

CARBON POLLUTION STANDARDS FOR EXISTING POWER PLANTS: KEY CHALLENGES



CENTER FOR CLIMATE
AND ENERGY SOLUTIONS

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In coordination with states, the U.S. Environmental Protection Agency (EPA) faces a number of policy challenges as it develops its guidelines for carbon pollution standards for existing power plants. These range from over-arching issues that will impact the foundation of the standard, such as whether it will come in the form of an emissions rate or a mass-based carbon budget for each state, to narrower questions such as how to account for offsets in an existing state greenhouse gas program.

This brief seeks to establish a common understanding of these intertwined challenges to help EPA, states, and other stakeholders see how these issues interact and where the solution to one may complicate another.

INTRODUCTION

As EPA develops its Clean Air Act Section 111(d) guidelines,¹ it must wrestle with a variety of novel issues. These guidelines will be followed by states as they choose how to implement Section 111(d),² meaning one major aspect of the guidelines is the boundary it sets around state interpretation. Additionally, EPA must ensure that the carbon dioxide (CO₂) emissions standard it sets is achievable and legally defensible. Once the guidelines are set, states will face many additional issues in determining how to implement the performance standards. Thus as the Section 111(d) process unfolds, both EPA and states will have to answer a number of questions. Some of these, such as determining the basis for a standard, are solely within the purview of EPA (though EPA is soliciting state

input on these points). Other issues will likely have to be addressed by both EPA and states, for example, what types of compliance options will be available to power plant operators.

This paper examines the major questions that must be addressed.³ Fundamentally, EPA must decide how it will set the performance standard and how states will be allowed to achieve this standard, also sometimes phrased as what state actions will be deemed “equivalent” to the guidelines developed by EPA. The specific issues covered in this brief are listed below. In a separate paper, C2ES will assess the possible solutions to these challenges through the perspective of a specific state or region.

ISSUES COVERED

This brief is divided into four sections, each dealing with a different broad category of questions EPA will have to address. Over-arching issues that impact EPA's approach are:

- Specificity of Guidance
- Basis for Standard (Best System of Emission Reduction)
- Form of Standard
- Source Categorization
- Accounting for Regional Variation
- Emissions Baseline
- Enforcement
- Treatment of New Plants

To integrate cap-and-trade programs, EPA will have to deal with several unique issues:

- Layering of Federal and Subfederal Standards
- Programs that Cover Multiple Sectors
- Offsets

- Cost Containment Measures
- Interstate Allowance Trading
- Subfederal Transnational Linkage

When it comes to integrating other state-level programs that reduce carbon emissions from the power sector, questions arise about:

- Additionality in Clean Energy Policies
- Crediting Changes in Dispatch Order
- Carbon Tax
- Energy Efficiency

Finally, due to the cross-sector and interstate nature of the U.S. energy system, EPA must solve some accounting issues on:

- Electricity Imports
- Electricity Demand that Reduces Net Emissions
- Electricity Emissions that Reduce Emissions in Other Sectors

OVERARCHING ISSUES

EPA must decide a handful of fundamental, over-arching questions that will impact its approach to the remaining questions. While some issues discussed in this paper could be made moot by EPA's approach to other questions, issues in this section will have to be addressed regardless. While most of the issues discussed in this brief must be sorted out through decisions of both EPA and states, these over-arching issues are primarily under the direct control of EPA, although EPA is seeking state input.

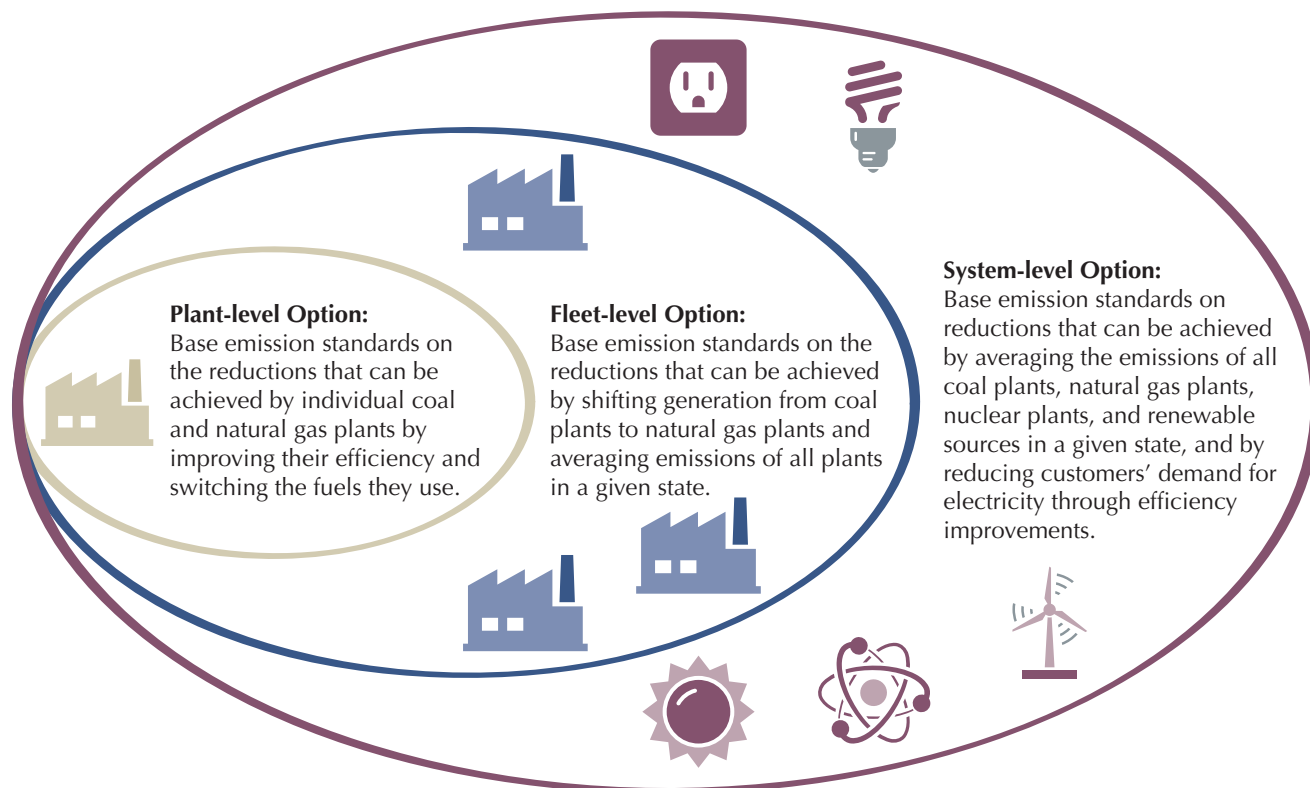
SPECIFICITY OF GUIDANCE

A general question that EPA must settle is how specific its guidance to states will be, and what aspects of this guidance will be mandatory. EPA will likely offer, at minimum, a performance standard (or set of performance standards) that states must meet or exceed as part of their state plans. EPA could also choose to set explicit requirements as to how a state can achieve the performance standards, or it could leave it entirely up to states. In other air quality rules, EPA has opted to be

