

# Markets Matter: Expect a Bumpy Ride on the Road to Reduced CO<sub>2</sub> Emissions

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# Markets Matter: Expect a Bumpy Ride on the Road to Reduced CO<sub>2</sub> Emissions

Wishful thinking is headed straight for the cold shock of reality in the attempt to engage market forces to reduce carbon dioxide (CO<sub>2</sub>) emissions from existing electric generation. Efficient outcomes in the reduction of CO<sub>2</sub> can only result from both appropriate incentives and well-functioning markets. Optimistic estimates of the potential reductions from recent proposals are based on the assumption that clear and consistent market forces will motivate an optimal mix of investments in renewable resources, fuel switching, shifting of generation among existing generators and substantial energy efficiency improvements.

There are, however, two major market impediments. First, the guidelines to be issued in coming weeks by the Environmental Protection Agency (EPA) concerning CO<sub>2</sub> emissions from existing electric generators are not expected to include the kind of nation-wide program that could send consistent and predictable price signals needed for market efficiency, because of statutory limitations on EPA's authority. Instead, EPA guidelines are expected to rely on the states to develop rules intended to shift generation away from high-emitting sources and reduce consumption. A system of such state-by-state rules will inevitably be less efficient than a unified approach. Second, the electricity markets in a large portion of the country currently operate with significant limitations that will impede the ability of the EPA to address CO<sub>2</sub> emission reductions. The current problems are most apparent in regional electricity markets that rely on capacity markets to incent new investment. Those capacity markets are already floundering over existing challenges and will be severely stressed by the added complexity of maintaining reliability while shifting to a lower CO<sub>2</sub> emission portfolio.

This is not to imply that CO<sub>2</sub> emission reductions are not possible. Only that they will be more difficult, more costly, and likely have unintended long-term consequences that are not reflected in optimistic assessments based on assumptions of perfect market efficiencies. The options available to the EPA are far from perfect, and based on considerations expressed in more detail in this analysis, EPA statements expressing the desire to give states flexibility in achieving CO<sub>2</sub> reductions are a positive sign. While this approach will contribute in some measure to market inconsistencies, states will need flexibility in terms of approaches, goals and timing as they face the realities of achieving CO<sub>2</sub> emission reductions in a problematic marketplace.

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## INTRODUCTION

The Environmental Protection Agency (EPA) is currently working on guidelines to limit CO<sub>2</sub> emissions from existing electric power stations and is scheduled to release them in draft form by early June of this year. There is considerable uncertainty over the extent of reductions EPA will seek, which will have significant implications for the environment and the electricity industry. Receiving less attention are the significant long-term implications of the structure of those guidelines. In particular, there are reasons to suspect that EPA guidelines will not adopt approaches that economists have long recognized as providing for the most efficient outcomes, and thus allow reductions to be achieved at the lowest cost. Another critical issue in considering the outcome of such emission guidelines will be the structure of the electricity industry. The U.S. electricity industry is a patchwork of different market structures, some of which create additional problems in attempts to deal efficiently with emission reductions. This report explores the interplay between potential inefficient emission reduction guidelines and the problems that might arise in applying such guidelines in the varied electric market structures across the country. The challenges of these problems should be of concern to anyone dealing with developing rules and guidelines, or attempting to respond to such requirements as market participants.

Economists have long recognized that emission reduction policies that invoke market forces, and in some fashion introduce a cost on emissions (\$/ton of CO<sub>2</sub>), hold the greatest promise for reducing emissions at the lowest cost. Market-based approaches provide a means to push emission considerations into the myriad of individual decisions such as power plant fuel choices, incremental power plant output levels and even homeowner attic insulation options. EPA's authority in devising such programs, however, is constrained. The methods it can employ and the level of reductions that can be achieved are very uncertain at this time. Standard

approaches to achieving efficient outcomes, such as carbon taxes and cap-and-trade systems, do not appear to be viable policy options at this time.

With respect to the electricity market, the country is divided into a confederation of varied and complicated structures that continue to evolve. In some areas, regional transmission organizations (RTOs) have taken on the responsibility of running energy markets. The RTOs administer energy markets where they set locational prices across broad geographic areas intended to create incentives to optimize energy production from all resources. Those optimizations are based solely on short-term signals and incentives. Another factor complicating the market structures has been the domination of merchant generators in some parts of the country. Merchant generators are for-profit companies that sell their energy at market prices and are neither under traditional utility ownership nor subject to state price regulation. They do not have any obligation to serve customers (load) and face minimal price regulation at the federal level. Even without consideration of CO<sub>2</sub> emission reduction objectives, the combination of RTO-run energy markets and domination of merchant generators has led to significant difficulties in providing longer-term investment incentives to maintain proper levels of generating capacity. Concerns over resource adequacy in these largely merchant markets have driven some RTOs to adopt mandatory capacity markets. These capacity markets involve heavily administrative, mandatory processes to force the market-clearing of all supply and demand through an auction-like mechanism that sets uniform (or zonal) prices.

Complaints over the operation of capacity markets are rampant. There is much debate over whether the problems are the result of imperfections in how the various RTOs have chosen to implement the auctions, or whether the problems are fundamental and unsolvable under the general auction framework that has been adopted.<sup>1</sup> Regardless, there is no

<sup>1</sup> The author is among those that are convinced that the auction framework is incapable of ensuring adequate capacity at a reasonable cost to consumers. See December 18, 2013 comments filed at FERC in Docket AD13-700. <http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13418473>.



dispute that these markets are buried under scores of regulatory and judicial proceedings attempting to address what seems to be an endless stream of complications and debate over pricing and market rules. And if there are already significant questions about whether these markets are supporting, or in fact impeding, the development of an optimal mix of supply and demand-side resources in the current market, the introduction of additional CO<sub>2</sub> emission reduction considerations will only further complicate the marketplace.

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As a result, the EPA cannot base the guidelines on the assumption that participants will undertake the complex process of determining the optimal long-term decisions to reduce emissions at the lowest cost. Even if it were clear that a specified mix of renewable generation resources, changes in operating patterns of fossil generation and heavy commitment to reductions in energy demand through efficiency measures could meet the desired objectives at a low cost, it is another matter to develop regulations that create effective incentives for this outcome. One cannot simply assume that a CO<sub>2</sub> emission reduction program that alludes to market forces will actually achieve the idealized efficiencies of a perfect market.

Economists often extol the virtues of placing a price on CO<sub>2</sub> emissions in creating market incentives for these reductions, with the implicit (or explicit) understanding that these prices will be uniform and sufficiently predictable to promote long-term investments. These kinds of incentives will be particularly needed in the merchant generator market sector, where decisions to construct and operate power plants are based solely on expected market revenue without any regulatory assurance of earning a return. Their investors are responsive to price signals, but if those signals come from markets that are unnecessarily volatile, unpredictable and susceptible to change, their actions may not include the cost-effective long-term investments that are desired. This is a current problem with auction-based capacity markets and will be compounded if CO<sub>2</sub> emission reduction requirements further complicate this situation.

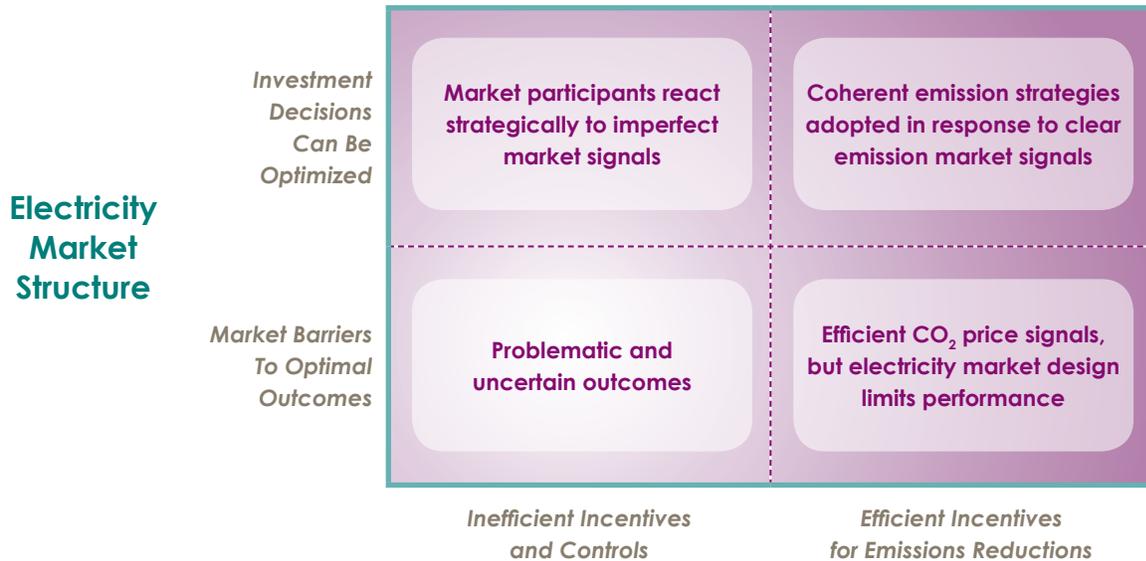
The Policy Grid below provides a visual depiction of these emissions policy and electricity market design issues. The horizontal X axis depicts the CO<sub>2</sub> reduction policy, with the right side associated with highly efficient CO<sub>2</sub> reduction policies, such as a carbon tax. A carbon tax would send direct and predictable market incentives to all participants to curb emissions. The vertical Y axis depicts the structure of the electricity industry. At the top of the Y axis, it is assumed that market participants can weigh options over the long term, making tradeoffs between supply and demand options, and are in a position to exercise judgments and consider factors that may not be included in short-term price signals. On the bottom of the Y axis, complications caused by poor market design impede the development of low-cost and efficient market outcomes.

