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In these comments, I offer observations about the political economy of the EPA's proposed Clean Power Plan, the practical difficulties of using market-based and regional mechanisms in the Western Interconnection to comply with the rule, and the distortive effects on wholesale markets that the rule may cause. Generally, state compliance plans will be caught between rival goals of political palatability and economic efficiency. My comments conclude by discussing the work of the Western Interstate Energy Board to identify modular approaches to trading renewable-energy and energy-efficiency credits across state lines.

Market Approaches to Carbon Emissions Reduction

Regional Transmission Organizations (RTOs) outside the West have observed that a carbon price can easily be built into the extant security-constrained economic dispatch (SCED). In this approach, an RTO would identify through modeling the price at which the market equilibrates around a reduction of carbon dioxide necessary to meet the aggregate state goals the EPA has established in a particular region. This carbon price would then be added either by generators to their bids, or by the RTO itself, accomplishing a re-dispatch that treats the cost of carbon dioxide emissions much like any other variable cost that is determinative of bidding behavior, such as fuel cost. Probably, this is the most efficient approach to carbon-dioxide reduction—if that is indeed the goal in mind—but such an approach will face institutional and political hurdles in the Western Interconnection and elsewhere.

The first and most obvious problem is that there is no central market operator in most of the Western Interconnection. The necessary software infrastructure simply does not exist outside of the California Independent System Operator (CAISO) and its nascent Energy Imbalance Market (EIM). Rather than relying on a SCED for real-time dispatch, the West's vertically integrated utilities typically schedule electricity deliveries on an hourly basis, matching the output of plants they own or power purchase agreements they control to their load, without the SCED of a market operator. The 38 balancing area authorities of the interconnection then individually dispatch resources, usually not on a primarily economic basis, to keep loads and resources in balance within the hour.

This is not to say that these utilities are insular; indeed, far from it. Utilities deliver electricity over long-distance, high-voltage lines across state boundaries in the West. California imports nearly one-third of its electricity; Wyoming exports nearly two-thirds of its in-state production.[1] Yet these transactions unfold in either a vertically integrated or bilateral context. Effecting a carbon reduction through re-dispatch likely would depend less on an explicit carbon price and more on command-and-control instructions that would cause a utility to change the way it schedules and dispatches its fleet for the purpose of avoiding carbon emissions. This, in turn, could warp marginal price signals on the liquid trading hubs in the Western Interconnection, where power is delivered to and from in the course of bilateral trading. For instance, a scenario could arise where one state or a large utility chose to establish a carbon price that affected a coal plant's marginal cost signals to the wholesale marketplace, while another state chose to comply with the rule through a mechanism that did not have a marginal-cost expression (such as embedding capital costs of renewables within a regulated cost-of-service revenue requirement). If those units had excess capacity, the thermal unit that is not subject to a carbon price as a variable cost would have a distinct advantage in the marketplace. Distortive effects on wholesale markets are certainly a significant consequence of the decision of states' choosing different approaches to compliance.

A regionally agreed-upon carbon emissions price to factor in to utilities' dispatch decisions could be used to accomplish carbon reductions, or the EIM's software could accomplish a result similar to what an RTO's could (at least for the purposes of real-time energy trading, to which the EIM is limited). However, these are approaches that would continue to face problems of political economy. Most notably, states have radically different carbon reduction goals. The building-block approach of EPA is one which operates on the logic of "from each

[1] For California, information on imports is at: http://energyalmanac.ca.gov/electricity/total_system_power.html (accessed Feb. 20, 2015). For Wyoming, the information is available through the U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report" (June 2014).

state according to its abilities," since a uniform percentage reduction would not pass legal muster under the Clean Air Act. As a result, each state has a different implied carbon price necessary to achieve its reductions. In the West, EPA's Integrated Planning Model (IPM) yielded costs per ton of avoided carbon dioxide ranging from $0 to $62.[2] Arriving at a common price for carbon in the West, or anywhere else, would depend upon state policymakers either agreeing to ignore the fact that EPA's rule creates winners and losers—which it is unlikely they would accede to—or to create what is sure to be a complicated allocation of the costly outcome of a carbon-reducing SCED or re-dispatch to parties that have relatively higher and relatively lower carbon goals.[3]

