Final Report: Implications of EPA's Proposed "Clean Power Plan"

Analyzing consumer impacts of the draft rule

Report prepared for NASUCA

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1. PREFACE

This report has been prepared by Synapse Energy Economics (Synapse), pursuant to a grant from the Energy Foundation, to enable National Association of State Utility Consumer Advocates (NASUCA) members to better understand the consumer impacts of the U.S. Environmental Protection Agency's (EPA's) Clean Power Plan.

Consumers will ultimately shoulder most of the costs of new environmental initiatives. NASUCA's members are designated by the laws of their respective jurisdictions to represent the interests of utility consumers in their states. Robust participation by NASUCA members in the decision-making processes which form and implement the Plan is therefore essential to assure that costs are not incurred unnecessarily and to assure that consumers receive the best possible value for money spent.

Recognizing that stakeholders have a wide range of reactions to the EPA's Plan, the intent of this report is not to take positions as to the Plan's substance or to comprehend every conceivable issue consumers in a particular state might face. Nor does the report in any way represent the distilled opinions of NASUCA's membership. Just as individual states will vary in their responses to the Plan, the intent of this report is to be a common resource to help all of NASUCA's members think through a broad range of potential implications of various compliance approaches to their respective consumers whatever their individual state's positions.

2. EXECUTIVE SUMMARY

Complying with the proposed Clean Power Plan will have implementation costs. However, overall, the Plan could lead to significant consumer benefits. These benefits include not only reduced health impacts and welfare risks from climate change, but also savings from reduced energy bills. To maximize these benefits, it is critical for consumer advocates to be involved in the process early on and to push for appropriate least-cost planning from states as they develop their compliance strategies.

Below, we summarize some important issues for consumer advocates to consider as EPA and states move toward implementation of the Clean Power Plan. These issues are discussed in more detail in the body of this report.

Intrastate Coordination: The Clean Power Plan creates a unique situation in which state agencies that are not accustomed to working on environmental planning must now take on key roles in helping craft reasonable compliance plans to reduce CO_2 from the electric sector. Compliance with the Clean Power Plan will require participation from state departments of environmental protection, air quality agencies, state energy offices, public utility commissions, and consumer advocate offices. States will benefit from early and comprehensive internal coordination among these groups.

Multi-State Coordination: In thinking through all the options for complying with the Clean Power Plan, states need to consider the benefits of coordinating with other states to maximize opportunities for low-cost compliance options. Such opportunities include: submitting a joint implementation plan, renewable energy certificate (REC) trading, trading some other type of permit or credit, capturing cheaper or more bountiful renewable energy, and capturing leaked energy efficiency. States working together to exploit these opportunities may benefit from additional flexibility to achieve reductions at lower cost.

Least-Cost Planning: It is important to note that EPA *did not* use least-cost planning in developing the state targets for the Clean Power Plan. As explained in Section 3.2, EPA determined the best measures for achieving reductions in carbon emissions and then modeled those measures to see whether the costs were "reasonable." Since the building blocks are not required to be implemented in the way that EPA lays out, states will need to undertake least-cost planning in order to determine the right combination of these and other options for reducing electric sector CO_2 emissions. This should include consideration of single- and multi-state compliance options.

Wholesale Price of Energy: Depending on its design, the price instrument necessary to shift dispatch from high-emitting coal and oil plants to lower-emitting gas plants can have either a strongly inflating effect or a neutral effect on the wholesale price of energy. Inflated wholesale market prices would mean more money for existing low-emission resources and higher costs to consumers. This is an important area for additional research and modeling, along with careful policy design, for all states. Looking to existing carbon markets, such as the Regional Greenhouse Gas Initiative (RGGI) in the Northeast and California's AB32 program, will provide useful insights into effective program design.

Mass- Versus Rate-Based Compliance: The choice of mass- versus rate-based compliance can impact on states' compliance costs. Mass-based compliance will require electric dispatch modeling for translating from a rate-based (lbs/MWh) to a mass-based (total tons) target. There is a lot of room for gaming this translation process that may (or may not) be worked out in the final rule. EPA is seeking comment on whether it should provide guidance for how a rate-based target should be converted to a mass-based target, and if so, how extensive that guidance should be. It is important that EPA provide this additional guidance to help states assess whether taking a mass-based approach will be beneficial. Further, the more standardized this translation process is, the easier it will be for states to coordinate with each other in a meaningful way.

Out-of-Rule Emissions: The treatment of new fossil generating units—those covered by Section 111(b) of the Clean Air Act—in the Clean Power Plan is not entirely clear. EPA is seeking comment on a number of issues related to how new emissions and emission reductions should be treated in the Clean Power Plan. This is another key area with potential for gaming the system, which will require attention from consumer advocates. It is important that EPA not allow perverse incentives to undermine the cost-effectiveness of a state's compliance options.

Coal Retirement: The treatment of coal retirement appears to be quite different under the mass- and rate-based systems (depending on the details of the mass translation in the final rule, and the details of 111(b) treatment in Clean Power Plan compliance in the final rule). States should monitor opportunities for retirement of uneconomic coal plants as a means of compliance with the Clean Power Plan, and should evaluate under which approach—mass- or rate-based—such retirements would provide the most benefit.

Enforceability: EPA is currently proposing that all measures included in a state compliance plan become federally enforceable, which means EPA and others would be entitled to take enforcement action if a measure were not implemented in accordance with the plan. Taking a mass-based compliance approach and participating in a carbon trading regime like RGGI may be ways to avoid this. EPA is also exploring the idea of a "state commitment approach," which would allow a state to take on an obligation to achieve some or all of the needed reductions in aggregate through state programs without specifying precisely which programs will lead to which reductions. While this gives some additional flexibility to states to figure it out as they go, it also leaves states vulnerable to legal action should reductions not be achieved as expected.

Nuclear Challenges and Opportunities: Nuclear retirements and failure to complete under-construction nuclear units could make it more costly for a state to comply with the Clean Power Plan. EPA's proposal assumes: 1) a credit for the preservation of a portion of states' existing nuclear capacity, and 2) all nuclear capacity currently under construction will be completed and available during the performance period. If these resources are not available, the reductions associated with their generation will have to be made up elsewhere.

Efficiency Measurement: The rule will require some standards for energy efficiency evaluation, measurement, and verification (EM&V), but these rules need not be onerous. EPA is seeking comment on whether to require harmonization of state energy efficiency approaches, what approaches are suitable, and the scope of guidance on EM&V to provide. The more standardized these rules are across the country, the easier it will be for states to coordinate for compliance purposes.

Rate and Bill Impacts: For most states, Synapse's analysis based on EPA data demonstrates that compliance with the Clean Power Plan (at least using EPA's building block compliance) will result in higher rates but lower bills for energy efficiency participants. Based on EPA expectations for energy efficiency utilization to increase substantially via Building Block 4, the number of consumers participating in energy efficiency programs would also be anticipated to grow substantially, meaning such people would be expected to see the benefit of lower bills. On the other hand, customers not participating in efficiency programs will not share in benefits and will face higher costs.

Equity: Finally, although we expect that many more consumers will realize the benefits of lower bills due to increased energy efficiency, consumer advocates still need to ensure that the allocation of costs and benefits among different customer types is equitable and does not unfairly burden any one group of customers (such as low-income households). Wide participation in efficiency programs is an important consideration for equity.

Compliance Options for States

The following tables summarize the pros and cons of various approaches to compliance available to states.

ES Table 1: EGU approach to implementation plans, pros and cons

Pros	Cons
Simple, straightforward plan development from state DEQ's perspective –full burden of compliance can be put on EGUs by setting enforceable permit limits on emissions from these sources	**Not all EGUs control means of reductions "beyond the fenceline"** – in deregulated states, EGUs may not control programs such as energy efficiency and renewable energy development, making enforcement and compliance uncertain
Can be used with emission rate- or mass-based limit • Plans with rate-based limits could incorporate enforceable RE & EE measures by adjusting EGUs' rate through either an administrative adjustment or a tradable credit approach • Plans with mass-based limits on affected EGUs would not require enforceable EE & RE measures, though states should implement these measures as a complement to the plan in order to reduce compliance costs	

ES Table 2: Portfolio approach to implementation plans, pros and cons

Pros	Cons
Provides more options for compliance and does not place entire burden on EGUs – spreads the responsibility for achieving reductions across multiple parties	**Enforceability and administration could be a challenge**
Could be "utility-driven" (IRP) or "state-driven" (RPS and EERS) – depending on how planning is carried out in each state, portfolio of options could be developed through existing processes	**Emission limits on EGUs would not be enough to achieve targets** – state programs (such as for RE & EE) would need to be included and would be enforceable against other (non-EGU) entities
Can be used with emission rate- or mass-based limit	**Most states do not want to make their state programs federally enforceable**

ES Table 3: State commitment approach to implementation plans, pros and cons

Pros	Cons
State EE & RE measures need not be made federally enforceable • States could opt to impose full responsibility for reductions on EGUs but credit EGUs for expected reductions from state RE or EE measures—states would assume responsibility for the credited reductions	**States could be held liable for Clean Air Act penalties if programs fail to achieve expected emission reductions** – if reductions are not achieved as expected, state is on the hook for correcting failure
Gives states additional flexibility – states can adjust measures and improve programs over time as new, potentially more cost-effective measures become available without going through formal plan approval	**Requires robust contingency measures** – without strong contingency measures, there is less of an incentive to achieve needed reductions

ES Table 4: Mass-based approach to compliance, pros and cons

Pros	Cons
Simplified compliance planning – meeting target means achieving a specified tonnage reduction, rather than achieving a particular emission rate, and makes it easier to account for program performance	**Potentially complex translation process to get rate-based target into mass-based form** – requires development of business as usual base case; may require complex economic dispatch modeling
May limit required enforceability of state programs – state programs may not need to be made enforceable in order to demonstrate compliance	
Probably essential for cap-and trade type mechanisms – emission trading programs, like the Regional Greenhouse Gas Initiative, require mass-based reductions	**Susceptible to gaming** – without additional guidance from EPA on translation process, gaming could jeopardize EPA approval of state plan; will require consistent calculation methodology to avoid gaming
Useful for states anticipating retirements of fossil generation – reductions from in-state retirements will be more fully captured under mass-based approach	
Useful for states with a lot of coal generation that choose to re-dispatch out of state – total emissions will go down while rate might not change at all	**May not work well for states anticipating significant load growth** – if load growth is expected to be greater than EIA projections used by EPA in setting targets, mass-based approach may make it harder to meet targets while accommodating growth
Useful for states expecting slower load growth than EIA forecast – fewer anticipated emissions	

ES Table 5: Rate-based approach to compliance, pros and cons

Pros	Cons
Provides flexibility to accommodate load growth – if a state is anticipating significant load growth (above EIA projections used by EPA in setting targets) a rate-based approach may provide more flexibility to accommodate such growth	**Makes cost-effective compliance approaches, such as emission trading schemes, more difficult** – most organized emission trading programs are mass-based
	Limited credit for retirements – emission benefits of retirement of high-emitting plants may not be fully reflected in rate-based approach
Full credit for energy efficiency for exporting states – under EPA's rate-based approach, states that are net exporters get full credit for reductions resulting from their EE programs	**Makes inter-state coordination more challenging** – uncertain how EPA or states would develop regional rate-based targets
	States that are net importers do not get full credit for energy efficiency – under EPA's rate-based approach, states that are net importers only get credit for their percentage of in-state sales for energy efficiency

ES Table 6: Multi-state approach to compliance, pros and cons

Pros	Cons
Expands potential reduction opportunities and renewable resource potential – allows states to capitalize on zero- and low-emission options developed in other states	**Complicated plan development process involving multiple state agencies** – may be difficult to coordinate multiple agencies from many different states, as well as groups with diverse interests
Likely to be more cost-effective – this approach allows least-cost opportunities in the region to be exploited and may reduce administrative costs	
Results in greater flexibility for system operators – system operators must coordinate delivery of electricity across state lines and are encouraging multi-state coordination	**Enforcement challenges if one or more states fail to uphold obligations** – may be difficult to handle enforcement across many responsible parties
Additional time to develop compliance plans – plans developed in coordination with other states have until June 30, 2018 to submit their plans to EPA	

ES Table 7: Single-state approach to compliance, pros and cons

Pros	Cons
Full state control over development of compliance strategy – state DEQ will be responsible for developing compliance plan (together with other relevant state agencies) and will not have to expend resources coordinating with out-of-state agencies and interest groups	**Limits opportunities for least-cost reductions** – may eliminate some opportunities to partner with other states on affordable reduction options or to capture leaked energy efficiency or renewable energy reductions
No reliance on measures in other areas over which state has no control – state would not have to rely on reductions occurring in other states over which it cannot exert control	**Shorter time-frame for compliance plan development** – individual plans will have to be submitted to EPA by June 30, 2016 unless a one-year extension is granted; multi-state compliance plans have an additional two years to develop plans

3. WHAT IS THE CLEAN POWER PLAN?

3.1. Background

When signed into law by President Nixon in 1970, the Clean Air Act established a first of its kind comprehensive federal program for reducing and preventing dangerous air pollution. The Act required the newly established U.S. EPA to set limits on any air pollutant that may "endanger public health or welfare." In 1990, under President George H. W. Bush, Congress revised and expanded the Clean Air Act to what it is today, providing EPA even broader authority to implement and enforce regulations reducing emissions, while also increasing the emphasis on cost-effective approaches to clearing the air.

In 2007, the U.S. Supreme Court determined that greenhouse gases are air pollutants that may be regulated by EPA if they are determined to endanger public health or welfare. Two years later, EPA found that the current and projected concentrations of six key greenhouse gases—including carbon dioxide (CO_2)—in the atmosphere threaten the public health and welfare of current and future generations. With this "Endangerment Finding," EPA established its authority to regulate greenhouse gases under the Clean Air Act.

The EPA found that the current and projected concentrations of six key greenhouse gases—including CO_2—in the atmosphere threaten the public health and welfare of current and future generations.

Section 111 of the Clean Air Act requires EPA to develop regulations for any category of stationary source that "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." These regulations apply to all new sources within a category. In March 2012, EPA proposed New Source Performance Standards (NSPS) aimed at reducing CO_2 from new fossil fuel power plants.[1] These regulations are based on EPA's assessment of available technologies, and establish emission performance standards using the maximum allowable emissions of CO_2 per unit of electricity generated (i.e., lbs-CO_2/MWh) for all new fossil fuel power plants.

Under Section 111(d) of the Act, EPA must develop emissions performance guidelines for *existing* sources of non-criteria pollutants (i.e., any pollutant for which there is no national ambient air quality standard) and non-hazardous air pollutants (which are covered by Section 112 of the Act) whenever EPA promulgates a standard for a new source of such a pollutant. Each state is then responsible for developing its own plan to implement EPA's emissions performance guidelines. These 111(d) plans are subject to EPA review and approval.

On June 2, 2014, EPA released its proposed emissions performance guidelines for reducing CO_2 from existing fossil fuel power plants. These plants are the largest single source of greenhouse gas emissions

[1] The rule was later withdrawn and re-proposed in September 2013 following extensive public comment and "new information," which caused the Agency to substantially change the original proposal requirements.

in the country, and EPA has stated that its 111(d) rule—known as the “Clean Power Plan”— will reduce emissions from these existing sources by 30 percent below 2005 levels by 2030.

Regulation of greenhouse gases has been controversial, with many opinions regarding the most appropriate approach to addressing climate change. As EPA’s Clean Power Plan moves towards implementation it is imperative for states—and consumers—to have a comprehensive understanding of the proposed rule and its potential impacts.

3.2. Best System of Emission Reduction

Performance standards set under Section 111 of the Clean Air Act must reflect the degree of emission limitation achievable through the application of the “best system of emission reduction” (BSER) that has been adequately demonstrated. In determining BSER, EPA generally conducts a technology review that identifies what systems for emission reductions exist and how much they reduce air pollution. This allows EPA to identify potential emission limits. EPA then evaluates each limit in conjunction with cost and technical feasibility, secondary air impacts from energy requirements, and non-air-quality health and environmental impacts (such as solid waste generation). EPA must also consider opportunities to promote the development and use of pollution control technology.

For new sources, the final emission standard is typically a numerical limit—expressed as a performance level (e.g., a rate-based standard)—that applies to each new source in its category. Though this standard is set based on a review of one or more specific systems of emission control, EPA may not prescribe a particular technology that must be used to comply. Instead, sources are free to elect whatever measure, or combination of measures, will achieve equivalent or greater emission reductions.

For existing sources, the process is similar to the criteria pollutant process in which EPA sets national standards for a particular pollutant and then states develop implementation plans showing how they will meet the standard. Under Section 111(d)—the Clean Power Plan—EPA must establish emissions guidelines specifying standards of performance for the existing sources in a category. These emissions guidelines are binding on states and set the goal that states must meet when developing standards of performance for existing sources. Clean Power Plan emissions guidelines are also required to reflect the degree of emission limitation achievable through BSER.

