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EPA Finalizes Historic Greenhouse Gas Emission Reduction Program

Existing and new power plants face increasing complexity as EPA's historic final rule regulating greenhouse gas emissions represents a major expansion of EPA's regulatory authority.

In a rare presidential announcement of new agency rules, President Obama released the final rules for the Clean Power Plan (Final CPP)[1] and the Carbon Pollution Standards (Final CPS) on August 3, 2015.[2] The Final CPP and the Final CPS are both Environmental Protection Agency (EPA) rules intended to reduce the carbon dioxide (CO_2) emissions from certain coal-fired and natural gas electric generating units (EGUs).

The Final CPP was promulgated pursuant to Section 111(d) of the Clean Air Act (CAA)[3] and applies to CO_2 emissions from existing EGUs. The Final CPP is expected to reduce national CO_2 emissions by approximately 32% below 2005 levels by 2030. The Final CPS rule was issued pursuant to Section 111(b) of the CAA and applies to the emissions of new, modified and reconstructed EGUs. The two rules are historic because they are the first rules ever adopted by the US federal government to comprehensively control and reduce CO_2 emissions from the power sector. In a simultaneous rulemaking announced the same day, EPA also issued a proposed Federal Implementation Plan (Proposed FIP) for the Final CPP.[4]

In this *White Paper*, we outline and analyze the Final CPP, the Proposed FIP and the Final CPS regulations. Additionally, our **August 7 Webcast discussing the Final CPP and Proposed FIP is available on demand here**. We have structured the *White Paper* in the following sections:

I. Summary of Significant Changes in the Final Rules

EPA's issuance of the Final CPP and Final CPS follows the Agency's June 2, 2014 issuance of the proposed Clean Power Plan (Proposed CPP) and proposed Carbon Pollution Standards (Proposed CPS).[5] The final rules include a number of important changes relative to the 2014 proposals. We summarize the significant changes below and discuss them in detail in the body of the *White Paper*.

Final CPP – Existing Source Rule (111(d))

- ***Coal and Gas Emission Standards***. The Final CPP established nationally uniform interim and final emission performance rate standards for two subcategories of affected EGUs (steam boilers and combustion turbines). The Final CPP set statewide emission reduction goals by applying the EGU emission performance rates to each state's mix of affected EGUs. The Proposed CPP set rate-based state-specific emission reduction targets that reflected the EPA's assessment of the potential for CO_2 reductions in each such state but did not set source-specific emission performance rates. *See Section II.*

- ***Changes in the Calculation of State Emission Reduction Goals***. There are three major differences in how EPA calculated state emission reduction goals in the Final CPP relative to the Proposed CPP. *See Section V*.

    - ***Removal of Building Block 4***. In the Proposed CPP, EPA included demand-side energy efficiency (EE) measures in its best system of emission reduction (BSER) "Building Block 4" as a factor to calculate state emission reduction goals. Under EPA's analysis, Building Block 4 EE measures contributed approximately 15% of the total CO_2 emission reduction goals. In the Final CPP, EPA dropped Building Block 4, meaning that EPA no longer takes into account potential EE reductions in setting the state targets. Even though EE is not included in the calculation of the goals, states (and sources, upon appropriate EE protocol development) can utilize EE as a voluntary compliance measure to meet their Final CPP.

    - ***Removal of In-Construction Nuclear from Building Block 3***. EPA also removed under-construction nuclear plants from consideration in the calculation of state goals under Building Block 3. EPA clarified that generation from any new or uprated nuclear plant can be relied on for compliance purposes.

    - ***Regional BSER Evaluation****.* EPA applied the three remaining BSER "Building Blocks" to all coal and natural gas power plants in three regions: the Western Interconnection, the Eastern Interconnection and the Electric Reliability Council of Texas interconnection (ERCOT). The Final CPP's BSER was calculated in steps for each of the Building Blocks for each region and EPA then chose the most easily achievable rate for each category among the regions to determine the uniform CO_2 emission performance rates for the country as a whole.

- ***Compliance Date and Interim Goals***. The Final CPP extends the initial compliance deadline from 2020 to 2022 and establishes a "glide-path" for state emission reductions. Interim goals are phased-in over three "steps" from 2022-2029. *See Section II.*

- ***Form of Emission Goal and Conversion of State Goals from Rate- to Mass-Based****.* The Proposed CPP included only rate-based emission reduction goals for states but allowed states to convert their goals into mass goals. Mass-based goals are necessary if a state wants to implement a cap-and-trade program to comply with the Final CPP. The Final CPP provides equivalent mass-based and rate-based goals for each state. *See Section VI.A.*

- ***State Implementation Option: Rate- or Mass-Based Approach****.* Although the form of the state goal — mass- or rate-based — is not intended to impact the stringency of a state program, there are a number of key differences in the implementation options available to states under each approach that will impact the compliance options available to EGUs. For example, whereas states implementing a mass-based program have the option to expand their cap-and-trade program to new units (*e.g.*, Northeast Regional Greenhouse Gas Initiative (RGGI) states) or to non-power sectors of the economy (*e.g.* California's cap-and-trade program), this option is not available to states relying on a rate-based approach. Other differences between the two approaches include leakage risk, market size, market liquidity and program complexity. To the extent that one approach is more efficient than another, the compliance costs will be different also for each approach. *See Section VI.B*.

- ***"Trading Ready" and "Ready-for-Interstate Trading" Programs***. The Final CPP gives states the option to develop "Intrastate Trading Ready" and "Ready-for-Interstate-Trading" plans that will allow EGUs to trade compliance instruments right immediately. Conditions include meeting certain requirements set forth in the Final CPP and, for interstate trading, using some common market architecture elements such as a registry. EGUs in states that do not implement a plan that is "ready" under the Final CPP may still be able to trade, but the trading components of the relevant state plan need to be approved first by EPA before trading can start. *See Section VII*.

- ***Federal Implementation Plan***. EPA issued a Proposed FIP and rate- and mass-based model state plans in conjunction with the Final CPP. EPA will implement the Proposed FIP if a state does not submit a state plan or otherwise implement the Final CPP in a timely manner. The Proposed FIP serves as a model state plan that could be adopted wholesale or in parts. The Proposed FIP describes in detail how the rate- and mass-based programs would work and clarifies EPA's language in the Final CPP. The Proposed FIP identifies several key areas open for public comment, including whether the model rule should use a rate-based or a mass-based approach. *See Section VIII*.

- ***Clean Energy Incentive Program (CEIP)***. The Final CPP includes an early action credit program not included in the Proposed CPP. The CEIP would apply to certain solar, wind and low-income community EE projects generating or saving megawatt-hours (MWh) in 2020 and/or 2021. EPA is seeking comment on the CEIP in the proposed Federal Implementation Plan rulemaking. *See Section II.E.*

- ***Reliability Safety Valve***. The Final CPP includes several features designed to ensure that the Final CPP does not interfere with the electric industry's ability to maintain the reliability of the nation's electricity supply, including a mechanism to allow states to seek revisions to their plans to address unforeseen reliability impacts and a safety mechanism to address emergency situations that threaten reliability. *See Section VII.D.*

Final CPS – New and Modified/Reconstructed Source Rule (111(b))

- ***Separation of Standards***. The proposed Section 111(b) Rule's emission standards differed depending on whether a modified source was covered by a Section 111(d) plan. The Final CPP, in contrast, allows for exclusion of all sources covered by Section 111(b) from Section 111(d) plans, and sets uniform emission standards regardless of Section 111(d) coverage. *See Section VIII.*

- ***Reduced Scope of Modified Source Rulemaking***. The proposed CPS covered all new, modified and reconstructed fossil-fuel EGUs. However, the final rule excludes from its scope (and technically withdraws that portion of the proposed rule related to) modified utility boilers and integrated gasification combine cycle (IGCC) units for which CO_2 emissions will increase by 10% or less after modification, and all modified combustion turbines. *See Section VIII.*

II. Clean Power Plan Overview

EPA adopted interim and final CO_2 emission performance rates for two subcategories of fossil fuel-fired EGUs: (1) fossil fuel-fired electric steam generating units (*e.g.* coal- or oil-fired power plants) and (2) (natural gas-fired) stationary combustion turbines.[6] The emission performance rates are nationally uniform for both EGU subcategories and were determined using BSER analysis, described in *Section V*.