On this spectrum, if CO<sub>2</sub> emission policies are efficient, reasonable outcomes are achievable regardless of electricity market structure complications. While poor market design will impede optimal long-term investment outcomes (as is currently the case), the imposition of efficient CO<sub>2</sub> emission reduction requirements will fit within the current market framework.



## POLICY GRID

### REDUCING CO<sub>2</sub> FROM EXISTING ELECTRIC GENERATORS



## CO<sub>2</sub> Reduction Policy

The more interesting outcomes are associated with inefficient CO<sub>2</sub> emission requirements. On the top left, if market participants are vertically integrated (either through generation ownership or long-term contracts) and capable of taking a strategic view of requirements and implications on behalf of their long-term customers, they can take actions that make sense over the long term, essentially discounting unproductive incentives in imperfect environmental policies. This could include supporting flexible generation to ensure reliability in a system with increased amounts of non-dispatchable renewable generation. It could include coordinating efficiency programs with resource planning efforts. And it could include voluntarily changing the dispatch of fossil generation to curtail emissions while ensuring reliability.

The bottom left quadrant is most problematic and hence is a major focus of this analysis. Here, CO<sub>2</sub> emission reduction programs do not provide clear and predictable market signals

for reductions. And within the electricity industry, individual participants are incited to respond to the immediate market signals they are given. Not only is there no single entity with the responsibility and resources to ensure that broader environmental goals are met and reliability is maintained, but there is no direct compensation for firms that might take the necessary steps when they are not included in the short-term and imperfect market signals. This is already clear with respect to long-term investments in the industry generally, due to problematic capacity auctions, but the real complications will come when CO<sub>2</sub> requirements are imposed in some form.

Much will depend on the details of EPA's proposed guidelines.

The extensive debate that will undoubtedly follow the release of the guidelines will include some arguing for aggressive actions on the basis of environmental goals and others calling for restraint based on concerns over costs and



industry capabilities. It is hoped that this analysis will inform this debate by serving as a reminder of the importance of considering long-term implications of structural issues. For not only will today's guidelines affect current decisions, but it will lay the groundwork upon which any potential further actions will be built, such as the more-efficient market-based alternatives that some claim will ultimately be required, such as a cap-and-trade framework or carbon tax. The adoption of inefficient CO<sub>2</sub> emission reduction policies today will squander resources and waste scarce political capital. Policies based on idealistic goals that produce a quagmire of legal battles become compromised beyond recognition. They squander public support on expensive and inefficient actions that will not make the best use of the opportunity at hand. The climate change challenge is inherently a long-term problem, and today's actions need to be evaluated on a long-term basis, building on past actions and facilitating further actions in the future.

The adoption of inefficient CO<sub>2</sub> emission reduction policies today will squander resources and waste political capital.

## FRAMEWORK FOR EPA GUIDELINES FOR CO<sub>2</sub> EMISSION REDUCTIONS

President Obama has made clear his desire to take substantial steps to curb carbon emissions.<sup>2</sup> The authority granted to the EPA for developing CO<sub>2</sub> emission guidelines for existing sources rests in section 111(d) of the Clean Air Act (CAA), and is implemented through regulations in 40 C.F.R. Part 60, Subpart B, Section 60.20–60.29. Any requirements will be implemented through state compliance plans. The EPA would appear to have broad authority in issuing guidelines for state plans and substantially narrower authority in approving (or disapproving) those plans as they are developed by the states. In setting guidelines in accordance with those requirements, a critical issue will be a determination of what constitutes a “system of emission reduction.”<sup>3</sup>

Some argue that those requirements limit EPA and state authority to feasible options that could be implemented at the unit level, with consideration given to technological feasibility.<sup>4</sup> Since CO<sub>2</sub> release is inherent in the fuel burned, reductions in emission rates would have to be tied to increasing the facility's efficiency. Others conclude that the system can be interpreted more broadly, encompassing actions across the entire electricity system, including actions by consumers.<sup>5</sup> This “system-based” interpretation provides for much greater reduction in emissions, as it allows fuel substitution, shifting generation from high-emitting to low- or non-emitting resources, and use of energy efficiency investments as a way to reduce emissions.

2 President Obama's 2014 State of the Union Speech, January 28, 2014. “That's why I directed my administration to work with states, utilities and others to set new standards on the amount of carbon pollution our power plants are allowed to dump into the air. The shift to a cleaner energy economy won't happen overnight, and it will require some tough choices along the way. But the debate is settled. Climate change is a fact. And when our children's children look us in the eye and ask if we did all we could to leave them a safer, more stable world, with new sources of energy, I want us to be able to say yes, we did.”

3 “EPA Regulation of Greenhouse Gas Emissions from Existing Power Plants: Issues and Options,” Van Ness Feldman, June 27, 2013. <http://www.vnf.com/1102>.

4 “Establishment of Standards of Performance for Carbon Dioxide Emissions from Existing Electric Utility Generating Units Under Clean Air Act Section 111(d),” Hunton & Williams, prepared for the Utility Air Regulatory Group, April 2013. [http://www.publicpower.org/files/PDFs/NSPS111\(d\)Analysis.pdf](http://www.publicpower.org/files/PDFs/NSPS111(d)Analysis.pdf).

5 “Questions and Answers on the EPA's Legal Authority to Set ‘System Based’ Carbon Pollution Standards for Existing Power Plants under Clean Air Act Section 111(d),” David D. Doniger, NRDC Issue Brief, IB: 13-10-D, October 2013. <http://www.nrdc.org/air/pollution-standards/files/system-based-pollution-standards-IB.pdf>. “Efficiency Rules: The Case for End-Use Energy Efficiency Programs in the Section 111(d) Rule for Existing Power Plants,” Kate Konschnik and Ari Peskoe, Harvard Law School, March 3, 2014. <http://blogs.law.harvard.edu/environmentallawprogram/files/2013/03/The-Role-of-Energy-Efficiency-in-the-111d-Rule.pdf>.



As of this writing, it has been widely rumored that the proposal EPA releases in June 2014 will contain and invite comment on several different approaches based on differing interpretations among stakeholders of its legal authority under section 111(d). From public and private statements, however, it appears that EPA may be favoring the recommendations of some to adopt a system-based approach. The Natural Resources Defense Council (NRDC) has been a strong advocate of this approach and has presented a comprehensive proposal based on this concept, along with an economic analysis of its implementation.<sup>6</sup> In a Congressional Research Service report to Congress, this approach is mentioned specifically (and, notably, none other) as a means of addressing CAA requirements for existing sources.<sup>7</sup>

Economists agree that placing a price on CO<sub>2</sub> emissions can be very effective in driving more efficient choices among the many carbon reduction options.<sup>8</sup> When CO<sub>2</sub> emissions have a price, entities will take all actions to reduce emissions that have internal costs below that price. Likewise, they will pay the price rather than take actions with higher implementation costs. There are two general approaches often discussed that can achieve this outcome. The first is a tax or fee on carbon emissions. This sets a clear price for emissions. The second involves a cap-and-trade system, where emissions are restricted to some level below current levels, and all current emitters are given tradable emission credits (or allowances) in proportion to existing emissions. The emitters can make their own determination of the degree they will reduce emissions, with the recognition that they can sell credits associated with over-control, or buy credits if needed as a result of under-control. A cap-and-trade approach involves the development of markets for the trading of emission credits. That market then provides the price signal to all entities

weighing emission reduction options. These approaches have a variety of pros and cons. The cap-and-trade approach provides the more certain emission reductions, while the tax approach sets a more predictable and stable price on carbon and therefore produces a more certain economic outcome. And there are modifications of the approaches, such as limiting the potential emission credit prices under a cap-and-trade approach. There have been attempts to adopt comprehensive legislation based on a cap-and-trade approach in the U.S., most notably the American Clean Energy and Security Act (Waxman-Markey) legislation that passed the House, but failed in the Senate, in 2009.<sup>9</sup>

With respect to the forthcoming EPA guidelines, there is no indication that EPA will propose options based on either a comprehensive national tax or cap-and-trade system. It would appear that there is consensus that such a comprehensive approach would fall outside of EPA's authority. This sets in place two challenges. First, how a comprehensive approach might be crafted that falls within EPA's legislated authority — with legal challenges virtually certain regardless of what approach might be attempted. And second, what efficiencies can be achieved over both the short and longer terms based on an approach that is forced to deviate from a theoretically optimal alternative.