In its Clean Power Plan, EPA is defining the term “system” broadly to include measures that are “beyond the fence-line” of affected power plants. This is because the highly interconnected nature of the electric system lends itself to a much broader range of controls. Here, EPA has determined that BSER includes not only upgrades and operational changes that could be made at the plant itself, but also measures such as: re-dispatch from higher-emitting resources like coal to lower-emitting resources like natural gas, increased renewable energy deployment, and increased demand-side energy efficiency. These measures reduce emissions at fossil fuel power plants by reducing their required output. Together, EPA says, these measures (called “building blocks”) represent meaningful reductions in CO_2 at a reasonable cost:

- Reduce Coal-Fired Emissions Rate (Building Block 1): a 6-percent heat rate improvement in the state's coal fleet;
- Re-Dispatch to Existing NGCCs (Building Block 2): raising the state's natural gas combined cycle units (NGCCs) to a 70-percent capacity factor;
- Nuclear and Renewables (Building Block 3): 5.8 percent of each state's nuclear capacity credited starting in 2020, and, on average across the states, a 13-percent renewable capacity achieved by 2030; and
- End-Use Energy Efficiency (Building Block 4): on average across the states, a 10.7-percent cumulative savings by 2030.

These building blocks make up the set of tools that EPA has determined represents the "degree of emission limitation achievable through the application of the best system of emission reduction…adequately demonstrated." They reflect neither the maximum emission reductions possible from these measures, nor the least-cost approach to achieving those reductions. They are simply used to establish what the EPA has determined is achievable from the power plant sector at a reasonable cost.

4. How Does the Clean Power Plan Work?

4.1. Setting the 111(d) Emission Rate Targets

The core of EPA's Clean Power Plan is its application of state-specific targets for reducing the carbon intensity of the electric sector in each state. The targets were developed by taking each state's power system as it operated in 2012 and then applying the pollution-reduction measures identified in the building blocks (above) to assess how much of a reduction each state could achieve by 2030. Since every state has a different mix of existing resources and opportunities, when the building blocks are applied on a state-by-state basis, the resulting targets can vary widely. This is why looking at one state's target and comparing it to other states' targets can be misleading. Just looking at the percent change in the emission rate from 2012 to the target won't necessarily convey how easy or difficult it will be for a state to achieve that target and at what cost.

The basic formula for calculating the state goal starts with the reported 2012 CO_2 emissions from fossil-fuel power plants in pounds (lbs) divided by state electricity generation from fossil fuel power plants in megawatt-hours (MWh). EPA then adjusts this 2012 emission rate to include the building block assumptions for low- or zero-emitting power sources and savings from existing energy efficiency programs. We refer to this as the "111(d) emission rate." Figure 1 illustrates this formula for the "proposed" or "Option 1" rule. (Section 8.1 discusses the "alternative" or "Option 2" rule.)

Figure 1. EPA's 111(d) emission rate formula for the "proposed/option 1" rule

$$\text{111(d) Emission Rate} = \frac{\text{Fossil Fuel Emissions (lbs of } CO_2\text{)}}{\text{Fossil Fuel Generation (MWh)} + \text{Nuclear Generation (MWh)} + \text{Renewable Generation (MWh)} + \text{Energy Efficiency (MWh)}}$$

Fossil Fuel Emissions (lbs of CO_2)
Coal, natural gas CC and CT, oil, and IGCC, and useful thermal from co-generation from generators that existed in 2012 and use of NGCC's under construction in 2012 above a 55% CF

Fossil Fuel Generation (MWh)
Coal, natural gas CC and CT, oil, and IGCC, and useful thermal from co-generation from generators that existed in 2012 and use of NGCC's under construction in 2012 above a 55% CF

Nuclear Generation (MWh)
From 2020, 5.8% of use of 2012 existing nuclear; Use of under construction in 2012+ nuclear

Renewable Generation (MWh)
Excludes hydro existing in 2012

Energy Efficiency (MWh)
Cumulative from 2017 with sunsetting; In 2012, this value is 0 MWh

Note that the 111(d) emission rate is not a state's fossil fuel emission rate, nor is it a state's average emission rate for all electric resources. Rather, the 111(d) emission rate is a newly introduced metric proposed by EPA in this rule.

When applying the building blocks, state- and year-specific data are plugged into this formula to get each state's own target. Each state's goal is different, because each state has a unique mix of emissions and power sources. Section 4.2, below, walks through an example of how this formula is applied, building block by building block.

4.2. EPA's Building Blocks for Target Setting

In the Clean Power Plan, EPA proposes both an "interim goal" 111(d) emission rate that a state must meet on average over the ten-year period from 2020-2029, and a "final goal" 111(d) emission rate that a state must meet at the end of that period in 2030 and thereafter. In this section, we use Colorado as an example to discuss how EPA developed each state's 2030 111(d) emission rate target for the "proposed" or "Option 1" rule.

Each state's target calculation begins with its initial 2012 fossil fuel emission rate for electric resources. Figure 2 illustrates the initial 2012 fossil fuel emission rate for the State of Colorado.

Figure 2. 2012 Initial Colorado fossil fuel emission rate

111(d) Emission Rate =		=	Coal	NGCC	O/G Steam	Other	Nuclear	Renewables	E.Efficiency	=
	million lbs		76,526	8,175	3	46	0	0	0	1,959
	million MWh		34	9	0	0	0	0	0	lbs/MWh

Note: All values are rounded to the nearest whole number. Any value less than 0.5 million will appear as a zero in this figure but will still be included in the equation to determine the final rate.

Building Block 1: Reduce coal-fired emissions rate

EPA's first building block measure involves reducing the carbon intensity of generation at individual coal plants through measures that improve the efficiency with which these units convert coal to electricity (i.e., heat rate improvements). EPA found that best practices to reduce hourly heat rate variability at coal plants could improve heat rates, on average, by 4 percent, while equipment upgrades could achieve an average 2-percent improvement. Overall, EPA determined that a 6-percent heat-rate improvement at each state's coal-fired power plants was reasonable.

A 6-percent improvement in the heat rate of Colorado's coal fleet would lead to a decrease of 4,592 million pounds of CO_2 from the 2012 initial total of 84,750 million pounds. This building block lowers Colorado's 111(d) emission rate by a 106 lbs/MWh increment (see the changes in formula elements shown in Figure 3).

Figure 3. Change in Colorado's 111(d) emission rate formula elements: From 2012 Initial to BB1 (Lower Average Coal Rate)

			Coal	NGCC	O/G Steam	Other	Nuclear	Renewables	E.Efficiency		
111(d) Emission Rate Δ	=	million lbs	-4,592	0	0	0	0	0	0	=	-106
		million MWh	0	0	0	0	0	0	0		lbs/MWh

It is important to note that EPA's Building Block 1 does not account for what it calls the "rebound effect" in which increased efficiency (and any resultant decrease in variable operating costs) might lead a coal unit to experience improved competitiveness and, therefore, increased utilization. In this situation, the reduction in the unit's CO_2 emissions caused by the decrease in its heat rate and rate of CO_2 emissions per unit of generation output could be partially offset by the increase in the unit's CO_2 emissions associated with the increase in generation. The extent of the offset would depend on the unit's generation after the heat rate improvements, as well as the CO_2 emission rates of the units whose generation would be displaced. EPA believes that the combination of approaches that make up the building blocks will encourage overall reductions in electricity demand, and increases in generation from lower- or zero-emitting resources.

Building Block 2a: Re-dispatch to underutilized NGCCs

Building Block 2 involves reducing mass emissions by shifting electricity generation from the most carbon-intensive units (coal and oil steam generators) to less carbon-intensive NGCCs. A typical NGCC produces less than half the CO_2 per MWh of a typical coal-fired unit. EPA identifies approximately 245 GW of NGCC capacity in operation in the United States in 2012, a substantial majority of which (196 MW) was built in the last 14 years. According to EPA, these resources are only being utilized at an average capacity factor of 46 percent—well below what the units may be capable of achieving.

In the Clean Power Plan, EPA's Building Block 2 increases the average NGCC utilization rate up to a maximum of 70 percent. To determine the total potential NGCC generation at a 70 percent capacity factor, EPA multiplied the state's 2012 existing NGCC nameplate capacity by 8,784 hours (the number of hours in 2012) and then multiplied by 70 percent. However, a state's generation can only be re-dispatched to this 70-percent NGCC ceiling if it has enough historic fossil sources to support such a level. Colorado, for example, would require an increase in its 2012 dispatch of NGCCs of 11.6 million MWh to achieve a 70-percent capacity factor. Colorado's 2012 coal and steam oil and gas generation was 34.4 million MWh, sufficient to allow for re-dispatch of NGCCs up to the 70-percent maximum. In contrast, if California re-dispatched all of its 2012 coal and steam generation to NGCCs, it would still only achieve a 49-percent NGCC capacity factor.[2]

Figure 4 illustrates Building Block 2a for Colorado, converting a 30-percent average NGCC capacity factor to a 70-percent capacity factor. Coal and steam oil and gas emissions and generation decrease, while lower-carbon-intensity NGCC emissions and generation increase. This building block lowers Colorado's 111(d) emission rate by a 315 lbs/MWh increment.[3]

Figure 4. Change in Colorado 111(d) emission rate formula elements: From BB1 to BB2a (Re-Dispatch to Existing NG)

111(d) Emission Rate	=		=	Coal	NGCC	O/G Steam	Other	Nuclear	Renewables	E.Efficiency	=	
		million lbs		-24,211	10,737	-1	0	0	0	0		-315
		million MWh		-12	12	0	0	0	0	0		lbs/MWh

Building Block 2b: Re-dispatch to under-construction NGCCs

Building Block 2 also includes re-dispatch to under-construction NGCC units. This applies to any unit that came online in 2013, or was under construction, site prep, or testing by January 8, 2014 (the cut-off date for classification as an "existing source"). In states that have under-construction NGCCs, EPA assumes the capacity factor of these units under a business-as-usual scenario would be 55 percent and—up to that level—would be unavailable for re-dispatch (EPA includes these emissions and MWh in the 111(d) emission rate formula under "other"). Building Block 2 assumes that these under-construction NGCCs could also ramp up to 70 percent and, therefore, 15 percent of their ultimate capacity factor is assumed to be available for re-dispatch purposes. This generation would displace coal and steam oil and gas generation in the same way that re-dispatch to existing NGCCs is described above.

There were two 100-MW NGCCs under construction in Colorado in 2012. Raising these under-construction NGCCs from 55-percent to 70-percent capacity factors lowers Colorado's 111(d) emission rate by a 17 lbs/MWh increment.

[2] In the proposed rule, in states like Colorado where the 70-percent capacity factor ceiling is reached through re-dispatch, the mix of coal and steam oil and gas generation is reduced in proportion to the state's historical generation mix. If coal accounts for 85 percent of a state's historical coal and steam oil and gas generation, then its historical coal generation would be displaced by 85 percent of the amount that the NGCC generation increases.

[3] We follow EPA's practice of reporting 111(d) emission rate impacts by building block as the changes in emissions and generation resulting from the addition of a building block onto the previous building blocks; that is, our reported building block 111(d) emission rate deltas are sequential.

Figure 5. Change in Colorado's 111(d) emission rate formula elements: From BB2a to BB2b (Re-Dispatch to Under-Construction NG)

111(d) Emission Rate =		=	Coal	NGCC	O/G Steam	Other	Nuclear	Renewables	E.Efficiency	=
	million lbs		-551	244	0	896	0	0	0	-17
	million MWh		-0.2635	0.2635	0	1	0	0	0	lbs/MWh

Building Block 3a: At-risk and under-construction nuclear

In Building Block 3a, EPA estimates the amount of existing nuclear capacity that is considered "at risk" of being retired and the total under-construction nuclear capacity in a state in 2012. EPA has identified 5.8 percent as the approximate amount of nuclear generation that was at risk of retirement in 2012 nationwide based on recent U.S. Energy Information Administration projections. EPA believes this represents a reasonable proxy for the amount of nuclear capacity that is at risk of retirement in the future and, therefore, assigns credit for a flat 5.8 percent of each state's nuclear capacity in state 111(d) targets.[4]

Three states had nuclear plants under construction in 2012: Georgia, South Carolina, and Tennessee. The entire amount of expected generation from these plants is included in the 111(d) emission rate formulae for these states.

Because Colorado had no nuclear capacity in 2012 and no under-construction nuclear capacity in 2012, this building block does not affect the state's 111(d) emission rate.

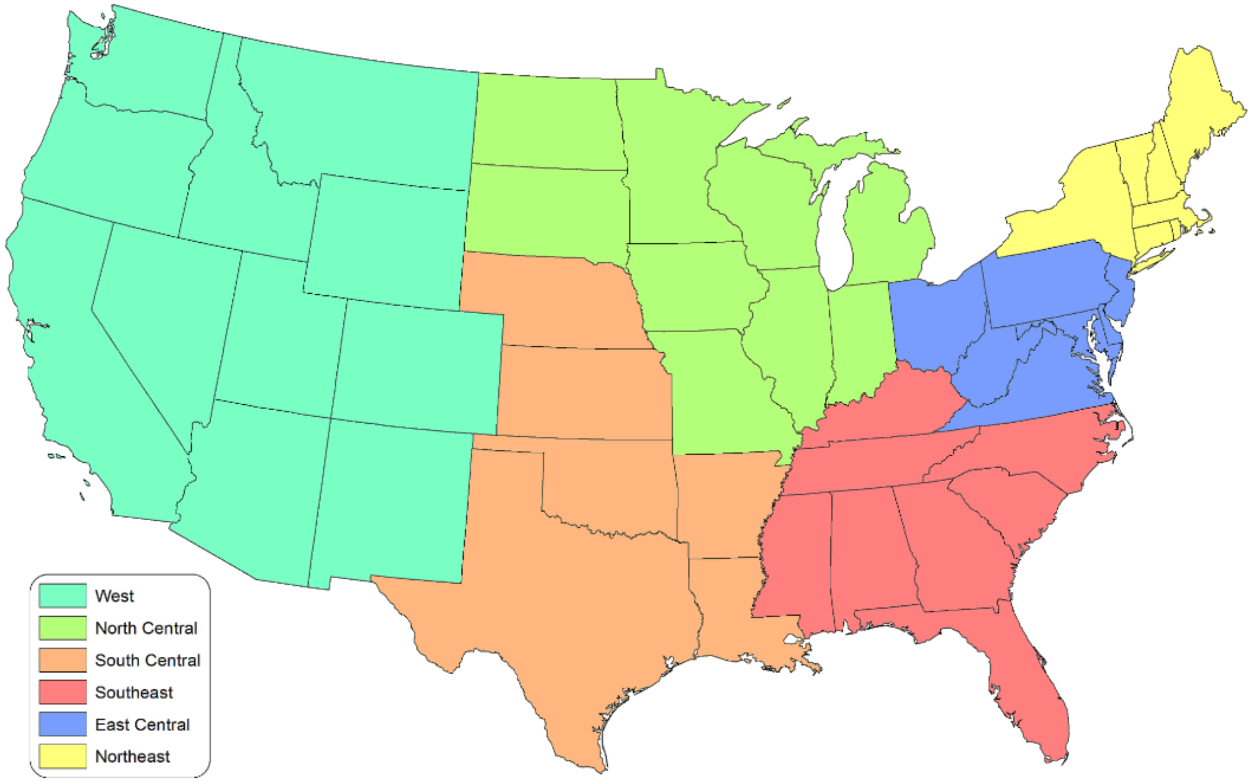
It is important to note that at-risk and under-construction nuclear generation are both used to set 111(d) emission rate targets, and are available to states to count toward compliance with their targets, to the extent that the nuclear resources are preserved. If states with existing or under-construction nuclear plants retire these resources before the compliance period, they will not be able to include this generation in compliance.

Building Block 3b: Renewables

In Building Block 3b, EPA determines its "best practices" scenario for renewables based on average existing Renewable Portfolio Standard (RPS) requirements in each region. The regions EPA uses to assess these best practices, called regional compliance zones, are shown in Figure 6.

[4] EPA assumes a 90-percent capacity factor for each state's 2012 nuclear capacity.

Figure 6. EPA regional compliance zones for renewables



Source: 2014 EPA Clean Power Plan Regulatory Impact Analysis at 3-13.

In each region, EPA first quantified the 2012 level of renewable generation in the region prior to implementation of the best practices scenario.[5] Next, EPA estimated the average of the state RPS percentage requirements for 2020 in each region and multiplied it by total regional 2012 generation for the region. EPA also calculated a maximum renewable energy target for each state by multiplying its 2012 generation by the average regional RPS percentage goal for 2020. This maximum acts as a ceiling for each state.