Table 1. Emission Performance Rates (Adjusted Output-Weighted-Average lbs CO_2/MWh)[7]

Subcategory	Interim Rate	Final Rate
Fossil Fuel-Fired Electric Steam Generating Units	1,534	1,305
Stationary Combustion Turbines	832	771

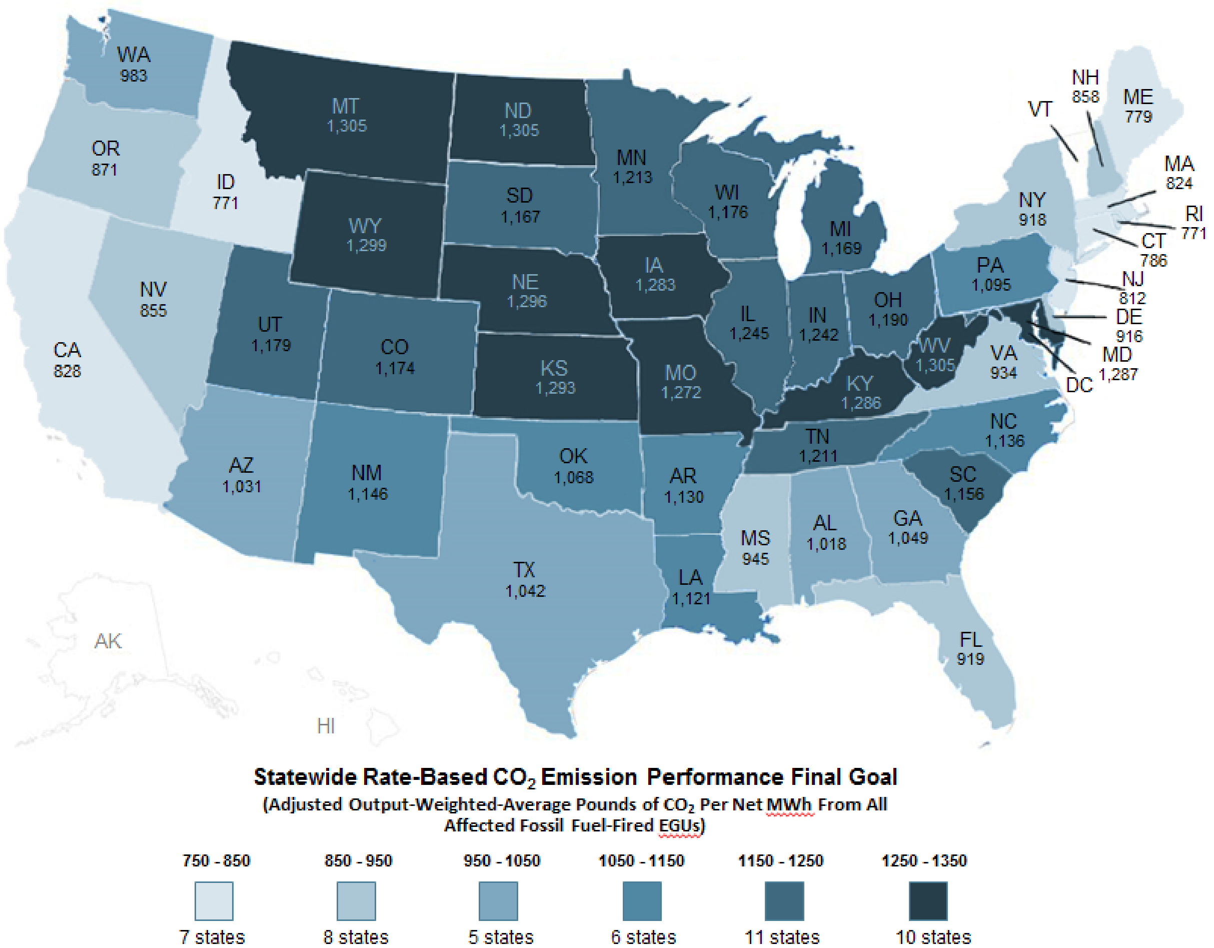
EPA established interim and final statewide CO_2 emission reduction goals by applying the final EGU emission performance rates to all affected sources in a given state. The statewide goals are expressed in state rate-based goals and state mass-based goals. Rate-based performance goal refers to an emission performance goal expressed as carbon intensity, namely pounds of CO_2 per net megawatt hour (lbs/net MWh). A mass-based performance goal is typically used in cap-and-trade programs and is expressed as a quantity of CO_2 emissions, typically in metric tons of CO_2 equivalent but in the CPP as short tons. The states, in turn, must implement the binding CO_2 emission performance rates through a state plan using either a rate or mass approach.

EPA established these standards pursuant to Section 111(d) of the CAA. Section 111(d) is a rarely used provision that directs EPA to establish procedures for states to establish plans for implementing and enforcing performance standards for existing sources of an air pollutant, once EPA has established a standard of performance for new sources of that pollutant, which EPA did concurrently with the Clean Power Standard rulemaking under 111(b).

Table 2. Projected National CO_2 Emission Reductions (Relative to 2005)[8]

	CO_2 Emissions (million short tons)	CO_2 Emissions: Change from 2005 (million short tons)			CO_2 Emissions Reductions: Percent Change from 2005		
[redacted]							
Base Case	2683	-528	-518	-456	-20%	-19%	-17%
Rate-based	-	-598	-750	-871	-22%	-28%	-32%
Mass-based	-	-610	-782	-869	-23%	-29%	-32%

Annex A – Final State Rate-Based CO_2 Emission Performance Goals.[9]



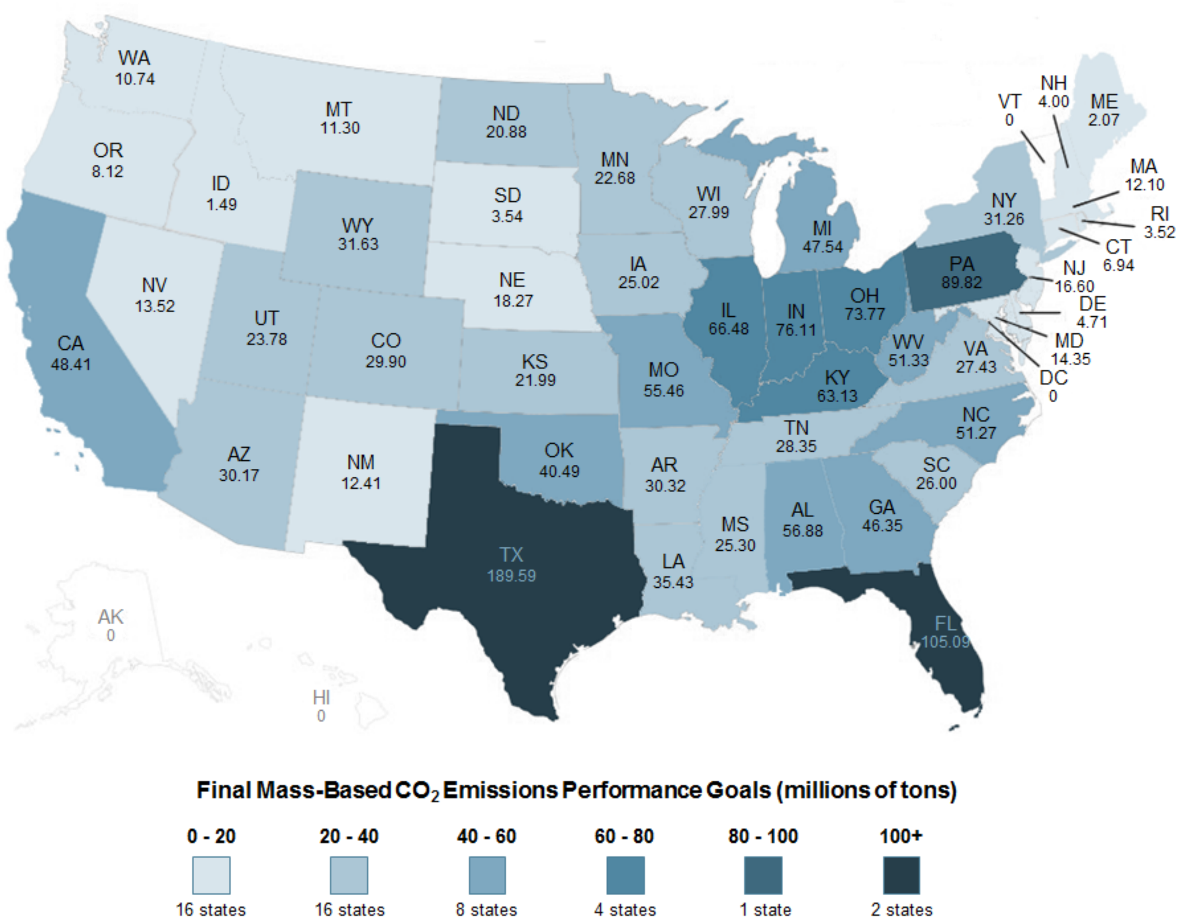
A. Rate-Based and Mass-Based Compliance Models

The Final CPP gives states the option of complying with either the rate-based or mass-based statewide CO_2 emission goals. Each state must determine whether to apply its emission reduction requirements to affected EGUs, or to meet the equivalent statewide rate-based goal or mass-based goal provided in the Final CPP. After choosing the rate- or mass-based compliance option, states must then choose between two types of state plans: "emission standards" plans or "state measures" plans. The type of plan affects the scope of the programs that the state will implement.

