose solutions, and may need to in the future if the steps RTOs/ISOs have taken or plan to take prove inadequate, we find that the appropriate next step is for each RTO/ISO to provide the Commission with additional information to explain how its market rules address fuel assurance challenges. Although there are some common issues affecting all the RTOs/ISOs, there are also significant differences in the nature and scope of the fuel assurance issues among the RTOs/ISOs and it may be that there is more than one right answer for addressing fuel assurance. Therefore, we allow each RTO/ISO the opportunity to identify the fuel assurance issues most relevant to its markets and comprehensively describe the set of actions it has already undertaken or proposes to undertake to address these issues.*[25]

Following a public comment period, FERC could assess whether improvements are necessary, especially for modeling retirements, compliance timelines, renewable energy, and demand-side

---

[25] *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators*, 149 FERC ¶ 61,145, at 19 (2014).

resources. The FERC-jurisdictional goal is to guard against inadequate planning that could result in unjust and unreasonable rates and potential reliability issues.

We also see a need for more transparency on the forthcoming NERC reliability assessments of the CPP. The NERC process for conducting assessments is opaque and limited primarily to members of NERC's Planning Committee. Considering the significance of the NERC assessments, NERC should provide a forum, with FERC involvement, for NERC to discuss modeling approaches, assumptions, and other modeling-related matters with all stakeholders. Most planning regions currently do this for their normal system planning – they seek stakeholder input on proposed planning metrics and models and adjust them as appropriate. NERC should do the same, with FERC providing the process framework for public participation and review.

The Clean Power Plan Is Designed to Protect Grid Reliability

It is important to emphasize how ensuring reliability is already well reflected in the CPP proposal. EPA has embedded three features in the structure of the CPP that provide the flexibility needed to accommodate the possibility that particular plants may have to run for reliability reasons, and thus obviate the need for any additional or external "safety valve":

- Flexibility over more than a decade (2020 to 2029 interim target) to trade, bank and borrow allowances or use other market-based approaches to avoid mandating reductions at any individual plant such as a reliability critical generator, or at any specific period of time (*e.g.*, during the summer peak demand period);
- Flexibility to use an array of system resources, including demand-side resources, for compliance; and
- Flexibility to use multi-state options to meet all or part of the CPP reductions.

These flexible compliance options will mitigate potential reliability needs. Indeed, the inherently flexible structure of the CPP, which takes advantage of the dynamic qualities of the electric system and its multiple means of delivering energy and ancillary services, is designed to allow compliance while putting minimal constraints on plants required for reliability purposes.

The CPP flexibility also stands in contrast to the MATS rules, which required that specific plants meet specific emission limits. Consequently, a "safety valve" allowing excess emissions beyond targets and compliance deadlines is unnecessary. And because of the flexible mechanisms provided by the CPP, there is no conflict between "must-run" plants and CPP compliance. A plant that needs to run for reliability purposes can comply with the standards by means of emissions averaging over time (inherent in annual and multi-year compliance periods), averaging among generation sources, and emissions credits from zero-carbon and efficiency resources.

Some reliability concerns appear to be premised on the idea that states will forgo the flexibilities available under EPA's proposal and instead dictate plant-by-plant operation limits. But it is highly unlikely that any state would adopt such an approach. Rather, states are likely to choose plans with flexibility – for example, emission rate standards that allow generators to comply through an emission credit regime, or mass-based emission standards that allow compliance through purchase of allowances.

Because the CPP is still not in final form, and because it will be necessary to conduct specific and granular regional and local system planning studies to account for new generation resources entering the system as well as transmission upgrades to alleviate constraints, it is premature to stipulate precisely what the contours of any additional reliability mechanism might be, much less foresee the nature of remedy or relief under hypothetical scenarios. However, if an otherwise unavoidable reliability problem is identified and cannot be accommodated under the state plan by normal market forces, we think that it will be recognized with ample time for EPA to use its authority under Section 111(d) of the Clean Air Act to adjust a state compliance schedule, provided that the emissions are made up elsewhere within the state or region. In any event, with the careful and accurate planning described above, state plan development and implementation will avoid reliability issues triggered by the CPP.