EPA then computed a regional growth factor that would be necessary to bring the region from the 2012 starting level up to the average regional RPS requirement in 2020. For this computation, EPA assumes that new renewable energy capacity investments begin in 2017, the year following the initial state plan submission deadline, and continue through 2029. The regional growth factor is then applied to each state's 2012 starting level, starting in 2017, but stops if it gets to the point where additional renewable energy generation would surpass the state's maximum target.

[5] According to EPA, hydropower is excluded from this 2012 starting level determination so as not to distort the regional targets in states that do not have hydropower capacity. New or incremental hydropower may be used for compliance.

Colorado's existing and expected renewables under Building Block 3b account for 11 MWh of generation (see Figure 7). This building block lowers Colorado's 111(d) emission rate by a 299 lbs/MWh increment.

Figure 7. Change in Colorado's 111(d) emission rate formula elements: From BB3aii to BB3b (Incremental Renewables)

111(d) Emission Rate Δ	=		=	Coal	NGCC	O/G Steam	Other	Nuclear	Renewables	E.Efficiency	=	
		million lbs		0	0	0	0	0	0	0		-299
		million MWh		0	0	0	0	0	11	0		lbs/MWh

Four states have 2012 111(d) qualifying renewable levels that surpass the EPA's 2020 renewable targets: Iowa, Maine, Minnesota, and South Dakota. In these states, this building block has the effect of raising the 111(d) emission rate (that is, making it less stringent) rather than lowering it (making it more stringent).

Building Block 4: Demand-side energy efficiency

The final building block consists of measures to decrease demand for generation through the use of demand-side energy efficiency. EPA provides an analysis of states' energy efficiency potential, and finds that the 12 leading states have achieved—or will achieve with existing requirements—annual incremental savings rates of at least 1.5 percent of the electricity demand that would have otherwise occurred. Therefore, EPA determined that for Building Block 4, each state's annual incremental savings rate should increase from its 2012 annual savings rate to a rate of 1.5 percent over a period of years starting in 2017.[6] The ramp-up from states' 2012 energy efficiency levels to an annual savings rate of 1.5 percent will occur at a rate of 0.2 percent per year, so states that are already near the 1.5 percent will reach 1.5 percent rate sooner than states that have not yet implemented significant demand-side energy efficiency. States that have already achieved 1.5 percent in 2012 are assumed to maintain that rate from 2017 through 2029. All states are expected to reach the 1.5 percent target rate by 2025 at the latest.

States that are net importers of electricity receive credit in their 111(d) emission rate formula for the product of their cumulative energy efficiency savings and their share of in-state generation. For this reason, Colorado receives 89 percent credit (its share of in-state generation) for its energy efficiency investments. Colorado is expected to ramp up to annual energy efficiency savings of 1.5 percent by 2021, and achieve cumulative savings of 11.4 percent, or 6 million MWh, by 2030 (Figure 8). This building block lowers Colorado's 111(d) emission rate by a 114 lbs/MWh increment.

[6] Each state's 2012 reported annual savings rate is assumed to be the starting point for 2017 calculation of the state target.

Figure 8. Change in Colorado's 111(d) emission rate formula elements: From BB3b to BB4 (Incremental Energy Efficiency)

111(d) Emission Rate Δ	=		=	Coal	NGCC	O/G Steam	Other	Nuclear	Renewables	E.Efficiency	=	
		million lbs		0	0	0	0	0	0	0		-114
		million MWh		0	0	0	0	0	0	6		lbs/MWh

After applying all four building blocks to each state's initial 2012 emission rate, EPA reports the final target for each state. These targets are unique to each state's specific resources and potential. As we saw above, Colorado's target is strongly dependent on under-utilized NGCC capacity in the state, and there is plenty of coal generation that can be shifted to those NGCCs. Figure 9 presents Colorado's final target for 2030: 1,108 lbs/MWh, calculated from all the steps described above.

Figure 9. 2030 target Colorado 111(d) emission rate

111(d) Emission Rate	=		=	Coal	NGCC	O/G Steam	Other	Nuclear	Renewables	E.Efficiency	=	
		million lbs		47,172	19,156	2	942	0	0	0		1,108
		million MWh		23	21	0	1	0	11	6		lbs/MWh

4.3. State Plans and Clean Power Plan Compliance

States have a great deal of flexibility for determining how they will meet their 111(d) emission rate targets. None of the building blocks described above are *required* for compliance; they are simply used to establish the emission targets each state must meet. States may employ as much or as little from the building blocks as they see fit, so long as their strategy achieves the required emission performance.

Once the Clean Power Plan is finalized (this is anticipated on June 30, 2015), states will have to develop and submit plans laying out how they will meet the 2030 emission targets, and will have to demonstrate interim progress between 2020 and 2029. These plans must be submitted by June 30, 2016—or one year from the date EPA's guidelines are finalized.

Individual states may request a one-year extension if they can demonstrate that a delay is necessary due to legislative or rulemaking schedules, or due to the need for multi-state coordination for the development of an individual state plan. States seeking an extension must submit an initial plan by June 30, 2016 demonstrating that they are on track toward submitting a complete plan. States that choose to join with other states to develop a multi-state compliance plan may also request an extension of up to an extra two years to submit a plan. These states would be required to submit an initial plan on June 30, 2016, and an update on June 30, 2017 describing their progress toward certain milestones and for developing and submitting a complete plan. Submission of final multi-state compliance plans is required by June 30, 2018—or two years after the date EPA's guidelines are finalized.

Compliance Plan Options

In the Clean Power Plan proposal, EPA outlines three ways states could design their compliance plans. Under the first approach, a state may submit a plan that holds affected sources solely responsible for achieving the performance standard. These affected sources would have to demonstrate compliance by obtaining credits for measures taken at the plant as well as "beyond the fenceline" measures. Compliance would be ensured through monitoring and reporting requirements. In this case, the state plan would not directly include the "beyond the fenceline" emission reduction measures such as renewable energy and demand-side energy efficiency programs. Instead, these activities would be coordinated at the state level to provide credits for affected sources. With this type of plan, only affected sources would be subject to federally enforceable requirements.

A second type of compliance would utilize a "portfolio" approach in which entities in addition to affected sources, such as state agencies or electric distribution utilities, take on a portion of the responsibility for reducing carbon emissions in the state. In this type of plan, all emission limits and "beyond the fenceline" measures become federally enforceable, but instead of the affected sources bearing the full burden of compliance, others would be subject to mandatory measures (such as for renewable energy and energy efficiency) that would ultimately reduce emissions at the affected sources. For this approach, states would have to demonstrate that they have legal authority to enforce mandatory measures included in the plan.

EPA is also considering a third approach (although it is not currently part of the proposal) referred to as a "state commitment" approach in which a state commits to achieving reductions through "beyond the fenceline" measures, such as renewable energy and energy efficiency programs. With this approach, it is the state's commitment to achieve specific reductions—and not the programs themselves—that is federally enforceable. This means that if a program fails to achieve the anticipated reductions, EPA or citizen groups could take enforcement action against the state for failing to meet its commitment.

A state can submit an individual plan demonstrating how it will comply with the performance standards on its own, or it can team up with others to develop a multi-state plan. Multi-state plans offer additional flexibility and opportunity to achieve emissions reductions at a lower cost.

No matter what type of plan a state decides to submit, Clean Power Plan compliance strategies must meet four general criteria and contain twelve specific components in order for EPA to deem them "satisfactory" under Clean Air Act Section 111(d)(2)(A). The four general criteria are as follows: First, all state plans must contain enforceable measures that reduce CO_2 emissions from affected sources. Second, these enforceable measures, when taken together, must be projected to achieve the equivalent or better than the 2030 emission targets set by the EPA. Third, CO_2 emission performance from affected sources must be quantifiable and verifiable. Fourth, the state plan must include a process for state reporting of plan implementation (at the level of the affected entity), CO_2 emission performance outcomes, and implementation of corrective measures, if the initial measures fail to achieve the expected reductions.

The 12 components each state compliance plan must contain are:

1. Identification of Affected Entities – a state plan must list all affected sources, provide an inventory of emissions from those sources from the most recent calendar year, and identify any other affected entities in a state plan with responsibilities for implementation and enforceable obligations under the plan.

2. Description of Plan Approach and Geographic Scope – the plan must describe its approach and geographic scope, including whether the state will achieve its required level of CO_2 emission performance on an individual state basis or jointly through a multi-state demonstration.

3. Identification of State Emission Performance Level – the plan must identify the rate-based or mass-based emission performance level that will be met; if the state chooses a mass-based goal, the plan must include a description of the analytic process by which the EPA's rate-based target was translated to a mass-based target. In multi-state plans, individual targets would be replaced with an equivalent multi-state target.

4. Demonstration that the Plan is Projected to Achieve the State's Emission Performance Level – the plan must have a demonstration that the measures included in the plan will achieve the interim and final performance levels; this demonstration must include a detailed description of the analytic process, tools, and assumptions used to project performance.

5. Milestones – the plan must include periodic milestones to show progress in program implementation and to ensure performance during the performance period is meeting expectations.

6. Corrective Measures – the plan must also specify corrective measures that will be implemented if the state does not meet its performance milestones, as well as a process and schedule for implementing any such measures.

7. Identification of Emission Standards and Any Other Measures – a state plan must identify the affected entities to which each emission standard applies (e.g., individual affected EGUs, groups of affected EGUs, all the state's affected EGUs in aggregate, other affected entities that are not EGUs), as well as any implementing and enforcing measures for such standards, and describe each emission standard and the process for demonstrating compliance with it.

8. Demonstration that Each Standard is Quantifiable, Non-Duplicative, Permanent, Verifiable, and Enforceable – an emission standard is quantifiable if it can be reliably measured, using technically sound methods, in a manner that can be replicated. An emission standard is non-duplicative if it is not already incorporated in another state plan, except in instances where incorporated in another state as part of a multi-state plan. An emission standard is permanent if the standard must be met for each applicable compliance year or period, or replaced by another emission standard in a plan revision, or the state demonstrates in a plan revision that the emission standard is no longer necessary for the state to meet its required emission performance level for affected EGUs An emission standard is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state and EPA to independently evaluate, measure, and verify compliance with it.

9. Identification of Monitoring, Reporting, and Recordkeeping Requirements – the plan must include monitoring, reporting, and recordkeeping requirements for CO_2 emissions and useful energy output (if using a rate-based approach) consistent with the requirements specified in the emission guidelines. State plans with a rate-based emission performance level must require reporting of hourly net energy output (including net MWh generation, and where applicable, useful thermal output) from affected sources to the EPA on an annual basis.

10. Description of State Reporting – a plan must require that the state will submit reports to the EPA detailing plan implementation and progress, including the actions taken by the state, affected EGUs, and any other affected entities under the plan; the status of compliance by affected EGUs and any other affected entities with their obligations under the plan; current aggregate and individual CO_2 emission performance by affected EGUs during the reporting year and prior reporting years; and any additional measures applied under the plan during the reporting period.

11. Certification of State Plan Hearing – the plan must certify that a public hearing was held on the state plan, including a witness list and summary of presentations and written comments.

12. Supporting Material – the state must provide supporting material and technical documentation related to applicable components of the plan, including a demonstration that the state has adequate legal authority for each measure included in the plan.

States can draw upon their experience developing Clean Air Act state implementation plans (SIPs) to meet national ambient air quality standards under Section 110 of the Act; however, in the proposal, EPA suggests that the approvability criteria for 111(d) compliance plans need not be identical to the approvability criteria used for SIPs. This will likely give states increased flexibility in designing compliance strategies.

In the Clean Power Plan, EPA is proposing both an "interim goal" that a state must meet on average over the ten-year period from 2020 – 2029, and a "final goal" that a state must meet at the end of that period in 2030 and thereafter. Ultimately, states will demonstrate compliance by comparing the actual emission performance of their affected sources against the final goal on a three-year rolling basis (2030 – 2032). States must then maintain this level of emission performance indefinitely (unless 111(d) targets are made more stringent in the future). For the interim goal, states will compare the actual emission performance of their affected sources during the period of 2020-2029 against the interim goal. Performance checks will occur during this period to make sure states are on track toward meeting their interim and final goals.

If a state fails to submit a plan, or submits a plan that EPA deems unsatisfactory, EPA has the authority to promulgate a federal plan for that state. If a state fails to meet either its interim or its final goals, EPA believes there should be consequences. However, in its proposal, EPA has not yet determined what those consequences should be. EPA identifies several potential consequences, such as the triggering of corrective measures, the requirement to achieve additional reductions on top of those needed to meet the state target (similar to a concept in the Acid Rain Program), or a "SIP-call" mechanism, which would require the development of a new plan upon the failure of an approved plan to meet a particular milestone.

4.4. Least-cost planning

EPA's 111(d) building blocks are neither mandatory nor "least cost." States are not required to use any specific building block or apply building blocks to the same extent EPA did in setting targets, nor are states limited to the levels EPA used in its building blocks. States may choose to employ measures other than those identified by EPA, as long as the 111(d) emission rate goal is met. While EPA has determined the costs of its Clean Power Plan are reasonable, the Agency has not performed a least-cost analysis for compliance in each state. Each state will need to do its own least-cost analysis to determine the least expensive way to achieve its target emission rate. Each state is unique, and costs will vary widely from state-to-state depending on existing infrastructure, renewable resource potential, and whether state is part of a multi-state plan. Best practices for least-cost planning for 111(d) compliance are discussed in greater detail in Section 7.1 of this report.

5. WHAT COSTS DID EPA ESTIMATE FOR THE CLEAN POWER PLAN?

5.1. National

According to EPA's Integrated Planning Model (IPM) modeling of the proposed rule, the net "system benefits"[7] to the electric sector would amount to $34 billion (see Table 1) in 2030. This estimate includes all of the electric sector costs and benefits that impact on consumer's bills with one exception: a total cost of energy efficiency measures paid by utilities or other program administrators of $21 billion. Combined, this means that in total, across the country, electric consumers' bills would fall by $13 billion. While the aggregate consumer's bill will fall, electric rates are expected rise as the fixed costs of electricity generation are spread out over fewer MWh of generation due to efficiency measures. For those consumers that do not participate in energy efficiency programs, higher rates for the same electricity use will mean higher bills. But for consumers that do participate at high enough levels, a higher rate on lower electricity use will mean lower bills. Energy efficiency consumers do face the additional cost of their own contribution to investment in these measures—in total $21 billion (see the second row in Table 1).

[7] That is, all of the costs and benefits of the electric system that are borne by ratepayers. System costs do not include the cost of energy efficiency measures to program participants.

Table 1. EPA's national cost of 111(d) implementation for 2030 in billions (proposed/option 1; state basis)

	Benefits	less	Costs	equals	Net Benefits
Electric Sector [for both EE program participants and non-participants]	**$34** [total system benefits net of costs in IPM modeling]		**$21** [EE program administrator costs]		**$13**
Energy Efficiency Program Participants	not monetized		**$21**		**($21)**
Societal	**$10-$94** [climate] **$24-$66** [health]		**$0**		**$10-$94** [climate] *$1-$10 per capita* **$24-$66** [health] *$69-$189 per capita*
Total	**$68-$194**		**$42**		**$26-$152**

In addition, EPA finds that there are important societal benefits of reduced climate and health damages associated with 111(d) compliance (see the third row in Table 1). Altogether, electric sector costs (including energy efficiency program administrator costs), energy efficiency program participants' costs, and societal benefits of 111(d) compliance are expected to result in a net benefit of $26-$152 billion in the year 2030.

5.2. State building block cost estimates

As noted earlier, EPA did not provide estimates of state-level 111(d) electric-sector compliance costs and benefits. Synapse has estimated these costs and benefits based on EPA's national estimates using the following assumptions:

- EPA's national costs (and our state estimates) assume that states follow the 111(d) building blocks exactly. A more likely course of events is that each state would achieve its 111(d) emission rate by following a least-cost compliance strategy.
- The purpose of EPA's building blocks is target setting; states can design their own compliance plans. EPA's national costs do not reflect least-cost strategies for states. EPA considers these costs to be "reasonable."

- EPA asserts that states complying jointly will have lower costs (and greater net benefits) than states complying singly.

- We estimate state costs by assuming EPA's average national costs by building block, and matching EPA's national costs by adjusting the avoided cost of energy. In the analysis shown in Figure 10, Figure 11, and Figure 12, Synapse has not assessed or revised EPA's costs based on its own research and expertise.

Figure 10 reports 2030 electric-sector costs (including system costs and energy efficiency program administrator costs, but not program participant costs or societal benefits) by state. Of the 49 states required to comply with 111(d), we estimate that 47 experience net benefits in 2030 based on following EPA's building blocks for target setting as well as EPA's national average cost for each measure. Only Arizona ($52 million) and Arkansas ($133 million) are expected to experience net costs under the assumption that EPA's building blocks are followed without least-cost planning.