- An *emission standards plan* would include federally enforceable, EGU-specific requirements that mandate affected EGUs within the state to meet their emission performance requirements.
- A *state measures plan* would include a portfolio of emission reduction measures, including such potentially non-federally enforceable measures as renewable energy standards and energy efficiency programs, in addition to the federally enforceable EGU-specific standards. This type of plan would require a federally enforceable "backstop" to ensure the state meets its emission reduction requirements.[10]

Both emission standards and state measures plans can be implemented by a single state, or through multi-state agreements.

Annex B – Final State Mass-Based CO_2 Emission Performance Goals.[11]



B. Timing of the Reductions

The Final CPP assigns each state two different goals — interim goals and final goals. The interim goals are phased-in between 2022 and 2030 in three "steps." While EPA accomplishes the phase-in of the interim goal by way of annual emission performance rates, states and EGUs may meet their respective emission reduction obligations "on average" over that period following whatever emission reduction trajectory they determine to pursue over that period.[12] Thus, the period associated with each step is the equivalent of a "compliance period" as this term is used typically in cap-and-trade programs.

Table 3. Interim and Final Goal Deadlines[13]

Interim Goals			Final Goals
"Step 1"	**"Step 2"**	**"Step 3"**	2030
2022-2024	2025-2027	2028-2029	

C. Affected Sources

An affected EGU is "any fossil fuel-fired electric utility steam generating unit (*i.e.*, utility boiler or integrated gasification combined cycle (IGCC) unit) or stationary combustion turbine that was in operation or had commenced construction as of January 7, 2014"[14] and meets the additional criteria. Those criteria include:

- Serves a generator capable of selling greater than 25 MW to a utility power distribution system
- Has a base load rating greater than 260 GJ/h heat input of fossil fuel

D. Costs and Benefits

EPA estimates that the net benefits of the CPP will be between US$34 to US$54 billion in 2030.[15] The benefits include both climate benefits and public health co-benefits, although the monetized benefits are heavily skewed toward co-benefits. EPA also estimated compliance costs for rate-based and mass-based approaches:

- <u>Rate-Based</u>: US$2.5 billion in 2020, US$1.0 billion in 2025 and US$8.4 billion in 2030
- <u>Mass-Based</u>: US$1.4 billion in 2020, US$3.0 billion in 2025 and US$5.1 billion in 2030[16]

E. Clean Energy Incentive Program

The Final CPP contains a proposed program called the Clean Energy Incentive Program (CEIP) designed to incentivize investment in certain types of renewable energy and energy efficiency projects. The program is optional for states and eligible projects are limited to projects that generate carbon-free energy or reduce low-income community end-use energy demand during the years 2020 and 2021. The CEIP would make additional allowances or emission reduction credits (ERCs) available to participating states to allocate to eligible projects. EPA is accepting comment on several aspects of the CEIP in the Proposed FIP rulemaking, including whether to establish an allowance reserve for the CEIP credits. For additional discussion of the CEIP in the Propose FIP rulemaking, *see Section VIII.*

Eligible CEIP projects must meet all of the following eligibility criteria:

- Located in or benefit a state that has submitted a final plan that includes a CEIP
- Implemented following the submission of a final state plan to EPA
- <u>CEIP Renewable Energy projects</u> must generate metered MWh from any type of wind or solar resource
- <u>CEIP Energy Efficiency projects</u> must result in "quantified and verified electricity savings" through (1) demand-side energy efficiency that is (2) implemented in low-income communities
- Generate or save MWh in 2020 and/or 2021

For states with CEIP programs, EPA will provide the following incentives:

- Matching allowances or ERCs up to an amount equal to 300 million short tons of CO_2 emissions
- 1 credit for 1 MWh of generation from eligible wind or solar projects
- 2 credits for 1 MWh of avoided generation for eligible demand-side energy efficiency projects

III. Carbon Pollution Standards Overview

In a separate but related rulemaking, EPA finalized CO_2 new source performance standards (NSPS) for new, modified and reconstructed fossil fuel-fired EGUs under CAA section 111(b).[17] These EGUs fall into the same two categories of sources regulated by the Final CPP: steam generating units (also known as "utility boilers and IGCC units"), which primarily burn coal, and stationary combustion turbines, which primarily burn natural gas. The finalized rule differs in significant respects from the proposed rule, especially for modified and reconstructed sources.

A. Covered Sources

A modified source is an existing source that undergoes a physical or operational change that increases the amount of an air pollutant emitted by the source, or which results in the emission of an air pollutant not previously emitted. For utility boilers and IGCC units, only modified sources which will increase their hourly CO_2 emissions by more than 10% will be covered under the Section 111(b) rule; for now, EPA has excluded small modifications from coverage and has withdrawn the small modification part of the rulemaking since EPA had insufficient information to complete it.[18] Similarly, modified combustion turbines are excluded from the rule altogether, and EPA has withdrawn that part of the rulemaking because of insufficient information as well.[19]

A reconstructed source is an existing source that replaces components at a capital cost exceeding 50% of the fixed capital costs of an entirely new facility, and for which compliance with NSPS is technologically and economically feasible. All reconstructed fossil-fuel fired EGUs are covered by the rule.

B. Integration with the Section 111(d) Rule

The proposed rule was closely integrated with the Section 111(d) rule, since the proposed rule imposed different standards depending on whether the EGU was covered under a Section 111(d) plan. The final rule, in contrast, is almost completely disconnected from the Section 111(d) rule. In fact, EPA in its final rulemaking explicitly provides for the exclusion of units subject to the Section 111(b) rule from Section 111(d) plans.[20] Therefore, if a source which is covered by a Section 111(d) plan is modified or reconstructed, it drops out of Section 111(d) coverage and needs to meet only the Section 111(b) requirements, unless the state specifically requires otherwise (for instance, as discussed below in *Section VI.C*, when the state elects to cover new sources to prevent leakage under a mass-based state plan). EPA adopted a state plan modification provision that allows states to make adjustments to their state plans when covering new sources.[21]

C. Standards

For those sources covered by Section 111(b), EPA provides a technological BSER and a corresponding numeric emission limit that sources must meet. For modified and reconstructed utility boilers and IGCC units, as in the proposed rule, standards differ depending on the heat input rating of the source. For reconstructed combustion turbines, standards differ depending on the fuel mix and electric sales, a change from the proposed rule. EPA provided the following overview of the rule’s requirements, which we present in slightly adapted form in Table 4.