Many states have demonstrated a strong desire for action in reducing CO<sub>2</sub> emissions and have already done so in the absence of federal requirements. It is anticipated that EPA guidelines would attempt to preserve the ability of the states to exceed any federal requirements. The states have considerable flexibility in how they can structure CO<sub>2</sub> emission requirements and several have adopted cap-and-trade emission limit requirements. States also have the ability to structure

6 "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluter," NRDC Report, by Daniel A. Lashof, Starla Yeh, David Doniger, Sheryl Carter and Laurie Johnson, NRDC, R-12-11-A, March 2013. <http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf>. This report was updated as "Cleaner and Cheaper: Using the Clean Air Act to Sharply Reduce Carbon Pollution from Existing Power Plants, Delivering Health, Environmental, and Economic Benefits," by Daniel A. Lashof, Starla Yeh, et al, NRDC Issue Brief Update, IB:14-03-A, March 2014. <http://www.nrdc.org/air/pollution-standards/files/pollution-standards-IB-update.pdf>.

7 "EPA Standards for Greenhouse Gas Emissions from Power Plants: Many Questions, Some Answers," by James E. McCarthy, Specialist in Environmental Policy, Congressional Research Service, CRS Report for Congress, 7-5700, R43127, November 15, 2013. <https://www.fas.org/sgp/crs/misc/R43127.pdf>.

8 The Carbon Tax Center maintains a record of economists, scientists and others that support carbon taxes. <http://www.carbontax.org/who-supports/>.

9 Waxman-Markey contained a provision for a strategic reserve of allowances that would act to cap potential prices.



programs in ways that deal directly with the electricity industry structure within their state. States may also have some ability to affect the electricity industry structure, although in many cases there are severe limits on that ability because of the presence of federally-regulated, multi-state markets.

## THE CHALLENGES IMPOSED BY THE STRUCTURE OF THE ELECTRICITY INDUSTRY

A system-based approach to CO<sub>2</sub> emission reductions, if successful, will require changes in the procurement of electricity supply and increased demand-side measures. As a result, there will be increased investments in lower-emitting technologies, high-emitting resources should run fewer hours or be retired, and actions to increase energy efficiency and otherwise reduce demand will be expanded. The challenge is in finding a means for this to be achieved within the market structures that exist. In markets with fully-regulated, vertically-integrated utilities, the challenges of integrating CO<sub>2</sub> reduction policies will be significant, but those utilities have the means to balance all of the options and develop a comprehensive strategy to meet these environmental goals. In markets that have restructured at the wholesale and retail level, and eliminated cost-of-service rates for electricity supply, resource decisions will be driven by competing firms in response to short term price signals (and expectations of future short-term price signals). While there are many industries where long term investments are routinely made on the basis of short term signals, electricity is unique in both the need to maintain near-perfect reliability and a market structure that sets hourly prices through an auction process.<sup>10</sup> The decision to adopt centralized capacity auctions as a means to achieve electric supply adequacy in some RTO-operated markets, which is an unprecedented step not required in other industries, is a *de facto* admission that short-term price signals alone are inadequate.

The EPA's approach to CO<sub>2</sub> emission reductions will have to work across all of the electricity market structures that exist. This will range from states with comprehensive regulatory oversight of resource decisions to those that effectively have no review authority at all. Substantial emission reductions will be a challenge in all states, but achieving the necessary investments will be particularly difficult in those states where decisions are made by unregulated firms on the basis of short-term energy and flawed capacity markets, coupled with potential disparate markets (or no markets) for CO<sub>2</sub> emission credits. There is no reason to expect efficient investment decisions with these flawed market incentives.

Achieving the necessary investments will be particularly difficult in those states where decisions are made by unregulated firms on the basis of short-term energy and flawed capacity markets, coupled with potential disparate markets (or no markets) for CO<sub>2</sub> emission credits. There is no reason to expect efficient investment decisions with these flawed market incentives.

<sup>10</sup> Investments in hotels, aircraft (passenger service), private toll roads and restaurants are typically made without significant long-term contracts, but unlike electricity, sellers are expected to set prices that allow for recovery of fixed costs and there is much less concern over supply shortages.



While the EPA has no authority to reform electricity market structures in response to the need for efficient CO<sub>2</sub> emission reduction strategies, this should be considered by others such as the Federal Energy Regulatory Commission (FERC), the RTOs, state regulators and other market participants. Even the most ardent supporters of auction-based capacity markets should recognize the limitations they create in EPA's attempt to reduce CO<sub>2</sub> emissions. The need to address CO<sub>2</sub> emissions only strengthens the case for rethinking the capacity auction approach and adopting a more practical and lower cost alternative. The author has been a strong proponent of such reform and has proposed an alternative, the BiCap approach, which not only solves many of the problems in existing capacity markets, but provides a much better framework for addressing CO<sub>2</sub> emission reduction requirements.<sup>11</sup>

### **Industry Evolution and the Development of Auction-Based Capacity Markets**

The drive for more competitive electricity markets has taken different regions of the U.S. electricity marketplace in different directions as a result of changes that date to the mid-1990s. As introduced earlier, the parts of the country that have moved most aggressively to restructure their wholesale markets have RTOs that manage regional hourly wholesale electricity markets and set locational prices in each hour of the day. This sends the price signals necessary for generators to change output as needed to keep the system in balance and to keep transmission lines from overloading. FERC is responsible for regulating the RTOs and has generally supported market restructuring and deregulation.

At the same time, a number of states undertook state-level retail restructuring that typically included the adoption of retail competition, and the removal of the generation function from the regulated utility. This step spurred the development of a merchant generation sector, which are for-profit, unregulated owners of generation facilities that compete for

sales on the basis of price and reduced (or eliminated) the reliance on vertically integrated, regulated, investor-owned utilities to serve customer load and develop resources. When these changes are made, the role of state authorities in long-term resource planning is greatly diminished. The market shift in this direction has been most pronounced in the PJM Interconnection (PJM), New York ISO (NY ISO), ISO New England (ISO NE) and Texas (ERCOT) RTOs, with substantial changes of this nature in other regions as well. California has an RTO (California ISO) but limited its retail restructuring following the year-2000 energy crisis and the region served by the Midcontinent ISO still is largely vertically integrated. It also needs to be recognized that virtually all states have some customers served by public power utilities or rural electric cooperatives, who were generally not included in retail restructuring. These entities generally remain vertically integrated (or served through long term arrangements with generators), although these market developments have affected their operations in numerous ways.<sup>12</sup>

In regions where RTOs operate wholesale energy markets, energy offers are used to determine the locational prices necessary to keep the system in balance in real-time. The incentives for longer-term supply investments have proven more problematic. Auction-based capacity markets have been adopted in some RTOs to provide an additional source of revenue to support these investments. Currently, these auctions are in place in what are commonly referred to as the "eastern RTOs" (PJM, ISO NE and the NY ISO). MISO operates a voluntary capacity market and utilities can choose to opt out of the market.

These capacity markets, based on auctions for short-term capacity products, have proven to be contentious and problematic. Despite years of operation, there are still dozens of open FERC cases dealing with controversial issues in the details of implementing these markets. In addition, FERC is currently reviewing thousands of pages of testimony and

<sup>11</sup> See [www.BiCapApproach.com](http://www.BiCapApproach.com).