Figure 10. EPA's 2030 national electric-sector cost estimates attributed to state building blocks

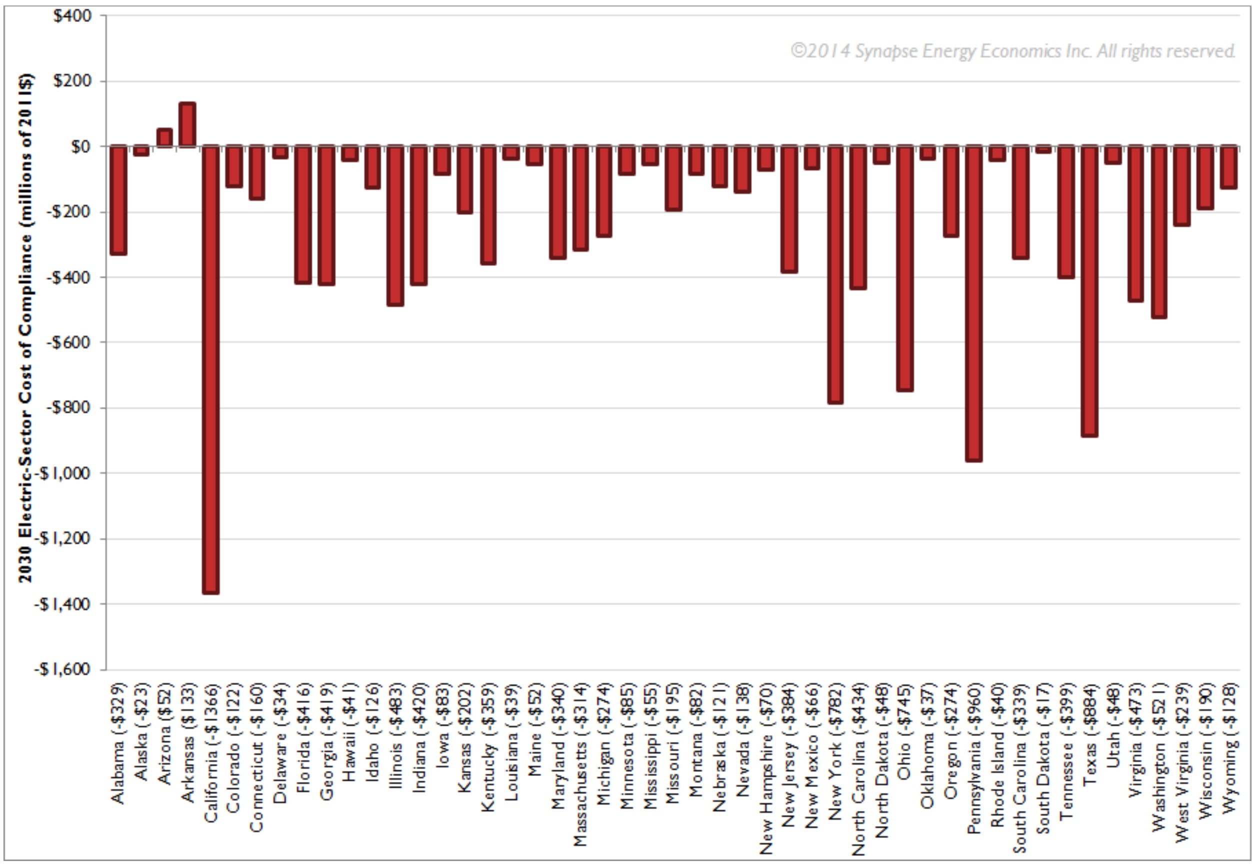


Figure 11 shows increased electric rates in every state. Most states experience a net benefit in dollars and, therefore, lower costs in the electric-sector; however, these lower costs are divided by lower generation because of efficiency measures, so the result is a higher rate under Clean Power Plan compliance than in the base case. Using the assumptions described above, we estimate that ***in the absence of least-cost planning*** rates will increase by 0.2 to 1.0 cents/kWh.

Figure 11. EPA's 2030 change in electric rate estimates attributed to state building blocks

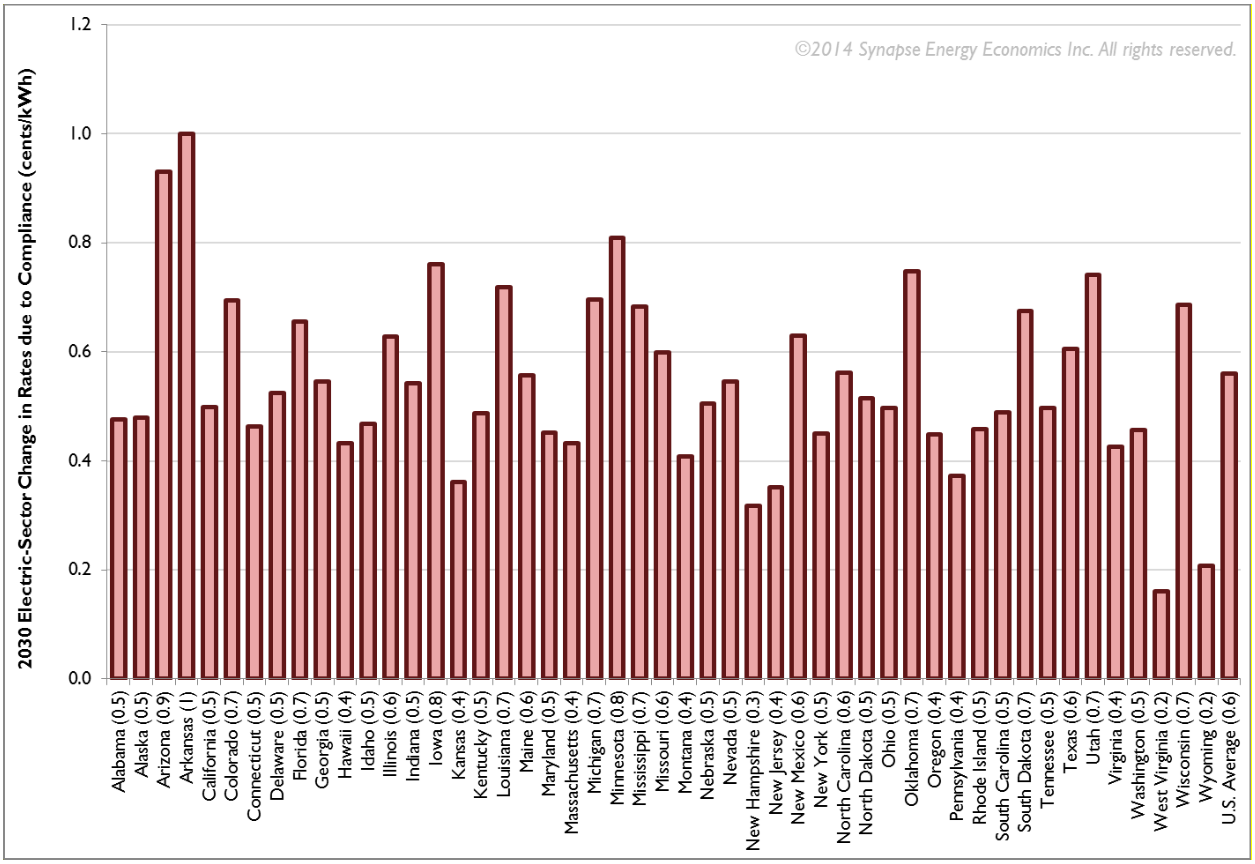
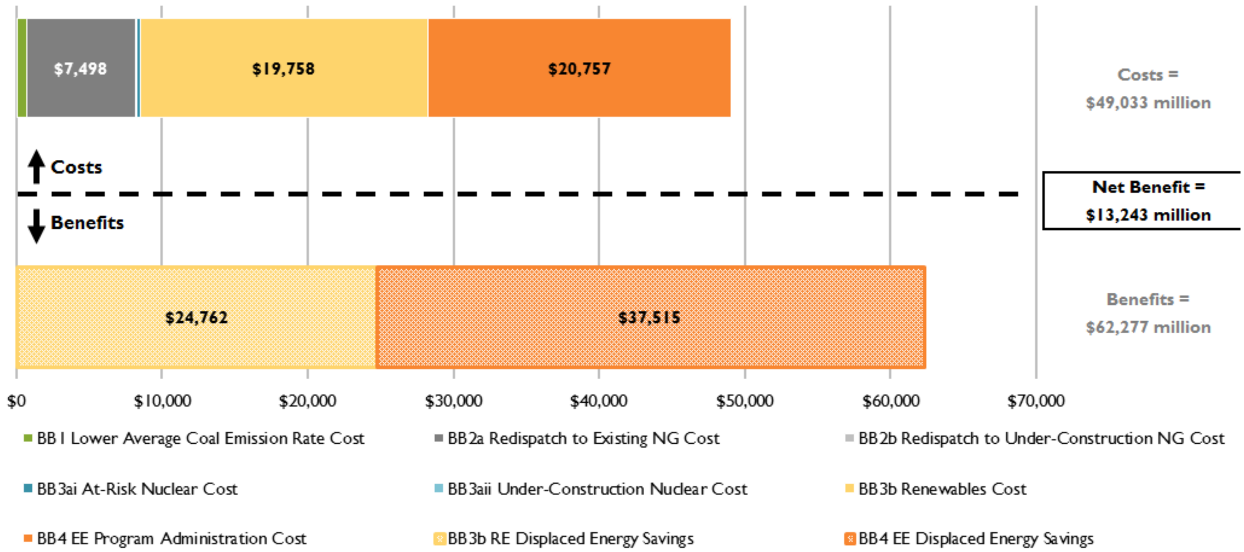


Figure 12 presents the breakdown of U.S. total costs and benefits by building blocks using the same set of assumptions. The greatest costs come from energy efficiency, renewables, and re-dispatch to NGCCs, but the benefits (or avoided costs) associated with energy efficiency and renewables are greater still. (See the Synapse "111(d) Cost Estimate Tool," available at http://www.synapse-energy.com/tools/111d-cost-estimate-tool-states, for state-specific versions of Figure 12 along with other information on state targets and building blocks; the percent of net savings is each building block's estimated net costs or benefits divided by total net costs or benefits for all building blocks.)

Figure 12. 2030 U.S. total electric-sector costs and benefits of 111(d) compliance (millions of 2011$)



Note: Values estimated by Synapse. Does not include energy efficiency participant costs or climate and health benefits.

	BB1	BB2a	BB2b	BB3ai	BB3aii	BB3b	BB4	BB3b	BB4	Net
(Costs) and Savings	($684)	($7,498)	($69)	($267)	$0	($19,758)	($20,757)	$24,762	$37,515	$13,243
Percent of Net Savings	1%	15%	0%	1%	0%	40%	42%	-51%	-77%	

5.3. Market price effects

One critical area for analysis in electric-sector modeling for Clean Power Plan compliance will be the effect of EPA's building blocks—and the Building Block 2 re-dispatch to NGCCs, in particular—on the wholesale market price of electricity. EPA assumed that any widespread re-dispatch to NGCCs would be implemented via a price instrument (for example, a CO_2 allowance price). In our judgment, a price instrument is essential to this re-dispatch; electric markets follow economic dispatch based on price signals. Emission allowance price instruments can have either a strongly inflating effect or a neutral effect on the wholesale price of energy depending on their design. The effect of an inflated wholesale market price would be windfall profits to existing low-emission resources, along with higher costs to consumers. This is an important area for additional research and modeling, along with careful policy design, for all states.

6. WHAT ARE THE CHALLENGES AND OPPORTUNITIES FOR STATES?

6.1. Lowering coal emission rates

Building Block 1 rests on the assumption that each state can reduce its emissions from coal units by six percent by adopting best practices for unit operation and maintenance (O&M) and implementing equipment upgrades. The efficiency of each state's fleet of coal plants differs, however, and some parties are concerned that such opportunities may not be cost effective or even possible for their state. This is especially true for states where equipment upgrades and best practices in O&M have already been implemented, or where such options are not available due to specific unit designs or fuel types.

Another concern is the potential for improvements in electric generating unit heat rates to create a "rebound effect." This could occur when an improvement in a plant's heat rate (and thus its operating efficiency) lowers its variable operating cost. The reduction in variable operating cost would likely result in the plant being dispatched more often, thereby raising the plant's generation output and lowering the amount of carbon emission reductions. However, the EPA expects that the rebound effect will be mitigated by Building Block 2, which substitutes natural gas generation for coal-fired and other steam-fired generation. In addition, it is likely that some coal units will be retired, while others receive upgrades and are dispatched more often. In such a scenario, the rebound effect would occur at the unit level but not at the fleet level.

States should also be aware that integration of large amounts of variable generation (such as wind and solar) will likely cause existing fossil units to cycle and ramp more often. Cycling and ramping cause most fossil units to operate less efficiently, raising the unit's heat rate, increasing maintenance costs, and increasing the frequency of forced outages. Lower power plant efficiency will in turn increase CO_2 emissions at the unit and may, to some extent, offset improvements made to O&M practices or equipment upgrades. Each power plant is designed and operated differently, and therefore the efficiency costs for each unit are unique. An attempt should be made to quantify these costs when identifying the least-cost option for compliance with the Clean Power Plan.[8]

6.2. Re-dispatch to natural gas

The ability of states to re-dispatch from oil and coal generation to natural gas combined cycle units is dependent upon the sufficiency of natural gas availability. While an adequate supply of natural gas is projected to be available, significant forecast uncertainty exists, particularly with respect to prices and pipeline availability. Certain regions, particularly the Northeast, already experience natural gas pipeline

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[8] General Electric International, Inc. *PJM Renewable Integration Study, Task 3A, Part G, Plant Cycling and Emissions*, March 31, 2014. Available at: http://www.pjm.com/~/media/committees-groups/task-forces/irtf/postings/pjm-pris-task-3a-part-g-plant-cycling-and-emissions.ashx

constraints that have caused regional spot market prices to spike to more than 35 times higher than the rest of the country. New pipeline development is underway, but demand growth[9] may outstrip the pace of construction, which takes years to complete.[10] In the meantime, re-dispatch to natural gas may result in higher electricity prices. Moreover, as states increasingly rely on natural gas, fuel diversity for electric generation will decline, potentially leaving states vulnerable to price spikes and other disruptions.

These challenges may become less of a concern for states that follow a multi-state compliance plan or that develop alternative low-carbon resources. Multi-state compliance options would enable groups of states (that are not necessarily contiguous) to take advantage of natural gas price differentials and varying levels of unit operating efficiencies to minimize costs and increase supply diversity.

Further, the EPA's estimates of each state's ability to re-dispatch to natural gas from other steam generation take into account the maximum amount of generation each state has available to displace. For states that have considerable natural gas capacity but little coal or oil generation that can be displaced, a multi-state compliance plan could allow the state to displace more high-carbon generation than the EPA estimated when setting the state's target—thereby lessening the obligation to achieve reductions from other measures.

An individual state's rate-based target may cause distortions in re-dispatch and coal retirement decisions. For example, some states may find that importing electricity is less expensive than re-dispatching to natural gas units, but states may experience a smaller reduction in emission rate or mass emissions from importing electricity than from substituting low-carbon generation within the state. For some coal plants, retirement may be the most cost-effective way to re-dispatch to natural gas combined cycle units, while concentrating remaining coal generation in the most efficient coal units. Again, however, states will need to understand how such decisions may impact electricity import or export economics.

Re-dispatch decisions will be further complicated by requirements that states continue to comply with FERC and regional wholesale dispatch protocols. At a minimum, compliance with such rules may necessitate the adoption of mass-based (rather than rate-based) compliance options to facilitate cap-and-trade mechanisms and allow for economic dispatch. This is a key area for further investigation for all states.

6.3. Nuclear

The EPA assumes that nuclear power will play a significant role in achieving state emission reduction goals. In each state with nuclear capacity, the target 111(d) emission rate is based on the state avoiding

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[9] Growth in natural gas demand also comes from households and industries. Natural gas is expected to increasingly replace fuel oil for heating due to favorable economics.

[10] Matthew Philips. "Northeast's Record Natural Gas Prices Due to Pipeline Dearth," *Bloomberg Business Week*, February 6, 2014. Available at http://www.businessweek.com/articles/2014-02-06/northeasts-record-natural-gas-prices-due-to-pipeline-dearth

the early retirement of 5.8 percent of its nuclear capacity (the amount deemed to be "at risk"),[11] and completing any under-construction nuclear units.

Avoiding early retirement of 5.8 percent of the nation's nuclear units due to what EPA refers to as "high operating costs and low electricity prices" may be technically feasible in the aggregate, but could pose a challenge for particular states. This challenge arises because the EPA does not calculate the amount of nuclear "at risk" within each state, but simply applies the 5.8 percent factor across the board. Thus states with no "at risk" nuclear may have fewer options to comply using this building block relative to states with a large portion of "at risk" nuclear. States that have few options to comply may consider preserving older units that would otherwise have been retired, but this option introduces significant safety concerns and costs. Other options available to states include partnering with other states to create multi-state compliance plans, or adding additional low-carbon generation and energy efficiency.