Table 4. Section 111(b) BSER and Final Standards of Performance[22]

Affected EGUs	BSER	Final Standard
Newly Constructed Fossil Fuel-Fired Steam Generating Units (utility boilers and IGCC units)	Efficient new supercritical pulverized coal (SCPC) utility boiler implementing partial (20%) carbon capture and storage (CCS)	1,400 lb CO_2/MWh-gross
Modified Fossil Fuel-Fired Steam Generating Units, ***only if*** as a result of the modification CO_2 hourly emissions increase more than 10%	Most efficient generation at the affected EGU achievable through a combination of best operating practices and equipment upgrades	The unit must meet a limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of modification), ***to be no more stringent than****:* (1) For large capacity units with heat input > 2,000 MMBtu/h: 1,800 lb CO_2/MWh-g ***or*** (2) For small capacity units with heat input $\leq$ 2,000 MMBtu/h: 2,000 lb CO_2/MWh-g
Reconstructed Fossil Fuel-Fired Steam Generating Units	Most efficient generating technology at the affected source (supercritical steam conditions for the larger units; and subcritical conditions for the smaller)	(1) For large capacity units with heat input > 2,000 MMBtu/h: 1,800 lb CO_2/MWh-g ***or*** (2) For small capacity units with heat input $\leq$ 2,000 MMBtu/h: 2,000 lb CO_2/MWh-g
Newly Constructed and Reconstructed Fossil-Fired Stationary Combustion Turbines[23]	Efficient NGCC technology for base load natural gas-fired units and clean fuels for non-base load and multi-fuel-fired units	(1) For base load natural gas-fired units: 1,000 lb CO_2/MWh-g or 1,030 lb CO_2/MWh-net (2) For non-base load natural gas-fired units: 120 lb CO_2/MMBtu (3) For multi-fuel-fired units: 120 to 160 lbs CO_2/MMBtu (calculated at the end of the month based on the amount of co-fired natural gas)

D. Adjustment to the CCS-Based Standard

While carbon capture and storage (CCS) remains BSER for new sources, EPA adjusted the standard based on comments regarding its cost. The final rule requires a lower level of partial CCS (20%), and imposes a correspondingly higher emissions limit.[24] EPA eliminated CCS as BSER for reconstructed steam generating units, stating that site-specific constraints for existing EGUs on a nationwide basis made this and other proposed technologies inappropriate as BSER.[25] EPA also eliminated CCS as BSER for natural gas-fired combustion turbines, citing insufficient information to determine whether CCS was technically feasible for such units.[26]

E. PSD Exemption

EPA did not provide for any PSD exemptions. Rather, EPA finalized its proposed provisions that clarify that the threshold requirements from the Tailoring Rule continue to apply to New Source Review (NSR) for sources now covered under Section 111(b). Under the Tailoring Rule, which was struck down in part by the Supreme Court in *Utility Air Reg. Group. v. EPA*,[27] only modified or reconstructed sources that would otherwise trigger PSD because of increases in other pollutants (so-called "anyway sources") and which emit at least 75,000 tpy/CO_2e trigger PSD. This means that regular BACT rules apply, which will be determined case-by-case, with the new Section 111(b) rule setting the BACT floor. EPA intends for this regime to be an interim approach while it revises the PSD rules.[28]

IV. State Obligations and Compliance Under the Final CPP

The CPP requires each state to submit an emission reduction plan to EPA for approval. Each plan must include a timeline with steps the state will take between its plan submittal and 2022, in order to ensure that the plan is effective as of 2022.[29]The plan must also include "a process for reporting on (1) implementation; (2) progress toward achieving CO_2 emission reductions; and (3) implementation of corrective actions, in the event that the state fails to meet its required emission levels."[30]

A. State Plan Components

All state plan submittals must also include all of the following:

- Description of the plan, including approach and geographic scope
- Applicability of the state plans to affected EGUs
- Demonstration that the plan submittal is projected to achieve the state's CO_2 emission performance rates or state CO_2 goal
- Monitoring, reporting and recordkeeping requirements for affected EGUs
- State recordkeeping and reporting requirements
- Public participation and certification of hearing on the state plan
- Supporting documentation demonstrating:
  - That the state considered electric system reliability
  - How the state is engaging stakeholders, including workers, low-income communities, communities of color, and indigenous populations impacted by the state plan[31]

The CPP contains additional requirements for state plans depending on whether they use an emission standard or a state measures approach.[32]

B. Submission Deadlines and Timing

State plan submittals are due on September 6, 2016,[33] and EPA will approve or disapprove a state plan within 12 months of submittal.[34] States may request a two-year extension of the plan submission deadline until September 6, 2018. Any extension must be requested in an initial submittal filed by September 6, 2016 that:

- Identifies a final plan approach or approaches that are under consideration
- Provides an explanation for why the state needs additional time to complete a final plan
- Includes a demonstration of how the state has been engaging with the public and will engage with community stakeholders during the additional time for development of a final plan[35]

If the initial submittal contains these elements and EPA does not notify the state that the initial submittal does not contain those elements, then the extension request is deemed granted after 90 days.[36] States whose extension requests are granted must submit a 2017 update by September 6, 2017.[37] States that miss the deadline to submit final state plans or initial submittals may be subject to a federal plan, and must meet the federal plan's first interim goal in 2022.[38]

C. Enforceability Backstop

EPA interprets Section 111(d) to require state plans to include federally enforceable emission standards to ensure the emission goals are achieved. For "emission standard" state plans, the rate- or mass-based emission standards are federally enforceable against the affected EGUs.[39] These federally enforceable standards are sufficient to ensure that the state meets its CO_2 reduction obligation and no additional backstop is required. For "state measure" plans, the plan must include a "mandatory contingent backstop of federally enforceable emission standards for affected EGUs." [40] This federally enforceable "backstop" would apply if the state measures failed to fully meet the state's CO_2 reductions. The state plan must include regulations fully specifying the "backstop" emission standard requirements for affected EGUs.

V. Basis For State Goals – BSER Analysis

EPA's BSER analysis provides the basis for the EGU emission performance rates and, ultimately, the state rate- and mass-based emission goals. In short, the BSER analysis examines the types of strategies, technologies and measures already being used to reduce air pollutant emission from EGUs. Using the BSER analysis, EPA determines the "standard of performance" for emissions of the targeted air pollutant, in this case CO_2. Based on that determination, EPA then establishes emission guidelines that set the minimum emission limitation standard that a state must impose on the affected sources through its state plan or that the state must achieve on a statewide basis by other means.

A. BSER Determination and Purpose of the Building Blocks

To determine the EGU-specific emission performance standards, EPA applied the three BSER Building Blocks to all coal and natural gas power plants in three regions: the Western Interconnection, the Eastern Interconnection, and ERCOT. The BSER was calculated in steps for each of the Building Blocks and EPA then chose the most easily achievable rate for each category to determine the uniform CO_2 emission performance rate for the country as a whole. The state goals were then determined by applying the CO_2 emission performance rates to all affected sources in a given state to determine the statewide rate-based and mass-based goals.

The Final CPP does not require that states use all of the building blocks or to apply any one of the building blocks to the same extent that EPA determines is achievable at reasonable cost. Instead, each state has the flexibility to select the measure or combination of measures it prefers in order to achieve its

CO_2 emission reduction goal. Thus, a state could choose to achieve more reductions from one building block and less from another, or it could choose to include measures that were not part of EPA's BSER determination, as long as the state achieves the CO_2 reductions at affected EGUs necessary to meet the goal EPA has defined as representing the BSER.

		Best System of Emission Reduction	Cost Per Ton
BSER Building Blocks			
1	Reducing the carbon intensity at individual affected EGUs through heat rate improvements	Improvement in average heat rate of coal-fired steam EGUs of: • 4.3% in the Eastern Interconnection • 2.1% in the Western Interconnection • 2.3% in the ERCOT	US$100 or less per kW or US$23/ton[41]
2	Reducing emissions from the most carbon-intensive EGUs by substituting generation from less carbon-intensive affected EGUs	Replacing coal and oil/gas fired steam generation by increasing generation from existing NGCC capacity (including NGCC units under construction) to a 75% utilization rate	US$24/ton[42]
3	Reducing emissions from affected EGUs in the amount that results from substituting generation from expanded low- or zero-carbon generation	Increasing capacity of onshore wind, utility-scale solar PV, concentrating solar power, geothermal and hydropower over time	US$37/ton[43]

B. Building Block 1 – Efficiency Improvements at Affected Coal-Fired Steam EGUs

In the final rule, EPA based the BSER for fossil-fuel fired EGUs on three building blocks. Building Block 1 includes "inside the fence" measures such as operational improvements (best practices) and equipment upgrades that sources can implement or undertake to reduce their CO_2 emission rates. In the proposed rule, EPA determined that Building Block 1 measures could achieve, on average, a 6% heat rate improvement for coal-fired EGUs in the US based on a 4% heat rate improvement from implementation of best practices and a 2% heat rate improvement from equipment upgrades. In the final rule, EPA reduced the 6% heat rate improvement to three regionalized figures of 4.3% for the Eastern Interconnection, 2.1% for the Western Interconnection, and 2.3% for ERCOT.[44] Unlike in the Proposed CPP, EPA did not specify in the Final CPP what proportion of the potential heat rate improvement would be from best practices as opposed to from equipment upgrades.[45] EPA also will not require any affected coal-fired EGU to improve its heat rate by any specified amount. Instead, consistent with how EPA ordinarily approaches standards of performance, EPA used the potential for heat rate improvement to determine a CO_2 emission performance rate.[46]