There is one final political-economy barrier to using a carbon price to accomplish re-dispatch, and that is the loss of autonomy of state policymakers who would otherwise be the center of action when it comes to conceiving of state 111(d) carbon dioxide reduction plans. Setting a carbon price and letting a SCED go to work prevents state policymakers from ordaining a solution that is politically pleasing to the constituencies that wield power in their states. SCED is by its nature insensitive to the fate of this or that coal or gas plant, or the fact that it might be utilized less (and eventually retired) in favor of some more efficient or low-carbon resource in another state.[4] This powerlessness, more than anything, makes this approach a political non-

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[2] Marginal Carbon Dioxide Costs from EPA IPM Results, Option 1: No State Cooperation, available in graphical form through "EPA's Proposed Clean Power Plan: Implications for States and the Electric Industry," Brattle Group (June 2014), p. 11, available at: http://www.brattle.com/system/publications/pdfs/000/005/025/original/EPA%27s_Proposed_Clean_Power_Plan_-_Implications_for_States_and_the_Electric_Industry.pdf (Accessed Feb. 20, 2015)

[3] In EIM, dispatch of carbon-emitting resources into California already triggers compliance under California Air Resources Board (CARB) standards. This has led to the innovation of bid adders for resources that affect their dispatch—but only if and when they are dispatched to a California load. In other words, the EIM builds in a carbon price in some parts of its market footprint, and not in others. Many questions remain as to the effects of this element of market design: How distortive of dispatch this feature has been; has it actually caused carbon-generating resources to be dispatched less than they otherwise would, or simply effectuated a "re-shuffle" of resources to serve different loads; and how durable would this design element be were jurisdictions outside of California to attempt to accomplish carbon reductions by the same means California has, causing several different local prices in carbon within the same market footprint.

[4] The market clearing price of electricity will rise in a SCED that incorporates an explicit carbon price, and the proceeds generated from the environmental bid adder can be used in a way that policymakers see fit. That is a kind of consolation prize to state politicians in search of a "jobs program" to ease the pain of the cost increases that inevitably result from EPA's rules. But it still suffers from allocation difficulties and the loss of autonomy to ordain the construction, *ex ante* of the market, of politically preferred resources.

starter in many parts of the country, notwithstanding its promise of efficiency. As rhetoric about "investment" and "jobs" from EPA and exponents of the rule underscores, the rule is *not* just about carbon reductions. Central to most state plans will be what may uncharitably be called rent-seeking in exchange for one or another lobby's acquiescence or support for a state plan.

Central Planning as an Emissions Reduction Method

In lieu of a market that arrives at carbon reductions in response to a carbon price, then, carbon reductions are likely to be achieved through some kind of planning-and-acquisition process. In the West today, most utilities construct new resources and assure themselves of cost-recovery by submitting for comment and approval by state regulators or their boards of directors a document called an Integrated Resource Plan (IRP). This process, and not procurement from a capacity auction, is generally how the need for a new plant is identified and is the impetus for its construction. Carbon could be, and is today, identified as a factor in IRPs.

However, the Clean Power Plan imposes a framework of state compliance to which IRPs are not necessarily well-suited. Utilities' service territories are not co-extensive with the political unit (the state) to which EPA goals apply. Some large utilities conduct a multi-state IRP. And any given state will have more than one entity to which 111(d) reduction obligations presumably would be allocated. Some Electric Generating Units (EGUs), moreover, are owned by entities like electric co-operatives who write IRPs that are reviewed by their board of directors, and not by an arm of state government. Other EGUs are owned by merchants who are not subject to IRP control. Perhaps most importantly, large coal-burning EGUs in the Western Interconnection are often located remotely from the load they serve. Such power plants are subject to the jurisdiction of the environmental regulator in one state, but are subject to IRP requirements of the utility commission in the state where the owner's retail service territory is located.