II. Identifying and Addressing Infrastructure Needs

Ensuring adequate infrastructure to support system changes due to the CPP is important to a successful program, and can be accommodated under current practices. FERC-jurisdictional planning regions and grid operators have a proven history of responding to both market- and policy-driven changes through annual planning processes and timely revisions to market rules and system operations, successfully maintaining both reliability and a stable market. These entities are similarly well-prepared to respond to the CPP if any need exists. The electric sector is already in the process of transitioning towards more natural gas and renewable generation.

Grid regions have tariff rules in place – such as regional planning processes and cost allocation for regional and interregional transmission facilities – that are responding to these and future system needs. According to the Edison Electric Institute's survey of utility transmission projects, total transmission investment is estimated to have reached a level of $17.5 billion (real $2012) in 2013 and is projected at approximately $60.6 billion through 2024.[26] According to the report:

> These transmission investments provide an array of benefits which include: providing reliable electricity service to customers, relieving congestion, facilitating wholesale market competition, supporting a diverse and changing generation portfolio and mitigating damage and limiting customer outages in extreme weather. New transmission investments also deploy advanced monitoring systems and other new technologies designed to ensure a more flexible and resilient grid. At the same time, all transmission projects are

---

[26] Edison Electric Institute, *Transmission Projects: At A Glance* (2014), available at: http://www.eei.org/issuesandpolicy/transmission/Pages/transmissionprojectsat.aspx.

> integrated into local systems in order to maintain the paramount objective of providing reliable electricity service to customers.[27]

Economic pressures arising from falling natural gas prices, new environmental standards, and other factors have resulted in a decrease in coal generation from 49 percent in 2007 to 39 percent in 2013, while maintaining the reliability of the grid. Grid managers have successfully addressed and incorporated these changes in their planning processes. PJM has successfully managed the largest number of fossil plant retirements anywhere in the country over the past several years. In the two years between November 1, 2011, and December 31, 2013, PJM received 171 deactivation requests, representing 20.4 GWs of capacity.[28] After a formal deactivation request is received, PJM conducts detailed reliability assessments to identify any potential reliability problems associated with the retirement as well as the upgrades needed to resolve any reliability criteria violations. Upgrades can include line terminal equipment upgrades, new substations, transformers, voltage support, substation reconfigurations, existing line rebuilds to achieve higher line ratings, and new transmission lines. PJM's successful management of generation retirements on this scale is a testament to the strength of the planning process and the abilities of the RTO staff and the transmission owners to manage these infrastructure changes through, among other things, infrastructure planning and development.

PJM also provides an excellent case study of successful response to market and other pressures. The winter of 2013-2014 – especially the "Polar Vortex" period – resulted in strain to natural gas and other fossil fueled plants and infrastructure across the country, especially in the Northeast. Since then, PJM has taken numerous actions to address specific causes of under-

---

[27] *Id.* (Executive Summary).

[28] PJM Interconnection, LLC, *2013 PJM RTEP Regional Transmission Expansion Plan: Book 1* (Feb. 28, 2014).

performance, such as winter testing requirements, maintenance and weatherization standards, and gas commitment and coordination improvements. PJM's swift response and adjustments demonstrates that regional grid entities are able to respond to circumstances, like the Polar Vortex, that arise far more rapidly and unexpectedly than any changes caused by the CPP.[29]

Some have questioned whether a perceived need for significant new interstate gas pipelines will impede compliance or otherwise create challenges in a carbon-constrained electricity sector. A recent Department of Energy (DOE) report answers that question firmly in the negative. It found that in a scenario assuming an illustrative carbon policy and high electricity sector natural gas demand resulting from accelerated coal retirements, the High Demand case (104 GW of coal plant retirements, a carbon price of $25/ton, and a 46% *increase* in natural gas consumption), only 10% additional gas pipeline capacity would be built by 2030 above the reference case of no carbon price – an increase which the report describes as "modest, relative to historical capacity additions."[30] Under the Intermediate Demand case (25 GW of retirements, $25/ton carbon price, and 25% increase in natural gas consumption), only about 4% of additional pipeline capacity would be built by 2030 above the reference case.[31] DOE attributed the low additional build to

---

[29] PJM also has proposed major changes to its forward capacity market, centered on a new "capacity performance" product, to further bolster capacity resource performance. *PJM Interconnection, LLC,* Docket Nos. ER15-623-000, EL15-29-000. The Sustainable FERC Project joined with numerous other organizations and companies in protesting PJM's filing, primarily on the grounds that PJM's other changes to reduce generator outages and non-performance precluded the need for the new product.