EPA estimated that heat rate reductions can generally be achieved at a cost of US$100 or less per kilowatt-hour (kW), or approximately US$23 per ton of CO_2 reduction.[47] EPA based its cost estimates largely on anticipated fuel savings, given that heat rate improvements are intended to increase efficiency and thereby reduce the amount of fuel consumed by EGUs.[48] While the implementation of Building Blocks 2 and 3 could reduce the fuel savings associated with heat rate improvements at coal-fired EGUs, EPA concluded that a significant fraction of the investment required to capture the technical potential for CO_2 emission reductions from heat rate improvements will be offset by fuel savings.[49]

C. Building Block 2 – Generation Substitution

Building Block 2 of the BSER continues to rely on reducing the carbon intensity of electricity generation by gradually substituting generation from fossil-fuelled steam units such as coal-fired EGUs for increased generation from existing NGCC units that are relatively less carbon-intensive.[50] Specifically, Building Block 2 now includes a glide path starting in 2022 that gradually increases the annual utilization rate of the existing fleet of NGCC to 75% of net summer capacity.[51] Under Building Block 2, the target level of 75% of net summer capacity would be reached in the Eastern Interconnection in 2024 and in both the Western Interconnection and ERCOT in 2027.[52] This increased utilization would result in the total electric generation from NGCC units increasing from 966 TWh in 2012 to 1,498 TWh as early as 2027 (an approximately 55% increase).[53]

Refinements to the Proposed CPP

While the general principle of increasing generation from lower emitting natural-gas fired EGUs to replace generation from more carbon-intensive fossil-fuel fired steam generation is consistent with the Proposed CPP, the Final CPP refines Building Block 2 (1) by phasing in the increased utilization rate of NGCC units and (2) by using those units' net summer capacity rather than nameplate capacity to set targets.[54] The Proposed CPP called for an increase in the utilization rate of NGCC units to 70% of nameplate capacity by 2020.[55] In the Final CPP, EPA responded to concerns regarding the timing of increasing the utilization of these units by adopting a phase-in schedule that begins in 2022.[56] The phase-in schedule is based on two parameters:

- A 22% increase in generation output from NGCC units compared to 2012 levels in each of the three Interconnections by 2022
- A 5% increase in generation output from NGCC units in each subsequent year until the target level is reached in each Interconnection[57]

The first parameter is based on the single largest annual increase in natural gas-fired generation output since 1990, which occurred between 2011 and 2012, while the second parameter is based on the average annual growth in natural gas-fired generation output between 1990 and 2012.[58] Assuming an annual 5% increase in generation output starting in 2022, NGCC units in the Eastern Interconnection region would reach the target utilization rate of 75% of net summer capacity in 2024, while units in the Western Interconnection and ERCOT regions would reach the target utilization rate in 2027.[59]

In addition to adopting the phased-in increase in utilization rates for NGCC units, EPA also refined Building Block 2 by using net summer capacity rather than nameplate capacity in calculating the potential utilization level of existing NGCC units.[60] This refinement is based on comments that net summer capacity better reflects actual generation output available from NGCC units to serve load.[61] EPA explains that the annual utilization rate of 75% of net summer capacity is similar to the 70% utilization rate of nameplate capacity included in the Proposed CPP.[62]

In support of the ultimate 75% utilization rate adopted as part of Building Block 2, EPA states that roughly 15% of existing NGCC units operated at 75% or more of net summer capacity on an annual basis in 2012 and about 30% of NGCC units operated at that level or higher during the entire summer of 2012.[63] EPA also states that the average annual availability of NGCC units in the US generally exceeds 85% and can exceed 90% for some groups.[64] According to our calculations based on data provided by EPA, 2012 utilization rates of NGCC units in each of the three Interconnections ranged between approximately 50% and 56% of net summer capacity.[65]

EPA also responds to concerns as to whether there is sufficient natural gas infrastructure to support the increased utilization rate for NGCC units by explaining that the existing natural gas pipeline system already supports a national average NGCC utilization rate of 60% or higher during peak hours and has supported an average monthly utilization rate as high as 65%.[66] Additionally, EPA refers to natural gas pipeline industry projections that an increase of up to 30% in total delivery capacity would be possible.[67] EPA concludes that the combined flexibility provided under the emission guidelines and the extended timeline to address any existing natural gas pipeline infrastructure limitations should result in a natural gas pipeline system capable of reliably delivering sufficient natural gas supplies to support Build Block 2.[68]

Implementation

While EPA asserts that any EGU can take steps to shift generation from fossil-fuelled steam units to NGCC units,[69] EPA also explains in the Final CPP that state environmental policies can be used to substitute increased generation from NGCC units in either of two ways:

- Operational restrictions such as permit limits on the number of hours that an EGU can operate in order to limit emissions
- Changes in relative costs of generation related to pollution reduction measures[70]

At a very general level, these two methods are not inconsistent with the process system operators typically use to dispatch EGUs known as Security Constrained Economic Dispatch where EGUs are subject to economic dispatch (based on their bids or estimated short-run marginal costs) while recognizing any operational limits of generation and transmission facilities.[71] Under this economic dispatch framework, EGUs are operated to produce energy at the lowest cost to reliably serve customers.

With respect to explicit costs associated with GHG emission allowances, certain Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) (*i.e.*, those covering California and the Northeast's RGGI states) already have EGUs directly incorporate such costs into their bids in accordance with market rules in tariffs that have been approved by Federal Energy Regulatory Commission (FERC). That is, CO_2 emission costs are directly monetized under their economic dispatch frameworks. At the same time, RTOs and ISOs also generally take into account various operational limitations on certain EGUs, such as environmental restrictions on operating hours, that are not and cannot be directly monetized under their economic dispatch frameworks. RTOs and ISOs vary in how they currently take into account these operational limitations, although commonly the RTO verifies the binding nature of the operational limitation before specific provisions — in terms of either scheduling, and in some cases opportunity cost-based compensation for the resource — become applicable.

As discussed above, the Final CPP lays out a number of paths and proposes various model rules to facilitate the creation and trading of ERCs that would in turn facilitate the monetization of CO_2 emission costs under an economic dispatch framework. However, as also discussed above, while the Final CPP appears to provide for various regulatory incentives to push and pull states into adopting single-state, multi-state or regional monetization schemes for CO_2 emission costs, the Final CPP neither mandates nor otherwise ensures that such monetization schemes will result under state-based goal or emission performance rate approaches.

D. Building Block 3 – Expansion of Renewable Generation

Building Block 3 supports the reduction of CO_2 by replacing generation from affected EGUs with expanded amounts of zero-emitting renewable energy generating capacity.[72]

Expanding Renewable Energy Generation

The Final Rule describes the historical growth of renewable energy generation, particularly in the last decade, and anticipated future expansion. Renewable energy continues to grow rapidly, with wind generation tripling and solar generation growing twentyfold just since 2009,[73] and the global market is projected to grow to US$460 billion per year by 2030.[74]

EPA relies on Building Block 3 to establish BSER because "[i]ntroducing more zero-emitting renewable energy generation over the long term will significantly reduce CO_2 emissions, as production of renewable energy predominantly replaces fossil fuel-fired generation and thereby avoids the emissions from that replaced generation."[75] For support, EPA points to numerous studies and policy developments, including California's adoption of a 33% by 2020 Renewables Portfolio Standard (which EPA notes will likely soon increase to 50%) as a key goal to cutting GHG emissions.[76] EPA also touted the ancillary benefits of increasing the use of renewable energy, including consuming less water than fossil-fuel generation and reducing other air pollutants (*e.g.*, fine particulates, ground-level ozone).[77]

Renewable technologies applied to Building Block 3 include onshore wind, utility-scale solar PV, concentrating solar power, geothermal and hydropower.[78] Each of these technologies is a utility-scale, zero-emitting resource. EPA chose not to include distributed technologies as part of the BSER due to "unique data and technical challenges" that complicate identifying a technically feasible and cost-effective level of generation.[79] However, EPA clarifies that distributed renewable energy technologies that meet eligibility criteria may be used for compliance.[80]

