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

Submission of Background Paper for the Commission's Benefit
In Preparation for the Technical Conference of February 19, 2015

The Commission has announced its' intention to conduct a Technical Conference on February 19, 2015 (Docket No. AD15-4-000) related to the potential implications of the Environmental Protection Agency's proposed Clean Power Plan on the reliability of the nation's wholesale electric markets, among other matters. The Energy Policy Group, LLC prepared a study for the Electric Reliability Coordinating Council (ERCC) that explored exactly these issues especially in the context of Regional Transmission Organizations. That study, entitled "The Clean Power Plan Endangers Electric Reliability: RTO and ISO Market Perspectives" was filed on December 1, 2014 as an Appendix to ERCC's comments in response to the EPA's request for comments on its Clean Power Plan.[1]

It was my feeling that this study may be helpful to the Commission in framing questions and discussion areas for the upcoming technical conference and in determining how it should respond to the issues presented, and thus I am providing the attached report to the Commission for its consideration in this Docket.

Bruce Edelston

Bruce Edelston
President
Energy Policy Group, LLC
January 23, 2015

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

The Clean Power Plan Endangers Electric Reliability:

RTO and ISO Market Perspectives

Supporting Analysis Prepared by

Energy Policy Group, LLC

for the

Electric Reliability Coordinating Council

November 28, 2014

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The Clean Power Plan Endangers Electric Reliability:

RTO and ISO Market Perspectives

EXECUTIVE SUMMARY

Background

The Environmental Protection Agency's proposed Clean Power Plan (CPP), published in June 2014, raises substantial operational challenges for regional transmission organizations (RTOs). In the CPP, EPA specifies emission reduction targets for 49 of the 50 states, based on EPA's modeling that purportedly shows that each state can achieve the specified reduction targets through the use of four "building blocks." States are to develop plans to meet the targets between 2020 and 2030, and are offered "flexibility" to use any combination of the four building blocks specified and/or other means (if approved by EPA) to achieve these targets. The State plans – required by June 30, 2016 (unless an extension is granted) - must specify how each state intends to meet the targets.

While there are many issues, questions and concerns with the ability of states and utilities to meet EPA's emission reduction targets based on the use of EPA's four building blocks (or through other means), building block 2, in particular, raises substantial issues for systems operators and RTO/ISO market operations because it involves changing the current methods of how electricity is dispatched throughout the nation's bulk power systems.

Either FERC or the states have *always* overseen how security constrained economic dispatch is conducted to maintain reliability while cost-effectively serving customers. But, if EPA's proposed rule becomes final, it, and *not* the system operators that federal and state regulators have entrusted, will make such critical decisions for our nation's utility customers regardless of costs.

Options and Issues

Implementing building block 2 to significantly increase dispatch of natural gas combined cycle (NGCC) generators while simultaneously decreasing dispatch of coal-fired generation would require a change in the way RTOs, ISOs and other system operators plan and operate their systems. It could have many unintended results and will likely lead to increased costs while reducing reliability. This change in economic dispatch will occur because building block 2 requires RTOs, ISOs and system operators to dispatch generation away from higher emitting generation (coal-fired generation) to existing lower emitting generation, and perhaps to new NGCC and co-firing of gas at coal plants, regardless of costs.

Dispatch today, in every RTO and ISO market, is accomplished according to a security constrained economic dispatch model which means, essentially, that units are dispatched in economic merit order, subject to reliability and security constraints. That means electric generating units with the lowest marginal operating costs are generally dispatched first and those with higher costs are dispatched as demand increases. Since fuel is typically the most significant component of marginal operating costs, plants with lower fuel costs (particularly nuclear and hydro) tend to get dispatched first. Since some renewables such as wind and solar have no fuel costs, they tend to also be used first, but since they are generally not-dispatchable, they are used on an as available basis assuming the system operator can do so reliably and that their market price bids are lower than alternatives.

There are basically two ways in which RTOs could change this existing dispatch procedure to implement building block 2. First, they could use some form of environmental dispatch – that is, rather than dispatching plants first in ascending economic order based on bids offered by competing generators, the RTO/ISO would explicitly take into account the emission profile of generators offering power and only accept those offers which have emissions characteristics that meet the requirements of the states' compliance plans. Whether a State takes a mass-based approach or a rate-based approach to their implementation plans, the state would have to restrict generation from higher-emitting sources and thus determine how many hours each plant within the state can operate, and the RTOs/ISOs would have to follow those guidelines. Thus, under environmental dispatch, RTOs/ISOs would be jettisoning security constrained economic dispatch based on locational-marginal pricing (LMP), which has been the entire basis for ensuring efficient market operations in those areas and replacing it with a system virtually guaranteed to increase costs and reduce reliability.

A second option to implementing building block 2 could be the addition of a carbon pricing mechanism to the existing security constrained economic dispatch model. Placing a price on carbon would allow RTOs/ISOs to continue to dispatch resources in economic order and to operate their systems, as plant owners would add the cost of carbon to their day-ahead and hour-ahead bids, and higher emitting sources would naturally drop in the economic dispatch order. Of course establishing the "right" carbon price is the key to making sure the mix of generation meets emission limitations. It is conceivable, for example, that future market developments (e.g., a significant decrease in the price of coal or, alternatively, an increase in the price of natural gas) could cause the price of higher-emitting sources to drop to a level that, even with the price of carbon, these higher-emitting units are more economical to run than lower emitting sources. How that "right" price is determined, and by whom, are complex issues with no easy solution.

A carbon price can be established in one of two ways – both of which would likely require action by state legislatures and/or state utility commissions. The first is a regional cap and trade program. The CPP specifically mentions the RGGI and California cap and trade programs. These existing cap and trade programs are voluntary. The problem is that the way the proposed rules are constructed, emission limitations must be met and enforced at the state level. It remains to be seen whether it would be possible for States to satisfy the proposed rules as written through a regional cap and trade program which simply prices carbon emissions through tradable allowances and is based on a single regional cap. Thus, one of the ways to price carbon would *require* some states to take a regional approach even if it was not in their customers interests to do so. The proposed CPP requires states to ensure compliance through self-executing laws or regulations which will require mandatory enforcement mechanisms not part of voluntary programs.

The second manner in which a carbon price could be established is through a direct price per ton on carbon emissions or a carbon tax. Each state could establish a future path of carbon taxes that would be modeled to reduce emissions to the state target for each year. Or states in an RTO could each enact the same carbon tax and determine a method for redistributing revenues on a multi-state basis. However, there is nothing in the preamble to the proposed rule suggesting that the EPA would accept a carbon tax (without more) as a compliance option. Each state is required to submit a plan to implement the CPP that sets forth emission performance standards that are quantifiable, permanent, verifiable, and enforceable, and that are projected to achieve the emission performance level prescribed by the EPA. It is questionable whether a carbon tax could meet all these requirements. And it Is not even clear whether a tax that would be imposed on power both used in the state and to be exported would be Constitutional under the Commerce Clause. And a carbon tax would have to be imposed by state legislatures. It would be very unlikely for many state legislatures to agree to pass a carbon (or any) tax in the current political environment and in some states it may not even be legal under state constitutions.

There are additional obstacles to the various regional approaches. Most prominently, there are important equity issues in any regional proposal. The proposed CPP assigns a different reduction target to each state. If each state's rate target is converted to a mass emissions target and then summed to calculate a mass emissions limit for the region, then when that regional limit is translated into a price (through a tax or auction of cap and trade allowances), there will be winners and losers. States with otherwise low compliance costs may pay more than they would have under an individual state tax regime and states with high compliance costs may pay less depending on how the regional program is crafted. Reaching agreement among many states within an RTO when so much money is involved will be a difficult obstacle to overcome.

Some point to RGGI as an example of a regional cap and trade plan that did at least attract nine states in the Northeast to participate, and was referenced by EPA as an example of a multi-state compliance plan. But some caveats are in order. RGGI was created as a voluntary mechanism for states with a pre-existing interest in reducing greenhouse gases. Thus, RGGI did not have specific mandatory targets to meet when they signed up and the cap was agreed to by the states participating. Also, the participating states were self-selecting. None of the states in RGGI (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont) are heavily dependent on coal. Whether RGGI would have formed within a region that includes both low cost and high cost states is questionable. What changes will be necessary to meet the CPP (or whether they can indeed meet the CPP with a regional mass emissions cap that doesn't require compliance by individual states) is a question yet to be answered and no one knows whether RGGI will survive under the new regime. And whatever one thinks, RGGI certainly cannot be characterized, even now, as a highly liquid market.

A state by state carbon tax would not have the same equity issues as a regional tax or cap. But there are other problems with state by state taxes. Presumably, the tax would be imposed on the output of the generating plants (*i.e.,* plants that emitted more CO_2 per megawatt would be charged a higher tax than plants with lower or no CO_2 emissions), and the tax would be paid in the state in which they were located. The tax would be factored into the price of the electricity, and RTOs would dispatch on that basis. But we all know that states and utilities both export and import power and that an RTO is normally indifferent to imports and exports within its footprint. So a state that has a small compliance obligation but a large load that imports much of its power needs won't have nearly as much of a tax burden as the state that was exporting the power that was consumed. Some of the inequities would be ameliorated to the extent that the burden of the tax is ultimately borne by the end user of the electricity, but sorting that out will be difficult.

There are other important obstacles to a carbon pricing regime. While EPA gives states an additional two years to file multi-state plans, given all the complexities involved that is clearly not enough time.

There is also the question as to whether a regional cap and trade or carbon price regime would add much efficiency to emissions reductions under the CPP – particularly if state by state targets are retained – given the stringency of the emission targets. EPA has already identified what it considers to be the "best" system of emission reduction for each state, *i.e.* how much each state can cumulatively reduce through its four building blocks. In order for a cap and trade system to work, however, there must be some cushion in the standards such that those states with lower compliance costs can over-comply with the limit, and then "sell" credits to the states with higher compliance costs which will under-comply. But given that the EPA has set each state's limit at the highest stringency it can achieve (according to EPA's estimation) each state will be forced to exhaust its own economic opportunities to meet its own goals, and there will be little opportunity to trade. Thus, a regional cap and trade under these circumstances may not have the same theoretical opportunities usually ascribed to these programs.

There are also issues created when a state is served by more than one RTO/ISO, or even an RTO/ISO and a non-RTO/ISO system operator - as is often the case. And what about states that are in RTOs/ISOs but have utilities that do not belong to the RTO/ISO and have to be dealt with separately? How does a state determine which RTO or non-RTO within the state has which proportion of the compliance obligation? What if one RTO is in a cap and trade system and the other isn't? How does the state determine proper dispatch of its generating plants in these circumstances? And the problems are exacerbated in that most states do not currently have regulatory control over independent power producers or public power and cooperative utilities. Such states will have to fundamentally alter its electric generating sector regulatory framework through legislation. And there are substantial equity issues within states' as to decisions on who gets to generate and when they can generate.