[30] DOE, *Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector* (Feb. 2015), at 24, available at: http://energy.gov/epsa/downloads/report-natural-gas-infrastructure-implications-increased-demand-electric-power-sector.

[31] *Id.*

several reasons, including diverse sources of supply relative to demand locations and increased utilization of existing pipelines.[32]

In addition to the conclusions of the DOE study, data from FERC and the Energy Information Administration (EIA), supplemented with data from SNL, on historical pipeline additions demonstrates that permitting and construction of pipeline projects generally takes fewer than three years.[33] Of the forty new pipeline projects included in the data set, the average duration between filing with FERC and the in-service date is two to three years, with most new pipeline projects taking two years from filing to completion. The average time between filing with FERC and completion for the two hundred eighty-four lateral, expansion, reversal, or conversion projects was one to two years. Most modification projects like these were completed one year from filing with FERC. Historical experience shows that both new pipeline projects and modification projects to existing pipelines are completed in fewer than thirty-six months. This guidance suggests that there is sufficient time for installation of additional infrastructure, even if State Plans are not approved until 2017-2018.

Even DOE's projected "modest" interstate pipeline expansion above the reference case likely is too high because the report fails to take into account likely future *decreases* in gas consumption. EPA's IPM model projects that power generation gas consumption will decline to a level below Reference Case gas consumption by 2030. EPA projected that by 2030, natural

---

[32] *Id.*

[33] *See, e.g.*, Energy Information Administration, *Natural Gas*, available at: http://www.eia.gov/naturalgas/data.cfm (information in the Pipelines tab); Federal Energy Regulatory Commission, *Major Pipeline Projects Pending (Onshore)*, available at: http://www.ferc.gov/industries/gas/indus-act/pipelines/pending-projects.asp; Federal Energy Regulatory Commission, *Approved Major Pipeline Projects (2009-Present)*, available at: http://www.ferc.gov/industries/gas/indus-act/pipelines/approved-projects.asp; and data from SNL Financial (available by subscription only; data available upon request).

gas consumption for electricity generation would fall 2.9-5.3% below the Reference Case. In fact, NRDC has shown that with more up-to-date assumptions than those EPA relied on in its analysis, power sector natural gas generation in the EPA policy case could decline by 19-23% in 2030 and as a result, natural gas consumption would decrease 17-22% below the Reference Case. NRDC also found that the natural gas share of the generation mix would decrease from 31% to 24% under more current assumptions.[34] Constructing significant new gas pipeline infrastructure, with long-term (20 year) shipper obligations, will divert resources from economically viable renewable energy sources and fail to account for increasing efficiency of energy use.

III. Potential Implications for FERC-Jurisdictional Markets

The history of the electricity sector teaches us that engineers, economists, and regulators can shape and reform wholesale power markets to meet challenges far more consequential than the CPP. In the 1990s, for example, many states restructured and deregulated their retail markets, upsetting decades of settled utility expectations for cost recovery of power plant operating expenses, and independent power producers sought non-discriminatory access to the transmission grid. FERC responded with Order Nos. 888[35] and 889[36] in 1996, and Order No.

---

[34] Natural Resources Defense Council, *The EPA's Clean Power Plan Could Save Up to $9 Billion in 2030* (Nov. 2014), available at: http://www.nrdc.org/air/pollution-standards/files/clean-power-plan-energy-savings-IB.pdf.

[35] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 75 FERC ¶ 61,080 (1996).

[36] *Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct*, 75 FERC ¶ 61,078 (1996).