Though the proposed rule allocated renewable energy goals for each state, the Final Rule quantifies Building Block 3 generation levels for each of the three BSER regions — the Eastern Interconnection, Western Interconnection and ERCOT.[81] EPA made this change due to the interstate nature of renewable energy and the power system.[82] EPA states that a regional approach takes into account opportunities to develop regional renewable resources and thus better aligns Building Block 3 generation levels with the Final Rule's approach to allowing the use of qualifying out-of-state renewable generation compliance.[83]

EPA notes that it updated the cost and performance estimates of renewable generation due to the decline in cost and increase in performance that have been demonstrated by current projects, particularly wind and solar.[84] As a result EPA believes continually assessing the development of renewable energy cost and performance trends has become increasingly necessary for any long-term outlook for the utility power sector.[85]

EPA calculated annual renewable energy generation levels from 2022 through 2030 under Building Block 3 for each Interconnection region based on a variety of factors, as summarized in Table 5.[86] EPA set these levels based on incremental renewable energy increases that are reasonable, rather than the maximum amounts that could be achieved.[87] EPA notes that much higher levels of renewable generation would be supported by historical trends and external analysis.[88] However, EPA believes that by identifying reasonable rather than maximum achievable amounts, assurance that the identified amounts are achievable by the source category will increase and provide greater flexibility to individual affected EGUs to choose among alternative measures for achieving compliance with the standards of performance established for them in their states' compliance plans.[89]

Table 5. Building Block 3 Generation Levels (MWh) By Interconnection Region[90]

Year	Eastern Interconnection	Western Interconnection	ERCOT
2022	166,253,134	56,663,541	18,963,672
2023	181,542,775	60,956,363	28,177,431
2024	218,243,050	75,244,721	39,382,162
2025	254,943,325	89,533,078	50,586,893
2026	291,643,600	103,821,436	61,791,623
2027	328,343,875	118,109,793	72,996,354
2028	365,044,150	132,398,151	84,201,085
2029	401,744,425	146,686,508	95,405,816
2030	438,444,700	160,974,866	106,610,547

No Longer Relying on New and Preserved Nuclear Capacity for Building Block 3

In the proposed rule, EPA relied on emission reductions achievable from the five nuclear units currently under construction as credited towards the state goals under Building Block 3. In the Final Rule, EPA has removed new and preserved nuclear generation from the calculations under Building Block 3. Under-construction or new nuclear generation is excluded as "likely of higher cost and therefore less appropriate for inclusion in the BSER." Preserved nuclear generation is excluded because EPA determined the preservation of existing nuclear generation is best evaluated under the baseline emissions assumptions because existing nuclear generation is already reducing the fleet's CO_2 profile.

VI. State Implementation Issues and Impacts on EGU Compliance

This section examines a number of implementation options available to states when implementing the Final CPP. These options will significantly impact the compliance options available to specific EGUs in each state (*e.g.*, intra- and interstate trading). Specifically, ***Subsection A*** examines the Final CPP's rate-based and mass-based reduction goals, ***Subsection B*** examines rate-based trading approach, ***Subsection C*** examines mass-based trading approach, ***Subsection D*** analyzes the role of energy efficiency in meeting state emission reduction goals, and finally ***Subsection E*** looks at the implications of the Final CPP for existing CO_2 trading programs.

A. Rate-Based and Mass-Based Emission Reduction Goals

The Proposed CPP allowed states to translate their rate-based emissions goals into mass-based emissions goals, in part to accommodate states that have already implemented cap-and-trade programs, which are mass-based. In November 2014, EPA released a technical support document illustrating calculations of mass-based goals using two approaches; one including only existing fossil-fuel fired sources, and the other accounting for both existing and new sources.[91] In the final rule, the EPA provided a table of mass-based goals that it has concluded are the equivalent of the rate-based emissions goals and an associated table showing the mass-based targets for existing or under-construction EGUs, as well as "complementary" emissions budgets for new, modified and reconstructed EGUs.[92] We have listed the state mass-based goals in *Annex B* and illustrated them on the map on pg. 6. If a state decides to expand a mass-based program to new, modified and reconstructed EGUs, the Final CPP provides also a "CO_2 emission complement" that reflects the emissions of the new, modified or reconstructed EGUs.[93] We have listed these additional emissions in *Annex C* to this *White Paper*.

To support its conversion calculations, EPA has issued a new Technical Document to replace the Technical Document issued in connection with the Proposed CPP. We are still reviewing these documents, as are a number of consulting firms. Importantly, the conversion of the goal from rate to mass (and hence the choice of the approach) is not intended to impact the stringency of a particular state program because EPA, in its conversion calculations, has taken into account load growth factors. Going forward, states (and sources) may well want EPA to be prepared to revisit its assumptions and to update its calculations of a state's growth complement based on actual or better-understood market conditions.

Pros and Cons of Rate-Based and Mass-Based Approaches

Assuming, for the purpose of this *White Paper*, that the rate- and mass-based approaches have equal stringency (but subject to further analysis), states and EGUs will wish to understand the pros and cons of each approach. Although this *White Paper* is not intended to provide a comprehensive analysis of this issue, the following factors likely will be relevant considerations:

- ***Program Scope***. As discussed below, the scope of mass-based programs can be expanded to cover new, modified and reconstructed EGUs subject to the Final CPS, but the scope of rate-based programs cannot.
- ***Leakage***. Also as discussed below, mass-based programs limited to affected EGUs (*i.e.*, without an expanded program scope) are subject to a greater emissions leakage risk that would need to be mitigated through specific allowance allocation procedures.
- ***Complexity***. A review of the Proposed FIP and model state rules indicates that rate-based programs raise implementation and operating complexities. In short, ERCs in a rate-based program must be issued through a mechanism similar to an offset mechanism in a cap-and-trade program.
- ***State Revenues***. Whether states will be able to raise revenues in a rate-based program remains unclear. Also, the model mass-based program uses a free allowance allocation approach. States will need to consider the advantages and disadvantages of other allocation approaches (*i.e.* auctions), which may provide revenue-raising opportunities, but potentially increase program cost to the extent states invest the revenue less efficiently than would the private allowance markets.
- ***Market Size, Liquidity and Private Capital***. Experience with rate-based programs (*e.g.*, the Low Carbon Fuel Standard in California) shows that rate-based markets are smaller, with less liquidity, price discovery and trading activity than equivalent mass-based programs. These less-optimal conditions may, in turn, result in less market participation by market makers and result in lower private capital investment in desired emission reduction opportunities. It will be interesting to see whether anticipated economic modelling will shed further light on the trade-offs among program designs.
- ***Government Interventions in Markets and Associated Distortions***. There is a growing view, especially in the Western United States, that selecting specific rate targets for each emission source potentially distorts the otherwise efficient market allocation of resources toward the lowest-cost abatement opportunities (*see, e.g.*, recent Nicholas Institute modelling of the proposed CPP that shows how different sources will respond to each approach).[94] Mass-based programs can suffer the same design flaw depending on their allowance allocation methodology, but according to the prevailing view this flaw is at least not inherent to a mass-based program.
- ***Implementation Trends***. EPA has now clarified that states using different approaches may not trade with each other (except in one instance involving renewable energy and discussed below).

B. Rate-Based Approach

Program Scope

A key difference between mass-based and rate-based programs is that states implementing a rate-based approach may not expand the program to new, modified or reconstructed EGUs, or to non-power sectors of the economy.[95] The rationale EPA provided in the Final CPP is that such expansion would result in leakage that may not be mitigated.

Three Types of Rate-Based Goals

In their implementation plans, states may choose among three types of rate-based goals. *First*, states may adopt the subcategory-specific rate-based goals for EGUs included in Table 1 above (one rate for coal, one rate for gas). *Second*, states may use a single rate-based goal that would apply equally to all EGUs in the state, irrespective of their fuel.[96] Such goals are provided in Table 12 of the Final CPP, and are reproduced in the map on page 5 and in *Annex A* of this *White Paper*. *Finally*, states may develop their own customized approach rather than one of these two out-of-the-box, streamlined approaches. The overall adjusted rate still needs to comply with the Final CPP, so this third option simply allows states to change the allocation of the burden among its EGUs.

Meeting Rate-Based Goals – What Counts and How Does it Count?