All of these issues are aside from the question of whether individual states – particularly those that are heavily fossil-fuel dependent, can meet the EPA's proposed reduction targets in time, and what the ramifications will be. EPA discusses reliability in the CPP and appears to assume that there won't be a problem. But individual RTOs and ISOs are beginning to learn that there may be problems and are seeking solutions and answers.

Conclusions

Planning and operating RTOs under EPA's proposed Clean Power Plan will be extremely difficult and raises numerous questions and issues that need to be resolved before EPA moves forward to finalizing and ultimately implementing this new regulatory regime. There are essentially two options that operators (RTOs, ISOs and other system operators) will have to incorporate in order to comply with the proposed regulations; (1) environmental dispatch; and, (2) pricing carbon through either a cap and trade regime or carbon taxes.

The environmental dispatch option may be possible on the individual system operator level – but whether multi-state RTOs will have the ability to conduct environmental dispatch depends on their ability to reach agreements with individual generators to dispatch their plants according to rules established by states. RTOs have no regulatory authority over the plants that they would be called upon to dispatch. And environmental dispatch would be very inefficient – RTOs would not be able to use bids made by generators to dispatch plants. They would instead have to dispatch plants in a combined way so that individual states meet their emission rate targets and overall reliability of the RTO's footprint is maintained – a very tough task indeed.

Theoretically, RTOs could operate more efficiently and could continue with current economic dispatch methods under a carbon pricing regime; however, how such a carbon pricing regime would work in practice and whether it could satisfy the proposed rules as written remain to be seen. Pricing carbon can be implemented at the state level (carbon taxes) or at the regional level (cap and trade or a uniform carbon tax), but as the CPP proposal stands now, regional solutions still must ensure that states meet their own targets, making a regional cap and trade regime unworkable at worst and inefficient at best.

Even if a single regional cap or price level (tax) for carbon were allowed, there would be equity concerns among winners and losers under that cap making agreement among multiple states difficult if not impossible. A state-by-state carbon tax within an RTO would work under the EPA

CPP proposal only if the State could show that such a tax would lead to verifiable and quantifiable emissions reductions and would thus achieve emission performance equivalent to the goals established by EPA. If such an approach were to be acceptable, then it may help solve the equity issues, and allow economic dispatch by the RTO. But a tax that varies by state raises issues regarding the handling of interstate power trading. And whether regional or state by state, carbon taxes would be difficult to get through state legislatures.

Both approaches lead to seemingly insurmountable obstacles. Environmental dispatch will be difficult to implement in the RTO context and very inefficient. And a regional plan like cap and trade or taxes, will raise equity issues and may not be permitted under the CPP. States have very difficult decisions to make.

EPA and FERC have not paid enough attention to any of these potential institutional problems that may be created by the Clean Power Plan, and even more significantly how constraints in the real world may lead to the CPP creating reliability problems in the nation's electric systems. Initial studies by RTOs of the ability to redispatch (and the associated costs) to meet the CPP's new requirements are troublesome and further study is critically needed before embarking down this path. The North American Electric Reliability Corporation, the group responsible for overseeing the reliability of the nation's electric systems, has also expressed concern. EPA and FERC should be examining the potential reliability impacts of the Clean Power Plan as proposed, and the results of those studies should be considered in developing a final rule. And more attention needs to be paid to the costs to end-use electric consumers that will result from the CPP proposal.

The Clean Power Plan Endangers Electric Reliability: RTO and ISO Market Perspectives

Introduction - RTO and ISO Issues

Background

The Environmental Protection Agency's (EPA's) proposed Clean Power Plan (CPP) raises substantial operational issues and challenges for electric utilities. In the CPP, EPA specifies emission reduction targets for 49 of the 50 states based on EPA's modeling that purportedly shows that each state can achieve the specified reduction targets through the use of four "building blocks." States are to develop plans to meet the targets for 2020 and 2030, and are offered flexibility to use the four building blocks specified and/or other means (if approved by the EPA) to meet these targets. The State plans – required by June 30, 2016 (unless an extension is granted) - must specify how each state intends to meet the targets.

The emissions rate targets are expressed in pounds of carbon dioxide (CO_2) per megawatt hour (MWh), and are based on the best system of emission reduction (BSER) for each state. The four building blocks on which the state targets are based are: (1) plant efficiency improvements of 6%; (2) replacing emissions from coal units by increasing generation from existing natural gas combined cycle (NGCC) capacity (including NGCC units under construction) to a 70% utilization rate; (3) replacing fossil fuel generation with non-emitting generation including renewables and nuclear; and, (4) Increasing state demand-side energy efficiency to generate 1.5% annual electricity savings.[1]

Because the states are given flexibility in how they can design their plans using the four building blocks or any other measures they come up with (and that are approved by EPA), it means that states will have to undertake considerable analysis to determine the best way to meet their targets. And the use of emission rate standards (in lbs/MWh) is important. Use of a rate standard by the state means that of any of the four building blocks will require use of Evaluation, Management and Verification (EM&V) of reduction measures as part of their SIP, which is difficult and problematic, especially for efficiency projects. It means that states will have to verify that efficiency measures directly lead to reductions in emissions at plants.

EPA does suggest that it will allow conversion of the rate standard to a mass emissions cap (in tons) standard. In November 2014 EPA issued a Technical Support Document which describes two potential ways in which implementing authorities may wish to translate the form of the goal

[1] On October 28, 2014, the EPA issued a Notice of Data Availability (NODA) which posed some additional questions about scenarios with respect to the various building blocks, including the possibility of making some less or more stringent. But the basic CPP proposed rules issued in June 2014 remain unchanged to date.

to a mass-based equivalent.[2] But because the translation involves forecasting future generation levels and emissions, and the proposed rules themselves affect those levels, selected methods may be controversial. Not properly accounting for demand growth in the conversion to a mass-based cap could make compliance more costly and difficult, as opposed to the rate cap which implicitly accounts for growth in emissions over time due to demand growth.[3]

While there are many issues, questions and concerns regarding the ability of states and utilities to meet EPA's emission reduction targets based on the use of EPA's building blocks (or through other means), building block 2 in particular raises substantial issues with respect to system and market **operations**, the focus of this paper.

Implementing building block 2 to significantly increase dispatch of NGCC generators while simultaneously decreasing dispatch of coal-fired generation would require a change in the way regional transmission organizations (RTOs) and independent system operators (ISOs) plan and operate their systems, and could have many unintended results and serious cost and reliability consequences. This change in dispatch will occur because building block 2 requires RTOs or ISOs (and other system operators) to redispatch generation away from higher emitting generation to lower emitting generation which will be existing and new natural gas combined cycle and perhaps co-firing of gas at coal plants, regardless of costs. Renewable energy, while non-emitting in most cases, cannot generally be dispatched and is used by system dispatchers as available when their price bids are acceptable. The EPA assumed a 70% dispatch rate for NGCC in setting its state targets off of EPA's estimated current dispatch rate for these plants of 46% nationally.[4] EPA points to the statistic that 10% of NGCC plants achieved a 70% capacity factor in 2012 as justification for its hypothesis that all plants could achieve that level through re-dispatch.[5] But there are multiple reasons why most such plants are not dispatched at such a high level today and that doing so would be costly and perhaps counter-productive.

First, the most obvious reason is that plants in RTOs or ISOs are dispatched today based on security constrained economic dispatch, which means essentially, that units are dispatched in economic merit order subject to reliability and security constraints. That means electric generating units with the lowest marginal operating costs are generally dispatched first and those with higher costs are dispatched as demand increases. Since fuel is typically the most significant component of marginal operating costs, plants with lower fuel costs (particularly nuclear and hydro) tend to get dispatched first. Since some renewables such as wind and solar have no fuel costs, they tend to also be used first, but since they are generally not-dispatchable,

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[2] U.S. Environmental Protection Agency, Technical Support Document (TSD) for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units Docket ID No. EPA-HQ-OAR-2013-0602, "Translation of the Clean Power Plan Emission Rate-Based CO_2 Goals to Mass-Based Equivalents," Office of Air and Radiation. November 2014

[3] MacCracken, Chris, et. al.., "EPA's Clean Power Plan: Challenges Ahead for Sources and States," ICF International White Paper. (undated).

[4] 79 *Fed. Reg.* at 34857

[5] *Ibid.*

they are used as available assuming the system operator can do so reliably. Even when the opportunity for greater dispatch of NGCC is available, there will be cost consequences. These costs include the stranded costs of coal plants that will no longer be operated and thus may be shut down and for which owners will still have debt obligations to pay, the costs of operating out of merit order dispatch, and increases in the costs of natural gas as a result of increased demand.[6]

Second, operating NGCC plants at a much higher capacity factor will place significant wear and tear on these plants and require significantly more maintenance. If the plants break down, their lost production may need to be met by less efficient plants, actually increasing emissions or possibly resulting in reliability problems.

The third reason is that gas supply and pipeline capacity may be insufficient to run gas plants at these higher capacity factors, particularly when and where gas is needed for home heating and other uses. Last winter's polar vortex effects in the northeast and elsewhere demonstrated that gas is not always available for use in electric production, even when needed. So gas may not be available at any price to run NGCC plants at higher capacity factors. And even where higher capacity factors are possible, lack of electric transmission capacity and infrastructure could be a constraint. The lead time for building new electric transmission usually exceeds the time needed to build new gas plants, so infrastructure may lag. For example, the Southwest Power Pool has estimated that the study, planning and construction process for new transmission facilities can take as much as eight and a half years.[7] The CPP fails to take into account the long lead time needed for new electric transmission projects.

Fourth, implementing building block 2 to accomplish a greater dispatch of NGCC will place significant challenges on the remaining part of the fleet to provide regulation (AGC) reserves. The NGCC technology has proven to be a very good source of regulation. By giving preference to NGCC as first-to-load and last-to-cut, other generating resources will necessarily be called upon to provide regulation reserves. These other resources are likely to include those resources with emission challenges, and are also likely to be resources that are not as efficient and capable of providing such reserves as NGCC resources. In fact, in this case building block 2 is in direct conflict with building block 1 which expects coal units to achieve heat rate improvements. The basic conflict is that heat rate efficiency of coal units decreases as the units are operated below their high limits. Giving dispatch preference to NGCC will necessarily require coal units to

[6] There are significant questions surrounding what effect increased demand on natural gas due to the CPP will have on prices, and more importantly, whether the gas pipeline network and related infrastructure is sufficient or can be expanded to meet the increased demand. Experience of Northeastern states during the polar vortex of the winter of 2014 suggests that there ought to be significant concern when even more demands are placed on gas infrastructure due to environmental limitations. Concerns about the inconsistencies between electric market rules and gas markets rules have also been cited as a continuing problem. These are all critical issues, but outside the scope of this paper.