more explicit in its guidance, but far fewer compliance options exist in these cases than for greenhouse gases. For instance, in previous examples of Section 111(d) guidelines, such as those issued for commercial and industrial solid waste incineration units, EPA set detailed requirements that states were required to meet or exceed in setting their own standards.⁴ Specifically, EPA identified rate-based performance standards along with requirements for monitoring, timelines, enforcement, recordkeeping, and other provisions. With this level of specificity, each state had the option of adopting the guidelines virtually wholesale as its state plan – meaning the guidelines functioned as a model rule. States had the option to impose stricter standards than those set by EPA, but otherwise had very little flexibility.

In the case of CO₂ emissions from existing power plants, EPA is very unlikely to be as detailed in its guidelines as it has been in the past. EPA has strongly indicated that it intends to give significant flexibility to states to determine how each will achieve the set performance standards. However, EPA must determine whether it will

FIGURE 1: Options for EPA’s Determination of the “Best System of Emission Reduction” (BSER)



EPA must decide the basis for the performance standards. In the language of the Clean Air Act, this is known as the “best system of emission reduction” (BSER). Though there are additional possibilities, EPA has three main options when determining which types of reductions will be used as the basis of BSER, ranging from only those available within power plants themselves to reductions available within the entire electricity sector, including electricity consumption.

Source: Center for Climate and Energy Solutions (2014).

offer a model rule for states to follow, and which, if any, model provisions are mandatory rather than suggested. For example, EPA might require that any trading be limited to intrastate to ensure cuts are made in each state, or it might merely suggest that offsets be prohibited so that reductions are made only within the power sector.

BASIS FOR STANDARD (BEST SYSTEM OF EMISSION REDUCTION)

One of the most fundamental questions EPA must answer is which carbon-cutting measures it will use as the bases for its performance standard. Section 111 language requires EPA to set a standard based on the “best system of emission reduction” (BSER) that has been “adequately demonstrated,” taking into account costs and nonair

benefits.⁵ Section 111 does not offer any guidance to EPA on what should factor into the BSER determination.

The most basic issue in interpreting BSER is whether it must be limited to the power plant itself, or if it can also include measures taken beyond the fenceline. EPA generally has set BSER based on what is achievable within an emission source. However, there is precedent for EPA to include beyond-the-fenceline measures. In one example, for commercial and industrial solid waste incinerators, EPA guidelines called for states to include in their state plans a “waste management plan” to reduce the amount of waste coming to the incinerators.⁶

From narrow focus to broad focus, EPA might consider the cumulative measures listed below when setting the performance standard. Each has several sub-options.

For example, system-level emissions averaging could be unrestricted nationally, or could be restricted by operator, state, region, or otherwise. Options could include:

- Plant-level efficiency improvements
- Plant-level fuel switching
- Power plant system-level averaging
- All electric system changes are considered, including demand-side efficiency and renewable and other low-carbon generation
- All possible greenhouse gas reductions are considered, with those outside of the electric sector being included as offsets

This choice will impact the level at which the standards are set, as illustrated in **Figure 1**. As with any rule, EPA must balance aggressiveness with compliance costs and legal certainty when choosing among the options above.

FORM OF STANDARD

Section 111(d) offers little guidance on whether the performance standard will be rate-based (each power plant can emit no more than X tons of CO₂ per megawatt-hour of electricity produced) or mass-based (each power plant can emit no more than X tons of CO₂ per year).⁷ EPA must wrestle with this question regardless of how it defines BSER, discussed above. Essentially, Section 111(d) only requires EPA to “prescribe regulations which shall establish a procedure” that states follow to “establish[] standards of performance” for existing power plants that “take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.” Section 111(a) of the Clean Air Act offers a definition of “standard of performance,” though it does not provide guidance on what form the standard should take:

... a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.
—42 U.S.C. § 7411 (2012)

Because of vagueness in the statute, and the absence of case law that would provide interpretive guidance, EPA has several options, but little experience, in how to structure regulations under Section 111(d). However, EPA’s current interpretation of “emissions standard,” from its existing Section 111(d) regulations, suggests three possibilities for the form of the standard:

Emission standard means a legally enforceable regulation:

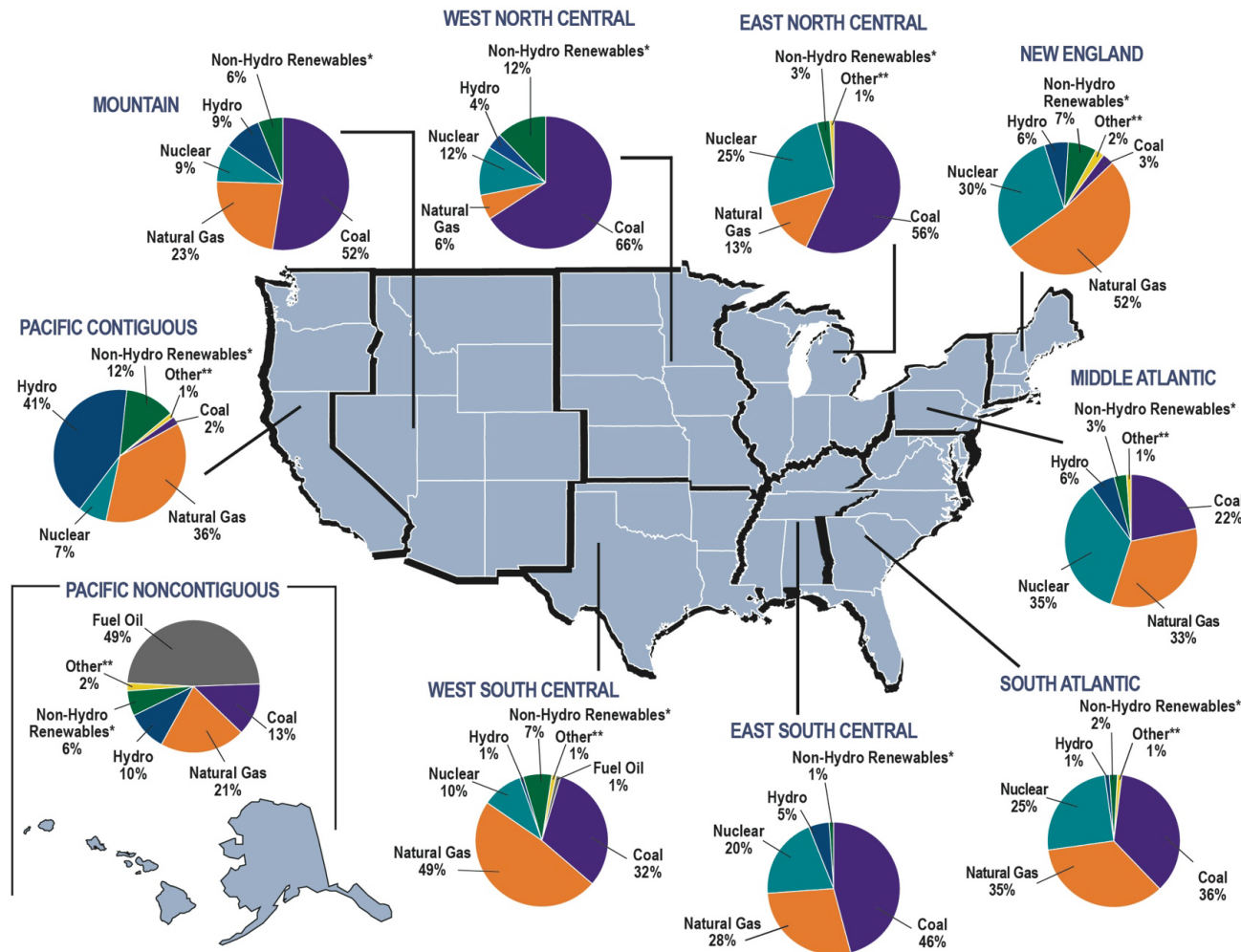
- 1. setting forth an allowable rate of emissions into the atmosphere,***
- 2. establishing an allowance system, or***
- 3. prescribing equipment specifications for control of air pollution emissions.***

—40 C.F.R. § 60.21(f) (2013) (numbers added)

EPA has extensive experience with its first option, an “allowable rate of emissions.” In the context of Section 111(d), EPA has made more limited use of “an allowance system,” which could take the conservative form of emitting units within a single plant being able to trade allowances to achieve compliance as a plant rather than separate units, or could be envisioned as a broad cap-and-trade program, such as exists in the Regional Greenhouse Gas Initiative (RGGI).⁸ EPA’s third apparent option, “equipment specifications,” would offer the least flexibility, and is largely incompatible because most measures available to reduce greenhouse gases in the power sector exist beyond the fence line of power plants. Even if EPA only allows reductions within the power plant fence line to count toward compliance, it historically only issues standards in the form of equipment specifications when the other two options are infeasible.⁹ Thus EPA’s options appear to consist of a rate-based emission standard or an allowance system.

If EPA chooses to employ an allowance system, it must also determine whether it will be mass-based (tons/year) or rate-based (pounds/megawatt-hour). Although allowance systems are typically associated with mass-based cap-and-trade systems, such as those in California¹⁰ or RGGI, a rate-based allowance system is an option. Under this approach, a power plant could earn rate-based credit each year for every pound per megawatt-hour (lb/MWh) below the standard it operated. For example, if the stan-

FIGURE 2: Electricity Generation Portfolio by Region (2012)



The fuel used to generate electricity, and most notably the use of coal, varies greatly across the country. It will be a challenge for EPA to craft standards that drive significant, but achievable, reductions in each region.

*Includes generation by agricultural waste, landfill gas recovery, municipal solid waste, wood, geothermal, non-wood waste, wind, and solar.

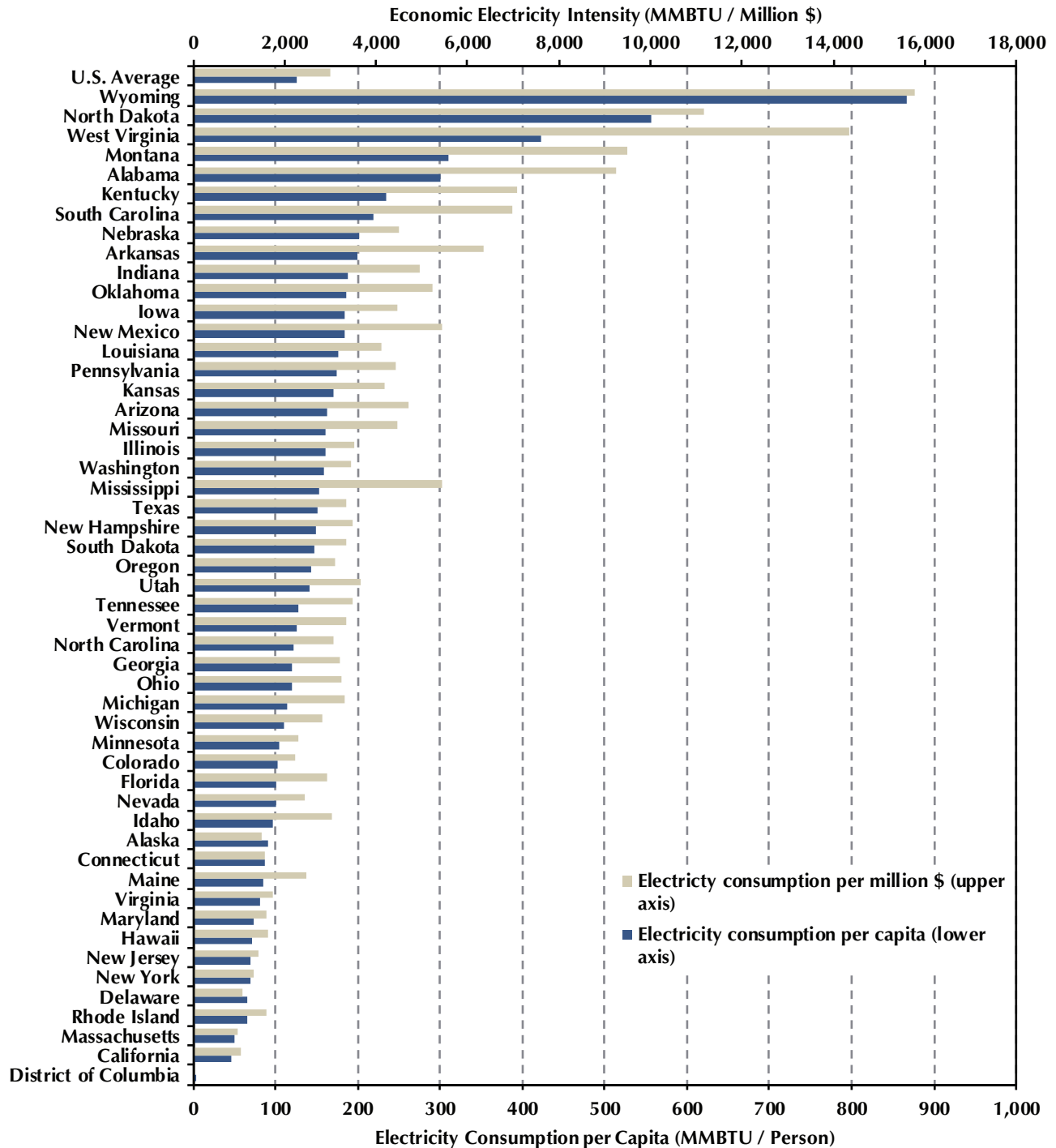
** Includes generation by tires, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies. Sum of components may not add to 100% due to independent rounding.