Affected EGUs can meet an applicable rate-based standard by achieving an emissions rate that is less than or equal to the applicable standard.[97] The EGU's emissions rate is determined by dividing the number of pounds of CO_2 emitted by the number of megawatt-hours produced. As discussed further below, the EGU's total megawatt-hours can be modified by purchasing and retiring ERCs, which are tradable credits representing a zero-emission megawatt-hours. The megawatt-hours represented by any ERCs that an affected EGU has retired would be added to the denominator of the EGU's lb CO_2/MWh calculation. For example, an EGU that released 10,000 pounds of CO_2 and generated 10 MWh would have a rate of 1,000 lb CO_2/MWh, but that same EGU could reduce its rate to 500 lb CO_2/MWh by purchasing and retiring ERCs representing an additional 10 MWh of zero-emission generation.[98]

Trading in Rate-Based Programs

States may implement the Final CPP without any intrastate or interstate trading component. If a state implements a rate-based program without a trading component, the state will have to rely, presumably, on command-and-control measures mandating reductions of emissions in the sectors that count toward meeting state compliance assessment (*e.g.,* EE and RE, discussed above). This approach, however, will place the onus on the state to ensure that the sum of all control measures included in a plan will achieve the rate goals mandated in the CPP, a process fraught with uncertainty and predictability challenges.

In reality, it is difficult to see how the states will not apply some emission rate requirements directly on the EGUs and allow such EGUs to meet the requirements through the purchase of ERCs from entities in the program. Indeed, it will be virtually impossible for the EGUs, with technologies commercially available today, to meet the rates mandated in the Final CPP (*i.e.*, in a subcategorized rate-based state, EGUs are all structural ERC buyers). Accordingly, trading ERCs seems to be the most efficient (and likely) implementation tool available to states in a rate-based program.

States implementing rate-based program may allow their EGUs to trade ERCs with EGUs located in other states also implementing rate-based programs (but not mass-based programs, with certain limited exceptions). We discuss this in *Section VII* below.

Generating ERCs

The Final CPP defines an ERC as "a tradable compliance instrument that represents a zero-emission MWh…from a qualifying measure that may be used to adjust the reported CO_2 emission rate of an affected EGU subject to a rate-based emission standard in an approved state plan under CAA Section 111(d)."[99] As shown in Table 8, below, the Proposed FIP would permit ERCs to be generated from the following activities: (1) over-performing covered EGUs; (2) certain switching to natural gas combined cycle generation; (3) new and expanded nuclear generation; and (4) utility-scale metered wind, solar, geothermal and hydropower.[100] In addition, EPA's proposed rate-based model rule would also allow generating ERCs from biomass generation, distributed renewables, demand-side energy efficiency measures, and combined heat and power.[101].

ERC Accounting

The accounting process for ERC generation varies depending on the type of qualifying measure.

- ***Over-performing EGUs*** would be eligible to receive ERCs representing the positive difference between their own emissions rate and a specified baseline CO_2 emissions rate.[102]
- ***Sources of incremental NGCC generation*** are eligible to receive ERCs for the displacement of other generation in accordance with Building Block 2, but the Final CPP does not establish a single accounting methodology for issuance of these "gas shift ERCs" (GS-ERCs). EPA has proposed highly detailed and complex mechanics for GS-ERC generation in its Proposed FIP.[103]
- ***Non-EGUs implementing other qualifying measures***, such as renewable energy projects, would be eligible to receive ERCs representing MWh of, for example, energy savings or zero-emission generation.[104] The accreditation process for ERCs from non-EGUs resembles the process for accreditation of carbon offset projects in other compliance and voluntary markets.[105] ERCs must be quantified and verified according to applicable "Evaluation, Measurement & Verification" (EM&V) requirements; all ERCs must be quantifiable, verifiable, enforceable, non-duplicative and permanent.[106] As with offset programs, the Final CPP contemplates that each ERC "project" must be registered with a state regulator or its agent[107] and subsequently verified by an independent verifier prior to issuance of any ERCs.[108]

Additional ERC Considerations

The Final CPP's treatment of ERCs further resembles offset credits in several respects, including the following.

- ***Invalidation***. The Final CPP emphasizes that improperly issued ERCs may not be used for compliance with applicable emission standards.[109] The Final CPP requires that states proposing to use tradable ERCs explicitly include this limitation in their state plans.[110] This limitation would appear to open the door to the "invalidation" of ERCs, similar to proceedings that have already taken place in environmental markets such as the California cap-and-trade program for GHG emissions or EPA's Renewable Fuel Standard/Renewable Identification Number market.

- ***Banking***. The Final CPP would allow banking of issued ERCs for use in future years. For example, an ERC issued for generation occurring in 2022 would be usable to demonstrate compliance in a future year.[111] Further, the Final CPP would allow ERCs issued during the interim plan performance period to be banked for compliance use in the final plan performance period.[112] However, states will ultimately establish rules on banking of ERCs on a state-by-state basis in state plans, and the Final CPP requires states proposing to use ERCs to specify any restrictions on banking in their state plans.[113] While banking of issued ERCs for use in future years is permitted, the opposite is prohibited. States may not authorize the borrowing of ERCs from future compliance periods.[114]

- ***Credit Stacking***. The Final CPP acknowledges that there may be overlap between an activity's eligibility for issuance of ERCs and for issuance of other environmental credits. For example, a MWh of generation from a renewable resource may be eligible for credit under a state renewable portfolio standard in addition to a state's plan for CPP compliance. The Final CPP at least leaves open the possibility that projects or programs could "stack" credits (*i.e.* receive multiple types of credits for the same activity) and recommends that states evaluate such interactions between programs in the course of developing their own state plans.[115]

C. Mass-Based Approach

Program Scope

States implementing a program in accordance with the mass-based approach may elect for their program to cover existing affected EGUs only. States also have the option to expand the scope of their mass-based program to cover new, modified and reconstructed EGUs subject to 111(b) and/or other sectors of the economy, such as the transportation, manufacturing or industrial sectors.[116] As discussed below in *Section VI.E*, these additional options are designed to accommodate RGGI, which applies to all EGUs — existing and new, and to the WCI/California cap-and-trade program, which covers more than 80% of the economy (including the industrials, cement and transportation sectors). Expanding a mass program to non-affected EGUs, however, will prevent the state program from being presumptively "ready for interstate trading".[117]

Meeting Mass-Based Goals

One of the benefits of implementing a mass-based plan is the relative certainty that the EGUs and the program will meet the Final CPP 2030 goal. Indeed, if a state sets up a cap and then requires EGUs to surrender allowances for each ton emitted, the cap should not be exceeded unless there are violations. If a state decides to expand the mass-based trading program to new EGUs or to other sectors (as discussed below), however, then there is a risk that the emissions reductions achieved by the program come primarily from new EGUs and such other sectors, whereas state compliance with the Final CPP will be established only on the basis of the affected EGUs.

Trading in Mass-Based Programs

In theory, states may implement a mass-based program without any intrastate or interstate trading component. For example, a state could set a quantitative limit for each EGU and require each such EGU to emit below that limit.[118]

Most likely, however, states choosing to rely on the mass-based approach will implement a cap-and-trade program and the Final CPP, unlike the Proposed CPP, provides further direction to states on how to implement such a mass-based approach. For example, the Final CPP provides that a mass-based trading program would include rules and requirements pertaining to the following issues: (1) CO_2 emission monitoring, reporting and recordkeeping requirements for affected EGUs; (2) provisions for state allocation of allowances; (3) provisions for tracking of allowances, from issuance through submission for compliance; and (4) the process for affected EGUs to demonstrate compliance (allowance "true-up" with reported CO_2 emissions).[119] Key requirements of cap-and-trade programs, such as the obligation to report emissions and surrender allowances, must be federally enforceable for affected EGUs, but not necessarily unaffected EGUs (*e.g.*, the obligations of a new natural gas generator would not be federally enforceable).

As discussed below in *Section VII*, states that have implemented a mass-based program may permit their EGUs to trade allowances with EGUs located in other states with mass-based programs. States may also limit the trading to EGUs located within the same state only.

Leakage in Mass-Based Programs

Leakage is typically understood as a shift in generation from one location to another, in a way that does not fulfil the stated objectives of a program. For example, the California Air Resources Board (CARB) included in its cap-and-trade program a prohibition on a type of leakage called "resource shuffling," which CARB defines as the substitution of high emissions power imports for low emissions power imports without any corresponding emission reduction.[120] In the Final CPP, EPA defines leakage as the incremental shift of generation from EGUs subject to the Final CPP to new, modified and reconstructed EGUs, relative to the situation that would occur when the Final CPP is implemented through subcategory-specific emission performance rates.[121] To prevent leakage in mass-based programs, the Final CPP requires states to include conditions that would minimize such potential leakage. Specifically, the Final CPP provides the following three options to states to minimize leakage.