In Illinois, for example, which currently produces approximately 91 million MWh from its nuclear generators, EPA has calculated the target 111(d) emission rate to be 1,271 lbs/MWh. This includes a credit for the preservation of just over 5 million MWh (5.8 percent) of the state's nuclear generation (see Figure 13 below).

Figure 13. Illinois' 2030 111(d) Emission Rate Target (including 91 million MWh of nuclear)

111(d) Emission Rate =		Coal	NGCC	O/G Steam	Other	Nuclear	Renewables	E.Efficiency	= 1,271 lbs/MWh
	million lbs	145,156	18,063	0	503	0	0	0	
	million MWh	66	21	0	1	5	18	18	

Without this nuclear preservation credit, however, the state's target 111(d) emission rate would have been less stringent at 1,325 lbs/MWh (see Figure 14). Critically, if Illinois' existing nuclear fleet were to retire, Illinois would have to meet its target emission rate without the benefit of the resources EPA assumed when calculating the target, and would have to find equivalent reductions elsewhere.

Figure 14. Illinois' 2030 111(d) Emission Rate if all nuclear retired

111(d) Emission Rate =		Coal	NGCC	O/G Steam	Other	Nuclear	Renewables	E.Efficiency	= 1,325 lbs/MWh
	million lbs	145,156	18,063	0	503	0	0	0	
	million MWh	66	21	0	1	0	18	18	

Tennessee, South Carolina, and Georgia face a unique challenge in that a portion of their targets are based upon the anticipated completion of their under-construction nuclear units. Should these projects not be completed, due to factors such as large increases in construction costs or technical issues, the ability of these states to reach their emissions reduction goals may be more challenging.

[11] Note that all retirements reported as planned during the next 10 years on U.S. Energy Information Administration Form 860 are assumed to occur. This building block is the retirement of an additional 5.7 GW of "at risk" nuclear capacity by 2020.

Figures 15 and 16 illustrate how Georgia's target 111(d) emission rate would change if the Vogtle nuclear units 3 and 4, which are currently under construction, had not been factored into EPA's target setting.

Figure 15. Georgia's 2030 111(d) Emission Rate Target (including 31 million MWh of existing nuclear and 17 million MWh of new nuclear)

			Coal	NGCC	O/G Steam	Other	Nuclear	Renewables	E.Efficiency		
111(d) Emission Rate =	million lbs	=	58,647	43,213	0	68	0	0	0	=	834
	million MWh		27	51	0	0	19	12	12		lbs/MWh

If EPA had not included the new generation from under-construction nuclear units, Georgia's target would have been 138 lbs/MWh higher (less stringent).

Figure 16. Georgia's 2030 111(d) Emission Rate with new nuclear not completed

			Coal	NGCC	O/G Steam	Other	Nuclear	Renewables	E.Efficiency		
111(d) Emission Rate =	million lbs	=	58,647	43,213	0	68	0	0	0	=	972
	million MWh		27	51	0	0	2	12	12		lbs/MWh

If Georgia's under-construction nuclear units are not completed, the state will have to find reductions from other low- and zero-carbon resources in order to meet its target.

6.4. Renewables

The EPA has developed estimates of the extent to which generation at carbon-intensive electric generating units can be replaced using renewable generation. The estimates for each state's renewable energy potential are based on regional analyses developed from existing state renewable portfolio standards for 2020. Currently RPS goals vary significantly from state to state and region to region, resulting in large variation between regional renewable energy targets. States will need to review the RPS targets that went into setting regional renewable energy targets to verify that the set of resources classified as "renewable" for RPS purposes—and, therefore, 111(d) emission rate target setting—is consistent with the set of resources classified as "renewable" for Clean Power Plan compliance purposes.

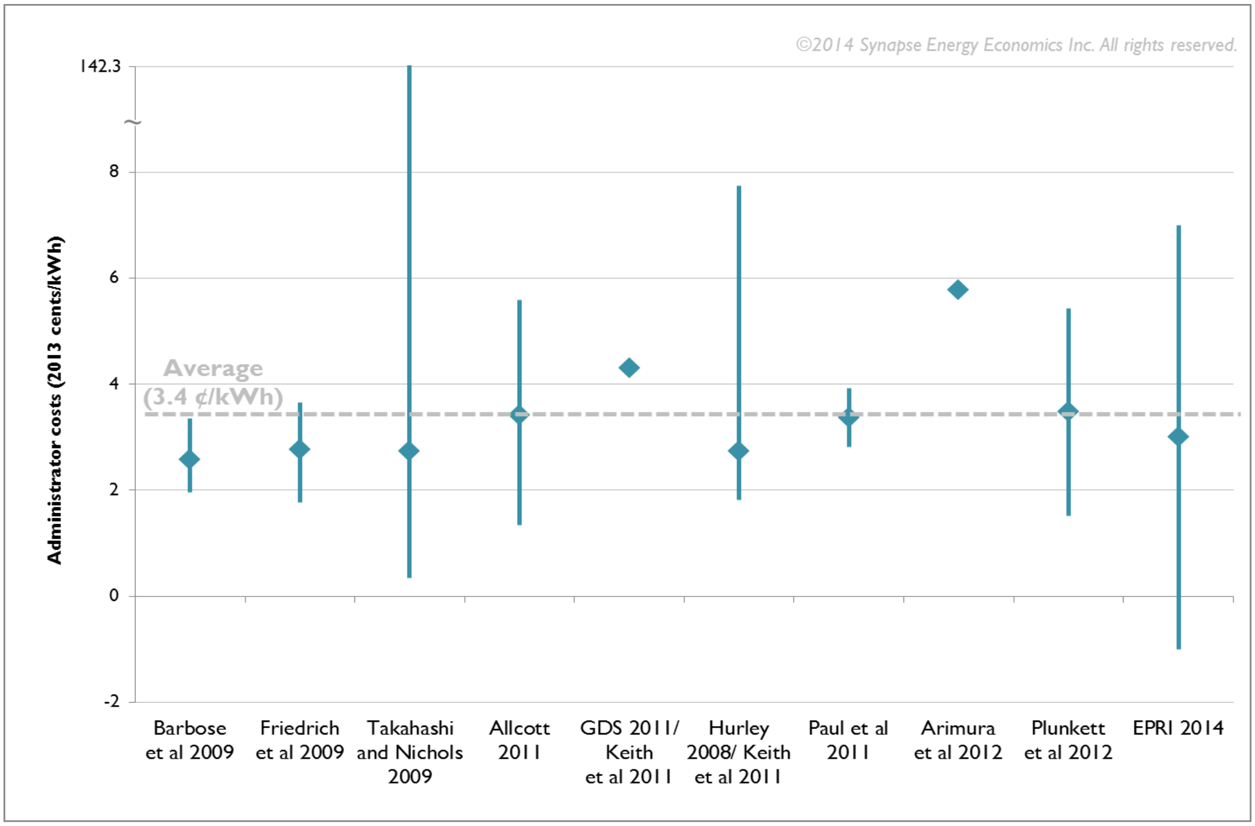
The regional estimates are applied to each state in the region to determine specific state goals. As such, these estimates may overestimate the technical and economic potential for some states to develop renewable energy, while underestimating other states' potential. This concern would be minimized if the EPA allows the use of RECs for compliance, as this system would allow trading among states and would allow both in-state and out-of-state renewable generation to count toward a state's compliance. Such an approach would also reduce the cost of compliance for many states. The EPA has requested comment on whether eligibility for renewables should be determined by geographic location or by REC purchase.

Although markets for RECs exist in many areas of the United States, if RECs will be relied upon for Clean Power Plan compliance, REC tracking systems will need to be expanded to areas where they are not currently used and may need to be upgraded to provide additional information about the timing and location of renewable energy generation.

6.5. Energy efficiency

Energy efficiency will play a large role in many states' implementation plans, not least because of the relatively low cost of this resource. EPA estimates that energy efficiency will cost, on average, 4.5 cents/kWh (excluding participant costs), but a review of ten recent studies indicate that the average cost is likely to be less than 3.4 cents/kWh, as shown in Figure 17.

Figure 17. Review of recent estimates of the cost of saved energy (excluding participant costs)



Source: Synapse research in progress

To calculate each state's emission target, the EPA assumes that all states will ramp up to a level of energy efficiency of 1.5 percent annual savings, excluding savings from building energy codes or other policies for which measurement and verification protocols are less consistently applied. The ramp up is expected to occur over a period of years, starting in 2017, at a rate of 0.2 percent each year, with all states reaching 1.5 percent annual savings by 2025.

Several states are already achieving savings greater than 1.5 percent, and 10 states are currently achieving savings of more than 1 percent per year, as evidenced in the table below. However, individual state situations may vary.

Table 2. Annual energy savings from energy efficiency for top ten states (2012)

Vermont	2.19%	Oregon	1.09%
Maine	1.96%	Pennsylvania	1.06%
Arizona	1.61%	Wisconsin	1.05%
California	1.24%	Iowa	1.05%
Minnesota	1.12%	Connecticut	1.01%

Source: EPA Calculations based on 2012 Form 861 data

The energy efficiency portion of this building block presents states with both opportunities and challenges. Some states that have well-established energy efficiency programs and funding mechanisms may find that achieving 1.5 percent annual savings requires only modest additional effort and funding beyond what they are currently doing. Other states, including but not limited to those with little experience in energy efficiency, may require find such reductions harder to achieve and maintain. At the very least, they may require additional time to work out program kinks, including coordination of programs across utilities and other entities, measurement and verification methods, and cost-effectiveness screening.

Some states may find that additional energy efficiency savings are achievable beyond 1.5 percent, and at reasonable cost. Although individual state experience may vary, energy efficiency frequently represents a lower-cost option than developing other resources, and recent experience has demonstrated that sustained savings of more than 1.5 percent are possible. Innovative programs, such as energy efficiency financing, also present opportunities to increase energy savings while minimizing administrative costs. For these reasons, states may wish to aggressively pursue energy efficiency for compliance with the Clean Power Plan.

Efficiency also presents unique challenges, as care must be taken to ensure that programs are well-run in order to be effective and low-cost, and the number of customers who participate in such programs should be maximized to ensure that as many customers benefit as possible. Although energy efficiency may lower costs in the long-run, customers are likely to experience higher rates. These higher rates will be offset by lower usage (and thus lower net bills) for participants, but non-participants may be adversely impacted. Expanding the percentage of customers who participate in energy efficiency programs, particularly low-income and hard-to-reach groups, is therefore critical for ensuring equity across rate classes.

Another challenge facing states in implementing energy efficiency lies in the evaluation, measurement, and verification (EM&V) of efficiency programs. EPA is proposing that state compliance plans must include an enforceable EM&V plan for both renewable and energy efficiency resources, which must specify analytic methods, assumptions, and data sources that will be used. While there currently exists a well-defined set of industry standard practices and procedures for renewable energy and energy efficiency EM&V, there can be considerable state-to-state variation in assumptions used for energy efficiency (e.g., net to gross ratios, equipment run-time, measure lifetimes, etc.).

States will likely wish to continue to use their own currently existing assumptions for EM&V, but this may be problematic for multi-state implementation plans. The EPA seeks comment on whether to require harmonization of state EE approaches, what approaches are suitable, and the scope of guidance on EM&V to provide.

It should also be noted that credit for energy efficiency contributions, as currently proposed, has the potential to result in some double counting. In calculating states' emission targets, the EPA has adjusted net-importing states' energy efficiency credit for the fact that their efficiency measures may result in decreased generation at electric generating units in other states. However, this treatment does not account for the fact that high-carbon generation may also decrease in the exporting state.

7. What Choices do States Have for Compliance?

The proposed rule offers states significant flexibility for compliance. The building blocks that formed the basis for the calculation of each state's target emission rate are not required for compliance. That is, states are not required to use any specific building block or apply building blocks to the extent EPA did when setting state targets. In addition, there may be other means of achieving emissions reductions beyond what the EPA considered for its building blocks. States may choose to employ measures other than those identified by EPA, as long as the 111(d) emission rate goal is met.

It is important to recognize that the EPA did not undertake an analysis of what options would be least-cost for each state, and thus each state must perform its own least-cost analysis to determine the least expensive way to achieve its target emission rate. Each state is unique. Costs will vary widely from state to state depending on existing infrastructure, renewable resource potential, and whether the state is part of a multi-state plan. States should ensure that they take full advantage of the proposed rule's flexibility by conducting a thorough analysis of compliance options, including resource choice, mass- or rate-based options, whether to join with other states in a multi-state plan, and whether to utilize market-based mechanisms, such as a carbon market.

7.1. Least-cost compliance

Best Practices for Developing Compliance Plans

States should begin as soon as possible to conduct advance planning to identify preferred Clean Power Plan compliance options and the potential emissions reductions that can be achieved through each option. If states have not already undertaken assessments of energy efficiency and renewable energy potential in their state or region, this is a logical first step to determining the optimal compliance strategy.

Integrated Resource Planning (IRP) provides a solid foundation for assessing least-cost compliance options when done well. States that use an IRP process should incorporate the EPA targets as a constraint in the IRP modeling to find the resource portfolio that achieves compliance with the Clean Power Plan while also meeting the other identified IRP criteria. States should also ensure that their analysis is performed using best practices in order to ensure that least-cost options are fully considered, risks are evaluated, and ratepayer impacts are equitably distributed.

When conducting planning, states should follow the following principles:

1) Evaluate the full range of resource options, including:
    a. Existing and emerging supply-side resources, including modifications to existing resources (such as fuel switching and retirement, discussed more below)
    b. Existing and emerging demand-side options, including energy efficiency, demand response, distributed generation, and storage technologies
    c. Imports and REC trading
2) Determine appropriate assumptions, risks, and constraints of each resource, including:
    a. Appropriate capital cost estimates, fuel prices (reasonable, recent, and consistent fuel price projections)
    b. Transmission upgrades required, resource availability constraints, etc.
    c. Risks posed by each resource, including the risk of reasonably likely future environmental regulations beyond 111(d)
3) Utilize appropriate analysis tools:
    a. The model used should capture relevant energy, capacity, transmission and distribution, and ancillary services impacts
4) Costs of various resource types should be analyzed on a consistent, comparable basis, and all benefits and costs accurately estimated
5) Impacts on both rates and bills should be considered when evaluating consumer impacts, and distributional impacts across rate classes should be assessed[12]

[12] Rachel Wilson and Bruce Biewald. *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans,* June 2013. Prepared for the Regulatory Assistance Project. Available at: http://www.synapse-energy.com/project/best-practices-electric-utility-integrated-resource-planning

Resources beyond the Building Blocks

States should bear in mind that EPA will permit measures other than the identified building blocks to count toward emissions reductions. Alternative compliance measures could include any listed in the table below, but each state will need to develop an estimate of their emissions reduction potential and costs based on state-specific data.

Table 3. Alternative Compliance Measures

Measure	Details and Considerations
Heat Rate Improvements at Non-Coal Fossil Plants	This could include efficiency improvements at oil-fired units, gas-fired steam units, and both simple-cycle and combined cycle natural gas units.
Carbon Capture And Storage	This measure offers the technical potential to reduce carbon emissions from coal plants by up to 90 percent, but the EPA found that the costs of applying this measure at a large scale would be substantial, potentially impacting the supply of electricity on a national basis.
Fuel Switching	Under this compliance measure, coal-fired units could be converted to natural gas (reducing emissions by approximately 40 percent), or natural gas could be co-fired at the unit. Capital costs for associated plant modifications are roughly $100 - $300/kW, excluding pipeline costs, but the most significant cost lies in the relative cost of natural gas relative to coal.
Co-Firing With Biomass	EPA is assessing the use of biomass and has developed a draft accounting framework. However, the reduction in CO_2 is dependent upon the type of biomass used, and the way in which it was grown, processed, and ultimately combusted.
Integrated Renewable Technology	Under this measure, a concentrating solar power installation would be used to meet a portion of the steam load of a fossil unit.
New Natural Gas Capacity[13]	New natural gas combined cycle units could offer substantial reductions in emissions, provided that the generation displaced by the new natural gas unit is in the state seeking the credit. However, costs of new natural gas units may include pipeline infrastructure and the additional cost associated with increased usage of natural gas (particularly if supply fails to keep up with increased demand.)
Credits from New Plant Over-Compliance	New Source Performance Standards are based on partial carbon capture and sequestration (CCS) for coal only. Additional reductions could be achieved through full CCS or installing CCS on non-coal units. These credits may be used for 111(d) compliance.