Source: Edison Electric Institute, *Different Regions of the Country Use Different Fuel Mixes to Generate Electricity* (Washington, DC: Edison Electric Institute, 2014), http://www.eei.org/issuesandpolicy/generation/fueldiversity/Documents/map_fuel_diversity.pdf.

standard for a gas plant were 1,000 lbs/MWh and a certain plant operated at an average of 990 lbs/MWh over the course of the year, it would earn 10 tradable, pounds-per-megawatt-hour credits. These credits could then conceivably be sold to an operator whose plant exceeded the 1,000 lbs/MWh standard, though a conversion ratio would likely be required to account for differences in output.

In addition to deciding whether the performance standard will be rate-based or mass-based, EPA would need to determine a methodology to enable states to convert from one form to the other if states are to have that option. If EPA sets a rate-based standard, states with cap-and-trade programs in place will need to be able to convert rate targets to mass values. Similarly, if EPA sets a mass-based standard, some states may wish to impose a

FIGURE 3: Electricity Consumption Per Capita and Per Million Dollars of GDP by State (2011)



There is wide variation in electricity consumption among states, whether measured on a per capita or per GDP basis. The 2011 United States averages were about 124 MMBTU of electricity consumption per capita and 3,000 MMBTU per million dollars of GDP. Per capita electricity consumption falls at or below 100 MMBTU in 14 states, while this figure is at or above 200 MMBTU in 8 states.

Sources: U.S. Energy Information Administration, *Electric Consumption by State, 2011*; U.S. Census Bureau, *Vintage 2011 State Tables, Annual Estimates of the Population for the United States, Regions, States and Puerto Rico*; U.S. Bureau of Economic Analysis, *Real GDP by State, 2009-2012*.

rate-based performance standard on its plants, and will need a conversion methodology in order to be able to do so.

SOURCE CATEGORIZATION

In its re-proposed regulation of carbon dioxide emissions from new power plants under Clean Air Act Section 111(b), EPA set separate standards for coal plants, large gas plants, and small gas plants.¹¹ This follows the typical EPA approach of setting separate power plant standards for separate fuels. An earlier proposal under Section 111(b) included a single standard that would apply to all power plants, though EPA abandoned this approach.

In the case of Section 111(d), EPA must again decide if it will approve standards that come in the form of a single performance standard for all plants, separate standards based on fuel, or separate standards based on technology (for example, separate standards for combined cycle and simple cycle natural gas plants). Since emissions from gas plants are far lower than those from coal plants, separate standards could lead to achievable goals for each type. A single standard across fuels would either push gas plants to make cuts but be unachievable for coal plants, or be achievable for coal plants while driving no cuts at gas plants. However, a credit trading system could be combined with a single standard (if sufficiently stringent) to promote cuts in all plants since gas plants would be encouraged to cut emissions in order to sell credits to coal plants that are operating above the standard.

ACCOUNTING FOR REGIONAL VARIATIONS

Current state emissions vary widely, meaning each will begin implementing Section 111(d) guidelines from vastly different starting points. This variation is impacted by a variety of factors, including resource availability, energy and environmental policies, industry, and climate. Electricity-related per capita CO₂ emissions range from under 1 metric ton annually in Vermont to over 75 metric tons annually in Wyoming. While these two are outliers and most states fall between 4 and 15 metric tons of electricity-related per capita CO₂ emissions annually, this figure is near or below 4 metric tons in 16 states, while 6 states fall above 15 metric tons. The national average, as of 2010, was 7.1 metric tons.¹²

This variation is a function of differences in generation portfolio, shown in **Figure 2**, and electricity demand. Even when only considering a state's fossil power

plant fleet, significant variation still exists due to the reliance of some on high-emitting coal plants versus lower-emitting gas plants. It would be possible for EPA to account for regional differences in coal versus gas usage for electricity by setting a unique standard for each fuel, but even this would not account for the wide variation among states in electricity consumption per capita, as shown in **Figure 3**. This figure also shows a wide variation in electricity consumption per unit of state GDP.

In setting its performance standard, EPA will have to determine whether it wants to drive cuts in all states or only in those that have not yet taken significant action on their own. If EPA aims to see reductions in all states, it will have to balance making a standard stringent enough to drive emission cuts in states that are already leading in power sector emissions, while achievable enough for states that are lagging in this regard. EPA could take one of two fundamental approaches to setting a standard: require that power plants meet either a given emissions rate or a given percentage reduction in emissions rate from a baseline. The national emission rate standard approach benefits states that have already been taking action to reduce power sector greenhouse gas emissions because they will have to take relatively less (if any) action to meet the standard. However, the presence of an interstate allowance system would provide an incentive for early movers to pursue additional cuts. EPA could also leverage its compliance timeline to inject flexibility into the guidelines. That is, it could create a national standard, but allow states varying amounts of time to reach it to account for their starting points.

EMISSIONS BASELINE

EPA will have to determine whether absolute reductions will be required as compared to a baseline year, or if reductions will be measured against a business-as-usual baseline that rises over time to account for changes in population and economic circumstances. If reductions are measured against a specific baseline year, EPA will have to decide what that year must be, or what criteria states must consider when setting their own baseline year.

If a business-as-usual baseline approach is used, EPA must determine what factors states must consider when determining what business-as-usual looks like. Under this approach, EPA must importantly decide whether currently existing efficiency measures will be included in this baseline such that only additional measures are credited, or if states can be credited for reductions driven by these existing programs. EPA must also decide

whether adjustments to the baseline will be made in the future to account for unanticipated changes in economy and population, or if the set baseline must remain static over time.