In the West, carbon emissions in one state are often caused by consumers in another state. Unlike renewable energy and its attendant credits (RECs), there are no "coal energy credits" for such electricity production. Instead, the state in which the EGU is located is responsible for carbon mitigation under 111(d) regulation, notwithstanding the out-of-state export of that electricity. In such states, a rate-based approach may well be attractive for political-economy reasons. In this approach, a state environmental regulator would identify an amount of renewable energy or energy efficiency development sufficient to "green" the denominator of the pounds-of-carbon-dioxide/megawatt-hour equation. The regulator would then assign the acquisition or payment responsibility (for instance, to acquire credits that can be retired through a state-specific compliance program) to EGUs in a pro rata allocation for their emissions. The question would then arise of who should own or be given an allocation for the value of the production of renewables and energy efficiency programs. This could be accomplished by a system of crediting, whereby the load-serving entity (LSE) that is the beneficiary of the EGU's energy efficiency acquisition pays an avoided-cost based contribution to the EGU acquirer. In such a scenario, the cost of 111(d) compliance is the cost of the acquisition of renewables and energy efficiency, less the market value of the energy produced by the former or the avoided-cost payment of the LSE for the latter. This cost is a proxy for a carbon price, but would vary considerably by state. Such an approach would be as politically palatable an approach as possible for coal-heavy exporting states who will struggle to comply with the 111(d) regulation, because it is a compliance strategy masquerading as a "jobs plan." The costs of this approach, moreover, fall on the EGUs' owners, whose customers are not, at least not entirely, citizens of the state whose environmental regulator creates the plan. Such an approach may achieve buy-in from the many constituencies to which an environmental regulator is subject, even if it is not a least-cost approach. Cross-state difficulties likely would continue to exist. It could confine energy efficiency acquisitions, for instance, to loads that are not co-extensive with those the EGUs typically serve. It could also lead to criticism that environmental regulators in another state are usurping the resource-planning function by a utility commission in an importing state.

State plans that have an IRP or other process of regulatory selection at their core could cause distortive effects in the wholesale market, not unlike how tax policy benefiting renewables has essentially bought down the capital cost of a low-variable-cost resource's entry into the market, depressing the marginal price signal in the wholesale market for energy. If state plans imposed the costs of compliance on regulated utility revenue requirements or directly upon EGUs as a kind of permitting cost, then this cost may not translate easily into the volumetric per-megawatt-hour price signal that serves to rationalize wholesale markets. Instead, it would be a kind of hidden carbon cost, with consumers paying for it through regulatory recovery mechanisms and not through wholesale transactions. Such an approach in the West would tend to disadvantage the majority of customers, who remain captive to regulated revenue requirements in which such costs likely would be embedded, but would perhaps benefit certain industrial loads that contract for energy supply based on the wholesale market price.

Avenues for Regional Cooperation in the Western Interconnection

Problematically, a market-based approach to carbon emissions reduction is plagued by difficulties of political economy, while an approach that revolves around central planning wants for efficiency. Ideally, a 111(d) compliance strategy will be as economically efficient as a state's politics allows.

As has been discussed above, there are significant hurdles for regional cooperation. However, it is incumbent upon state stakeholders to try to find avenues of cooperation. An explicit carbon price built into a market is unlikely because of both the absence of institutions and software infrastructure in the West to achieve this, and the allocation difficulties engendered by aggregating state goals. Short of a regional plan, however, there may be a "modular" approach to 111(d) compliance that allows states to remain in charge of attaining their own goals, but through trading and a tracking platform that allows EGUs or those responsible for them to obtain renewable-energy and energy-efficiency credits in one state for the purpose of offsetting a goal in another state. There are significant hurdles to this approach, also. It allows utilities to cost-effectively obtain energy efficiency in a state where opportunities are more abundant, for instance, but that might still leave the state with the compliance goal at a loss if such reductions are enough to cause the retirement of a power plant on which a local economy depends. Nonetheless, a modular approach would continue to vest the state with authority to meet its goal in a way acceptable to it, but with more options on the table. The Western Interstate Energy Board (WIEB) has contracted with Cadmus Group to work on a project that explores the usefulness of current tracking mechanisms for 111(d) compliance purposes, and to raise the policy questions that would have to be answered before a module could be used within a state plan. Additionally, WIEB's contractor is exploring the possibility of cross-state re-dispatch in a way that allows a regional-portfolio approach to complying with individual state goals. Such work, if successful, falls far short of baking a carbon price into SCED's least-cost-dispatch function, and is unlikely to result in a regional plan. However, if permissible under the final rule, it would allow an EGU in a state to engage in interstate trading for the purpose of helping to achieve a state goal.