[13] For example, the Midcontinent Independent System Operator recently released a study in which the least-cost compliance method was found to be construction of a large number of new natural gas combined cycle units. These units would be regulated under 111(b), but would enable states to reduce emissions from existing units, thereby complying with 111(d). See: MISO. "GHG Regulation Impact Analysis – Initial Study Results." Presentation on September 17, 2014.

Measure	Details and Considerations
Transmission & Distribution Efficiency	Reducing line losses through upgrades to transmission and distribution equipment can reduce the amount of electricity generation required to meet load, thereby also reducing the amount of emissions.
Increased Utilization Of Natural Gas Combustion Turbines	The Clean Power Plan highlights the potential for natural gas combined-cycle units to reduce carbon emissions. However, increased utilization of simple-cycle natural gas combustion turbines could also provide emissions reductions, albeit to a lesser extent than combined-cycle units.
Energy Storage	Storage facilitates the integration of variable resources (such as wind and solar) and reduces the need for fossil-fueled backup generation.
Distributed Generation and Alternative Forms of Energy Efficiency	The installation of renewable distributed generation on customer premises reduces the energy consumed from central-station fossil generators, thus reducing emissions. Similarly, energy efficiency measures that are not measured and verified (such as building and appliance standards or combined heat and power) may also help reduce energy consumption and emissions.
Smart Grid Innovations	Customer-facing smart grid applications can help customers manage their load, allowing them to shift load from on-peak hours to off-peak hours, potentially reducing the emissions from peaking generators. Greater control frequently also results in reduced total energy consumption, thereby reducing emissions.

It is important to note, however, that these alternative measures must directly or indirectly result in reductions in CO_2 emissions at electric generation units. Reducing emissions from other sources (such as manufacturing facilities or vehicles) that does not reduce CO_2 from electric generation units will not count toward compliance.

Example Least-Cost Compliance Approach

As noted above, the EPA's building block approach is not likely to represent the least-cost compliance option for most states. The particular compliance strategy chosen by a state will be highly dependent upon local resource availability and costs. States should therefore seek to utilize the most accurate and up-to-date information available regarding resource options and costs when developing their compliance options.

In this section we present an example of how the use of better cost assumptions and resource mixes can reduce the costs facing a state relative to the compliance costs assumed by the EPA through the use of the standard building blocks. In this example, eight adjustments are made to move from a compliance plan consisting of EPA's standard building blocks assumptions to a compliance plan using an alternative resource mix and updated assumptions. After each adjustment, we report how this adjustment changed the net cost (or benefit) of compliance with 111(d). The inputs to each state's least-cost analysis will of course vary, but the below steps can help each state figure out what its range of least-cost approaches will be, and therefore how it can most cost-effectively comply with the EPA's requirements. We use Arkansas as an example, but note that the basic premise can be applied to any state.

1. Compliance Costs under EPA's Standard Building Blocks: Using the standard building blocks discussed earlier in this report, the EPA set an emission rate target rate of 910 lbs/MWh for Arkansas. The state's estimated net cost of compliance using these same building blocks would total $133 million, with the state accruing $819 million in costs and $686 million in benefits.

2. Adjusting the Cost of Energy Efficiency: As discussed in Section 6.5, the costs that EPA assumes for energy efficiency program administration are higher than the average costs recently reported in numerous other studies, though of course individual states' costs may vary. Therefore, the first adjustment is to adjust the average energy efficiency program administration cost to the state's likely cost. In this example, we used 3.4 cents/kWh as a more realistic estimate of what a typical state might face to meet its compliance obligation. This adjustment reduces the overall net cost of compliance to $90 million.

3. Changing the Excess Retrofit Assumption: The next step is to adjust the cost of plant level efficiency upgrades. Using the Building Blocks as applied by EPA coal plants first receive investments in heat rate improvements in Building Block 1 and then are no longer called upon to generate energy because of re-dispatch in Building Block 2. To avoid investments in retrofits that are not then used for generation, we adjust the cost of these retrofits downward from $14 million to $5 million, resulting in a revised net cost of $81 million.

4. Update Avoided Cost Assumption: The benefits of compliance with 111(d) are largely based on avoided cost assumptions. That is, through reducing energy consumption and relying more heavily on renewable resources, the need to purchase higher-priced energy, capacity, and ancillary services is reduced. Here we replace national avoided cost assumptions with assumptions that are Arkansas specific. This adjustment impacts the benefits side of the cost-benefit calculation, decreasing benefits by nearly $200 million. This leads to a revised net cost of $281 million.

5. Adjust the Cost of Wind: Next we replaced national cost for constructing new wind generation with Arkansas-specific costs. Reducing the estimated cost of wind lowers the cost of the renewables building block by over $100 million, leading to a net cost of $178 million.

6. Include Re-dispatch from Renewables and Energy Efficiency: EPA's Building Block method adds renewable generation and energy efficiency in Building Blocks 3 and 4 without adjusting total state generation to correspond with electricity sales. We displaced fossil resources to take account of new generation and lower loads. Taking this step reduces compliance costs by more than 50 percent. After a final adjustment to assure that emission rates meet the Clean Power Plan target, this step reduces costs below the level of benefits, resulting in net benefits for ratepayers of Arkansas.

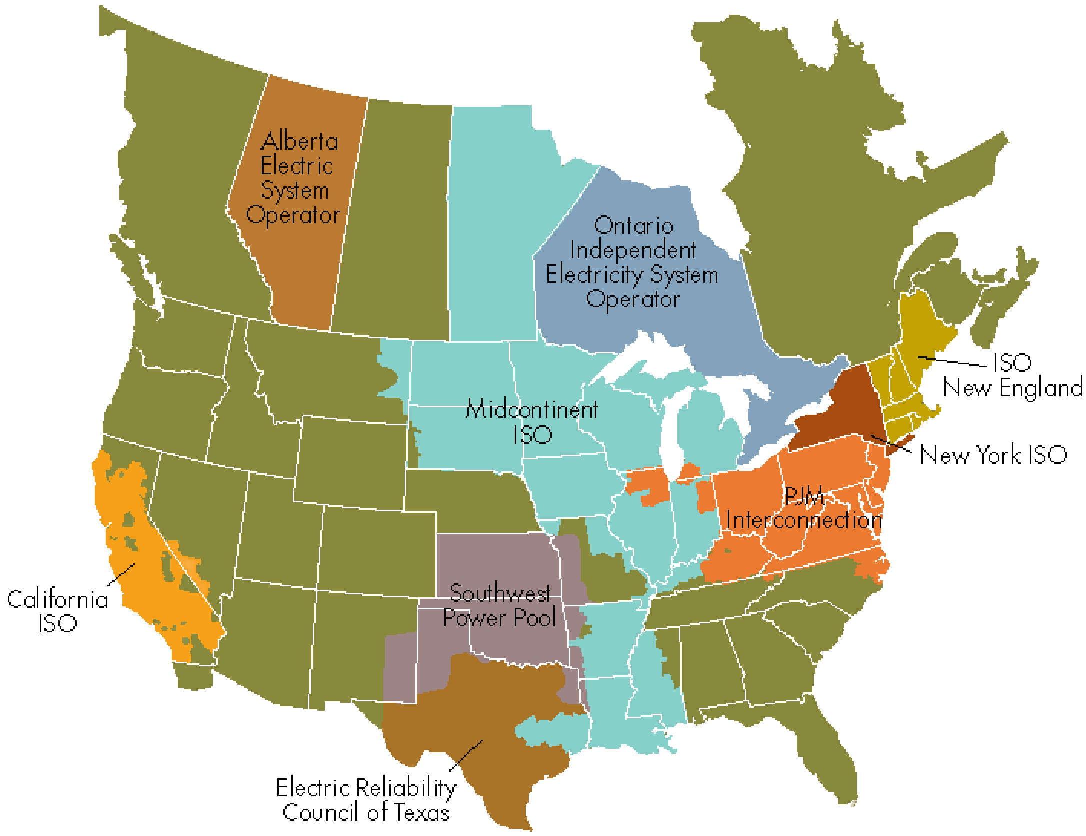
Through the above adjustments to the state's compliance strategy, the costs of compliance for Arkansas ratepayers were reduced from a net cost of $133 million to net *benefits* of $181 million. These adjustments were made based on improved resource costs assumptions and better accounting of the fossil generation that would be displaced by new renewables and energy efficiency, but would need to be revised as more state-specific data becomes available or modeling is conducted using dispatch models.

7.2. Multi-state compliance

The ability to comply on a multi-state basis as opposed to an individual state basis is a key point of flexibility in the proposed rule that offers the potential to significantly reduce compliance costs for states. Multi-state implementation plans are likely to be more cost-effective than single-state implementation for a number of reasons. First, multi-state compliance expands the number of potential emission reduction opportunities. States will differ in the amount of "at risk" nuclear they have available to preserve, the quantity of wind or solar energy available, and the amount of coal and oil generation that they can offset through greater utilization of NGCCs.

Second, multi-state compliance allows least-cost opportunities in the region to be exploited, similar to how ISO/RTO regions enjoy efficiencies of dispatch of plants across state borders. A multi-state plan would provide system operators with greater flexibility and may result in one state reducing emissions only slightly, while another state reduces significantly due to differences in the marginal cost of emissions reduction. One logical grouping for multi-state implementation exists that would roughly follow the current boundaries of the wholesale market areas, as shown in the figure below, although the boundaries do not align precisely with state borders.

Figure 18. Current RTO/ISO regions



Alternative state groupings are also possible, and states may wish to group with states that are not contiguous. Such groupings could successfully exploit highly diverse resource endowments (solar, wind, geothermal), existing infrastructure ("at risk" nuclear plants, natural gas capacity, plant efficiencies), and fuel price differentials (particularly natural gas).

Finally, multi-state compliance may reduce administrative costs through allowing states to pool resources to create a centralized, standardized administration. Close collaboration may also facilitate the sharing of best practices.

In contrast, a state-by-state approach could cause distortions related to cross-state re-dispatch or coal retirement, raising prices for customers. Under an individual state approach, complications are likely to arise for states that participate in regional wholesale markets, or even for those in cross-state balancing areas. Utilities whose service territories span state lines could be required to significantly alter their dispatch procedures to meet different states' compliance needs. In addition, state-by-state compliance using different compliance systems (i.e., a combination of rate-based and mass-based) could result in perverse incentives related to imports and exports that do little to reduce emissions.

Examples of Multi-State Compliance Advantages

Recently, the Midcontinent Independent System Operator (MISO) conducted modeling to analyze the costs of compliance under various compliance strategies. The report found that regional compliance options would reduce compliance costs by approximately $3 billion annually compared to sub-regional compliance approaches.[14] To illustrate ways that states may benefit from joint compliance, consider the following three examples:

- Full Credit for Energy Efficiency: Two states that are of similar size may benefit from joint compliance if one state is a net importer of energy from the other state, while the other is a net exporter. If State A only generates 60 percent of its own electricity, it only receives credit for a portion of its energy efficiency target. If State B generates 140 percent of the electricity it needs, it receives full credit for is energy efficiency target. By complying jointly, the two states would receive credit for all of their energy efficiency, increasing benefits significantly.

- Accessing Lower-Cost Renewable Resources: Consider a scenario in which State A relies heavily on coal, with little opportunity to re-dispatch to natural gas and high renewable energy costs. Over half of State A's emission rate reduction is based on transitioning to renewable energy, but this would only be accomplished at a high cost. In contrast, State B has significant low-cost renewable potential, but its target includes only a portion of this potential. By jointly complying, State A can purchase excess renewable generation from State B at a much lower cost than developing additional renewable generation in-state.

- Re-dispatch Across States: Suppose State A is heavily reliant on coal with no opportunity to re-dispatch to natural gas, while State B possesses large amounts of underutilized natural gas combined cycle generators, but has little coal to displace. Even after re-dispatch, State B's natural gas capacity factor remains below 70 percent. However, if State A and State B comply jointly, State B's natural gas generation can reach higher capacity factors, while displacing State A's high-emitting coal generation.

7.3. Mass-based compliance

The rule permits states to translate the EPA's rate-based emission target to a mass-based amount, which places a cap on the absolute number of metric tons of CO_2 that may be emitted in a particular year. The mass-based approach is designed to facilitate implementation of cap-and-trade programs, whether implemented within a single state (such as California) or across multiple states (such as the Northeast's Regional Greenhouse Gas Initiative). Cap-and-trade programs represent a market approach to achieving least-cost compliance, relying on price signals to drive resource investments and

[14] MISO. "GHG Regulation Impact Analysis – Initial Study Results." Presentation on September 17, 2014.

retirements. Mass-based compliance may also be useful for states with high concentrations of coal generation that choose to re-dispatch to out-of-state NGCCs or, more generally, for states contemplating coal unit retirements.

EPA's technical support documents explain the process for "translating" state 111(d) emission rate-based targets measured in pounds of CO_2 per MWh into mass-based targets measured in tons of CO_2. In our judgment, following EPA's methodology for translating rate-based targets to mass-based targets—for the purpose of measuring compliance in tons in state compliance plans—would require electric dispatch modeling.

A highly simplified method for generating a rough estimate of a state's mass-based target would estimate the range of possible mass-based targets between two thresholds while accounting for potential changes in electricity demand (for all resources including energy efficiency) over time, and assuming that states do not serve their electricity demand with generation from new (not covered under 111(d)) resources. The key thresholds for these mass-based targets would be (1) assuming that all re-dispatch of business-as-usual generation due to EPA's building blocks would occur within the state; and (2) assuming that all re-dispatch of business-as-usual generation due to EPA's building blocks would occur outside of the state. Dispatch modeling would be essential to more closely estimate mass-based targets within this range.

7.4. Market mechanisms to reduce carbon

Market mechanisms, such as tradable carbon emissions permits and renewable energy certificates, provide a potentially low-cost means for states to comply with the EPA's Clean Power Plan. If designed well, market mechanisms provide a price signal that enables carbon reductions from a variety of resources at least cost and encourages technological innovation. Market mechanisms may also be more politically palatable to key stakeholders than a regulatory compliance plan. However, the implications for consumers are highly dependent upon how the proceeds from these markets are used, the transaction costs associated with administering a market, and any risks associated with compliance options.

Establishment of a market mechanism requires attention to specific design criteria, including the choice of tradable instruments used, allocation of permits, geographic boundaries, point of measurement and compliance, and legal compliance. The EPA has not established requirements for specific market mechanism frameworks, but there are numerous examples already in existence on which states can model their programs.

Market mechanisms can use a number of different tradable instruments, such as:

- Allowances per ton of CO_2 produced during a particular time period
- Allowances for producing emissions in excess of a particular threshold (e.g., emissions above 1,000 lbs/MWh)
- Carbon reduction credits (for emissions reductions relative to a baseline)

- Renewable energy or energy efficiency certificates

The choice of instrument will depend on the state's strategy for compliance and may have important implications for the type of measurement and verification required. For example, to enable emissions reductions from a MWh of energy efficiency to be traded in a market, the measurement of the displaced emissions will be critical, and will rely on an electric dispatch model or a model such as AVERT, which estimates marginal emissions rates.

Perhaps the most critical component of designing market mechanisms based on CO_2 allowances (e.g., a cap-and-trade program) is the decision of how to allocate emissions permits. If permits are given to generators for free, owners of power plants will experience windfall profits. This would occur because the generators will raise their prices to reflect the cost of purchasing emissions permits, which will then increase costs for consumers. If, however, generators are required to purchase emissions permits (either through an auction or from another entity), the revenues from the permits can be returned to ratepayers or invested in programs such as energy efficiency, which will mitigate the electricity price increase.[15]

At the outset, the technical framework for a market mechanism must clearly establish geographic boundaries, which could be designed to align with utility service territories, state boundaries, organized wholesale market footprints, or any number of other options (including non-contiguous regions). These decisions require careful consideration in order to cost-effectively reduce carbon emissions, reduce administrative burden, and prevent carbon "leakage" that could undermine the effectiveness or economics of the market.[16] We note that current electricity market boundaries need not prescribe the boundary of a market, as exemplified by the Northeast's RGGI, which spans both the New England ISO, the New York ISO, and parts of PJM.

A related market design issue is the specification of whether measurement and compliance is determined at the point of emissions, the point of consumption, or the first point of sale within the relevant geographic boundary, and who has the legal obligation to comply. The Northeast's RGGI, a cap-and-trade program for carbon emissions, requires compliance at the generator, with each generator responsible for obtaining permits for each ton of CO_2 it emits. In contrast, RECs represent a MWh of clean energy and generally must be purchased from renewable generators by distribution utilities or retail suppliers, with compliance determined at the utility or retail supplier level. Tradable energy efficiency certificates would likely operate in a similar manner to RECs.

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[15] For example, proceeds from the sale of RGGI permits have been returned to ratepayers through bill credits and energy efficiency programs.