[7] Southwest Power Pool, "Comments to the EPA on the "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" ("Clean Power Plan" or "CPP")," October 9, 2014.

operate at lower capacity factors, resulting in average heat rates for coal plants that will decline compared to current levels. Giving such high dispatch preference to NGCC, and the resulting increased use of coal for regulation (AGC) could also require the system operator to carry more operating reserves in order to maintain sufficient regulation reserves, and in particular to provide the minimum ramp rates necessary to meet reliability standards.

And the final reason – and potentially the most significant – is that many areas simply don't have alternatives to the current dispatch of coal as discussed in the following section.

Coal-Dependent States and Utilities

In adopting building block 2, EPA recognized that some states have little existing NGCC to turn to for dispatch because they are heavily coal dependent. For example, West Virginia relies on coal for nearly 97% of its generation, so increasing its NGCC dispatch within the state to reduce emissions is not possible. The building block 2 targets were thus adjusted for these states. These states thus have to rely more on the other building blocks, particularly if buying credits in some manner from other states isn't possible. But in the Notice of Data Availability (NODA) issued on October 28, 2014 the EPA seeks comment on stakeholder proposals to increase the dispatch to natural gas in these heavily dependent states by either including co-firing or new NGCC plants in the target.[8] Given that EPA's emission reduction requirements is largely frontloaded to 2020, building enough new gas plants (along with the associated gas and electric infrastructure) in time is likely not possible. And the costs of replacing a large portion of existing generation with new gas plants or with co-firing would be exorbitant.

In the NODA, the EPA also asked for comments on the suggestion that regional availability of NGCC should be considered for these coal-dependent states, allowing coal-dependent states to rely on other states that may have more than a 70% dispatch capability for NGCC.[9] The EPA seeks comment on the appropriate regional structure to use in such a framework and the appropriate manner in which the goals could be derived and allocated among states.

But it is not clear that even a regional trading system will help. The four building blocks on which the EPA targets are based were developed using the BSER. This simply means that each state will have to use the ***"best"*** system of emission reduction to meet its targets. If it can't exceed the "best," then it will <u>not</u> have lower emissions generation to sell to states without options to switch to gas. If it can, then it is likely that those credits or lower emission generation will come only at an extremely high cost, perhaps more than customers can pay. Again, reliability concerns arise. Even in a very large RTO, if each state is tasked to meet its BSER-based emission limitations, there will not be much of a market to trade for lower emissions.

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[8] 79 *Fed. Reg.* at 64546-47
[9] *Ibid.*

The same problem holds true for individual utilities that are heavily coal dependent. Such utilities will not have gas units to switch to and will be dependent on the existence of some sort of intra-state, multi-state or regional trading system to reach the emission reductions of building block 2, but other states and utilities have their own requirements to meet. Without such a trading system, either within the state or regionally, such utilities again would either be required to build new combined cycle gas-fired generation (and associated infrastructure) very quickly or face reliability problems for their customers, unless they are able to achieve Herculean results with respect to the other CPP building blocks.

The NODA raises additional concerns. EPA states:

> With respect to building block 2, stakeholders have offered a range of views. Some have commented that this component should be less stringent (i.e., require shifting less utilization from existing coal-fired units to existing NGCC units), some have offered that it should be more stringent (i.e., require shifting more utilization from existing coal-fired units to existing NGCC units), and others have offered that it should be more stringent in some states and less stringent in other states. Some stakeholders have also noted that they believe the higher levels of utilization of existing NGCC units proposed for building block 2 are not feasible in the early years of the 2020-2029 compliance periods due to infrastructure constraints and recent significant capital investments at some existing coal-fired units.
>
> Other stakeholders have suggested that focusing solely on increasing utilization of existing NGCC units ignores opportunities for emission reductions from the use of natural gas from states that are not already using natural gas for electricity generation.[10]

EPA does seek comment in the NODA on possible changes to the glide path of reduction targets between 2020 and 2030 and the possible phase-in of building block 2, which might be incrementally helpful. But while EPA appears to recognize the difficulty of implementing building block 2 based on the original CPP proposal – particularly in coal-dependent states - it appears now to be seeking comments on increasing the requirements for these states based on the option of building new NGCC plants in these states – making building block 2 even more difficult to address.

Several RTOs have already pointed to potential reliability problems even assuming a regional solution to emissions reduction (which may not be allowed under the proposed rules). The Southwest Power Pool (SPP) has issued preliminary results indicating increased thermal overloads and low voltages due to EPA's assumed retirements in the CPP. In addition, they found that summer peak cases are not solving under single contingency, which indicates low voltages due to lack of reactive support.[11] The Mid-Continent Independent System Operator (MISO), while not pointing to specific reliability difficulties, found that the cost for the region of

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[10] 79 *Fed. Reg.* at 64545
[11] Nickell, Larry, "Southwest Power Pool Presentation on Effects of 111(d)" (undated).

implementing building block 2 only was $53 per ton of carbon reduced, and gas use would increase from 5% to 26%.[12] The effects of the CPP, according to MISO, were distributed fairly evenly and broadly across its footprint. MISO did, however, find in a zonal survey conducted of its members that there is uncertainty as to whether parts of the system will have adequate reserves in 2016, even before implementation of the CPP.[13]

The Electric Reliability Council of Texas (ERCOT) in a recently completed analysis found:

> ERCOT anticipates that implementation of the proposed Clean Power Plan will have a significant impact on the planning and operation of the ERCOT grid. ERCOT estimates that the proposed CO2 emissions limitations will result in the retirement of between 3,300 MW and 8,700 MW of coal generation capacity, could result in transmission reliability issues due to the loss of generation resources in and around major urban centers, and will strain ERCOT's ability to integrate new intermittent renewable generation resources. The Clean Power Plan will also result in increased energy costs for consumers in the ERCOT region by up to 20% in 2020, without accounting for the costs of transmission upgrades, procurement of additional ancillary services, energy efficiency investments, capital costs of new capacity, and other costs associated with the retirement or decreased operation of coal-fired capacity in ERCOT. [14]

Other RTOs will be looking at impacts on their systems. Importantly, the North American Electric Reliability Corporation (NERC) has also weighed in. While NERC did not develop nor advocate any policy positions, it did suggest that

> ... the proposed CPP requires comprehensive reliability assessments to identify changes in power flows and ERSs. ERSs are the key services and characteristics that comprise the following basic reliability services needed to maintain BPS reliability: (1) load and resource balance; (2) voltage support; and (3) frequency support. New reliability challenges may arise with the integration of generation resources that have different ERS characteristics than the units that are projected to retire. The changing resource mix introduces changes to operations and expected behaviors of the system; therefore, more transmission and new operating procedures may be needed to maintain reliability.[15]

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[12] Mid-Continent Independent System Operator, "GHG Regulation Impact Analysis – Initial Study Results," September 17, 2014.
[13] Moeller, Claire, "Presentation on MISO-OMS Survey results to the Federal Energy Regulatory Commission," September 18, 2014.
[14] Electric Reliability Council of Texas, "ERCOT Analysis of the Impacts of the Clean Power Plan," November 17, 2014.
[15] North American Electric Reliability Corporation, "Potential Reliability Impacts of EPA's Proposed Clean Power Plan," Initial Reliability Review. November 2014.

NERC also suggested that more time may be needed for CPP implementation to accommodate changes to the bulk power systems necessary to maintain reliability.[16] As part of its mission, NERC intends to conduct more studies and has requested that the RTOs and ISOs also conduct or continue such studies.

Many observers have suggested that Federal Energy Regulatory Commission (FERC) should also undertake or require reliability studies of the CPP proposal, but so far nothing has been forthcoming. Such reliability studies are critical to determine the viability of the CPP and its potential impacts. FERC Chairman Cheryl LaFleur has stated publicly that she expects the Commission will have to get involved to make sure that reliability is protected as the CPP os implemented, and that such involvement should be built into the process. She further suggested that some type of reliability mechanism be incorporated into the final rule.[17]

A State Focused Rule in a Multi-state Operating Environment

Another critical problem with the CPP arises from the fact that responsibility for meeting and enforcing targets appears to be left only with the states, even though regional approaches are encouraged. When the state becomes the relevant unit-of-analysis for carbon planning purposes, anomalous and peculiar results follow. For example, the state plans required by the Clean Power Plan require the states to develop means to meet individual targets using in-state resources and operating mechanisms and enforce the targets, but at the same time suggests regional implementation is viable, referencing specifically the northeastern Regional Greenhouse Gas Initiative (RGGI) or California's cap and trade program (which has been made available to regional and Canadian participants) – both of which are voluntary programs that the states have adopted. EPA says nothing about whether or what changes to these existing programs would be necessary to meet the proposed requirements. California has a particular issue in that they assign carbon emissions from imports to the state to the first seller in the state, which would not work in a regional plan. California also has multi-sector coverage as opposed to the EPA plan which covers electric generating units only. And RGGI uses a mass-based emissions target that is regionally based and does not require individual states to meet state emission targets as long as they have bought sufficient credits from someone else in the region. EPA should at a minimum provide further guidance in its final rule on how existing regional frameworks need to be modified and how or if new regional frameworks can be established.

As it stands today, however, EPA and proposed 111(d) regulations require individual states to meet and enforce their required emission rates. Regional organizations, RTOs, ISOs or groups of states are not expressly provided this authority. This apparent conflict in state obligations and

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[16] *Ibid.*

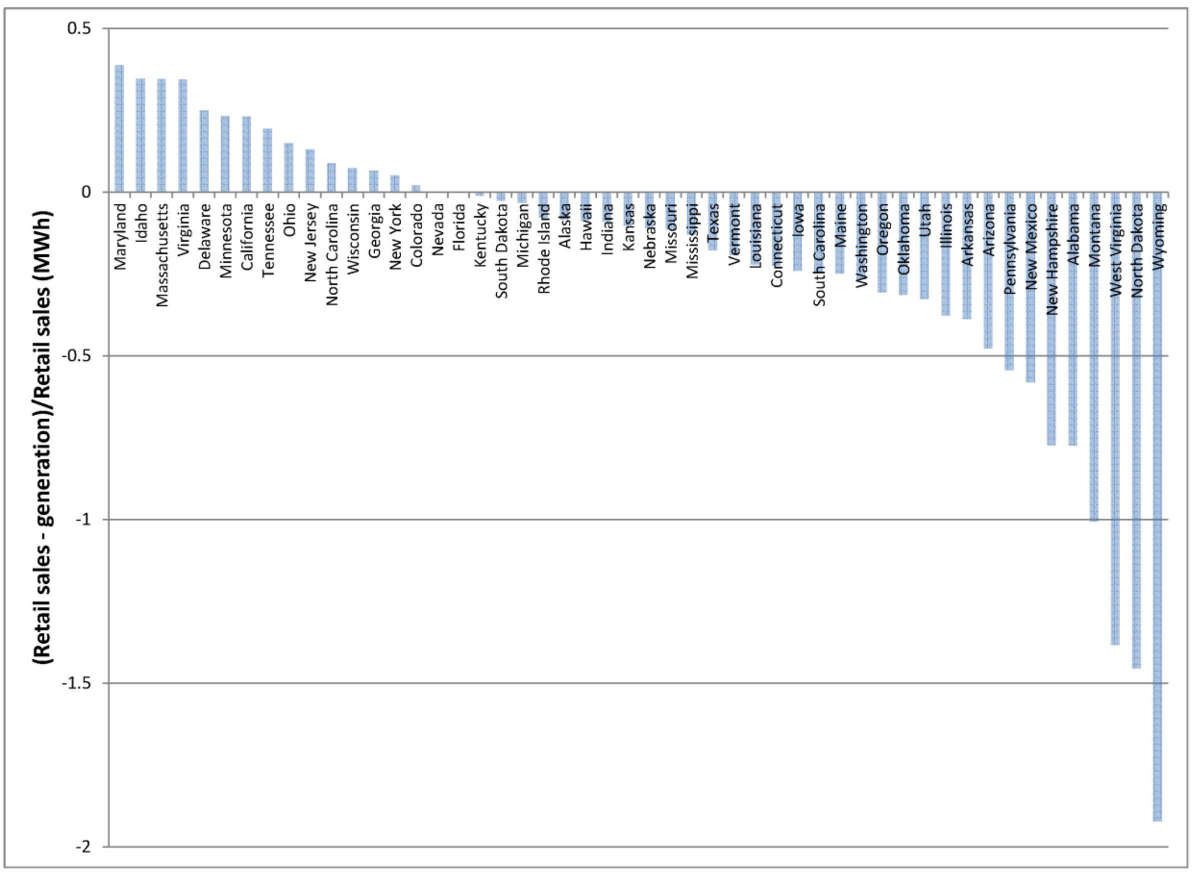
[17] Kuckro, Ron, "FERC's LaFleur wants 'reliability mechanism' in EPA Clean Power Plan. Energy Wire. November 10, 2014.