<sup>12</sup> EPA regulations apply to all generation sources, regardless of ownership structure or regulatory oversight for economic issues.



filings in a technical conference docket dealing with the operation of capacity markets in these eastern RTOs.<sup>13</sup> Those comments include economists and RTOs extolling the necessary role of capacity markets in electricity markets, owners of generation explaining why they feel they need capacity payments and consumer representatives complaining that they are not getting value for their expenditures. This author has expressed his view that auction-based mandatory capacity markets adopted in the eastern RTOs are inherently flawed and incapable of providing incentives for a reliable system at a reasonable cost. One source of problems with the eastern RTO capacity markets is the use of short-term prices for capacity (such as for one year established three years in advance). For new generation investments that span decades, such a short-term signal is inadequate, and for demand-side resources, the three-year-forward timing is much earlier than appropriate for lining up customers. This complicates the bidding of resources into the market by both supply-side and demand-side resources. In order to have an auction that sets prices and attempts to provide incentives for exit and entry of new investment, the eastern RTOs created capacity markets with complex administratively-determined demand levels and demand curves, rules on market behavior intended to limit market power on both the buy- and sell-side, and a long list of other behavioral controls.

Auction-based mandatory capacity markets adopted in the eastern RTOs are inherently flawed and incapable of providing incentives for a reliable system at a reasonable cost.

What has resulted is a highly administrative process that sets prices, with people debating whether this is a market at all. A major reason for this is because very few participants engage in activities that resemble market behavior. Consumers of energy do not participate in the actual auction, and are instead told what price they have to pay afterward. Generators participate, but most bid as price-takers (effectively bidding zero) with significant restrictions on bidding activities based on concerns over market power. For the vast majority of market participants, after year-round turmoil in setting rules and requirements, the capacity auctions themselves have become billion dollar events in which they are mere bystanders.

#### **Incompatibility of Capacity Auctions and Support for Renewable Resources**

The existing capacity markets have complicated the deployment of low-CO<sub>2</sub>-emitting resources. As the auctions deal with a fungible capacity product, there is no way to distinguish between resources on the basis of environmental attributes. Each megawatt (MW) of deliverable capacity gets paid the same amount, regardless of how it is produced and whether it is a supply-side or demand-side resource. To the extent that capacity markets promote new generation investments, the lowest cost supply options will be selected, regardless of environmental performance. In many cases renewable or otherwise environmentally preferred resources are more expensive. State attempts to support such resources have run into concerns of buyer-side market power and the rules put in place to address these concerns, primarily the minimum offer price rule (MOPR), which is subject to FERC oversight.

Adoption of MOPRs in the eastern RTOs was motivated by the fact that capacity prices are very sensitive to the exact amount of capacity that clears in the auction. An extra few percent of capacity (MWs) in the market could cause prices to fall by half or more. Supporters of MOPRs contend that

<sup>13</sup> FERC's Supplemental Notice of Technical Conference, August 23, 2013, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, in Docket AD13-7, contained a listing of dozens of current dockets involving capacity market issues at the time of the conference.



such responsive prices produce an incentive to exercise buyer-side market power through the subsidy of additional supply. To address this issue, under a MOPR, a new resource has to bid a price that is at least as high as an administratively-determined levelized cost of new supply. By having a "high" minimum bid, the new resource will not drive down the auction price to an "unfairly depressed" level. Instead, if there is adequate supply from other resources, the new generator will simply not clear in the auction. In that case the seller gets paid nothing for capacity and the utility has to buy their full requirement from the auction and is not allowed to count the new resource towards their reliability obligation. Having to pay twice for capacity reduces the incentive to support "uneconomic" new resources.

These rules have very real consequences, as the states of Maryland and New Jersey found in 2011 when they contracted for new generating capacity in their states. Those states separately concluded that they needed to contract for new generation facilities because the markets were not producing the necessary supply, despite high prices. In response, generators and others argued that the states were acting to unfairly depress capacity market prices, and brought a complaint to FERC requesting greater restrictions on price offers from these new resources in the capacity auctions. A similar pattern of events occurred in ISO New England, spurred on by actions taken by Connecticut. FERC has also given a very strict interpretation to similar rules in the New York ISO. The generators also brought suits in the federal district courts of Maryland and New Jersey, and those courts found that the states had engaged in an unconstitutional attempt to bypass federal regulation of electricity prices.<sup>14</sup> Those decisions are under appeal.<sup>15</sup>

Among the problems with the MOPR is the assumption that the administratively-determined offer floor reflects competitive behavior. This fiction pervades the problems with annual

capacity auctions. Truly competitive behavior would involve offering the resource at the marginal cost of supply, which might be zero (if the commitment to build the facility was already made) or the total construction cost (if the decision to build was dependent on the outcome of auction). In reality, it is obvious that the auction only determines the payment for a single year, and a new generator will operate for decades, so that a truly competitive participant might offer capacity at a price that could range anywhere between those two figures, depending on how the developer considers future revenues in its determination. But a MOPR eliminates the low end of this range, placing a priority on concerns over limiting buyer-side market power.

All of this is merely background for the issues that are raised when states act to promote renewable resources. As these supply options generally cost more than the conventional resources, state support is required. Support for renewable resources has been a routine part of state actions for decades, but now concerns over the potential for state actions to influence prices in capacity auctions have produced rules that interfere with state environmental policies. That is because state support of resources is the fundamental concern of buyer-side market power. Currently the PJM MOPR only applies to natural gas facilities, but some generators and the market monitor have argued for its application to all resources. In New England, the MOPR applies to all capacity, including renewable resources and demand response. Further, it should be noted that in scenarios where substantial CO<sub>2</sub> emission reductions are accomplished, especially through major expansions of energy efficiency, there is very little need for additional conventional generation and capacity prices could be kept very low for many years. Challenges to pricing rules that would allow this to happen would be inevitable.

<sup>14</sup> *PPL EnergyPlus, LLC v. Nazarian*, 2013 U.S. Dist. LEXIS 140210 (D. Md., Sept. 30, 2013); *PPL EnergyPlus, LLC v. Hanna*, 2013 U.S. Dist. LEXIS 147273 (D.N.J., Oct. 11, 2013).

<sup>15</sup> *PPL EnergyPlus, LLC v. Nazarian*, Fourth Cir. Nos. 13-2419, et al.; *PPL EnergyPlus, LLC v. Solomon*, Third Cir. Nos. 13-4330, et al.



Concerns over the potential for state actions to influence prices in capacity auctions have produced rules that interfere with state environmental policies.

### Energy Efficiency Investments

Another means of reducing CO<sub>2</sub> emissions that will be important in a system-based approach will be increased energy efficiency in consumption. Reducing the amount of electricity consumed is perhaps the most direct means of reducing emissions associated with its production. There are numerous state programs designed to support efficiency, as well as federal programs to achieve this result through such things as higher efficiency standards. While the benefits of reduced consumption are clear, there are complexities in measuring demand reductions and in developing compensation mechanisms (or incentive approaches more broadly) for efficiency improvements. Each state has its own approach, with these often being different for different kinds of programs. The NRDC proposal (discussed in detail below) focuses considerable attention on this source of CO<sub>2</sub> emission reductions and critical issues in measuring benefits.

There is an obvious interplay between RTO-operated markets for energy, capacity, other incentives for energy efficiency adopted by states and new incentives for CO<sub>2</sub> reductions that might be motivated by the forthcoming EPA guidelines. Many states have been implementing energy efficiency programs for a long time, and in locations where capacity markets exist, there is the potential for some efficiency programs to receive payments associated with their ability to reduce

peak demand. If CO<sub>2</sub> emission programs give credit for efficiency improvements, that will add another program that will seek to measure benefits. There is certainly the potential for inconsistencies between how these different programs might measure benefits from energy efficiency programs. Capacity payments for efficiency improvements have not been subject to a MOPR, even though they produce similar price-depressing effects, possibly because energy efficiency has so far been a very small percentage of total capacity clearing the auctions and opposition has been limited. If substantial CO<sub>2</sub> reductions are required, the effects of energy efficiency improvements on capacity prices will likely be substantial, depressing prices for many years, and calls for further changes to capacity markets to reduce this effect might be expected. The growth in the participation of demand side resources in PJM's capacity markets, for example, has led to significant controversy.<sup>16</sup>

### Threats to Reliability in the Evolving Markets

Variable renewable generation resources, such as wind and solar, are characterized by their inability to be dispatched on demand. Increased reliance on these resources places additional stress on the system and increases demand for generation that can change output in response to the direction of the system operator. Such resources, often called flexible generation, will be of increased importance as the share of variable renewable resources increases. This problem is well-known. In a market dependent on merchant generation and market prices, currently there is no separate compensation mechanism for this flexibility. Energy prices alone have not proven to be sufficiently strong to incent generation with this fast-acting capability. Capacity markets are also ineffectual, as they merely provide for generation capacity, not specific attributes, such as responsiveness.