ENFORCEMENT

Section 111(d) guidelines face two related enforcement problems: 1) Will each regulated power plant have to demonstrate individual compliance; and 2) Which entity, the state government or EPA, will enforce the performance standard?

In response to the first question, EPA could require all plants to demonstrate compliance either by meeting the performance standard or holding sufficient emission allowances to cover their annual emissions. Alternatively, EPA could choose to give states the flexibility to meet a sector-wide target without imposing any requirements on individual plants. This latter course of action would give states more flexibility to achieve emission cuts, but would remove EPA's authority to enforce its Section 111(d) guidelines on power operators that are not taking action to reduce emissions. However, this would not prevent EPA from taking over implementation and enforcement authority if it found the state were not meeting its carbon reduction obligations.

The second question is relatively straightforward. Traditionally, Clean Air Act laws are enforced on emission sources by state governments, with EPA stepping in if the state cedes enforcement authority or is doing an inadequate job. This model would likely be followed if power plants must demonstrate compliance individually. However, since states may be allowed to comply with

Section 111(d) on the basis of their power sector emissions in aggregate, rather than on the basis of emissions of individual power plants, the traditional enforcement model may not work.

If states are allowed to demonstrate compliance through their aggregated power sector, EPA would have to be the entity enforcing the standard.

TREATMENT OF NEW PLANTS

By the time Section 111(d) regulations are being implemented, greenhouse gas standards for new power plants will also be in place through Clean Air Act Section 111(b).¹³ This means any new plants coming online will have to meet a minimum level of greenhouse gas performance. Due to the state of natural gas technology and the likely inclusion of a carbon capture and storage (CCS) requirement for new coal plants, any new plant is likely to have lower emissions than the levels EPA sets under Section 111(d). However, at some point EPA may decide to fold plants built after Section 111(b) regulations are put in place into the Section 111(d) system to ensure additional cuts are made, if feasible. Additionally, a state may decide to include these newer plants in their Section 111(d) regulations because these plants are likely to bring down the average emissions of its fossil power fleet.

EPA must therefore determine whether plants subject to Section 111(b) will ever be part of the Section 111(d) program, and whether it will be on a voluntary or mandatory basis. EPA would then have to establish criteria to determine when this transition would take place.

INTEGRATING CAP-AND-TRADE PROGRAMS

EPA has indicated that it intends its guidelines to enable existing cap-and-trade programs to function as comprehensive compliance measures, as well as the expansion of existing programs to new states and the creation of new programs. Cap-and-trade programs have been shown in RGGI to reduce power sector emissions in a cost effective way while providing additional benefits to states.¹⁴ However, integrating state and regional cap-and-trade programs with Section 111(d) guidelines poses a few challenges.

LAYERING OF FEDERAL AND SUBFEDERAL STANDARDS

Once a federal power plant carbon dioxide standard is in place, power plants in some states¹⁵ will be subject to both a federal standard and a state standard in one or both of two possible forms: a state cap-and-trade program and a state performance standard imposed on individual power generators or importers.

In the context of state cap-and-trade programs, EPA can choose to either allow state programs that will achieve equivalent emission reductions to function as a complete compliance strategy for the federal standard, negating the need for a distinct federal crediting system, or it can layer a federal program on top of state programs. If EPA does not impose a federal program, it would have to define what steps a state would have to take to demonstrate that its program achieves equivalent reductions. In this scenario EPA would also have to determine whether and how trading could occur between plants inside and outside of state programs. EPA could instead layer a separate federal program on top of existing state programs. This would be administratively burdensome on emitters subject to two programs, but could also ease interstate trading of federal compliance credits.

If a state uses rate-based performance standards (i.e., allowing each plant to only emit a certain amount of greenhouse gases per megawatt-hour of electricity produced) to implement Section 111(d), there would likely be neither the need nor the legal authority for distinct federal and state programs. A rate-based performance standard driven by Section 111(d) guidelines would preempt existing state performance standards.

PROGRAMS THAT COVER MULTIPLE SECTORS

Some existing state and regional programs only cover the power sector, such as RGGI or Renewable Portfolio Standards (RPS) policies. In these cases, the sub-federal program drives power plant emission cuts, which should make them easily adaptable for the purpose of implementing Section 111(d). However, in the case of California, the cap-and-trade program covers industrial, heating, and transportation emissions as well. In theory, power companies could comply with California's program without cutting any emissions, instead relying on the availability of excess allowances from regulated firms in other sectors.

EPA must determine whether it will accept California's broad program as equivalent to its Section 111(d) guidelines, or if it will require a showing that emission cuts are required in the power sector specifically.

OFFSETS

Existing cap-and-trade programs in California and RGGI allow for the use of offsets for a limited percentage of a regulated firm's compliance requirement. Offsets gener-

ally come from outside of the power sector, for example through forestry projects. In the case of California, offsets can even be generated outside of the United States. Thus power companies covered by RGGI or California's cap-and-trade program can comply with those programs, at least partially, through measures that do not directly reduce power sector emissions.

EPA will have to decide whether offsets can count toward compliance with the performance standard, and if so, EPA and states will have to decide what types of offset projects will be allowed. If EPA denies the use of offsets for Section 111(d) compliance, it will have to determine how offsets will be kept distinct from compliant emission allowances.

COST CONTAINMENT MEASURES

Cap-and-trade programs can employ a variety of flexibility and cost-containment measures to reduce cost uncertainty for regulated power companies.

EPA must determine whether each of these flexibility measures will be allowed as states implement Section 111(d) guidelines. If a certain provision is not allowed, EPA must determine whether the problematic provision must be struck from existing programs, or whether it can somehow be kept insulated from each regulated firm's demonstration of compliance.

Banking: Regulated entities are allowed to carry surplus allowances into future compliance periods. This provision removes some of the disincentive for power plant operators to overestimate the number of allowances they must acquire in a given compliance period. Banking also allows for temporal compliance flexibility since operators can over-comply in one year and use the excess allowances in the next. Since banking does not affect the overall integrity of the cap, EPA is unlikely to take issue with it. Both California and RGGI allow banking.

Price ceiling / Alternative Compliance Payment (ACP): A price ceiling is a maximum price entities can pay for an allowance. That is, an unlimited number of allowances would be made available at the price ceiling. Similarly, an ACP is a financial payment a regulated power company could make in lieu of surrendering allowances. In either case there is a set price that companies could pay per ton of emissions, which would be unlimited. If a state allows regulated emitters to eschew their allowance obligations through either measure, the integrity of the ceiling would be damaged. No greenhouse gas cap-and-trade program in the United States uses a price ceiling or ACP.