enforcement versus an allowance for regional approaches is at the heart of one of the major problems with the Clean Air Plan – the electric utility industry throughout the United States, with few exceptions, **operates** on a regional or multi-state basis. This is true in both traditionally regulated areas of the country with large multi-state companies like the Southeast (e.g., Southern Company, Duke Energy) and Northwest (Bonneville Power Administration and PacifiCorp), and in RTO centralized markets that cover much of the rest of the country.[18]

Figure 1 below provides a sense of the extent of power flows among states. The graph shows that Maryland, for example, imports a high proportion of its power needs (almost 50%) while Wyoming exports almost twice as much power as it uses within the state. All other states are between these extremes.

Figure 1

Electricity sales (MWh) in excess of generation (MWh) as share of sales in 2012[19]



[18] With the exception of California, New York and Texas ISOs which operate within single states.

[19] Energy Information Administration and Fowlie, Meridith, "Cross-state Power Flows Complicate the Clean Power Plan," The Energy Collective, November 12, 2014.

This means that state and federal regulators, and both vertically-integrated utilities and RTOs/ISOs with responsibility for operating their systems will likely need to fit a square peg – i.e., EPA's state-by-state requirements approach - into the round-hole of the multi-state planning, dispatch and operations that characterizes much of the electric power industry. All of this will have to be done by regulators, utilities, and RTOs/ISOs while maintaining reliability of the electric systems and striving to meet environmental requirements at a reasonable cost. Whether all of these operational changes can be made while the critical requirements of reliability and affordability are satisfied, within the 2020 deadline in the CPP for meeting initial targets, is extremely problematic if not impossible.[20] The NODA, issued October 28, 2014 does request comments on a potential phase-in of building block 2 which presumably would give more time for regional approaches to be considered.

The multi-state nature of grid operations also holds the potential to be disrupted by a state by state compliance approach in unintended and detrimental ways. A state that looks solely to itself to ensure compliance, and institutes restrictions for generating power within the state (and increasing its emissions) to export outside the state, would result in no one being able to look within that state with confidence for possible power purchases – even if purchases might be needed for system reliability. And what if utilities or independent power producers within a state not subject to state jurisdiction act on their own in ways that increase costs or emissions, or reduce reliability, in other parts of the interconnected network. Has the EPA provided states the authority to override existing governance of these different entities? And as one continues down this slippery slope, what incentives are there in the future for that state to consider expanding transmission interconnections with other states? If this state is not interested in exporting power, then why would other states be interested in moving power into that state? This state-by-state implementation/compliance plan could ultimately result in the loss of both economies of scale and economies of scope currently derived from multi-state operations of electric networks. Planning and operating reserves would have to be increased to reflect less dependence on neighboring systems. The potential movement towards an isolationism paradigm implicit in a state-by-state compliance approach will lead to all kinds of unintended consequences.

To some degree, building block 2 will be easier to implement in the traditionally vertically-integrated markets (the areas not covered by RTOs or ISOs). At least in these markets, utilities remain regulated as to generation output by the state public service commissions, and state regulated utilities are the ones who make dispatch decisions within the states. Thus, even though state regulators in regulated states may not have the authority to directly dictate dispatch and/or may not feel comfortable doing so, they likely could provide direction on how

[20] EPA states in its proposed rule: "To support state flexibility and encourage multi-state coordination in the development of multi-state and regional programs and policies, the EPA recognizes that flexibility in both the timing of plan submittal and the timing of CO2 emission reductions will be necessary." (79 *Fed. Reg.* at 34851) However, while the EPA gives a two year delay in filing a state plan if a state is participating in a multistate plan, it does not currently allow for a delay in meeting the initial 2020 emissions targets.

many hours plants could operate in a given period similar to what is done with respect to other pollutants. Thus, instead of dispatching the lowest cost mix of generation at any point in time (within reliability and security constraints), utilities could dispatch based on plant emissions to meet the EPA environmental requirements – known as environmental dispatch. This form of dispatch would by definition result in higher costs because plants would need to operate out of economic merit order, but it is one of the few options. Another option could be for the state to set a mass-based limit and require its utilities to meet that requirement through the plants it operates – perhaps by closing coal plants or limiting the hours per year coal plants can operate. Of course there are significant equity issues in these determinations if there are plants with multiple owners within the state. How does a state decide which plants must close or limit operations to meet the state requirements? In any event, once the decisions are made, utilities would then use economic dispatch the best they could with generation remaining available to the system in any period.

In either of these cases – where a utility itself alters dispatch or the state determines allowable periods of operation - inefficiencies will result in cases where the vertically-integrated utility operates in multiple states, as the utility must operate plants according to individual state requirements when lower cost options for dispatch to reduce emissions might be available in another state. So to this extent, traditional vertically-integrated utilities operating in multiple states have some of the same problems and concerns with a state-by-state approach as do multi-state RTOs and ISOs. But because utilities in the vertically-integrated states still control dispatch under supervision of state regulators, they do have a clearer path to implementation of the CPP than do the RTOs and ISOs. That is why this paper focuses mainly on how the CPP might be implemented in the RTO/ISO context.

Implementation Issues in RTOs/ISOs

Complications in States with Multiple RTOs or both RTO and non-RTO Utilities

Implementation of the Clean Power Plan in RTOs and ISOs will be extremely difficult and raises many significant issues that will need to be resolved. Assuming that RTOs/ISOs can get through these issues to have a workable plan in place by the initial target deadline of 2020 is wishful thinking. RTOs/ISOs have been in existence for less than 20 years and are still working on getting their markets to work well with existing issues facing the industry. Adding environmental requirements to these market issues could raise the level of complexity of market operations by factors of 10. But before even discussing how RTOs/ISOs could implement the CPP, there are some threshold RTO/ISO issues that have not been resolved by the proposal. The first is the set of issues created when a state is served by more than one RTO/ISO, or even an RTO/ISO and non-RTO/ISO vertically-integrated utility as is often the case. And what about states that are in RTOs/ISOs but have utilities that do not belong to the RTO/ISO and have to be dealt with separately.

Additional isssues include:

- How does a state determine which RTO/ISO or non-RTO/ISO within the state has which proportion of the compliance obligation?
- What if one RTO/ISO uses one compliance method while the other uses an incompatible method?
- What if one RTO/ISO is in a cap and trade system and the other isn't? How does the state determine proper dispatch of its generating plants in these circumstances?

And the problems are exacerbated in that states do not typically have regulatory control over independent power producers, so it is not even clear if the state on its' own can order independent generators to alter their emissions. And there are substantial equity issues in states' decisions on who gets to generate and when they can generate.

In these cases of states with multiple entities performing dispatch, it may even be necessary for states to insist on their utilities withdrawing from RTOs so that dispatch within the state can be regulated by the state in a manner that allows the state to meet the EPA emission requirements in the most efficient way possible for the state, without concerns for regional impacts. At the very least, states might insist on a certain dispatch order within the state to be conducted by the RTO so that the state ensures that it can meet its obligations at the lowest possible cost. That leads to the question of whether and how RTOs could conduct state by state environmental dispatch to meet individual state emissions targets.

Environmental Dispatch within RTOs

The seven RTOs/ISOs in the United States were formed beginning in the mid-1990's for very specific reasons – primarily to provide an institution for broader economic dispatch, integrate independent power production into that dispatch, and provide open access transmission in the face of perceived discrimination by vertically-integrated utilities. RTOs (including ISOs), after some experimentation and fine tuning, all adopted basically the same model of locational marginal pricing, whereas generators bid into a centralized markets on both a day ahead and hour ahead basis and get dispatched by the central system operator in order from the lowest bid to highest bid, taking into account security constraints. Generators get paid the highest cost bid that is used (dispatched) at their location (the "locational marginal price" or 'LMP"), and buyers - typically distribution companies on behalf of customers - pay that same amount for power. Both buyers and sellers can enter into any kind of side deals they want to shift risks to other parties, and buyers can also self-schedule their generation.

The key to RTO/ISO markets is that they are based on bids – no seller has to divulge its cost to the dispatcher, and the generator itself is the one with responsibility to meet any applicable environmental laws or regulations applicable to it. There are exceptions. Certain plants may have to run to maintain voltage control in the system and thus reliability. In these cases, the

RTO generally has must-run contracts with the generator which specifies when they can be called upon and how much they get paid. While each RTO has different rules and operates in different environments, they all have these common characteristics.

What does it mean to RTOs for states to have emission targets that they must satisfy under the Clean Power Plan? Let's assume for the time being that a single RTO/ISO emissions target (or emissions cap) would not be acceptable under the rule or cannot be developed by the RTO/ISO members. Later we discuss options that would allow such a target such as cap and trade on an RTO-wide basis. Without a regional solution, RTOs as the central dispatcher would have the responsibility for dispatching the generation in each state according to the state's plan for meeting emissions targets. In other words, the RTOs would conduct state-by-state environmental dispatch. Can it do that? First of all, RTOs have no regulatory authority to dispatch (or order a plant to operate). It would have to negotiate terms and conditions with every owner of generation in its geographical footprint, and presumably would need Federal Energy Regulatory Commission (FERC) approval for each one of those contracts. Several questions arise:

- Can the RTO force a generator to agree to be dispatchable?
- Can EPA, FERC, DOE, the states (or anyone) force such a result? For FERC-jurisdictional utilities? For utility-owned generation? For independent power facilities? For utilities (such as municipal utilities and cooperatives) that are not subject to FERC or state jurisdiction? For Power Marketing Administrations? For PURPA facilities?
- While the federal government can impose limitations on power plant source emissions, can it impose and enforce dispatch requirements if states or RTOs can't?
- What new local market power problems or issues arise as a result of any redispatch regime? What does that mean to end-use customers?