[16] The establishment of a geographic boundary and treatment of permits from outside of that boundary should ensure that there is no double counting of permits. This may be particularly difficult when a permit or credit traverses compliance systems. For example, if a state using mass-based compliance sells a REC to a state using rate-based compliance, the emissions reduction may be counted twice, since the mass-based system automatically captures the reduction in carbon intensity.

Legal compliance may present a complicated issue for states, and may vary based on the choice of tradable instrument. For example, in a classic cap-and-trade system for CO_2 emissions permits, generators may be legally obligated to comply through holding the appropriate number of emissions permits. But use of RECs, energy efficiency certificates, or other instruments may shift legal compliance to utilities, retail providers, or state agencies. If compliance legally rests with state agencies, the specific state agency that holds this responsibility must be identified.

7.5. State Compliance Plan choices, and changing plans over time

States must develop compliance plans establishing emission performance levels that will allow them to meet the targets set by EPA. The Agency is proposing that all measures relied upon to achieve the emission performance level (including EE and RE measures) be included in the state plan, rendering those measures *federally enforceable* (meaning EPA and the public can file suit for failure to comply). EPA is seeking comment on an alternative called the "state commitment approach," in which measures such as state EE and RE programs would not be included in the state plan directly. Instead, states would make enforceable commitments to implement these programs to achieve a specified portion of the emission performance level on behalf of the affected electric generating units. While some stakeholders have expressed concern over subjecting state programs to federal enforcement, including these measures in state plans would allow consumer advocates to ensure these programs are carried out in the interest of consumers by providing the option to take enforcement action against the state or other entity for failing to meet its obligation.

EPA does anticipate that plans may need to be amended or updated after they are approved due to the long planning and implementation period for the Clean Power Plan. EPA is proposing to allow measures to be revised or new measures to be added to the plan in the place of old measures, provided they do not result in "backsliding," i.e., a reduction in the required emission performance level. Such revisions would require new projections of emissions performance, to ensure the new measures would achieve the same or better emissions performance. This is good for consumers, as it provides an opportunity to change or abandon measures that turn out to be more expensive than expected and replace them with more cost-effective alternatives.

7.6. Summary of recommendations for state compliance plans

For most states, compliance with the EPA's proposed rule does not have to be costly or burdensome due to the wide latitude that states have in determining their own compliance strategy. However, it is up to states to take advantage of this flexibility.

To minimize costs to consumers, it is imperative that states conduct (or update) resource potential studies and undertake significant resource planning efforts. States may want to do an initial assessment of cost-effective compliance options, and then team with other states that offer complementary compliance strategies, including other states within a wholesale market area or a carbon trading area (e.g., RGGI states). In-depth, multi-state planning may then be necessary to establish an implementation plan. Such processes will be lengthy and complex, and should therefore be initiated at the earliest possible date. The complexity of multi-state compliance plans will likely be outweighed by the numerous efficiencies that multi-state compliance will enable, as well as by the additional time given to complete multi-state compliance plans.

State energy planning, energy efficiency screening, resource procurement, and retirement decisions are all related to 111(d) compliance planning. How well these efforts are carried out will have significant long-term impacts on the total cost of compliance faced by ratepayers. For this reason, states must carefully consider the full range of resources when evaluating their compliance options, and look ahead to other reasonably likely future environmental regulations to ensure their preferred compliance options are able to cost-effectively comply with forthcoming environmental rules.

Consumer advocates should also communicate and coordinate with state air regulators in a timely manner and should pay special attention to assumptions about how savings are allocated in EPA's proposal and in compliance plan development.

8. On what Issues is EPA Requesting Comments?

EPA is seeking comments on all aspects of its Clean Power Plan proposal.

EPA is offering the opportunity to comment on the proposed BSER, the proposed methodology for computing state goals based on application of the BSER, and the state-specific data used in the computations. Once the final goals have been promulgated, a state would no longer have an opportunity to request that the EPA adjust its CO_2 goal. The final state-specific CO_2 goals would reflect any adjustments, as appropriate, based on comments provided to the EPA to address any data errors in the analysis for the proposed goals.

In Appendix A to this report, we identify each of the issues on which the EPA is seeking specific comments. In this section, we highlight a few of those issues that we believe consumers should give special attention as EPA works to finalize the Clean Power Plan.

8.1. Short- versus long-term compliance

EPA is seeking comment on whether its final rule should be more stringent and require final compliance in 2030 (the "proposed" or "option 1" rule), or whether the rule should be somewhat less stringent and require final compliance in 2025 (the "alternative" or "option 2" rule). Table 4 details the differences between the two rule options.

Table 4. EPA 111(d) proposed and alternative rule comparison

	Proposed Rule (Option 1)	Alternative Rule (Option 2)
End of rule roll-out	2030	2025
(BB1) Lower Average Coal Emission Rate	6% reduction by 2020; steady to 2030	4% reduction by 2020; steady to 2025
(BB2a) Redispatch to Existing NG; **(BB2b) Redispatch to Under-Construction NG**	redispatch from coal and steam to 70% NGCC capacity factors by 2020; steady to 2030	redispatch from coal and steam to 65% NGCC capacity factors by 2020; steady to 2025
(BB3a-i) At-Risk Nuclear	credit for 5.8% of nuclear in use in 2020; steady % to 2030	credit for 5.8% of nuclear in use in 2020; steady % to 2025
(BB3a-ii) Under-Construction Nuclear	credit for all post-2012 nuclear in 2020; steady to 2030	credit for all post-2012 nuclear in 2020; steady to 2025
(BB3b) Incremental Renewables	annual state targets starting in 2020; growing each year through 2030	same annual state targets starting in 2020; growing each year through 2025
(BB4) Incremental Energy Efficiency	annual state targets starting in 2020; growing each year through 2030	lower annual state targets starting in 2020; growing each year through 2025
Annual electric-sector net costs (billions of 2011$):		
in 2020	$2.3	$1.4
in 2025	($9.0)	($4.8)
in 2030	($12.6)	N/A

8.2. REC purchases versus in-state renewable generation

States' ability to use renewables for 111(d) compliance will depend, in part, on EPA's decision in the final Clean Power Plan rule on whether qualifying renewable generation must be sited within the geographic boundary of the state or whether a state's purchase of RECs from other states may count towards compliance. Trading of RECs between states—at an appropriate "exchange rate" to account for differences in the emissions displaced in one state versus another state—may be a viable path for states to cooperate without jointly filing implementation plans.

If trading is allowed, then states will be able to meet their compliance target emission rates by conducting trades of emission certificates. Unlike trading for RPS compliance, the commodity being traded is tons or incremental reductions in an emission rate, not MWh.

Synapse developed the AVERT (Avoided Emissions and Generation Tool) model for EPA as an intermediate-complexity, publicly accessible tool for estimating the potential of energy efficiency and renewable energy programs to displace sulfur dioxide, nitrogen oxides, and carbon dioxide emissions within the continental United States.[17]

Using Ohio and Texas as examples, AVERT calculates that one MWh of renewable energy yields:

- 1,541 lbs of displaced CO_2 in Ohio
- 1,288 lbs of displaced CO_2 in Texas

In this way, one MWh of renewable energy generated in Ohio is 1.2 times (1,541 / 1,288) as valuable to someone in Texas as one MWh of renewable energy generated in Texas. Construction of additional renewables beyond 15-percent of generation in Ohio would result in over-compliance with the Clean Power Plan (see Figure 19 and Figure 20). Instead, Ohio could sell, in this example, an excess 21 million MWh of renewable generation to Ohio.

Figure 19. Ohio's 2013 111(d) Emission Rate Target (includes 15% annual growth in RE)

111(d) Emission Rate	=	million lbs / million MWh	=		Coal	NGCC	O/G Steam	Other	Nuclear	Renewables	E.Efficiency	= 1,338 lbs/MWh
		million lbs			159,898	26,387	396	2,791	0	0	0	
		million MWh			80	27	0	3	1	14	16	

Figure 20. Ohio's 2013 111(d) Emission Rate with 30% annual growth in RE

111(d) Emission Rate	=	million lbs / million MWh	=		Coal	NGCC	O/G Steam	Other	Nuclear	Renewables	E.Efficiency	= 1,165 lbs/MWh
		million lbs			159,898	26,387	396	2,791	0	0	0	
		million MWh			80	27	0	3	1	35	16	

17 See http://epa.gov/avert/

APPENDIX A. LIST OF SPECIFIC ISSUES ON WHICH EPA IS SEEKING COMMENT

We have grouped the issues into eight major categories:

1. Best system of emission reduction (BSER)
2. Building Block 1
3. Building Block 2
4. Building Block 3
5. Building Block 4
6. State Goals
7. State Plans/Compliance
8. Other

Best System of Emission Reduction (BSER)

EPA is seeking comment on:	Reference
An alternative to its proposed (Option 1) approach to setting BSER that has a less stringent set of emission performance levels (lower deployment of the four building blocks) over a 5-year compliance timeframe (2025).	Proposal at 34839
Application of only the first two building blocks as the basis for the BSER, while noting that this approach achieves fewer CO_2 reductions at a higher cost.	Proposal at 34836
Different combinations of building blocks and different levels of stringency for each building block.	Proposal at 34839
How BSER should be applied in Indian Country, particularly for building block 4; EPA seeks data sources for setting renewable energy and demand-side EE targets.	Proposal at 34855
Whether there are special considerations affecting small rural cooperative or municipal utilities that might merit adjustments to the BSER proposal, and, if so, possible adjustments that should be considered.	Proposal at 34886
Whether natural gas co-firing or conversion should be part of the BSER. EPA also requests comment regarding whether—and if so, how—it should consider the co-benefits of natural gas co-firing in making that determination.	Proposal at 34876
All aspects of applying CCS to existing resources, though it does not anticipate finalizing CCS as a component of BSER in this rulemaking.	Proposal at 34876
Whether EPA should consider construction and use of new NGCC capacity as part of the basis supporting the BSER. Further, EPA seeks comment on ways to define appropriate state-level goals based on consideration of new NGCC capacity.	Proposal at 34877
Whether heat rate improvements for oil-fired steam EGUs, gas-fired steam EGUs, NGCC units, and simple-cycle combustion turbine units should be identified as a basis for supporting the BSER, with particular reference to U.S. territories.	Proposal at 34877
Whether trading programs or other similar approaches should be considered as the BSER.	Proposal at 34892

EPA is seeking comment on:	Reference
On an alternative BSER that uses building block 1 plus reduction in utilization of affected EGUs, which is estimated using building blocks 2-4: Could measures in addition to those in building blocks 2, 3, and 4 support the showing that reduced utilization is ‘‘adequately demonstrated,’’ including additional NGCC capacity that may be built in the future, as discussed in Section VI.C.5.c?	Proposal at 34890

Building Block 1

EPA is taking comment on all aspects of its findings related to heat rate improvements, but specifically asks for comment on:	Reference
Whether building block 1 (heat rate improvements) should include potential improvements at more than just coal plants.	Proposal at 34856 (fn 95)
Whether EPA should use 6% (as opposed to 4%) as a reasonable estimate of heat rate improvement that could be achieved at coal plants through use of best practices to reduce hourly heat rate variability.	Proposal at 34860
Whether EPA should use 4% (as opposed to 2%) as a reasonable estimate of heat rate improvement that could be achieved at coal plants through equipment upgrades. (Combined with the previous issue, this would mean the total estimated potential from heat rate improvements would be 10%, rather than the proposed 6%.)	Proposal at 34860
The quantitative impacts on the net heat rates of coal-fired steam EGUs of operation at loads less than the rated maximum unit loads.	Proposal at 34862

Building Block 2

EPA is seeking comment on all aspects of its findings related to re-dispatch, but specifically asks for comment on:	Reference
Whether the regional or state scenarios should be given greater weight in establishing the appropriate degree of re-dispatch to incorporate into the state goals for CO_2 emission reductions, and in assessing costs.	Proposal at 34865
Whether EPA should consider a higher utilization rate (up to 75%) for NGCCs.	Proposal at 34866

Building Block 3

EPA is seeking comment on all aspects of its findings related to RE and nuclear, but specifically asks for comment on:	Reference
RENEWABLES	
Treatment of Alaska and Hawaii as separate regions for setting RE targets. (Their RE targets are based on the lowest regional RE target among the continental U.S. regions, and their growth factors are based upon historical growth rates in their own RE generation).	Proposal at 34867
Whether the approach for quantifying the RE generation component of each state's goal should be modified to include a floor based on reported 2012 RE generation in that state (four states'2029 RE goals are below their 2012 RE generation).	Proposal at 34869
Whether the RE approach should be modified so that the difference between a state's RE generation target and its 2012 level of corresponding RE generation does not exceed the state's reported 2012 fossil fuel-fired generation.	Proposal at 34869
Whether to include 2012 hydropower generation from each state in that state's ''best practices'' RE quantified under this approach, and whether and how the EPA should consider year-to-year variability in hydropower generation if such generation is included in the RE targets quantified as part of BSER.	Proposal at 34869
An alternative to the proposed method of calculating RE targets, based on two sources of information: A metric representing the degree to which the technical potential of states to develop RE generation has already been realized, and IPM modeling of RE deployment at the state level under a scenario that reflects a reduced cost of building new renewable generating capacity. The questions in the previous three rows also apply to this alternative.	Proposal at 34870
Other possible "techno-economic" approaches to quantifying RE potential (see TSD).	Proposal at 34870
NUCLEAR	
Whether it is appropriate to reflect completion of under-construction nuclear units in the state goals and alternative ways of considering these units when setting state goals	Proposal at 34871
If so, how should EPA do so—for example, according to EGU owners' announcements, the issuance of permits, projections of new construction by the EPA or another government agency, or commercial projections? What specific data sources should EPA consider for those permits or projections?	Proposal at 34871

Building Block 4

EPA is seeking comment on all aspects of its data and methodology for demand side energy efficiency programs—as well as on the level of reductions proposed as best practices suitable for representation consistent with the BSER—but specifically asks for comment on:	Reference
Increasing the annual incremental savings rate to 2.0 percent and the pace of improvement to 0.25 percent per year to reflect an estimate of the additional electricity savings achievable from state policies not reflected in the 1.5 percent rate and the 0.20 percent per year pace of improvement, such as building energy codes and state appliance standards.	Proposal at 34875
Alternative and/or data sources (other than EIA Form 861) for determining each state's current level of annual incremental electricity savings.	Proposal at 34875
Alternative approaches and/or data sources for evaluating costs associated with implementation of state demand-side EE policies.	Proposal at 34875

State Goals

EPA is seeking comment on all aspects of the proposed form of the state goals and the goal computation procedure, but specifically asks for comment on:	Reference
Its proposed state goals, and says "A state may demonstrate during the comment period that application of one of the building blocks to that state would not be expected to produce the level of emission reduction quantified by the EPA because implementation of the building block at the levels envisioned by the EPA was technically infeasible, or because the costs of doing so were significantly higher than projected by the EPA."	Proposal at 34893
However, if weakening the goal, a state must show that the difference can't be made up in another of the building blocks; OR, if the state finds that one of the building blocks just won't yield the reductions EPA calculated, the state would have to look to make up those reductions elsewhere before EPA would change its target. EPA wants comments on this approach.	Proposal at 34893
The Option 2 state goals (set using the Option 2 BSER approach with less stringent building blocks but nearer-term compliance (2025)) or combinations of the lesser and more stringent building blocks.	Proposal at 34898
Its proposal to set goals for Indian Country based on the collection of EGUs located in that area of Indian Country.	
How BSER would apply in American Territories (PR, US VI, Guam), on appropriate alternatives for territories that do not have access to natural gas, and on ways to determine appropriate RE and demand side EE targets using other data sources.	Proposal at 34893
Whether the goals and reporting requirements for existing EGUs should be expressed in terms of gross generation instead of net generation for consistency with existing reporting requirements and with the proposed requirements under the GHG standards of performance for new EGUs.	Proposal at 34894-5

EPA is seeking comment on all aspects of the proposed form of the state goals and the goal computation procedure, but specifically asks for comment on:	Reference
The state-specific historical data to which the building blocks are applied in order to compute the state goals, and the data used to develop the state-specific data inputs for building blocks 3 and 4 (see Goal Computation TSD and Abatement TSD).	Proposal at 34896-7
As an alternative approach to calculating building block 2, step 3, whether EPA should decrease generation from the coal-fired steam group first, then the oil/gas-fired steam group, instead of decreasing them proportionately (as proposed).	
As an alternative approach to calculating building block 4, step 5, whether EPA should scale up the estimated reduction in the generation by affected EGUs in net electricity exporting states to reflect an expectation that a portion of the generation avoided in conjunction with the demand-side EE efforts of other, net electricity-importing states would occur at those EGUs, analogous to the proposed adjustment for net electricity importing states described in step 5; or whether EPA should instead make no adjustment in step 5 for either net electricity-importing or net electricity-exporting states.	Proposal at 34897
Whether, and if so how, the EPA should incorporate greater consideration of multi-state approaches into the goal-setting process; and whether, and if so how, the potential cost savings associated with multi-state approaches should be considered in assessing the reasonableness of the costs of state-specific goals.	Proposal at 34899