This issue is already a challenge in places like California with significant market shares of renewable supply, and the ISO and Public Utilities Commission are considering market

<sup>16</sup> See FERC Dockets ER13-2108, ER14-1461, ER14-822, ER14-504 and EL14-20.



changes to address it. It will undoubtedly be a bigger issue for all regions if there is a further shift to non-CO<sub>2</sub>-emitting supplies such as wind and solar that do not change output in response to market conditions. Options include further market design changes, including the potential for capacity markets composed of multiple tranches of generation with specific characteristics<sup>17</sup> or non-market requirements for regulated entities to procure flexible resources.<sup>18</sup>

In theory one can just keep adding requirements for different kinds of capacity, such as flexible generation, and hold additional auctions. As a practical matter, however, each time a new attribute is added or another product is defined, the markets become more complicated, as these products all interrelate. There are already markets for energy, voltage control (AGC), spinning reserves and non-spinning reserves, with capacity markets attempting to provide the additional funding needed to spur investment. Complicating these markets through the creation of products to ensure flexible generation will drive up costs unnecessarily, if not cause the markets to fail entirely. That is because markets for additional products will increase the real-world problems of lumpiness of investments, the conflicts between long-term investments and short-term price signals, the effects of investments on market prices, and the compounding complexity of multiple prices from the RTO-operated markets. Lumpiness refers to the size of investments relative to needs, such that an extremely high price might indicate a desperate shortage of a given product, but if the standard size of a unit of supply to provide the product is much greater than the need, it would cause the (yearly) price to collapse and the investor would not earn an adequate return. In such situations investments will not be made despite obvious needs. On top of this there are locational requirements for capacity and some of these features,

but not others, which further compounds the problem of multiple products. Participants at the September 25, 2013 FERC technical conference were in near-unanimous agreement that further complicating the markets by creating products with different attributes would create problems and could threaten the proper functioning of the existing capacity markets.<sup>19</sup>

Complicating these markets through the creation of products to ensure flexible generation will drive up costs unnecessarily, if not cause the markets to fail entirely.

#### Market Challenges in Supporting Other Non-CO<sub>2</sub>-Emitting Resources

One problem with rules designed to achieve specific outcomes for narrowly defined concerns is the elements that fall between the cracks of various programs. This is another example of general problems associated with the reliance on RTO-operated markets with imperfect short-term price signals to maintain reasonable (and in some cases, obviously needed) resource mixes of generation facilities. This can be seen with the current lack of support in these programs for nuclear capacity, a large CO<sub>2</sub>-free source of energy that has pro-

<sup>17</sup> Opening Statement by Michael Hogan, Regulatory Assistance Project, FERC Technical Conference on the Future of Centralized Capacity Markets, Docket No. AD13-7-000, September 25, 2013.

<sup>18</sup> For example, in California which does not have a mandatory capacity market, the resource adequacy requirements were revised in 2013 to include an interim flexible capacity procurement requirement. The California ISO is in the process of further developing this flexible resource procurement program.

<sup>19</sup> Participants of the September 25, 2013 technical conference (AD13-7) expressing concern over making the markets too complicated included: Peter Cramton (University of Maryland) said that adding tranches would be a "nightmare" (Tr. 249:22-250:21); Dan Curran (EnerNOC Inc.) said that attempting to do more with the markets could impede the ability to maintain adequacy (Tr. 145:21-147:8); Shahid Malik (PSEG Energy Resources and Trade) said, "And we do feel that trying to introduce a lot of policies through the capacity market may, at the end of the day, make it so complex that it becomes self-defeating," (Tr. 160:23-161:1); Ed Tatum (Old Dominion Electric Cooperative, Tr. 162:21-18); William Massey (COMPETE Coalition, Tr. 165:12-18); and James Wilson (Wilson Energy Economics, Tr. 227:19-23).



vided roughly twenty percent of the electric energy resources in recent years. Whether these resources will be supported depends on the nature of policy options that are adopted, but in recent years there have been retirements that point to a lack of support in current markets.

The retirement of these heavily used, baseload CO<sub>2</sub>-free generators is inconsistent with longer-term goals of emission reductions. The owners are certainly aware of the benefits these units provide in meeting low-CO<sub>2</sub> objectives, but they are compelled to deal with price signals in the market, and inevitably greatly discount the potential value that might result from market changes in the future. After all, current support for low-CO<sub>2</sub> emitting resources, such as through renewable portfolio standards, is generally technology-based (e.g., wind, solar, etc.) which is not applicable to nuclear generation.

#### **Cost Implications of Unnecessary Volatility and Uncertainty**

Lastly, while price signals in the RTO-operated markets provide some incentives for resource development, the role such signals can play in ensuring efficient reductions at a reasonable cost depends on predictability. Highly volatile prices that are not predictable introduce uncertainty that will detract from investments, driving up costs and raising customer costs over the long term. The volatile pricing produces an uncertain revenue stream for capacity resources, reducing the ability to finance investment with long-term debt. This is already a problem in capacity auction markets. Today's capacity prices are higher than necessary by 20% or more because of the price volatility inherent to the mandatory auctions.<sup>20</sup> This problem is borne by customers, as they are the ones who pay for the resources over the long term.

Today's capacity prices are higher than necessary by 20% or more because of the price volatility inherent to the mandatory auctions.

New requirements for CO<sub>2</sub> emission reductions will change the operation of all electricity markets. Costs will be incurred and suppliers compensated under whatever policy choices are made. If policy options create unnecessary volatility in those costs and revenues, it will increase costs that will ultimately be passed on to customers. It could also lead to reliability issues. This is not a problem for programs involving a CO<sub>2</sub> price based on a tax rate which should be predictable. But, programs where the price changes in response to supply and demand can introduce considerable uncertainty. In years of shortage, prices will escalate, potentially dramatically. In a market with merchant generation, a shortage of CO<sub>2</sub> emission credits simply leads to a decision to shut down, with the potential for that outcome much greater if the owner has other sources of supply that will then enjoy even higher prices. Clearly the incentives are not aligned with ensuring reliable system operations. Regulatory provisions such as making additional emission credits available at a fixed price cap can act as a safety valve and ensure reliability is not threatened. But again, the interaction between these factors will be important.

<sup>20</sup> Post-Technical Conference Comments of CPV Power Development, Inc., Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, Docket No. AD13-7-000, January 8, 2014, p. 6 where CPV states that "Longer-term revenue commitments reduce project risk, which allows for lower financing costs, which in turn facilitates non-recourse project financing, resulting in lower fixed charges for the project, savings which are passed on to ratepayers. In some cases, a traditional debt financing with a 75/25 debt to equity ratio can cost over 20% less than a "merchant" project financing with a 50/50 debt to equity ratio."



## Challenges for Vertically Integrated Utilities

Among vertically integrated utilities, investments are made with the expectation of cost recovery through rates. These utilities are responsible for all resource procurement needed to serve load. They develop long-term plans for resources, with consideration of environmental implications, and do so with the approval of state or local regulatory bodies. This allows for a comprehensive and strategic assessment of the choices available and the overall strategy for accomplishment. The age of generation stations can be considered, with decisions for such things as retirements tied to the station's replacement. Transmission upgrades, such as for access to new wind generation locations, can be timed with investments in resources and the retirement of others. Energy efficiency programs can be reviewed on an ongoing basis with the potential for adjustments to programs based on performance. And investments to maintain sufficient flexible generation to accommodate wind generation can also be managed.

The ability to manage these issues does not, by itself, ensure that the desired outcomes will be achieved or the costs will be reasonable. The nature of the CO<sub>2</sub> guidelines will be critical and issues associated with unclear standards or unpredictable (or volatile) emission costs will complicate performance. And additional care must be focused on the nature of competition in the electricity markets. When regulated monopolies play a central role in resource procurement, competition will still be present when the utility competitively procures new resources, such as through competitive solicitations for renewable generation or efficiency improvements. Consumer costs can even be lower if utilities provide support for needed investments through long-term contracts that allow new generators to arrange for lower cost financing than achievable when selling into solely short-term markets.