All of these are unanswered questions critical to whether the Clean Power Plan (and building block 2 in particular) can ever be made to work in RTO/ISO environments.

And how would the RTO consider economics in determining what plants get dispatched within emission limits. Would all plants still bid into the RTO but the RTO would eliminate bids coming in that don't meet a specified emissions limitation in a particular hour? And what hours would the RTO limit emissions and by how much, given that the targets are calculate annually, not hourly or daily? And there are security and reliability considerations that must be made as well. A state could decide on a certain dispatch order that has reliability implications in a larger region. And as Commissioner Moeller of FERC has pointed out, while a specific generating plant may not contribute much power to the grid and might be a candidate for shutting down or not running to reduce emissions, that plant may "have other outputs voltage support or "inertia" qualities that may contribute significantly to grid stability."[21]

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[21] Moeller, Phillip D., Commissioner, Federal Energy Regulatory Commission, " Written testimony Before the Committee of Energy and Commerce, Subcommittee on Energy and Power, U.S. House of

And once the RTO has accomplished environmental dispatch, how is LMP, the basis for charging customers and paying generators determined? It may be necessary to dispatch high cost gas units that would not otherwise be used absent environmental requirements. The supply curve that results will be anything but linear and will be very unpredictable. Should all generators still get paid the price for the highest cost dispatched generator? And would lower emission generators bid more than their marginal costs knowing that they are needed in the dispatch for environmental reasons? Would generators in RTOs now have to disclose their actual costs in order to prevent the exercise of market power? And interestingly, since dispatch often sets the real time prices paid by customers participating in demand-side management programs, what effect will environmental dispatch and non-linear supply curves have on participation in those programs? Will RTO markets even have a usable LMP price signal with environmental dispatch?

More importantly, how does the RTO ensure that enough generation gets enough revenues to ensure that it doesn't retire and remains operational to maintain reliability, amid what is likely to be a constantly changing base of generation due to retirements of plants. Which plant retirement breaks the back of the system? And all plants, regardless of their emissions, are going to want to run in the hours with the highest prices. Plants that would be economic to continue running if they run in high price hours might be uneconomic if they are shut out of those hours. If they don't get to run in those high-price hours, it may not be economic to keep the plants operational and more retirements will result. Will RTOs need to make some extra payments to keep those plants from retiring? Who will cover the costs of those payments? How is it determined what plants get such reliability payments?

And changes in dispatch will change flows within the transmission system. The existing transmission grid is built and maintained based on fairly predictable patterns of load and the location of generation. It is not clear that existing grids will be able to handle the new flows that result from environmental dispatch, and new infrastructure may be needed. Transmission constraints will change, which will have a feedback effect and may require further changes in dispatch. It will certainly take time, and will be costly to build out the grid to reliably operate the system with changes in power flows that will result from changes in dispatch.

As Professor Bill Hogan at Harvard has observed, mandating priority for low carbon technologies in energy dispatch presents more complications than might first appear because of the nature of the transmission system interaction with electricity market design.[22] As he points out, the complex interactions in the grid mean that changing how demand is met at one point in the grid changes flows in the grid, affecting multi-plant dispatch that may increase emissions elsewhere in the grid and increase overall emissions. Thus, the system impacts of emissions reductions at any particular plant location are not always easily predictable. Under environmental dispatch,

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Representatives, Hearing on FERC Perspective: Questions Concerning EPA's Proposed Clean Power Plan and Other Grid Reliability Challenges," July 29, 2014.

[22] Hogan, William W., "Electricity Wholesale Market Design in a Low Carbon Future," prepared for volume on Harnessing Renewable Energy edited by Jorge Padilla and Richard Schmalensee. Draft, January 23, 2010.

according to Hogan, "… market structures currently based on bids and LMP in a framework of security constrained economic dispatch would confront a substantial disconnect between the economic prices applied in the settlements system and the opportunity costs of changes in the dispatch. As we have seen from much experience, whenever market prices used in settlements systems diverge materially from the costs of real system operations, arbitrage opportunities and temptations are created that could undermine the dispatch and the market."[23]

Within RTOs, transmission is free flowing, but there are a set of property rights to transmission which are known as financial transmission rights (FTRs). Owners of FTRs have rights to receive payments from RTOs for those rights, which are based on the differences in LMPs (or the congestion costs) between two locations within the RTO defined by the FTR. In many cases, these FTRs are owned or acquired by load-serving entities so as to be able to hedge against their congestion costs consistent with their planned energy deliveries. Some RTOs auction FTRs and in some cases they are allocated to load-serving entities, but they are a tradable commodity. FTRs are important in that changes in an RTO's dispatch methods affect FTR values significantly. Thus changes due to environmental restrictions that do not have an economic dispatch basis will be extremely controversial as there will be winners and losers created in the FTR markets. Changes in the value of FTRs resulting from environmental dispatch will have numerous unintended consequences.

Assuming that RTOs are to run environmental dispatch based on state direction, within states there will be options as to what plants to run to meet environmental criteria (and some cases where there may be plants that must run for reliability purposes). Some of those plants could be independent generators beyond the reach of both RTOs and state regulators. How will fairness be ensured among generators within a state? Can states even dictate to RTOs how plants in the state should be dispatched? Can states, RTOs or FERC require NGCC plant owners to operate their plants at higher capacity factors? Will NGCC owners demand higher payments to account for increased wear and tear? And what about cases (described above) where there is no NGCC generation to turn to. Who has the responsibility for ensuring gas supply so that the NGCC plants can increase their capacity factors? Does the RTO simply not dispatch the coal plants in that state and assume that regional demand will still be met by increased generation in other states that have their own targets to meet? What if a state or states in the region fail to meet their target because other states have been leaning on them for lower emissions power? Under an environmental dispatch scheme, there would not be any price signal to prevent such leaning if generators are bidding their marginal costs as expected.

Even if all of these questions get answered, state-by-state environmental dispatch by RTOs is likely to be extremely inefficient. RTOs will not be able to take advantage of lower cost emission savings in other parts of their footprint. It will be important to understand the implications of an RTO dealing with a patchwork dispatch regime that treats generators differently depending on the state where they are located. Power flows within the RTO would certainly be affected,

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[23] Ibid.

and actions taken in one state could have detrimental effects on the emissions rate and costs of electricity generation in other states. It would, to use the technical terms, be extremely messy and inefficient. And it would no longer be clear what the extra expense of administering an RTO for a region is bringing to the table. Individual utilities can environmentally dispatch their own generation just as effectively as an RTO can dispatch their generation. And while the back office systems of RTOs may still have value for billing and settlements, it seems all the existing dispatch algorithms and software would become sunk costs.

Given all of these issues and problems with environmental dispatch at the RTO level – particularly given state by state targets and enforcement – it is likely that RTOs will seek alternatives. Environmental dispatch in the RTO/ISO context involves too many regulatory, institutional and cost questions to be viable. In the next section we discuss alternatives to pure environmental dispatch that RTOs and states within RTOs will likely want to consider but have their own issues and questions.

Alternative Operating Schemes for RTO Operations under the CPP

Multi-Objective Dispatch

There has been some research done in academia on the idea of dispatching electricity with multiple-objectives.[24] But it has not been field-tested at least in the United States. The idea behind multi-objective dispatch is that rather than develop a dispatch order solely based on economics (and then testing against reliability constraints), the optimal dispatch order would be developed – using complex mathematical models not described here – based on minimizing costs and emissions (or water use or some other resource constraint) at the same time. One significant problem with multi-objective dispatch is that there is never a single optimal solution to a single target- it is designed more to find a mix of lower emissions and lower cost scenarios - not to meet a single emissions constraint. While further work may be done to test the viability of these models in real world applications, it does not look like they are currently suitable for designing a dispatch regime designed to meet stringent environmental requirements, particularly where cost is not a major consideration.

Pricing Carbon

Pricing carbon in some manner is a second option for utilizing building block 2 in RTOs. By placing a price on carbon in real time, high emitting plants will have a higher marginal cost, will be forced to bid a higher price into the market, and thus will be less likely to be dispatched.

[24] See, for example, Dash, D.P, Das, S., and Pattanaik, J., "Multiarea Environmental Dispatch with Emission Constraints using Hybrid Intelligence Algorithm," International Journal of Engineering Research and Development, Volume 10, Issue 6. June 2013. Pp. 52-59.

RTOs will be able to continue using their existing methods of security constrained economic dispatch. The trick will be setting the price right to get the desired emissions mix. Setting it too high will place additional burdens on consumers. Setting it too low will result in not meeting required targets. But as discussed a little later, some of the same concerns and issues associated with environmental dispatch arise even with carbon prices. And while pricing carbon may be a more viable solution to meeting carbon emissions standards than environmental dispatch, absent Congressional action the legal authority for RTOs or groups of states to act in a way that is mandatory as envisioned by the CPP is uncertain. Putting a price on carbon would require unified action on the part of most or all states within a region, and action by the state legislatures and/or state public utility commissions would likely be needed. Whether that is possible, especially given the tight time frames and the political connotations of "pricing" carbon, is another critical question. If not, then RTOs (or states acting outside the RTO framework) will have to rely on some form of environmental dispatch – as inefficient as that may be.

There are two general ways that carbon might be priced. The first – cap and trade - was proposed in the most recent Congressional effort to deal with climate change, and ultimately failed. But in mentioning RGGI and the California cap and trade program in the proposed rule, EPA is clearly thinking that it is an option to comply with the CPP. The second general means of pricing carbon is a carbon tax. Each of these options is discussed in more detail below.

Cap and Trade (e.g. RGGI, California)

Basically, cap and trade works by setting a limit for a geographic area for the amount of carbon (in tons) that may be emitted within the area (along with rules about how imports and exports into and out of the defined area are handled). For each ton (or sub-unit) of allowed emissions, an "emissions certificate" is created. These certificates then are either sold (usually through an auction), or distributed at no cost according to some pre-determined formula, or some combination of the two. All emitting sources are then required to turn in an emissions certificate for each ton of carbon they emit.[25] Emissions certificates may be bought and sold within the geographic area covered. In some cases, offsets are permitted where emitters can earn certificates by investing in emission reductions elsewhere in the economy, in other geographic areas, or in energy efficiency or renewable energy. It is not clear from the proposed rule whether energy efficiency and renewables (building blocks 3 and 4) would be able to participate in a cap and trade market and how they would do so, since they are separate building blocks.

[25] Whether new sources that meet EPA's new source performance standards would also need emissions certificates is an open question that will be debated.