2000 in 1999, which established voluntary regional transmission organizations.[37] RTOs now serve, through their utility members, two-thirds of the nation's electricity consumers.[38]

Grid regions also have deep experience in making changes to market design to adapt to changing grid dynamics, and they do not need to wait for the Commission to order them to take steps. For example, in 2014 the California ISO proposed, and FERC largely approved, capacity requirements intended to ensure the availability of flexible resources sufficient to allow integration of high levels of wind and solar power into its balancing area.[39] FERC also approved changes to ISO New England's capacity market, coupled with a winter fuel assurance program, to improve reliability and resource adequacy in a very gas-dominant market. Even more recently, PJM has proposed significant structural changes to its capacity market in an effort to address its concerns about generator performance, fuel assurance, and related issues.

Looking more deeply into the future, independent of the CPP, capacity market design likely will need to shift its focus away from peak load-focused goals and the assumption that all resources provide the "same service" and toward flexible performance as variable energy resources, energy efficiency, and distributed resources increase their contributions to daily dispatch models.[40] The Regulatory Assistance Project's work on *Beyond Capacity Markets* provides a productive discussion of market design with a focus on meeting net demand. We

---

[37] *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (1999).

[38] FERC, *Energy Primer, A Handbook of Energy Market Basics* (July 2012), at 42, available at: http://www.ferc.gov/market-oversight/guide/energy-primer.pdf.

[39] *Cal. Indep. Sys. Operator Corp,* 149 FERC ¶ 61,042 (2014).

[40] For example, by 2015, the California ISO's mid-day peak load will be almost 8 GW less than currently, due to displacement by solar power plants. *See* CAISO, *Flexible Resource Adequacy Criteria and Must-Offer Obligation* (Dec. 2012), at 8, available at: http://www.caiso.com/Documents/StrawProposal%E2%80%93FlexibleResourceAdequacyCriteriaMustOfferObligation.pdf.

concur with RAP's general analysis and many of its recommendations, which address several investment timescale market design ideas for flexible, performance-focused resources.[41] In addition, improved distribution system planning, deployment of advanced grid communication and control technologies, and the improving economics of storage and demand response will provide this flexibility.[42]