## LIMITATIONS IN EPA'S AUTHORITY CREATE PROBLEMS IN ACHIEVING ECONOMIC EFFICIENCY

As discussed earlier, it appears that the EPA does not have the authority to propose a rule that will achieve maximum efficiencies in its guidelines to reduce CO<sub>2</sub> emissions through the means most often advocated by economists: emission taxes or a cap-and-trade program. To evaluate the efficiency of a likely alternative, assumptions must be made as to the workings of such an alternative approach and for this reason the NRDC proposal will be reviewed in some detail in this section. This proposal was formally released in March 2013<sup>21</sup> with updates in December 2013<sup>22</sup> and March 2014.<sup>23</sup> NRDC also provided summary results of the analysis supporting this proposal and a description of the analytics conducted using ICF's Integrated Planning Model (IPM).

NRDC's initial analysis concludes that the proposal would reduce CO<sub>2</sub> emissions by 26% in 2020 and 34% in 2025. This would be accomplished with wholesale power prices 4% lower than would be expected absent the proposed rule (p. 5). In a December 2013 update to the analysis, NRDC incorporates the more recent 2013 Annual Energy Outlook by the Energy Information Administration, which has an 11% lower forecast of 2020 carbon emissions in the reference case. Under various scenarios modeled by NRDC, reductions of up to 30% below that 2020 EIA figure are projected under its proposal, at costs below what was originally predicted. Further scenarios with more optimistic outcomes were produced in the March 2014 update. Central to these conclusions are assumptions about the availability of low-cost energy efficiency improvements and other means of reducing emissions. The analysis presented in this section of the paper does not review those assumptions, and instead focuses on the market issues that underlie the proposal.

21 "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluter," NRDC Report, by Daniel A. Lashof, Starla Yeh, David Doniger, Sheryl Carter and Laurie Johnson, NRDC, R-12-11-A, March 2013.

22 Update December 2013. [http://switchboard.nrdc.org/blogs/dlashof/even\\_bigger\\_carbon\\_reductions.html?utm\\_source=feedburner&utm\\_medium=feed&utm\\_campaign=Feed%3A+switchboard\\_dlashof+%28Switchboard%3A+Dan+Lashof%27s+Blog%29](http://switchboard.nrdc.org/blogs/dlashof/even_bigger_carbon_reductions.html?utm_source=feedburner&utm_medium=feed&utm_campaign=Feed%3A+switchboard_dlashof+%28Switchboard%3A+Dan+Lashof%27s+Blog%29).

23 Cleaner and Cheaper: Using the Clean Air Act to Sharply Reduce Carbon Pollution from Existing Power Plants, Delivering Health, Environmental, and Economic Benefits, by Daniel A. Lashof, Starla Yeh, et al, NRDC Issue Brief Update, IB:14-03-A, March 2014.



NRDC's analysis rests on an assumption of perfect efficiency in the marketplace that is neither justified nor reasonable.

NRDC's analysis rests on an assumption of perfect efficiency in the marketplace that is neither justified nor reasonable. The underlying logic in the IPM used for the analysis is a linear program which, by its nature, finds the lowest cost means of meeting the requirements of the system demand and CO<sub>2</sub> emission limits (among other requirements).<sup>24</sup> This is a common approach in electric system modeling and can be appropriate for many instances, but its flaw is that the potential concerns addressed in this paper are simply assumed not to exist.<sup>25</sup> In the IPM analysis, every market participant faces the same limits and has access to the same alternative resources at the same costs. Vertically integrated firms respond in the same manner as merchant generators. There are no differences among states with different approaches to addressing the CO<sub>2</sub> guidelines. RTOs with energy and capacity markets respond in the same manner as regions where the industry is still vertically integrated. Local problems of flexible generation are assumed not to exist. These issues are mere backstory to the fundamental problem that this modeling approach essentially assumes a national CO<sub>2</sub> emission trading mechanism, where there is a single CO<sub>2</sub> emission price that forms the basis for all actions of all market participants. This does indeed support efficient outcomes, but it is mere assumption,

with no consideration of how such a market would operate or even be motivated by the proposed EPA guidelines.

The analysis in this paper points out a deep flaw in the NRDC proposal. Beyond developing a means by which EPA may set targets for states, it provides no details on how the states would implement programs to achieve those targets. Shifting obligations to the states may be appropriate; in many respects the states may be better positioned to address their unique market considerations, but there is no basis for concluding that all states will adopt approaches that lead to the optimal nation-wide combination of actions to achieve the desired outcomes. It is inevitable that a process in which each state develops its own program will lead to widely divergent strategies.

As stated in the report, "NRDC's proposal is designed to give power plant owners freedom to choose how they would achieve the required emission reductions, giving credit for increases in [demand side] energy efficiency and electricity generation using renewable sources and allowing emission-rate averaging among fossil fuel-fired power plants."<sup>26</sup> While this might be possible, the means for achieving this is not in the proposal or even part of the recommended EPA guidelines. Consider, for example, the owner of a merchant coal-fired plant. That owner is not given any limitations on performance, no emission credits, no means by which tradeoffs mentioned in the quote might be achieved (such as among energy efficiency and renewable resources), or anything else. That owner, typically, does not have any responsibility for implementing demand-side programs and may not own other lower-carbon sources of generation whose capacity factors can be increased. In a pure merchant environment, no incentive is even provided, per the proposal, for the merchant generator to reduce output. All of that will depend on the state plans.

<sup>24</sup> Details on IPM are available on ICF's website, <http://www.icfi.com/insights/products-and-tools/ipm>.

<sup>25</sup> This problem is inherent in the use of standard industry optimization models to analyze CO<sub>2</sub> emission reduction policies. See also, "The Costs and Consequences of Clean Air Act Regulation of CO<sub>2</sub> from Power Plants," Resources for the Future Discussion Paper, RFF DP 14-01, Dallas Burtraw, Joshua Linn, Karen Palmer and Anthony Paul, January 2014, <http://www.rff.org/RFF/Documents/RFF-DP-14-01.pdf>.

<sup>26</sup> NRDC Proposal, p. 4.



## More Detail on the NRDC Proposal

The NRDC proposal has been modeled as if it had characteristics similar to a cap-and-trade system, but there is no requirement for states to adopt such an approach. Instead, the proposal focuses on establishing a limit on carbon emissions, which is based on emission rate assumptions, other factors in yearly calculations, and adjustments are made for energy efficiency changes. The details matter, but in the end, for each year, each state will have an allowed number of tons of CO<sub>2</sub> that it is permitted to emit.

Under the NRDC proposal, states would be required to adopt plans that meet a state-wide, rather than unit-specific, emission rate. There are provisions that would allow willing states to engage in cross-state trading of emission credits (or even joining in multi-state regions for compliance purposes). The emission limit for each year, in pounds of CO<sub>2</sub> per megawatt-hour (MWh) of system load, is set by a formula. The key elements in this formula are emission rate benchmarks for coal and natural gas generators (pounds of CO<sub>2</sub>/MWh). These proposed benchmarks, which are reduced over time, drive the reduction in the state-wide limit. For 2020, NRDC proposes that the benchmarks be 1,500 lbs CO<sub>2</sub>/MWh for coal units and 1,000 lbs CO<sub>2</sub>/MWh for those fueled by natural gas. Another element in the formula requires a state-specific determination of the historical production of electricity from coal and gas units. Under the proposal, the baseline period of 2008 to 2010 would be used to establish the historical production and this becomes a constant in the calculations for yearly emission limits in the future. The limit for a given year would be based on a formula where the percentage of electricity coming from coal and gas units matches the baseline period, with those sources emitting at their benchmark rates.

As an example, if a state historically produced 45% of its energy from coal and 25% from gas, its CO<sub>2</sub> emission rate limit for 2020 would be equal to:

## State-wide emission rate limit

$$\begin{aligned} &= 45\% \text{ coal} * 1,500 \text{ lbs CO}_2/\text{MWh} + 25\% \text{ gas} * 1,000 \text{ lbs CO}_2/\text{MWh} \\ &= 925 \text{ lbs CO}_2/\text{MWh} \end{aligned}$$

This emission rate is an average for all generation in the state. To achieve this emission rate, coal and gas units could generate more efficiently, there could be a switching of generation from high- to low-emitting resources and non-emitting renewables (such as nuclear power) could be expanded. The annual rate limit is independent of total consumption, and therefore provides some allowance for growth in demand, but does not provide any incentive for reduced consumption.<sup>27</sup> To address this issue, a provision is also detailed to allow energy efficiency improvements to generate credits that can be used to meet the target. And lastly, while limits are established on a state-by-state basis, multi-state programs are encouraged that would allow for trading of emission reductions to increase overall efficiency. NRDC predicts that this approach, with benchmarks that decrease over time, will produce substantial reductions in CO<sub>2</sub> emissions, primarily through the retirement of coal plants and an increase in energy efficiency.