Strategic reserves: A reserved set of allowances that is only released at auction if the clearing price rises above a set level. Since this does not affect the integrity of an emission cap (assuming the reserve is factored into a state's total allowance budget), EPA will not likely take issue with this provision. Auctions in both California and RGGI include strategic reserves.

INTERSTATE ALLOWANCE TRADING

States may wish to implement EPA's Section 111(d) guidelines through a multi-state trading program. Under this scenario, power plants in states operating under such a program would be able to trade allowances. Each power plant would be able to demonstrate compliance by surrendering the necessary number of allowances. The states' aggregate emissions rate would drop, but each individual state would not necessarily hit EPA's performance standard.

EPA will have to determine if this multi-state compliance would be allowed. To the extent that other types of credits, such as Renewable Energy Credits (RECs), are also usable for Section 111(d) compliance, EPA will have

to determine any trading restrictions. Outside of the context of a multi-state system, EPA must decide if it will allow any trading across state borders, or if each state (that is not part of a multi-state program) will be walled off from other states.

SUBFEDERAL TRANSNATIONAL LINKAGE

For the purposes of compliance with California's cap-and-trade program, allowances issued in California and Quebec are interchangeable. This means that a regulated power company in California can demonstrate compliance with California's program by purchasing allowances from a Quebec firm. That is, compliance in California, at the firm level, does not necessarily correspond with emission reductions that took place in California.

EPA will have to determine if it will allow credits that originated in Quebec to count toward California power companies' Section 111(d) obligations. If EPA denies the use of allowances originating in Quebec for Section 111(d) compliance, it will have to determine how these allowances will be kept distinct from those originating in California.

OTHER COMPLIANCE PROGRAMS

Many states already have programs in place to reduce greenhouse gas emissions in the power sector, either directly or indirectly.¹⁶ Additionally, states will very likely have the flexibility to develop novel programs to comply with Section 111(d). Fundamentally, EPA must decide how it will judge what is required from a state-designed program for its emission cuts to be deemed "equivalent" to those that would occur if a plant-level standard were imposed. That is, if a state chooses to comply through a system that does not include each of its power plants demonstrating compliance with the performance standard in EPA's guidelines, EPA must set criteria relating to how it will judge these state plans. In the case of any existing program, EPA will have to determine whether the resulting emission reductions will count toward Section 111(d) compliance, or if only additional reductions will count. Additional program-specific issues are also addressed in this section.

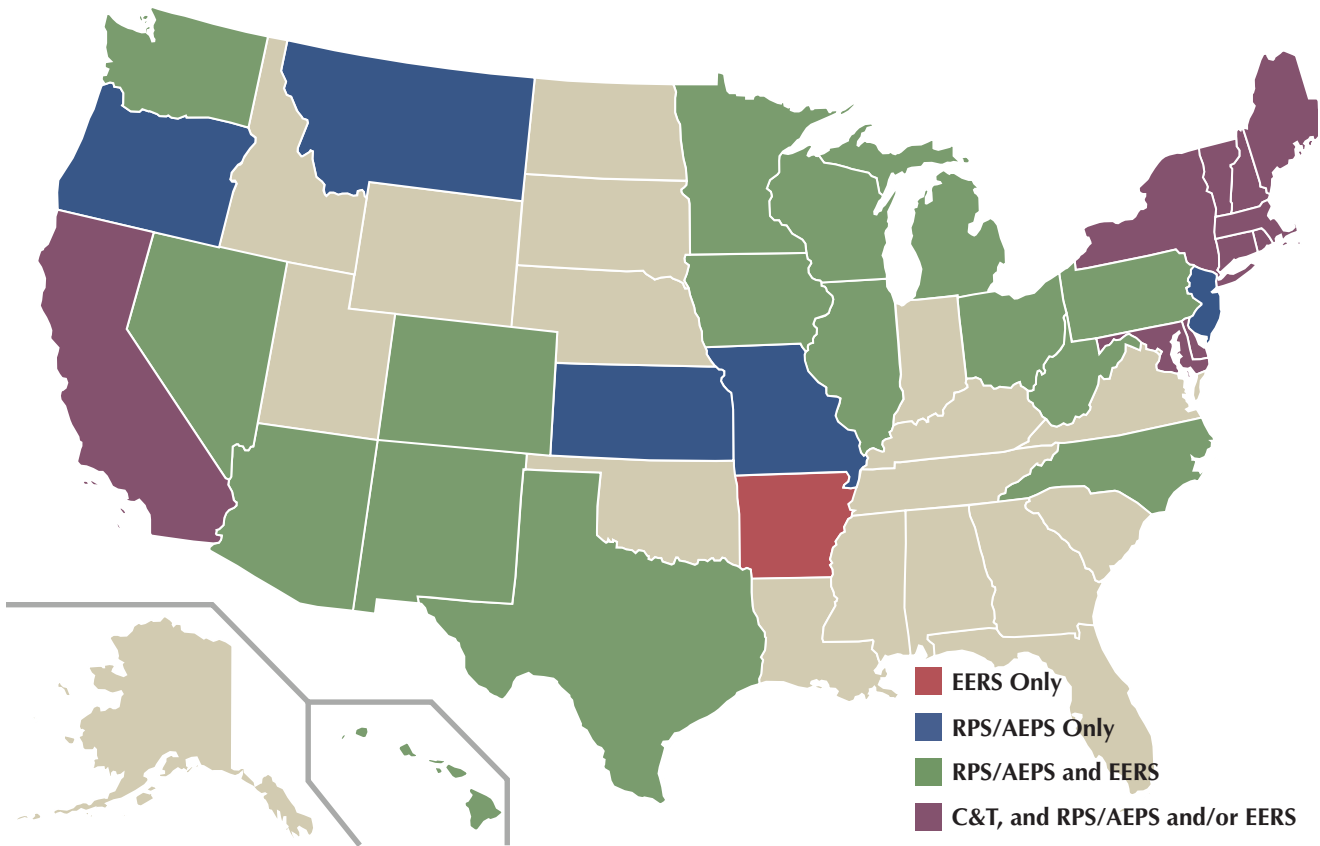
ADDITIONALITY IN CLEAN ENERGY POLICIES

States will likely wish to use existing clean energy programs, highlighted in **Figure 4**, that reduce power sector

CO₂ emissions as part of their compliance strategy. For example, a majority of states have RPS policies, which require a certain percentage of utility load to be met with renewable, usually zero-carbon, generation. Such policies provide states with a variety of benefits in addition to reduced CO₂, such as a reduced level of toxic air pollutants, reduced reliance on fuels imported from other states or countries, and economic support for local industries.