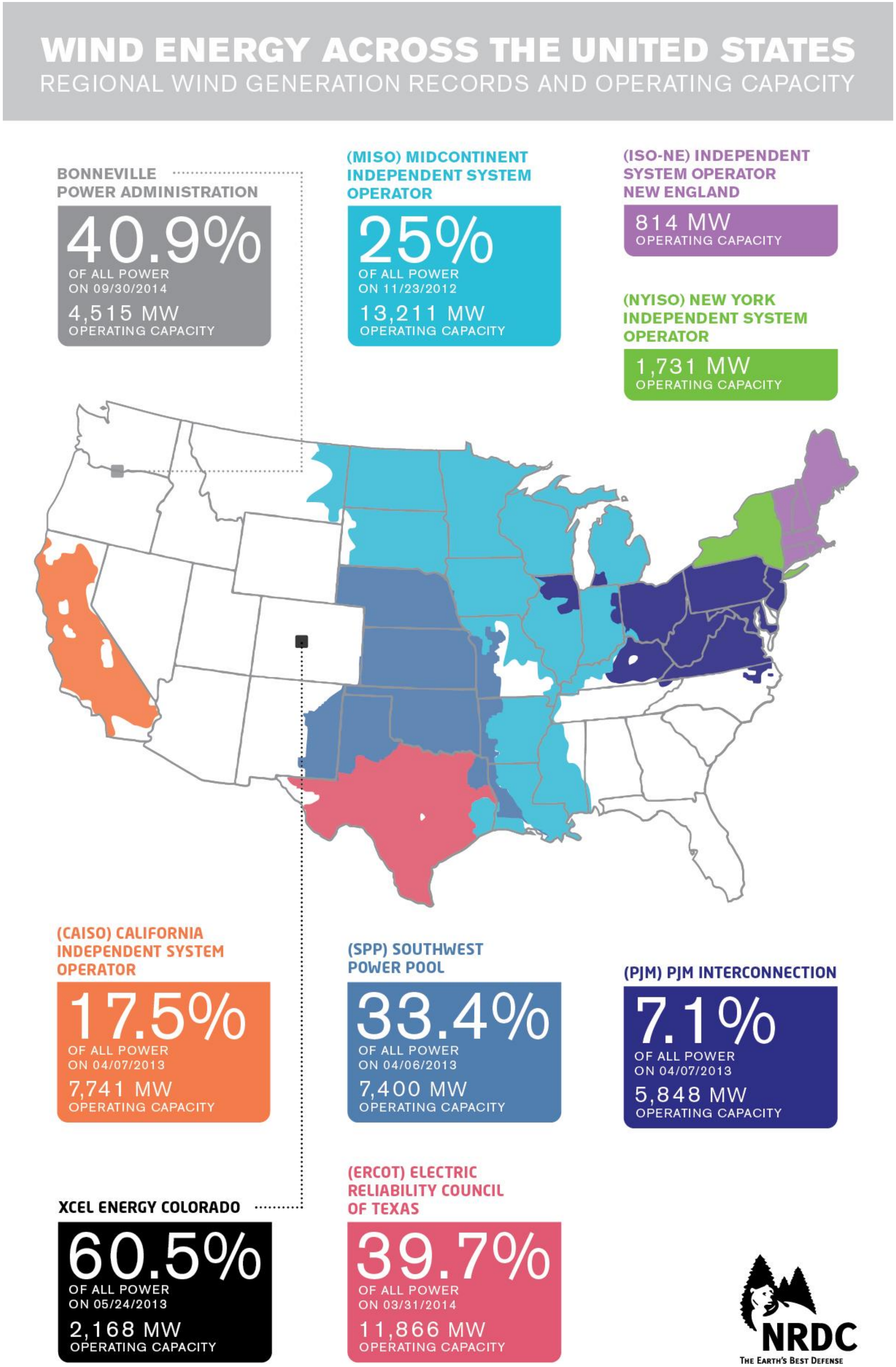
Dated: February 11, 2015

---

[41] *See* Regulatory Assistance Project, *Beyond Capacity Markets: Delivering Capability Resources to Europe's Decarbonising Power System*, available at: http://www.raponline.org/featured-work/beyond-capacity-markets-delivering-capability-resources-to-europes-decarbonised-power.

[42] *See California 2020 Low Carbon Grid Study*, available at: http://www.lowcarbongrid2030.org.

Exhibit A


WIND ENERGY ACROSS THE UNITED STATES
REGIONAL WIND GENERATION RECORDS AND OPERATING CAPACITY
BONNEVILLE POWER ADMINISTRATION
40.9%
OF ALL POWER ON 09/30/2014
4,515 MW OPERATING CAPACITY
(MISO) MIDCONTINENT INDEPENDENT SYSTEM OPERATOR
25%
OF ALL POWER ON 11/23/2012
13,211 MW OPERATING CAPACITY
(ISO-NE) INDEPENDENT SYSTEM OPERATOR NEW ENGLAND
814 MW OPERATING CAPACITY
(NYISO) NEW YORK INDEPENDENT SYSTEM OPERATOR
1,731 MW OPERATING CAPACITY
(CAISO) CALIFORNIA INDEPENDENT SYSTEM OPERATOR
17.5%
OF ALL POWER ON 04/07/2013
7,741 MW OPERATING CAPACITY
(SPP) SOUTHWEST POWER POOL
33.4%
OF ALL POWER ON 04/06/2013
7,400 MW OPERATING CAPACITY
(PJM) PJM INTERCONNECTION
7.1%
OF ALL POWER ON 04/07/2013
5,848 MW OPERATING CAPACITY
XCEL ENERGY COLORADO
60.5%
OF ALL POWER ON 05/24/2013
2,168 MW OPERATING CAPACITY
(ERCOT) ELECTRIC RELIABILITY COUNCIL OF TEXAS
39.7%
OF ALL POWER ON 03/31/2014
11,866 MW OPERATING CAPACITY
NRDC
THE EARTH'S BEST DEFENSE