State Plans/Compliance

EPA is seeking comment on all aspects of its proposed state plan approach, but specifically asks for comment on:	Reference
Other potential mechanisms for fostering multi-state collaboration.	Proposal at 34900
EPA's proposed approach of letting states decide whether to submit plans that hold the affected EGUs fully and solely responsible for achieving the emission performance level (EGU Sole Obligation Approach) OR to submit plans that rely in part on measures imposed on entities other than affected EGUs to achieve the balance of that level (Portfolio Approach).	Proposal at 34901
Whether EPA can reasonably interpret CAA section 111(d)(1) to allow states to adopt plans that require EGUs and other entities to be legally responsible for actions required under the plan that will, in aggregate, achieve the emission performance level.	Proposal at 34901
Appropriateness and policy ramifications of the "State Commitment Approach."	
A variation of this plan in which full obligation for emission performance level is on EGUs, but states credit EGUs with (and take responsibility for) the amount of emission reductions expected from RE or EE measures.	Proposal at 34902
The extent to which measures such as RE and demand-side EE may be considered "implement[ing]'' measures in state plans if they are not directly tied to emission reductions that affected sources are required to make through emission limits, and if they are requirements on entities other than the affected sources.	Proposal at 34903

EPA is seeking comment on all aspects of its proposed state plan approach, but specifically asks for comment on:	**Reference**
Whether EPA must interpret section 111(d) to require sole responsibility for achieving the emission performance level to be on affected EGUs; and, if so, whether there is a way, nonetheless, to allow states to rely on the Portfolio Approach to some extent and/or for some period of time.	Proposal at 34903
Applicability of state 111(d) plans to sources that are subject to plan requirements, even if they undertake modification or reconstruction, making those sources subject to BOTH 111(d) and 111(b) standards.	Proposal at 34903-4
Whether it should require an additional plan submittal in 2025 (or another year?) showing whether plan measures would maintain the final-goal level of emission performance over time.	Proposal at 34905
The appropriate start date for the performance period for the interim goal.	Proposal at 34905
The proposed and other approaches to specifying performance periods for state plans.	Proposal at 34906
Whether there are other types of state plans that would be self-correcting.	Proposal at 34907
Whether states should be required to adopt legal authority and/or adopt regulations for correcting future deficiencies as part of their state plan development process, rather than having the option to wait until a deficiency is discovered.	Proposal at 34907
What conditions should trigger corrective measures. Is 10% appropriate? Would somewhere in the range of 5 to 15% be better? What about the 8% for plans without contingency measures? Would 5 to 10% be better?	Proposal at 34907
How the milestones and emission performance checks would work in the context of the alternative 5-year compliance timeframe.	Proposal at 34907
How EPA should handle the consequences of failing to meet interim or final goals. Should consequences include the triggering of corrective measures in the state plan, or in plan revisions, to adjust requirements or add new measures? Should corrective measures be required to achieve additional emission reductions to offset any emission performance deficiency that occurred during a performance period for the interim or final goal? What should the process be for invoking requirements for implementation of corrective measures in response to a state plan performance deficiency?	Proposal at 34908
Whether EPA should promulgate a mechanism under CAA section 111(d) similar to the SIP call mechanism in CAA section 110.	Proposal at 34908
Whether EPA should require continued improvement after the target year, instead of just maintenance.	Proposal at 34908
What a state would need to require in its plan to show that performance will be maintained after 2030, for plans that rely in part on end-use EE programs and measures.	Proposal at 34908, fn 281
An alternative in which the state plan would be required to include projections demonstrating that emission performance would continue to meet the final goal for up to 10 years beyond 2030. This approach could be implemented through a second round of state plan analysis and submittals in 2025 to make the demonstration and strengthen or add measures if necessary.	Proposal at 34908

EPA is seeking comment on all aspects of its proposed state plan approach, but specifically asks for comment on:	Reference
Whether EPA should set BSER-based goals for affected EGUs that extend further into the future, and if so, what those levels of improved performance should be over what time period.	Proposal at 34908
Whether the 111(b)(1)(B) requirement that NSPSs be updated every 8 years should also apply to 111(d).	Proposal at 34908
For the alternative state goals, EPA requests comment on whether a state plan should provide for emission performance after 2025 solely through post-implementation emission checks that do not require a second plan submittal, or whether a state should also be required to make a second submittal prior to 2025 to demonstrate that its programs and measures are sufficient to maintain performance.	Proposal at 34909
The criteria EPA is using to determine whether a plan is "satisfactory" under 111(d)(2)(A).	Proposal at 34909
The appropriateness of existing EPA guidance on enforceability of measures in state plans in the context of 111(d).	Proposal at 34909
All aspects of enforceability of state plans and how to ensure compliance, including under different state plan approaches considered in this rulemaking.	Proposal at 34910
Whether RTOs should help implement multi-state plans and demonstrate emission performance across existing RTOs/ISOs.	Proposal at 34910
The scope of reporting requirements for each affected entity in a state plan.	
Whether states participating in a multi-state plan should also be given the option of providing a single submittal—signed by authorized officials from each participating state—that addresses common plan elements. Individual participating states would also be required to provide individual submittals that provide state-specific elements of the multi-state plan. Under this approach, the combined common submittal and each of the individual participating state submittals would constitute the multi-state plan submitted for EPA review.	Proposal at 34910-11
Or, an approach where all states participating in a multi-state plan separately make individual submittals that address all elements of the multi-state plan. These submittals would need to be materially consistent for all common plan elements that apply to all participating states, and would also address individual state-specific aspects of the multi-state plan.	Proposal at 34911

EPA is seeking comment on all aspects of its proposed state plan approach, but specifically asks for comment on:	**Reference**
Two options for calculating a weighted average, rate-based CO_2 emission performance goal for multiple states: ▪ *First option:* The weighted average emission rate goal for a group of participating states is computed using each state's emission rate goal from the emission guidelines and the quantity of electricity generation by affected EGUs in each of those states during the 2012 base year that the EPA used in calculating the state-specific goals. ▪ *Second option:* The weighted average emission rate goal for a group of participating states is computed using each state-specific emission rate goal and the quantity of projected electricity generation by affected EGUs in each state. The calculation would be performed for the 2020 – 2029 period to produce a multi-state interim goal, and for 2030 to produce a multi-state final goal. This projection of electricity generation by affected EGUs would be for a reference case that does not include application of either the state-specific rate-based emission performance goals for the participating states or the requirements, programs, and measures included in the multi-state plan.	Proposal at 34911
Whether, to assist states that seek to translate the rate-based goal into a mass-based goal, the EPA should provide a presumptive translation of rate-based goals to mass-based goals for all states, for those who request it, and/or for multi-state regions. As another alternative, the EPA could provide guidance for states to use in translating a rate-based goal to a mass-based goal for individual states and for multi-state regions. This could include information about acceptable analytical methods and tools, as well as default input assumptions for key parameters that will likely influence projections, such as electricity load forecasts.	Proposal at 34912
The process for setting mass-based emission goals, including the options summarized in the previous row for EPA's and the states' roles in the translation process.	Proposal at 34912
The amount of emission rate improvement or emission reduction that the corrective measures included in the plan must be designed to achieve, and whether the emissions guidelines should establish a deadline for implementation of corrective measures.	Proposal at 34912
Longer or shorter averaging times for emission standards included in a state plan. (EPA is proposing no longer than 12 months.)	Proposal at 34913
Whether an emission reduction becomes duplicative (and therefore cannot be used for demonstrating performance in a plan) if it is used as part of another state's demonstration of emission performance under its CAA section 111(d) plan.	Proposal at 34913
Two possible adjustments to the Part 75 Relative Accuracy Test Audit (RATA) requirements for steam EGU stack gas flow monitors that can affect reported CO_2 emissions. The first possible adjustment would be to require use of the most accurate RATA reference method for specific stack configurations, while the second possible adjustment would be to require a computation adjustment when an EGU changes RATA reference methods.	Proposal at 34914
Whether EGUs producing both electric energy output and useful thermal output should be required to report both.	Proposal at 34914

EPA is seeking comment on all aspects of its proposed state plan approach, but specifically asks for comment on:	Reference
The proposal for reporting of net rather than gross energy output, and on the proposed protocols for net energy output under 40 CFR Part 75 that would allow the ECMPS to be used for purposes of meeting the net energy output reporting requirement.	Proposal at 34914
A range of two-thirds to 100 percent credit for useful thermal output in the final rule, or other alternatives to better align incentives with avoided emissions.	Proposal at 34914
Its proposal that state plans must include a record retention requirement of ten years; EPA requests comment on this proposed timeframe.	Proposal at 34914
The appropriate frequency of reporting of the different proposed reporting elements, considering both the goals of minimizing unnecessary burdens on states and ensuring program effectiveness; and, particularly, whether full reports containing all of the report elements should only be required every two years, and whether they should be submitted electronically.	Proposal at 34914
Additional circumstances for which an extension of time for submitting a complete plan would be appropriate (beyond legislative schedule and multi-state coordination), and what justifications should not be permissible.	Proposal at 34915
Any additional elements that a state must include in its initial submittal to qualify for a date extension; specifically, whether the guidelines should require a state to have taken significant, concrete steps toward adopting a complete plan for the initial plan to be approvable.	Proposal at 34916
Whether, for complete state plans under these guidelines, the agency may use two approval mechanisms provided for in CAA sections 110(k)(3) and (4): first, a partial approval/partial disapproval; and second, a conditional approval.	Proposal at 34916
Whether EPA should interpret the CAA as providing the flexibility to approve a plan on the condition that the state commits to curing the minor deficiencies within one year. Any such conditional approval would be treated as a disapproval if the state fails to comply with its commitment.	Proposal at 34917
Whether, when substantively changing measures in an approved plan, the required new projections of emission performance—including the projection methods, tools, and assumptions used—should match those used for the projection in the original demonstration of plan performance; or, whether they should be updated to reflect the latest data and assumptions, such as assumptions for current and future economic conditions and technology cost and performance.	Proposal at 34917
Whether EPA should create a template for initial and complete state plan submittals, or whether a template would be more appropriate for initial plan submittals.	Proposal at 34917
Whether states should be allowed to submit plans electronically.	Proposal at 34917
Whether EPA should provide guidance on enforceability considerations related to requirements in a state plan for affected entities other than EGUs (and if so, which such entities).	Proposal at 34917

EPA is seeking comment on all aspects of its proposed state plan approach, but specifically asks for comment on:	Reference
While EPA is proposing that reductions that occur as a result of programs that are adopted before the performance period count toward compliance as long as they were adopted after the proposal date, EPA is also taking comment on other cut-off dates, such as: the start date of the initial plan performance period; the date of promulgation of the emission guidelines; the end date of the base period for the EPA's BSER-based goals analysis (e.g., the beginning of 2013 for blocks 1–3 and beginning of 2017 for block 4, end-use energy efficiency); the end of 2005; or another date. Is there a rational basis for choosing a date that predates the base period from which the EPA used historical data to derive state goals?	Proposal at 34918
As another option, should EPA recognize emission reductions that existing programs achieved prior to the start date of the plan performance period, such as: the date of promulgation of the emission guidelines; the date of proposal of the emission guidelines; the end date of the base period for the EPA's BSER-based goals analysis (e.g., the beginning of 2013 for blocks 1–3 and the beginning of 2017 for block 4, end-use energy efficiency); the end of 2005; or another date?	Proposal at 34919
Different approaches for providing crediting or administrative adjustment of EGU CO_2 emission rates for EE and RE measures.	Proposal at 34919-20
How emission reductions at non-affected EGUs (i.e., new units) that are achieved as a result of EE or RE should be addressed in state plans.	Proposal at 34920
The suitability of current EM&V approaches for RE and EE in the context of approvable state plans, and whether harmonization should be required.	Proposal at 34920
EPA intends to establish guidance for acceptable quantification, monitoring, and verification of RE and demand-side EE measures for an approvable EM&V plan, and is seeking comment on critical features of such guidance, including scope, applicability, and minimum criteria, as well as the appropriate basis for and technical resources used to establish such guidance, including consideration of existing state and utility protocols, as well as existing international, national, and regional consensus standards or protocols.	Proposal at 34920
Its decision not to limit the types of RE and demand-side EE measures and programs that can be included in a state plan, provided that supporting EM&V is rigorous, complete, and consistent with EPA's guidance.	Proposal at 34920
How to account for CO_2 emission reductions from demand-side EE measures in state plans, and how to avoid double counting emission reductions using the proposed approach of counting only the reductions in generation that occur in the state from in-state EE measures.	Proposal at 34922
Whether it should only count CO_2 reductions from in-state RE measures, rather than the proposed RE approach of allowing states to take into account all of the CO_2 reductions from RE measures implemented by the state—whether they occur in state or in other states. Also, how to avoid double-counting reductions using the proposed approach.	Proposal at 34922
The considerations for conducting EGU emission projections for state plans, and whether EPA should develop guidance that describes acceptable projection approaches, tools, and methods for use in an approvable plan, as well as providing technical resources for conducting projections.	Proposal at 34923

EPA is seeking comment on all aspects of its proposed state plan approach, but specifically asks for comment on:	Reference
Any additional emission reduction options that EPA has not used to set proposed targets, such as partial CCs, biomass, new NGCCs, etc.	Proposal at 34923
An alternative nuclear capacity baseline for compliance purposes, rather than using the proposal date as the baseline.	Proposal at 34923
The treatment of new NGCCs. Specifically, should the calculation consider only the emission reductions at affected EGUs, or should the calculation also consider the new emissions added by the new NGCC unit, which is not an affected unit under section 111(d)? Should the emissions from a new NGCC included as an enforceable measure in a mass-based state plan (e.g., in a plan using a Portfolio Approach) also be considered?	Proposal at 34924
Whether incremental emission reductions from new fossil fuel-fired boilers and IGCC units with CCS, based on exceeding the CAA section 111(b) performance standards for such units, should be allowed as a compliance option to help meet the emission performance level required under a CAA section 111(d) state plan.	Proposal at 34924
Whether industrial combined heat and power approaches warrant consideration as a potential way to avoid affected EGU emissions, and whether the answer depends on circumstances that depend on the type of CHP in question.	Proposal at 34924
Whether there are circumstances other than a major capital investment that could lead to a prospective state plan imposing unreasonable costs considering a facility's remaining useful life.	Proposal at 34926, fn. 305
EPA is proposing that the remaining useful life of affected EGUs, and the other facility-specific factors identified in the existing implementing regulations, should not be considered as a basis for adjusting a state emission performance goal or for relieving a state of its obligation to develop and submit an approvable plan that achieves that goal on time. EPA wants comment on this position.	Proposal at 34926
Whether a tribe wishing to develop and implement a CAA section 111(d) plan should have the option of including the EGUs located in its area of Indian Country in a multi-jurisdictional plan with one or more states (i.e., treating the tribal lands as an additional state). EPA is also seeking comment on whether it should develop federal plans for Indian Country areas with affected EGUs, and whether it should consider coordinating these plans with nearby states on a multi-jurisdictional basis.	Proposal at 34854

Other

EPA is also seeking comment on:	Reference
Reliability and resource adequacy concerns.	
Stakeholder proposals not included in the rule: ▪ Model Rule on Interstate Emissions Credit Trading and Price Ceiling ▪ Equivalency Tests (rate-based, mass-based, or market price-based test) ▪ Plant specific (inside the fenceline) approach	Proposal at 34847-8
Whether it should combine the two existing categories for affected EGUs (fossil-fuel-fired steam generating boilers and combustion turbines); and, specifically, whether	Proposal at 34892

combining the categories is, as a legal matter, a prerequisite for: (i) identifying, as a component of the BSER, re-dispatch between sources in the two categories (i.e., re-dispatch between steam EGUs and NGCC units), or (ii) facilitating averaging or trading systems that include sources in both categories, which states may wish to adopt.	
Its proposed approach to partially quantifying demand-side energy efficiency employment impacts, that is, the use of energy-sector model projections of the first-year costs required for states to attain the goal of demand-side efficiency improvements set by building block four, which it then multiplies by the jobs per additional dollar figure to get projected employment impacts for demand-side energy efficiency activities. EPA also wants comment on other data, identification of related studies and peer reviewed articles, and other methods related to quantifying demand-side EE employment impacts.	RIA at 6-28, and RIA at 6-30 & 31
How the rule will impact small entities, such as munis and rural electric cooperatives.	RIA at 7-5
The treatment of CT units, especially in light of more recent information on the integration of CTs and renewables, in the 111(b) modified/reconstructed source rule.	RIA at 9-7