Emission rates vs. mass emissions targets

One feature of cap and trade markets is that they are typically based on mass emissions, as opposed to the proposed rule which is based on emission rates. EPA does suggest that states can convert from emission rates to mass emissions, and have provided illustrative examples of how that might be done.[26] The method matters because the conversion is based on projected generation and demand and could either increase or reduce the burden on states depending on projections used. The amount of reductions expected by the other building blocks also enters into the conversion, as EPA uses a rather unconventional formula to determine the rate-based state targets. Specifically, the building block assumptions are included in the formula by which the rate caps were calculated.

It may be possible to design cap and trade around an emissions rate protocol, and in fact NRDC developed such a "flexible intensity-based" proposal prior to release of the CPP.[27] But it is not clear how a tradable emission rate credit program such as that proposed by NRDC could be translated into generator marginal costs that would be bid into an RTO economic dispatch. In fact, EPA modeled its program analysis around a tradable emission rate limit. Under such a regime, states that can reduce their emissions rate below their target would sell credits to those states above their targets.[28] Those costs would increase rates in high cost states and revenues could be used to further reduce rates in lower emitting states, but unless those costs and revenues are faced by generators in real time, it would not affect their bid prices in an organized market. Thus, it is hard to see how environmental costs could be reflected in RTO dispatch under a regime relying on emission rates.

The worst of both worlds would be if some states within an RTO use a mass-based approach and some use a rate-based approach. Bruce Phillips of the Northbridge Group has produced a paper demonstrating the inefficiencies that would arise.[29] In short, less efficient gas units in a rate-based state could replace more efficient gas units in a mass-based state because of differences in production incentives under the two different methods. Even if one RTO developed a mass-based system and another used a rate-based system, problematic seams issues would result. Absent a national standard, the path to uniformity is complicated.

[26] U.S. Environmental Protection Agency, Technical Support Document (TSD) for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units Docket ID No. EPA-HQ-OAR-2013-0602, *op. cit.*

[27] Lashof, Dan et. al., "Cleaner and Cheaper: Using the Clean Air Act to Sharply Reduce Carbon Pollution from Existing Power Plants, Delivering Health, Environmental, and Economic Benefits," NRDC Issue Brief Update, March 2014.

[28] MacCracken et' al., *op. cit.*

[29] Phillips, Bruce, "Alternative Approaches for Regulating Greenhouse Gas Emissions from Existing Power Plants under the Clean Air Act: Practical Pathways to Meaningful Reductions," The NorthBridge Group, Prepared at the Request of the Clean Air Task Force, February 27, 2014

Cap and trade options

It is theoretically possible that cap and trade could be developed for a single state (as California has done), but it makes little sense given that the EPA rules apply only to electric generating plants. The only trading that could occur is between generating plants within a single state, and such trading would be limited. In states that have a large proportion of coal generation, there would be few other generators to trade with. California – currently a single state cap and trade regime - has multiple sectors covered and allows some offsets, so there is more opportunity for trading than would be available under the CPP which covers only one sector and doesn't allow offsets. Given these facts, only a regional cap and trade regime makes sense.

The proposed rule mentions RGGI as an example of a multi-state regime that might be adapted to meet CPP requirements. RGGI sets a single regional carbon cap for its members and auctions 90% of the emissions certificates. It covers electric generating units greater than 25 MWs and has a cap that declines 2.5% from 2015 to 2020. Projections are that emissions will be reduced in 2020 to one-half of 2005 levels. The auction proceeds in RGGI are invested in a range of clean energy, direct bill assistance, GHG abatement, and climate change adaptation programs. According to a Maine regulator and the former Chair of RGGI, the member states are working to ensure that RGGI is an effective compliance plan to satisfy the obligations of the Clean Power Plan.[30]

Most economists believe that cap and trade is the most efficient means to implement any limitation on environmental emissions. Cap and trade allows trading of emission certificates (also referred to as allowances) so that emissions reductions are made at the plants or in the ways which are most cost-effective to perform. Prices for allowances, in theory, rise or fall to the costs of eliminating a ton of emissions. By providing a trackable measure of emissions (allowances), it makes tracking and compliance relatively easy to verify. If public policy so desires, offsets can be provided for doing other things that reduce emissions (although offsets don't seem to be allowed in the CPP). Or renewables and energy efficiency can be encouraged by allocating them emissions allowances that they can then sell. These kinds of cap and trade program elements were part of the cap and trade bill considered by Congress several years ago.

Another advantage of cap and trade is that there is some precedent in its use for environmental programs. EPA has established cap and trade programs in the past for sulfur dioxide (the Acid Rain Trading Program) and for nitrogen oxides (the NOx Budget Trading Program). Both of these programs have been successful. But in this case, we are not talking about a program set up by EPA – under the CPP states would have the responsibility of establishing a cap and trade program on their own.

Cap and trade involves a decision as to whether to sell allowances or to allocate them on a no cost basis. If allocated, decisions must be made on what basis the allocations should be made –

[30] Littell, David. EPA's Proposed Clean Power Plan & Regional Compliance Options," presented at EISPC Washington, DC meeting, October 2, 2014.

to load-serving entities (and ultimately electric customers) proportional to the impact of the rules on their customers, according to size of the load served by the entity, or on some other basis. If allowances are to be sold, an auction is most likely to be the mechanism adopted. But what to do with auction revenues becomes the key question. Depending on public policy decisions, revenues might be used to reduce the cost burden of the emissions reductions to affected customers, provided back to states based on their relative size or load, or, as in the case of RGGI, used to fund clean power programs. Revenues might also be used to reduce government deficits, reduce other taxes, or any other of thousands of possibilities and combinations. Under the CPP, decisions on whether to allocate or sell allowances, and how to allocate or how to divvy up revenues will be left to voluntary agreement of the participating states. Reaching agreement among states when so much money is involved, absent an act of Congress, will be just one of the many difficult obstacles for states to overcome if they pursue a regional cap and trade system. And without Interstate Compacts which have their own set of issues, it is unclear how cap and trade rules within a regional entity could be enforced – raising the question of whether regional cap and trade regimes will ultimately meet the burdens that EPA requires for state emission plans.

From an operational perspective, the costs of allowances simply become another marginal cost for generators that would be added to their bid prices to the RTO's LMP market and thus would greatly simplify implementation of the CPP. The RTO is essentially blind to the operation of the allowance market – it simply sees higher prices for higher carbon emitting sources and thus lower carbon emitting sources are favored in the dispatch order. Current algorithms and software would not need to be changed. Assuming that the regional cap has been correctly established, prices of allowances will theoretically rise to the point where the right mix of generation is utilized to meet the cap. Compliance is more or less guaranteed because generators unable to acquire an allowance will not be allowed to bid into the dispatch.

Reliability Issues within cap and trade

There are operational issues related to reliability however, that will arise. Whether allowances are purchased by or allocated to fossil fuel-fired generators, they become valuable commodities. Thus, generators with a limited number of allowances are more likely to want to use those allowances when prices are high, and thus there could be generation shortages faced by the RTO during shoulder and off-peak, lower price periods. It is also conceivable that towards the end of the calendar year, allowances might be used up and again shortages possible. And units that aren't expected to be dispatched in enough hours to ensure sufficient revenues are likely to be retired and can't be called upon at any price. Furthermore, generators that can't buy allowances can't bid into the dispatch. Thus, the viability of cap and trade depends on their being enough clean generation to meet reliability requirements.

This means that for reliability purposes, the RTOs may need some kind of authority on their own to track allowances and plan the use of allowances so as to ensure that generation is available when needed. Each dispatch period over the year would have to have a certain number of allowances allotted for that dispatch period so that over the year, the proper number of allowances is used, at least based on predicted demand. How RTOs will do this and under what authority is unclear. And what happens if demand is higher than forecast in a particular period and allowances allocated for that period get used up is unclear. The RTOs themselves, through their trade organization - the ISO/RTO Council - have suggested a reliability safety valve for such situations that would be similar to a safety valve negotiated for the EPA MATS rule but would incorporate an up-front and continuing reliability analysis to ensure sufficient generation.[31] Under the ISO/RTO Council proposal, RTOs would conduct electric system reliability impact reviews related to compliance requirements and, where relevant, provide for appropriate compliance and/or enforcement flexibility to accommodate solutions to mitigate issues that would otherwise compromise reliability requirements. FERC Chairman Cheryl LaFleur has also suggested that the final EPA rules should contain a reliability mechanism as previously mentioned. The current CPP does not provide such a safety valve nor does it allow any exceptions for reliability.

Other obstacles

There are numerous other problems and obstacles to a regional cap and trade system. The biggest obstacle is probably the fact that with a single cap and uniform price developed for emissions within a region under cap and trade, there are significant winners and losers. Under the CPP, required state reductions range from 0% (Vermont) to 72% (Washington State) by 2030 over the base year of 2012.[32] The difficulty of meeting the targets varies from state to state, not only based on the percent reduction required but on other factors including the 2012 base emissions, opportunities with respect to the other building blocks (some states will have more renewable potential than others), and many other factors. Costs of meeting the targets vary significantly as well. A cap and trade program that prices the emissions reductions of every state within the cap and trade region the same thus means that states with less costly reductions pay the same for reductions as states with more expensive reductions. It is unlikely that states will be altruistic enough to agree to essentially subsidize required reductions in other states.

Some point to RGGI as an example of a regional cap and trade plan that did at least attract nine states in the Northeast to participate, and was referenced by EPA as an example of a multi-state compliance plan. But some caveats are in order. RGGI was created as a voluntary mechanism for states with a pre-existing interest in reducing greenhouse gases to participate. Thus, states participating in RGGI did not have specific mandatory targets to meet when they signed up and the regional cap was agreed to by the states participating. Also, the participating states were self-selecting. None of the states in RGGI (Connecticut, Delaware, Maine, Maryland,

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[31] ISO/RTO Council. "EPA CO2 Rule – ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals," (undated).

[32] Latham & Watkins. " EPA Proposes Unprecedented Greenhouse Gas Emission Reduction Program," Client Alert White Paper, June 6, 2014.

Massachusetts, New Hampshire, New York, Rhode Island and Vermont) are heavily dependent on coal. Whether RGGI would have formed within a region that includes both low cost and high cost states is doubtful. What changes will be necessary to meet the CPP (or whether they can indeed meet the CPP with a regional mass emissions cap that doesn't require enforceable reductions within each state) is a question yet to be answered. And whatever one thinks, RGGI certainly cannot be characterized, even now, as a highly liquid market.

Aside from the questions of equity with a regional cap and trade regime, there is the question introduced earlier in this paper as to whether a regional cap and trade would add much efficiency to emissions reductions under the CPP – particularly if states are still required to meet state requirements under a regional cap – but even if a regional cap can be agreed to. Because individual state targets are based on BSER, EPA has already identified how much each state can do along the four building blocks if it does its' best. Cap and trade, particularly if applied only to the electric generation sector, provides efficiencies only where there are lower cost opportunities for emissions reductions in one state as opposed to another state, so that allowances can be bought, sold, and traded. But when each state has to exhaust its own economic opportunities to meet its own goals, there will be little opportunity to trade. Thus, a regional cap and trade under these circumstances may not have the same theoretical opportunities usually ascribed to these programs.