In these cases, EPA will have to determine if the same unit of renewable energy can both count toward the state's RPS and count toward Section 111(d) compliance. Put another way, EPA must determine whether Section 111(d) must drive emission reductions that are additional to those that would otherwise be driven by existing state programs. EPA may choose to exclude state policies in place prior to the finalization of its Section 111(d) guidelines, and/or policies not aimed directly at reducing greenhouse gas emissions. This issue is closely related to the Emissions Baseline issue discussed above since EPA essentially must decide whether existing RPS programs will be factored into a state's baseline emission level.

FIGURE 4: Existing State Policies That Reduce Carbon Emissions in the Power Sector



States currently use a variety of policies that reduce CO₂ emissions from power plants. These include Energy Efficiency Resource Standards (EERS), which require electric utilities to reduce electricity demand, Renewable Portfolio Standards and Alternative Energy Portfolio Standards (RPS/AEPS), which require electric utilities to deliver a set percentage of renewable or alternative energy to consumers each year, and cap-and-trade (C&T) programs, which drive emission cuts through a declining number of available allowances. Each individual EERS and RPS is unique, and states employ these policies in several combinations.

Sources: Center for Climate and Energy Solutions, Climate Action Maps: Standards and Caps for Electricity GHG Emissions; Renewable & Alternative Energy Portfolio Standards; Energy Efficiency Resource Standards.

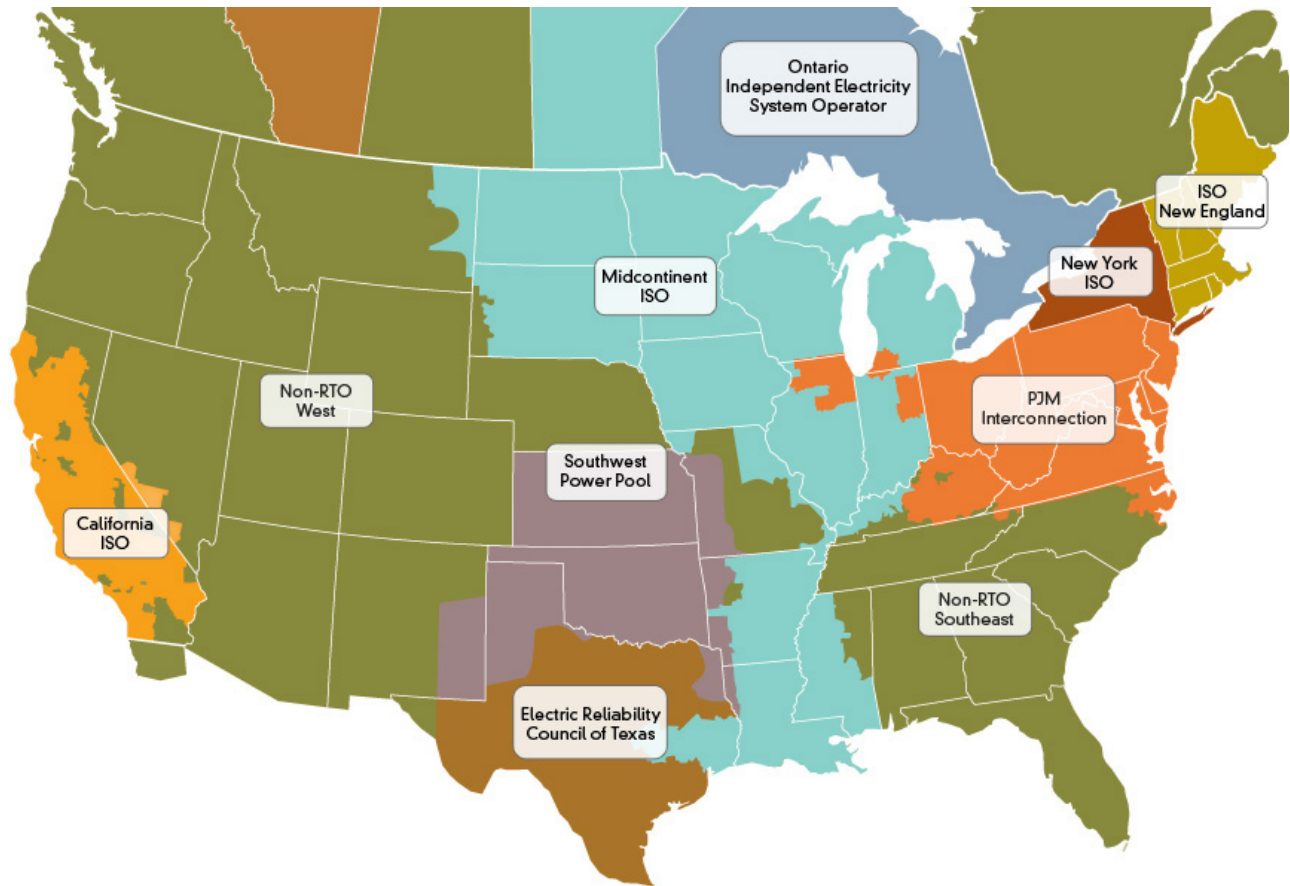
CREDITING CHANGES IN DISPATCH ORDER

One possible method of compliance is a relative shift in dispatch priority from coal power plants to natural gas plants, which have much lower CO₂ emissions. This shift likely cannot be done directly due to existing state and federal rules dictating how electricity system operators must prioritize generation sources. System operators are typically required to dispatch based on cost. Thus, if a state wants to adjust dispatch order as a means of 111(d) compliance, it will likely be most straightforward to do so through a pricing mechanism that makes coal generation relatively more expensive compared to gas. By including a carbon price, the grid operator would still base

dispatch priority on a least cost basis, but this would now favor gas over coal and reduce system-wide emissions.¹⁷

EPA must determine how such an approach would be monitored and enforced, and which entity, the power plant operator or the grid operator, or both, would have to demonstrate compliance. Accounting in this case would have to be done on a mass basis because emission rates at the plant level would not necessarily change in this approach, though the average emission rate for the state (or grid control region) would decline. This approach also generates complications relating to the fact that grid operator lines do not always follow state boundaries, an issue discussed further below.