The NRDC proposal is a creative alternative that ties the requirement for state-wide emission reductions to a formula dependent on benchmark rates for coal and gas generators. Meeting the emission limit does not require any specific action at any unit. Instead, the state will have virtually unlimited flexibility in taking actions to achieve the overall reductions. This would undoubtedly involve some combination of switching electricity production to lower-emitting or non-emitting resources, and energy efficiency improvements. The NRDC proposal also makes clear that states would be given wide latitude to adopt different strategies if they achieved even greater reductions.

<sup>27</sup> To take an extreme example to demonstrate this point, if a state cut its use of electricity in half, emissions would undoubtedly decrease. But the 925 pounds CO<sub>2</sub>/MWh would still apply. Thus, whether or not further actions were required would depend on whether the reduction in generation came predominantly from high- or low-emitting resources.



### NRDC Analysis Assumes Perfect Market Efficiency

The IPM model used in the NRDC analysis assumes all states have access to the same options and are subject to the same cost of CO<sub>2</sub> emissions reductions. It assumes that market participants weigh their actions without regard to electricity market structure, electricity regulation or incentives provided by different ownership structures (such as merchant generators, vertically integrated investor-owned utilities, public power utilities or for-profit retail service providers). It also assumes that each participant in the marketplace reduces emissions to the same marginal cost per ton of each CO<sub>2</sub> emission reduction. This common marginal cost of reduction is not described explicitly, but it is inherent in the optimization program that looks at all options and finds the best solution. In essence, buried within the modeling of the NRDC proposal is a CO<sub>2</sub> emission reduction market, with CO<sub>2</sub> emission prices that allow for optimization. Yet the proposal itself, by relying on state-level programs, would all but prevent such a national marketplace. Efficiencies in the analysis are achieved by assertion, not through policies that have been articulated. Achieving efficiencies will not be easy. They certainly cannot simply be assumed. The real world is a much more complicated place.

Achieving efficiencies will not be easy. They certainly cannot simply be assumed. The real world is a much more complicated place.

A full review of the NRDC proposal and the accompanying analysis is beyond the scope of this review. In general, economists tend to be suspicious when the imposition of a constraint (in this case restrictions on CO<sub>2</sub> emissions) ends up lowering costs. In this study, critical assumptions that drive the results involve the extent to which efficiency improvements

are available and their cost. But of perhaps more significance is that the emphasis on wholesale prices in the NRDC report is misleading: the cost of efforts needed to reduce demand is not included in the wholesale price (p. 34, footnote 79). Accounting for such efforts gets complicated as consumers are paid to reduce consumption, with those costs spread among all customers at the retail level. The reader will be seriously misled if they focus solely on the drop in wholesale prices and ignore all of the costs incurred that produce that outcome and are passed on to consumers by other means.

One critical element is the cost of emission credits and treatment of any payments that are made to purchase them. The NRDC proposal does not prescribe how credits will be given to the generators that need them for operations, although it does recommend that they be auctioned (p. 15, NRDC March 2013). The revenues could be used to "expand these [energy efficiency] programs, make other clean energy investments, or otherwise benefit electricity consumers" (p. 15). Whether those credits are sold or allocated, there are clearly huge distributional effects of such decisions. From a modeling perspective, it appears that such costs are not calculated nor included in the report. Thus, the wholesale electricity price does not include any cost associated with the purchase of CO<sub>2</sub> emissions credits.

The IPM analysis needs to model the proposed emission standards as constraints to find the optimal mix of generation and efficiency improvements. To incorporate these emissions standards as a linear programming constraint requires the use of a shadow price for the cost per ton of CO<sub>2</sub> emissions in the model to determine the choices that will be made among resource options. In the real world, to achieve these results a liquid market for CO<sub>2</sub> emission credits would have to develop so that all participants could use the same market price as an indication of whether to take actions to reduce emission or buy credits. Generators would certainly include such a cost in their offer prices in RTO-operated energy markets, meaning that ultimately it would become part of the



wholesale price, but this element is not included in the reported wholesale market prices. Not only is not included, but the CO<sub>2</sub> emission credit (shadow) price is not even presented in any of the results.

It is unclear how the NRDC analysis determined the resource investment decisions and considered other longer-term actions such as plant retirements, but this was ultimately driven by NRDC's assumptions. As has been discussed, there are substantial differences across the country in how the power sector is structured, how investments are made, and how market participants respond to market or regulatory influences. The modeling approach, however, simply assumes the most efficient options are chosen. It is not that the state-by-state market structures and rules are assumed to work perfectly, as those rules are not even detailed. Thus, the analysis simply assumes that the actions of all of the market participants are driven by the same cost assumptions and assumed to operate under the same incentives of achieving overall market efficiencies, regardless of individual situations or incentives.

Before leaving the discussion of modeling results, it is worth recognizing that such an analysis of the costs involved and resulting optimal resource choices made to comply with CO<sub>2</sub> emissions standards could play an important role in the setting of standards for any requirements that might be adopted under this "systems" approach to emission reduction. As has been discussed, the legal definition of system underlying the NRDC proposal is the entire portfolio of existing and new energy resources, including energy efficiency. Accepting this approach, however, leads to the secondary question of how the standard would be set. Generally, this would involve an assessment of technological options and, to some extent, consideration of economics. Under this proposal, there is no single technological option, but instead a continuum of outcomes associated with increasing reliance on renew-

able resources and energy efficiency options. It would seem that any standard would have to be set based on economics, where the marginal cost of meeting the last increment of reduction would be an acceptable cost based on CAA criteria. This heightens concerns over analyses such as that in the NRDC proposal. A standard based on an analysis that assumes perfect efficiency will understate the associated costs. In particular, if the analysis assumes interstate trading of CO<sub>2</sub> emission credits, but a program for such trading is not established or required, costs have surely been understated. Other cost assumptions would also have to be vetted to assure that what is considered economically achievable in setting the standard meets CAA requirements.

### **State Considerations Will Produce Disparate Approaches and Inefficiencies**

The NRDC analysis also assumes all states' plans provide for efficient and compatible emission reductions. But states vary in their situation and outlook. As a starting point, states have already expressed views demonstrating very different outlooks toward the potential for EPA rules in this area. At one end of the spectrum, representatives from fifteen states that have already taken significant actions to reduce CO<sub>2</sub> emissions have made a collective appeal to the EPA "to tackle head-on the challenge of climate change...to develop a stringent but flexible framework..." to achieve meaningful reductions in CO<sub>2</sub> emissions from existing power plants.<sup>28</sup> At the other end of the spectrum Attorney Generals from eighteen states have voiced opposition to new guidelines for existing power plants; they reference concerns of "harm to the nascent economic recovery" and specifically oppose approaches that result in reducing output of still-viable coal-fired power plants in their conclusion that EPA lacks authority for such guidelines, clearly signaling a willingness to fight the legality of such requirements.<sup>29</sup>

28 Letter from Mary D. Nichols, California Air Resources Board, et al, to Gina McCarthy, EPA Administrator, December 16, 2013. [http://www.georgetownclimate.org/sites/default/files/EPA\\_Submission\\_from\\_States-FinalCompl.pdf](http://www.georgetownclimate.org/sites/default/files/EPA_Submission_from_States-FinalCompl.pdf).

29 "Perspective of 18 States on Greenhouse Gas Emission Performance Standards for Existing Sources under § 111(d) of the Clean Air Act," <http://www.americaspower.org/sites/default/files/AG%20White%20Paper.pdf>.



Differences among states not only reflect what they believe should be done, but what actions have already been taken. Roughly half the states have renewable energy standards, most adopted years ago — and half do not (although some of those have voluntary standards or goals). There is widespread variation in demand-side management and efficiency programs that have been adopted by states, and by individual utilities within the states. Each state's plan would build on past actions, resulting in very different alternatives and different expectations of the costs involved with further CO<sub>2</sub> emission reductions. Plus, a number of states have already committed to CO<sub>2</sub> emission reduction programs.