While not specific to cap and trade under the CPP, other issues generally arising in the cap and trade context are leakage and resource shuffling. Leakage can occur as a result of imports or exports among regions. Leakage is the possibility that plants not subject to regulation will increase emissions to replace plants that lower emissions (and production). Leakage could occur, for example, if new gas plants are not required to obtain emissions certificates and replace more efficient existing NGCC or other plants that must obtain allowances. Resource shuffling is defined in California as "any plan, scheme or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid."[33] Resource shuffling can easily occur due to the fact that electricity is a commodity and is often sold and traded multiple times before reaching the end user. It is possible; therefore, that a purchase represented as coming from a particular source is actually coming from a higher emitting source. California has dealt with the problem by requiring the first deliverer within California to certify the emissions of the original source of power it has imported (with a long list of exceptions). But that first deliverer policy works only in a single state context. Policing such potential leakage or resource shuffling in an RTO context will not be an easy matter.

EPA may provide a hint of what it is thinking regarding regional versus state by state compliance in the notice of data availability (NODA) that it issued on October 28, 2014. While not referring to building block 2 specifically, EPA sets out a third way in which the renewable energy (RE)

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[33] California Air Resources Board. Cap and Trade Regulation Instructional Guidance, November 2012, Appendix A.

targets of building block 3 could be satisfied by discussing a regional approach to renewable energy. Specifically, EPA suggests the following possible approach for RE:

> This approach adjusts each state's RE target based on the RE potential available across a multi-state region in which the state is located. Under this approach, a state's goal would be informed by the opportunity to develop out-of-state RE resources as part of its state plan, and thus better align RE targets with the proposal to allow the use of certain out-of-state renewables for compliance, …. This regionalized approach could group states into regions; aggregate RE generation potential across states within each region; and **then reapportion the aggregate identified RE generation to individual states according to criteria that assume regional RE development in which parties in multiple states participate, regardless of the specific state where the generation occurs**. One example of this type of regionalized approach would be grouping states into the regional structure shown in the June 2014 proposal (79 FR 34866-34867); for each region, summing the RE target generation identified under the alternative approach in the June 2014 proposal for all states in that region; and then reallocating that summed generation proportionally to each state within that region by a chosen criterion, such as each state's share of total electricity sales within that region in 2012. The EPA requests comment on this regionalized approach for RE target setting, and specifically on the reallocation criterion.[34] (*emphasis added*)

EPA simply seeks comment on this approach, but the key is that EPA is suggesting that meeting a regional target for RE by itself isn't sufficient, but rather the regional target has to be re-apportioned to states and that states still have to meet overall individual state targets. This is possibly suggestive of what EPA is thinking with respect to a regional cap and trade requirement. They may be thinking that the regional mass emissions limitation be apportioned back to individual states in some manner.

Thus, there is nothing in the proposed CPP rules that confirms that a single cap and trade regime with a regional mass emissions limit will pass muster under the CPP. Until this question is clearly answered, it will not be known how a regional cap and trade program must be structured under the CPP.

Cap and trade summary

Thus, while cap and trade has some attractiveness as a means of complying with the CPP, there are legal, institutional, and maybe most of all equity issues that have to be addressed successfully before states can move forward along this path. At the very least, state legislatures and/or public utility commissions would have to give permission for their states to participate in a regional cap and trade plan (or there would have to be an Interstate Compact to make the Rule enforceable, likely requiring Congressional approval), and equity issues (as well as increased costs) will weigh heavily in state legislative and regulatory debates. Given the many

[34] 79 *Fed. Reg.* at 64551

hurdles and difficulty in getting there, it is just not clear that regional cap and trade is a viable option for RTOs and ISOs, in spite of it clear attractiveness for easing the complexity of system dispatch under the CPP.

Carbon taxes

A second manner in which a price can be put on carbon, allowing RTOs to continue to operate on a competitive-bid, LMP basis is through a direct price on carbon – a carbon tax. Carbon taxes would be established by acts of state legislatures and in the CPP context would likely be imposed on all carbon-emitting power sources on a $/ton emitted basis. While a regional carbon tax could be envisioned that would be set high enough to provide the right mix of generation, such a regional tax would require each state legislature to approve the same tax[35], and would come with exactly the same equity issues as a single price regional cap and trade regime. But unlike cap and trade, an advantage of a carbon tax regime is it could be done on a state by state basis, with different tax levels in each state to reflect the different levels of reduction required. Thus, the equity issues would be somewhat mitigated. And state-by-state carbon taxes would still allow security-constrained economic dispatch to be performed within an RTO. Each generating plant in the region would bid into the market a price that includes the state carbon tax to which it is subject.

There are legal questions as to whether the EPA has authority to approve state compliance plans that rely on carbon taxes. The Brookings Institution has prepared a paper that suggests that a state carbon tax is consistent with the Clean Air Act.[36] Brookings suggests that two requirements must be met – the tax must be a "standard for emissions" and that the tax results in a standard of performance reflecting the best system of emissions reduction. Thus, the state would have to show, at a minimum, that the tax results in emissions reductions that would otherwise be achievable with BSER – which according to EPA are the targets proposed in the CPP. The proper level for such a tax could be estimated through economic modeling, but there would need to be provisions for changing the tax if emissions reduction is greater or smaller than projected. Thus, year to year flexibility (and maybe the ability to bank reductions between years) will be needed in the final EPA regulations. And just like cap and trade, conversion to a mass emissions limit for each state, rather than a rate-based limit would probably be required. And the legality of a state carbon tax, again absent Congressional action, to meet a Clean Air Act requirement will ultimately have to be decided by the Courts,

The Brattle Group, in a report prepared for Great River Energy, has prepared the most comprehensive proposal of how a carbon tax might be implemented in a regional context for

[35] It is conceivable that a tax might be imposed through an Interstate Compact approved by Congress, but state legislative approval would still be needed to enter into such a Compact.
[36] Isenberg, Samuel D., "A State Tax Approach to Regulating Greenhouse Gases under the Clean Air Act," Brookings Institution Climate and energy Economics Discussion Paper, May 22, 2014.

regulating carbon.[37] The Brattle proposal was developed before issuance of the EPA proposal so it may need some tweaking to conform, but the framework is still relevant. The Brattle Group's proposal is based on a regional carbon price (which they smartly avoid referring to as a "tax"), so that there is still the problem of getting states to agree on a single "carbon price" level, but they seem to believe that through an independent facilitator such a single price could be developed. And Brattle assumes that individual states would meet their legal obligation under a single regional carbon price, which does not seem to be supported by the CPP as issued. But even with these caveats, looking at the Brattle approach is useful.

Under the Brattle approach, the rate-based standards would first be converted to mass emissions targets and summed to the regional level to develop a target path of mass emissions for the relevant RTO market. Those mass emissions target would be translated into a trajectory of carbon prices based on agreement by participating states. Brattle suggests that it would not be required that all states participate – states could meet their requirements in other ways. RTOs would continue their security-constrained economic dispatch with generators adding the regional carbon price to their day-ahead and hour-ahead bids. The proposed approach is intended to reduce short-term emissions to the regional target and alter the generation mix over time toward cleaner sources. Brattle proposes that all sources (including new) pay the carbon price.

While there are other methods for distributing the carbon "tax" revenues received, Brattle suggests that the most efficient, simplest and fairest long-term approach to distributing revenues is to refund them to load-serving entities in proportion to their contribution of load to the region. Load-serving entities would then refund these revenues back to consumers who paid for them in the first place. Brattle emphasizes that such a distribution does not distort the price signal to generators and results in a similar distribution of costs that would have occurred with a state by state or source by source approach. And Brattle goes into detail into its report on how imports and exports should be dealt with, another constraint to regional approaches discussed in more detail below.

While well thought out, the Brattle approach may or may not be consistent with the state by state requirements of the CPP and as discussed above in the cap and trade section, reaching agreement on a regional carbon price will be just as difficult because of equity differences among participants, although maybe not quite as hard as complying with a regional emissions limit through the sale of allowances. But if EPA ultimately allows such regional averaging, it could be a viable plan for states to consider that allows RTOs to continue to operate as they have with security constrained economic dispatch.

The other option is taxes that vary state by state. The tax levels would be calculated in much the same way as described above, except that the converted state mass emissions target would

[37] Chang, Judy, Weiss, Jurgen, PhD., and Yang, Yingxia, PhD. , "A Market-based Regional Approach to Valuing and Reducing GHG Emissions from Power Sector" A Discussion Paper Prepared for Great River energy, The Brattle Group, June 2014.

be used to project a path of individual state taxes, rather than regional emissions determining the proper level for a uniform regional tax. The RTO would still dispatch plants based on bids, but bids would be based on the specific state tax that was imposed on the specific generator. The RTO would collect a revenue stream of these different state taxes.

The state by state tax approach, while attractive from an RTO planning, operational and dispatch viewpoint, has difficult hurdles as well. First, there is no clear way to distribute revenues collected by the RTO. Using a load-based approach, as in the Brattle proposal, would mean that utilities with a lot of load but a smaller compliance requirement would collect more revenues than a smaller utility with a much greater compliance requirement. A fairer way to allocate revenues in this case might be based on the level of taxes paid – which should be proportional to the severity of the compliance requirement. But this might seem to penalize states who complied early, or result in some transfers from low cost to high cost states,

The problem is further complicated by imports and exports. With the exception of Alaska and Hawaii, states do not rely usually on in-state plants to meet all of their in-state needs. Some states are net-exporters of electricity and some are net importers. Would you charge taxes to plants solely on the basis of the state in which it is generated? The CPP is based on emissions from only in-state generation so that this might be the right answer. But take a state like Idaho which has little coal-fired generation within the state but imports a lot of coal-fired power. Surrounding states would pay more and Idaho less as a result. Unless imports and exports are properly accounted for, more equity issues will result. And could differing taxes in differing states that are charged on exports but not imports result in Commerce Clause violations?

Other issues arise. Should all electric generators, including new sources, pay the tax? Brattle says yes, but others would exclude new generation under the theory that their investment to meet new source performance standards is already a cost that will be included in their bids, and charging a carbon price would be charging twice. And as is the case with environmental dispatch and cap and trade, carbon taxes or prices still don't help if there is not enough clean power to rely on, or if new NGCC plants can't get built in time. Enforcement of the tax could be very expensive. And states might even have constitutional limits on what they can tax and who they can tax, making any state-level carbon taxes a near impossibility unless imposed by Congress.