FIGURE 5: Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs)



Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) are independent entities that control the electric grid, including deciding which generators are chosen to deliver power on a real-time basis, in many states. Most ISOs and RTOs cross state borders, and several states are divided among more than one operator. Grid operation is generally controlled by individual utilities in regions where there is not an ISO or RTO.

Source: Sustainable FERC Project, "ISO RTO Operating Regions", last visited, April 28, 2014, <http://sustainableferc.org/wp-content/uploads/2013/10/ISO-RTO-Operating-Regions.jpg>.

CARBON TAX

A state may wish to reduce its power sector carbon emissions through an explicit price on greenhouse gas emissions in the form of a carbon tax.¹⁸ Rather than setting a cap on statewide (or regional) power sector emissions and letting the trading market determine carbon price, a carbon tax sets a price and lets the market set the level of emissions. A tax could function similarly to an ACP in a cap-and-trade program by setting an explicitly maximum price regulated firms would have to pay to emit a ton of CO₂. A state might have to adjust the tax to ensure

the reductions mandated by Section 111(d) are being achieved.

EPA must determine whether it will allow a carbon tax as a compliance pathway. Such a tax would be unprecedented at the state and federal levels, though EPA could draw on experience from some Canadian provinces.

ENERGY EFFICIENCY

States are likely to want to use efficiency measures, such as EERS programs, as one approach to implementing the Section 111(d) guidelines. This would result in lower

power sector emissions by reducing demand. EPA has two major decisions to make regarding demand-side energy efficiency measures: 1) Whether to include such measures in its basis for the standard, discussed above, and 2) Whether to allow states to include such measures in their compliance pathways. If EPA includes demand-side efficiency measures in its basis for the performance standard, it will have to allow states to include these measures in their compliance pathways. However, the opposite is not necessarily true.

If energy efficiency is allowed as a compliance pathway, EPA may need to set an assumed greenhouse gas emissions rate for avoided electricity demand or develop a methodology for this figure to be calculated on a state-by-state basis. Alternatively, EPA could decide to focus exclusively on power plant emissions and ignore what steps are being taken to reduce them. In this case, it would be up to the states to implement an accounting mechanism to ensure demand reduction measures are appropriately incentivized and are leading to verifiable emission cuts.

INTERSTATE AND CROSS-SECTOR ISSUES

The interstate nature of the electrical grid creates special problems for EPA's Section 111(d) guidelines. Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) control the grid in most regions of the United States, meaning they pick which generators are operating and how the electricity is directed.¹⁹ Since ISO and RTO territories typically cross multiple state lines, shown in **Figure 5**, states would have to coordinate efforts in any approach to Section 111(d) that addresses the power system in aggregate rather than focuses only on individual power plants.

EPA faces cross-sectoral challenges in addition to interstate challenges. Certain energy services can be performed by different types of energy, with varying CO₂ emissions, and EPA must determine how to account for shifts in consumptions that cross sectors. Prominent examples include automobiles, which can be powered by liquid fossil fuel or electricity, and home appliances such as stoves and water heaters, which can be powered by natural gas or electricity.

ELECTRICITY IMPORTS

Many states, such as California, will likely wish to include existing demand-side energy efficiency measures as part of a portfolio of programs to reduce power plant emissions. Efficiency programs have been in place for decades in some states, and are often one of the most cost-effective methods to reduce emissions in the power sector.

EPA has indicated that it aims to craft its guidelines in a way that encourages energy efficiency. In addition to intrastate accounting challenges not addressed in this brief, the interstate nature of the grid means complications will arise when trying to account for emission cuts

that result in one state from reductions in electricity demand in another. Efficiency improvements in California, for example, could reduce electricity emissions in Nevada, Utah, or Arizona while not necessarily reducing emissions from power plants within California. If EPA aims to maintain and advance existing incentives for states to promote efficiency programs, it will have to develop a methodology that accounts for electricity movement across borders and could potentially assign credit for efficiency improvements where they take place, regardless of where emissions are reduced.

ELECTRICITY DEMAND THAT REDUCES NET EMISSIONS

Some measures that states are taking to reduce greenhouse gas emissions may shift emissions from one sector to another, while reducing net emissions. For example, many states are taking steps to encourage plug-in vehicles. While these vehicles have net greenhouse gas benefits, they increase power sector emissions.²⁰

Since EPA's Section 111(d) guidelines will be focused on the power sector, the agency will have to decide how, or whether, the guidelines will include provisions to avoid discouraging measures that increase power consumption (and therefore emissions) while reducing net emissions. It would be a technical challenge to develop a protocol to assign emissions to plug-in vehicles. EPA may also face a legal hurdle. Clean Air Act Section 111 targets stationary sources and requires a "standard for emissions of air pollutants," which suggests that covered sources have to meet a set standard, regardless of how the electricity is consumed. However, EPA currently interprets "emission standard" to include the possibility of an allow-

ance system. An allowance system could be used to credit power companies for the emissions avoided by electric vehicles against the increased power plant emissions.

ELECTRICITY REDUCTIONS THAT INCREASE EMISSIONS IN OTHER SECTORS

The inverse problem presented above can also exist: Policy measures that reduce power plant emissions while shifting these emissions to another sector. For example, programs that encourage a shift from electricity to gas

for cooking or heating could be more efficient overall, but result in increased emissions outside of the power sector.

EPA will have to decide whether it wants to account for emissions in other sectors that result from measures that reduce power sector emissions. It may, however, be infeasible for EPA to account for these shifted emissions since it could be difficult to estimate the change in emission rate when switching from electric to gas heating, for example.

CONCLUSION

EPA, in coordination with states, has a variety of issues to address as it develops its Section 111(d) guidelines to ensure its performance standard can be smoothly implemented by states. Due to the relative novelty of both Section 111(d) rulemaking and greenhouse gas regulation in general, many of these issues must be solved without the guidance of historical precedent. Some of the questions raised in this paper, such as the form of the performance standard, will fundamentally shape EPA's program. Yet even the relatively minor challenges, such as offsets, must be solved by EPA before a comprehensive program can be established.

Complicating matters further, decisions made on some issues will have implications in others. For example, if EPA allows both ACPs and interstate trading, this

could mean that one state using an ACP would essentially create a nationwide ACP. A power plant in a state that ostensibly does not have an ACP would still be able to purchase ACPs from plants located within the state that has an ACP, which would functionally create a nationwide price ceiling regardless of the intention of most states.

What becomes clear is that it is impossible to address any of these questions in isolation. EPA and state policymakers must determine which issues are of critical importance, settle those, and then address the implications of those decisions on the remaining questions. This paper aims to serve as a foundation of that process, and future papers will begin to explore the implications of possible decisions.

END NOTES

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