Seven states banded together to form the Regional Greenhouse Gas Initiative (RGGI) with its cap-and-trade system in 2005, with Maryland joining in 2007 and New Jersey exiting as of 2012. The prices for credits allowing the emission of a ton of CO<sub>2</sub> have generally been in the \$2 to \$4 per ton range. The RGGI states have claimed a 30% reduction in CO<sub>2</sub> emissions, with substantial further reductions built into the program,<sup>30</sup> and have achieved reductions substantially greater than other states.<sup>31</sup>

The Western Climate Initiative started in 2007 with an agreement among Arizona, California, New Mexico, Oregon and Washington, and over the next two years, Montana, Utah and four Canadian provinces joined in the process. All 11 jurisdictions collaborated in the 2010 release of a program design based on a cap-and-trade system. The level of cooperation, however, soon unraveled and today California is the only state still involved with the program (some participation in Canada remains). Auctions have been held since 2012 for emission credits going out as far as 2016 (starting for 2013), and prices have been in the \$10–\$14/ton range. In the Midwest, the 2007 launch of the Midwest Greenhouse Gas

Reduction Accord (MGGRA) called for a cap-and-trade program and started with six active states and one Canadian province, but is now moribund.<sup>32</sup>

The state programs to promote renewable energy, energy efficiency, and CO<sub>2</sub> emission reductions through cap-and-trade are not the only means by which carbon reductions are being achieved. Even in cases where there may be no explicit requirements, vertically integrated utilities may choose lower-CO<sub>2</sub>-emitting alternatives, perhaps in direct consideration of the desires of their owners (such as public power) or under the scrutiny of state regulators.

As a result of this diversity of past experience, plus the widely different portfolio of resources in each state, the costs for further reductions will vary considerably. Recognition of past reductions, and treatment of efficiency programs, will undoubtedly vary in state programs. While states can cooperate, the lack of a national emission credit market will inherently build inefficiencies into the market. And even if credits are created, there may be differences in how such credits are defined, creating separate markets for different kinds of credit programs and producing additional inefficiencies.

In addition, each state will have to deal with its own electricity industry structure issues that were discussed earlier. States with vertically integrated utilities will have different options and control over resource decisions than those relying entirely on merchant generators for supply. Sales of electricity between states could also be impeded. With emission limits based on state-wide load, curtailment of exports could be part of a compliance program — despite the effect such reductions in sales would have on the purchasing state. The shifting of energy production among states — or electricity trade — could be significantly affected by different rules

30 RGGI press release, September 6, 2013. [http://www.rggi.org/docs/Auctions/21/PR090613\\_Auction21.pdf](http://www.rggi.org/docs/Auctions/21/PR090613_Auction21.pdf).

31 "U.S. Energy-Related Carbon Dioxide Emissions, 2012", Energy Information Administration, October 21, 2013, <http://www.eia.gov/environment/emissions/carbon/?src=Environment-b1>.

32 <http://www.c2es.org/us-states-regions/regional-climate-initiatives/mggra>.



and state plans. This issue has not been addressed. Indeed, it would seem to be impossible to address until the state programs are defined. But trade effects have implications for costs, efficiency, reliability and even the achievement of CO<sub>2</sub> emission objectives. This is an issue of significant importance.

It should be expected that EPA's current efforts to reduce CO<sub>2</sub> emissions from existing generators will be done with less efficiency, and at higher costs, than could be achieved through a more comprehensive approach such as a carbon tax.

#### **A Long-Term Perspective on Climate Policy Evolution**

It should be expected that EPA's current efforts to reduce CO<sub>2</sub> emissions from existing generators will be done with less efficiency, and at higher costs, than could be achieved through a more comprehensive approach such as a carbon tax. Those concerned about the lack of a comprehensive federal program for emission reductions may welcome aggressive guidelines, however imperfect. Opposition has generally focused on issues of legal authority and concerns over the economic costs of reductions in general. Missing in much of this debate are the long term implications of the specific guidelines that might be adopted at this time. Climate change is a global, long-term problem, with each year's CO<sub>2</sub>

emissions typically expected to stay in the atmosphere for decades. The environmental effects from emission reductions will only have a gradual effect on climate. The effect of new regulations needs to be assessed over a meaningful time-frame, which again would be measured in decades, and needs to consider the implications today's policy choices will have on future decisions.

The EPA's 2014 actions on emissions will not be the last. Assuming growing political will for more substantial actions on climate concerns, there will in time be further policy actions to address emissions from other sources (such as industry), other greenhouse gases, and further reductions from the electricity sector than will likely be proposed at this time. It is a classic policy-makers' conceit to believe that decisions can be reached today that will remain unchanged and faithfully executed in the future over a period of decades, despite new developments and shifts in public opinion. While this is a common assumption, it is rarely true. This is particularly likely in instances like this where the challenge is massive, costs are uncertain, political will is shifting and the problem is global.

Today's decisions are indeed critical, not only because of the direction chosen, but because of the opportunities created (and lost) as a result of those choices, as policy continues to evolve over time. If policymakers pursue a path of inefficiency and compromise, it may constrain future regulatory actions to conform to the same inefficient structures. And, perhaps more importantly, if the options chosen prove to be ineffectual, political will for expending resources to achieve reductions may be compromised. In particular, if promises of substantial, low-cost CO<sub>2</sub> emission reductions prove to be unobtainable in this iteration, the political will to attempt a more aggressive approach in the future will likely be diminished.



## CONCLUSION

The EPA is preparing to issue draft guidelines that will call for existing electric generation stations to reduce CO<sub>2</sub> emissions. Those guidelines will be applied, through state actions, on an industry that is a complicated patchwork of market structures and regulations still evolving from efforts launched in the 1990s to introduce greater competition in the sector. There is strong academic support for market-based solutions to this problem, but those theories exist in a world where the complications of industry structure and limitations of EPA authority are ignored. The real world is more complicated.

The challenge of dramatically reducing CO<sub>2</sub> emissions from the generation of electricity is daunting, and will require countless actions, large and small, deployed over a time scale measured in decades. Central to these actions will be reductions in the use of electricity and shifts in its generation to sources that either emit much less CO<sub>2</sub>, or none at all. In June of this year the EPA is expected to issue proposed guidelines for limiting emissions from existing electric generators, and there is much anticipation and debate over the approach EPA ultimately will take. There is much debate over the anticipated guidelines, with much attention focused on the extent of reductions and EPA's legal authority for different approaches. Too little attention is being paid to the means by which these changes in behavior will be motivated and accomplished.

Economic efficiency is essential to maximizing CO<sub>2</sub> emission reductions over the long term. The magnitude of the desired changes to existing patterns of electricity generation and use is so large that the ability to achieve reductions will ultimately be limited by the political will to impose costly reductions. It is conventional wisdom that a market-based approach will be needed to achieve substantial carbon dioxide reductions. Either directly or indirectly, a cost needs to be placed

on each ton of CO<sub>2</sub> emissions in order to optimize decisions throughout the economy and achieve efficiencies. Conventional approaches would involve a uniform cap-and-trade system imposing restrictions, or a tax on all emissions. Neither approach is available to EPA under its current authority.

Options for new EPA guidelines under discussion involve relying on the states to develop rules that will induce shifting generation away from high-emitting sources and reducing consumption. A system of such state-by-state rules will inevitably be less efficient than a unified approach, but may be necessitated by the limitations on EPA's authority. In addition, the emission regulations (however they may be configured) will be applied in an industry where firms already face widely different incentive structures. Those utilities that remain vertically integrated and regulated at least have the ability to consider broad portfolio based approaches to meeting long term objectives.

In much of the country where wholesale electricity markets are administered by RTOs, however, merchant firms sell electricity and related services (such as demand-side management) on a for-profit business model where market prices will dictate strategies and there is no incentive for firms to adopt portfolio-based solutions to meeting the CO<sub>2</sub> emission reduction goals. These market areas already have problems in getting appropriate investments in generation capacity to meet supply adequacy and other capability requirements (such as locational or flexible-generation needs). The annual mandatory electric capacity auction markets that have been adopted have proven to be problematic, costly and uncertain in meeting reliability goals. And, these auctions have already run into direct conflicts with state-sponsored attempts to manage resources for reliability and environmental goals.



EPA's options are limited and do not appear to allow for the kinds of theoretically pure, market-based programs that economists generally believe can lead to the most economically efficient reductions in emissions. Instead, the states will play a leading role in the deployment of rules by which restrictions will be accomplished. The evidence points to the conclusion that an overly prescriptive approach by the EPA in its guidelines would be counterproductive, reducing state flexibility and limiting the long-term development of economically efficient CO<sub>2</sub> emission reduction options.



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