But there is one huge caveat to this whole discussion of carbon taxes that needs to be at the forefront of any discussion. Carbon taxes would be a huge political problem for state legislatures or even for Congress. There has been no state, other than the RGGI states and California that has yet to show a willingness to put an explicit or even implicit price on carbon. While carbon taxes again have attractiveness as a means for implementing carbon emissions reductions while retaining current dispatch methods, it is unlikely that they would ever get the attention of a sufficient number of states, let alone approval.

Thus, again while carbon taxes, or pricing carbon, either on a state by state or regional basis have attractive features for RTOs and probably present fewer equity difficulties than cap and trade because they can be imposed differentially state by state, the political, institutional and fairness questions that arise are still difficult if not impossible to overcome. Again, inefficient and costly environmental dispatch may be the only route states can adopt, unless given substantially more time to develop equitable regional solutions and get state legislatures and regulators on board.

Relationship to FERC Regulation

The EPA Clean Power Plan will be implemented in the context of FERC regulations that are already affecting how RTOs (and non-RTOs) operate their systems. The overlay of Section 111(d) regulations on these FERC regulations will have important implications to the workability of the both sets of rules (from EPA and FERC). Some of the issues related to potential friction between these rules are discussed below.

Order 745

FERC issued Order 745 on demand response in organized markets in March of 2011. The order was intended to ensure that a demand response resource participating in an RTO wholesale is compensated at the energy market price, also referred to as the locational marginal price (LMP). The rule was controversial in several respects. First, demand response in most cases is provided by retail customers, who traditionally were considered to be under the purview of the state regulatory commissions. Second, there was concern expressed by many that demand side resources were not comparable to supply-side resources and should thus not be paid the same. Ultimately, the U.S. Circuit Court of Appeals for the District of Columbia voided Order 745 on both jurisdictional and substantive grounds, although the FERC is still considering an appeal to the U.S. Supreme Court.

While the legal status of Order 745 is in limbo, the fact that all RTOs have set up mechanisms with which to solicit and obtain bids from demand side resources is important, and some of these mechanisms may survive in different forms and with different compensation after the Courts are done. PJM, for example, has proposed an alternative method for demand side participation in its market which they believe is consistent with the Court's decision.

Demand response is defined as a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy.[38] While demand response is not always the same as energy efficiency, which is the subject of building block 4 in

[38] 18 CFR 35.28(b)(4) (2010)

the CPP, there is considerable overlap. Many of the energy efficiency measures that have been or might be implemented by states in response to the CPP will be demand response measures, as cutting energy use during peak hours will have the potentially greatest reduction potential for carbon emissions.

The problem comes in where states propose and adopt energy efficiency measures which then become bidders into RTO markets as Order 745 envisioned. Building block 4 in the CPP requires states to be able to verify that energy efficiency measures result in reduced emissions at power plants within the state. But if energy efficiency or demand side measures are bid into an RTO market, there is no way to tie energy efficiency measures to emissions reductions at any specific power plants. The bid-in demand-side measures become part of the overall resources of the RTO, and while they may reduce overall emissions in the region, there is no way of determining which measures had effects at which plants.

Thus, there is a direct conflict in the building block 4 energy efficiency measures and the objectives of FERC in Order 745 to encourage demand-side participation in organized markets. Allowing energy efficiency to participate in regional cap and trade markets could tie the concepts together, but as currently formulated the CPP does not allow a regional approach to energy efficiency.

Order 1000

FERC Order 1000 was issued in July of 2011. The purpose of Order 1000 is to promote regional and inter-regional transmission planning and to encourage the development of regional and inter-regional transmission projects by requiring jurisdictional utilities to form regional entities that would perform planning and would have in place cost allocation methods for such projects. The Order laid out in considerable detail a set of principles under which planning and cost allocation was to be developed, and specified that cost allocation must be done in a manner proportional to the benefits received. After issuance of Order 1000, several revisions were made and resulted in Orders 1000A and 1000B. Order 1000 was also appealed to US Circuit Court of Appeals for the District of Columbia but has been upheld in all of its aspects by that Court. It is not yet known if there will be further appeals.

The thrust of Order 1000 which is towards regional planning and the development of resources that are optimally located also appear to be in conflict with the requirements of the CPP. For example, one of the major objectives of Order 1000 is to ensure that utilities can meet public policy requirements in the most cost-effective manner possible, so that if low-cost renewables needed to meet renewable portfolio requirements are located distant from load, there would be a mechanism for transmission to be built to access the distant renewables. But building block 3 of the CPP was formulated based on the amount of in-state renewable resources, so that imports from another state or region apparently won’t count towards individual state goals, even if the power was otherwise eligible to be counted in the state's RPS. This appears to be the case even if the purchasing utility has also acquired a renewable energy certificate or some other right to count an out of state resource towards a state's renewable portfolio standard.

The NODA issued on October 28, 2014 does present a scenario for which it requests comments that allows for a regional formulation of building block 3, but as explained previously, even a regional target for RE would have to be allocated back to individual states for counting in the state plans under this alternative proposal. And RE purchased outside the region would still apparently not be counted. This is another apparent conflict between FERC's goals of promoting regional and inter-regional markets and EPA's adoption of a state by state approach.

The EPA's CPP, while not directly addressing transmission, will have other impacts on transmission planning and investment. Most critically, changes in dispatch under building block 2 will change flows on the transmission system, and could even overload certain lines. Utilities and RTOs with responsibilities for transmission planning and operations will have to take these changes into account, but without knowledge of what the final rules will look like or how plants will be dispatched, it is extremely difficult to do the kind of transmission planning envisioned and encouraged by FERC Order 1000. It seems like the two agencies – EPA and FERC – have different visions of how the future electric industry should operate.

Reliability Standards

The Energy Policy Act of 2005 gave the FERC authority to set reliability standards governing the nation's interconnected electric systems. The standards themselves are developed, pursuant to that law, by the North American Reliability Corporation (NERC) and its Regional Reliability Councils. FERC has authority to approve those standards or reject them and send them back for revisions. FERC also has authority to impose fines and penalties for violations of the approved standards.

The EPA's Clean Power Plan makes some broad statements that it does not expect that reliability of electric systems will be harmed by requiring states to meet the proposed emission requirements. But the CPP is silent about what happens if an operating RTO or utility is faced with violating emissions requirements or violating reliability standards or criteria. Operators are trained to ensure reliability first, but there may be situations where choices are necessary with economic consequences. FERC has not yet said anything about its expectations for maintaining reliability under the CPP, nor has it initiated any studies. As mentioned previously, some RTOs have conducted their own studies, with troubling results.

The interaction between emission requirements and reliability standards is a critical one and it is troubling that neither federal agency with significant regulatory authority over the industry is addressing the issues or suggesting how the two regulatory regimes will be reconciled so that utility operators are not faced with the reliability versus environmental penalty dilemma.

FERC's Role in Dispatch Decisions – Just and Reasonableness

FERC has regulatory authority over the rates, terms and conditions of wholesale power sales and interstate transmission. This includes exclusive authority over RTOs (with the exception of the Electric Reliability Council of Texas ISO which exempt from FERC regulation under a provision of the Federal Power Act). Regulation of RTOs occurs primarily under sections 205 and 206 of the Federal Power Act, which require that rates, terms and conditions of service be "just and reasonable" and not unduly discriminatory. Traditionally, this has meant that rates be set at the lowest possible level consistent with adequate returns for investors.

The just and reasonableness standard of the Federal Power Act is really an economic standard, but under the CPP, RTOs may be required to make planning and operational decisions based on environmental requirements. The changes in operating and other agreements that will be needed to allow the RTO to make these decisions will have to be approved by FERC under the just and reasonable standard. There is little precedent, and not much analysis to suggest how FERC can and will apply this economic standard to environmental decisions.

Conclusions

Planning and operating electric systems under EPA's proposed Clean Power Plan will become extremely difficult and raises numerous questions and issues that need to be resolved before EPA moves forward to implementing this new regulatory regime. There are essentially two options that operators (both RTOs and non-RTO utilities) will have to comply with regulations; (1) environmental dispatch; and, (2) pricing carbon through either a cap and trade regime or carbon taxes.

The environmental dispatch option can be done on the individual utility and state level – but whether multi-state RTOs will have the ability to conduct environmental dispatch depends on their ability to reach agreements with individual generators to dispatch their plants according to rules established by states. RTOs have no regulatory authority over the plants that they would be called upon to dispatch. And environmental dispatch would be very inefficient – RTOs would not be able to use bids made by generators to dispatch plants. They would instead have to dispatch plants in a combined way so that individual states meet their emission rate targets and overall reliability of the RTO's footprint is maintained – a very tough task indeed.

RTOs would operate more efficiently and could continue with current economic dispatch methods under a carbon pricing regime. Pricing carbon can be done at the state level (state carbon taxes) or at the regional level (cap and trade or a uniform regional carbon tax), but there are questions as to whether regional solutions that don't require that states meet their own targets are allowable under the proposed CPP rules. Even if a single regional cap or tax were allowed, there would be equity concerns among winners and losers under any cap making or tax-setting agreement making agreement among states difficult if not impossible. A regional carbon tax suffers from some of the same equity issues as cap and trade, and also would fail to ensure that states meet individual targets. State by state carbon taxes within an RTO might work under the EPA CPP proposal, helps solve the equity issues, and would allow economic dispatch by the RTO. But a tax that varies by state raises issues regarding the handling of interstate power trading. And whether regional or state by state, carbon taxes would be difficult (and likely impossible in many states) to get through state legislatures.

Any regional RTO-wide solution is also complicated by the fact that there are multiple states that are located within more than one RTO, or that may have both RTO and non-RTO utilities. And the efficiency of any regional plan may be limited by the fact that state targets are set based on the best system of emission reductions, limiting the ability of states to reduce emissions beyond their own targets and sell allowances or clean power to other states facing more expensive reductions. And then, finally, some states may just not have options to redispatch from coal to gas and may be faced with having to build new gas-fired generation very quickly or paying penalties.

Commissioner Philip Moeller FERC put it very well when he stated:

> … the proposal's state-by-state approach results in an enforcement regime that would be awkward at best, and potentially very inefficient and expensive. The interstate nature of these markets is illustrated by the example of Idaho. While that state currently does not generate electricity from coal plants within its borders, it consumes coal-generated energy produced in at least five other states. If those states decrease their coal generation and Idaho compensates by increasing generation from its existing natural gas plants, it creates complications related to its initial carbon baseline and its carbon baseline going forward.[39]

EPA and FERC have not paid enough attention to the potential institutional problems, economic impacts, and unintended consequences that may be created by the Clean Power Plan, and how constraints in the real world may lead to the CPP creating reliability problems in the nation's electric systems. Initial studies by RTOs of the ability to redispatch (and the associated costs) to meet the CPP's new requirements are troublesome and further study is critically needed before embarking down this path. EPA and FERC should be examining the potential reliability impacts of the Clean Power Plan as proposed, and the results of those studies should be considered in developing a final rule. And more attention needs to be paid to the costs to end-use electric consumers that will result from the CPP proposal.

[39] Philip D. Moeller, op. cit.