- First, states can include new, modified and reconstructed EGUs under a mass-based program cap. Essentially, this is the model currently in place in California and RGGI, in which the cap covers all EGUs, not only those that existed as of a certain date.[122]

- Second, as an alternative to, or in addition to, the first option, the Final CPP provides that states can allocate a certain quantity of allowances for free to existing EGUs and providers of incremental renewable energy and energy efficiency.[123] Specifically, the Final CPP provides that a plan that contains the allowance set-aside provisions from the model rule included in the FIP will be "presumptively approvable."[124]

- Finally, states can demonstrate that other allocation mechanisms included in their plan will counter the risk of leakage.[125]

State Flexibility

Except for the enforceability, design elements and leakage conditions discussed above, states have relatively wide discretion on how they implement their mass-based trading program. For example, a state that expands its mass-based trading program to cover new EGUs (therefore addressing leakage) will have the flexibility of allocating allowances without any restrictions.[126]

D. Energy Efficiency

Despite EPA's decision to remove energy efficiency from the BSER analysis, EPA continues to believe that significant emission reductions can be achieved through the use of EE measures, with potential emission reductions rivalling those from Building Blocks 2 and 3. Accordingly, the Final CPP allows EE as a compliance measure, explicitly recognizing that EE likely will represent an important component of some state plans — particularly for those plans utilizing the state measures approach.[127] EE can be recognized as part of a state plan, but only for the emission reductions EE provides during a plan performance period: "Specifically, this means that measures installed in any year after 2012 are considered eligible measures under this final rule, but only the quantified and verified MWh of…electricity savings that they produce in 2022 and future years, may be applied toward adjusting a CO_2 emission rate."[128]

The Final CPP defines a demand-side EE measure as "an installed piece of equipment or system at an end-use energy consumer facility, a strategy intended to affect consumer energy use behaviours, or a modification of equipment, systems or operations that reduces the amount of electricity that would have delivered an equivalent or improved level of end-use service in the absence of EE."[129] Examples of EE measures EPA has identified include:

- Measures that reduce electricity use in residential and commercial buildings, industrial facilities and other grid-connected equipment
- Water efficiency programs that improve EE at water and wastewater treatment facilities
- Measures installed as the result of individual EE projects, such as those implemented by energy service companies
- Measures installed through an EE deployment program (*e.g.*, appliance replacement and recycling programs, and behavioural programs) administered by electric utilities, state entities, and other private and non-profit entities
- State or local requirements that result in electricity savings, such as building energy codes and state appliance and equipment standards[130]

The Final CPP permits EE to accrue ERCs if the generation avoided is adequately evaluated, measured and verified. Similarly, EE measures can receive allowances in a mass-based state, should that state exercise its discretion to allocate allowances to encourage investments in demand-side EE.[131] However, EE measures located in mass-based states are restricted from ERC issuance in rate-based states, potentially reducing incentives for EE projects in certain states.[132]

Further, ERCs must be tracked via to-be-developed systems that would be administered or approved by EPA. States must require that EM&V plans include several specific components.[133] EPA notes these components reflect existing provisions in a wide range of publicly or rate-payer funded EE programs and energy service company projects. Concurrent with the Final CPP, EPA also released draft EM&V guidance for public comment. This draft EM&V guidance is not a regulatory document; rather, it provides supplemental information to help states and EE providers successfully implement the EM&V provisions in the emission guidelines and proposed model rule. Contents include background information and EM&V definitions, best practices for applying quantification protocols and methods, and procedures for determining appropriate baselines.

The CEIP, discussed in more detail in *Section II.E* would also allow ERC accrual for EE measures, but with two notable differences. First, ERCs could accrue earlier, for generation avoided during 2020 and/or 2021. Notably, EPA expects the CEIP will improve the liquidity in the early years of ERC and allowance markets expected to emerge under the Final CPP. Illiquid market conditions represent a compliance risk for EGUs as the adequacy of ERC and allowance supplies remains uncertain at this early stage. Second, EE projects must be implemented in low-income communities, which EPA brands as consistent with the technology-forcing and development purposes of Section 111.[134]

E. Considerations for Existing Trading Programs

The Final CPP contemplates that states can use existing emission CO_2 programs in a mass-based state or multi-state plan. The Final CPP sketches out how California and RGGI member states can use their existing programs with broader source coverage and other flexibility features in their state plans to comply with the CPP.[135] In particular, the state measures "plan type would allow the state to implement a suite of state measures that are adopted, implemented, and enforceable only under state law, and rely upon such measures in achieving the required level of CO_2 emission performance from affected EGUs."[136]

However, neither California's state measures nor the RGGI member states' obligations would be federally enforceable emission standards. As such, their submitted state plans would have to include a backstop of federally enforceable emission standards for all affected EGUs. Such a backstop likely would impose federally enforceable emission standards on affected EGUs in those states in the event that California's Assembly Bill 32 or the Northeast states' RGGI emission reduction measures fail to achieve the Final CPP's mass-based CO_2 goals.[137] EPA explains that these states' plans would have to "specify the backstop that would apply federally enforceable emission standards to the affected EGUs" and "include promulgated regulations (or other requirements) that fully specify these emission standard requirements, which must be quantifiable, verifiable, enforceable, non-duplicative and permanent."[138] These requirements must be submitted with the state's federally enforceable plan.[139]

California

Due to the GHG emissions reduction measures promulgated under the landmark Assembly Bill 32, California should be able meet the interim and final CO_2 goals which EPA assigned to it in the Final CPP. Indeed, the CARB previously concluded that California could achieve its 2030 goal in the Proposed CPP as much as 10 years early via implementation of existing climate programs.[140] Moreover, the Final CPP weakens California's goals compared to the Proposed CPP. The final goal in the Proposed CPP was 537 lbs CO_2/Net MWh, reflecting a 23% reduction from the 2012 baseline, and the Final CPP final goal is 828 lbs CO_2/Net MWh, reflecting a 14% reduction.[141] Accordingly, the expectation is that that California is well positioned to comply without major disruptions to its programs. One caveat, however, is that California policies designed to accelerate the deployment of electric vehicles to meet both criteria pollutant and GHG emission reduction mandates are likely to result in the need for more generation capacity. If these policies succeed in electrifying a significant portion of the transportation sector, compliance with the Final CPP may prove more challenging and/or more complex for California.[142]

The precise manner in which California will comply currently is unknown, but even EPA suggests the state will seek approval of its existing program(s): "California has indicated that it intends to maintain its current state program, which this rule would allow."[143] Assuming California uses the EPA-provided mass budget and adopts a backstop, it may be able to submit a "presumptively approvable plan."[144]

Similar to the Proposed CPP, the Final CPP allows out-of-sector GHG offsets in the state measures plan type. In other words, California could retain the offset program under its cap-and-trade program. However, EPA emphasizes that compliance with state mass-based CO_2 goals will be determined based solely on stack CO_2 emissions from affected EGUs. This means that affected EGUs will not receive federal backstop compliance credit for any offsets they have procured.[145] As such, California likely will need to continue to track the extent to which affected EGUs use offsets for cap-and-trade program compliance.

Regional Greenhouse Gas Initiative

RGGI may also provide a vehicle for its member states and prospective member states to meet their interim and final CO_2 goals. RGGI's CO_2 cap was restructured in 2013 and the total budget for CO_2 emissions from the power sector was set at 91 million tons for 2014, declining 2.5% annually through 2020.[146] A preliminary examination suggests the 2015 CO_2 Allowance Base Budgets for several member states may be below the Final CPP's first interim goal thresholds for those states. However, a more detailed analysis is necessary to determine whether the current RGGI CO_2 goals could serve as a compliance mechanism for those members. Members with RGGI budgets exceeding the Final CPP thresholds could adjust their budgets as necessary.

Irrespective of RGGI's CO_2 budgets and allowances, a number of structural changes would likely be required for RGGI to meet the Final CPP's requirements. *First*, RGGI's cap only extends to 2020. The cap would need to be extended to 2030 to be consistent with EPA's final state goals. *Second*, as noted by EPA, RGGI contains a Cost Containment Reserve of a fixed supply of additional CO_2 allowances that are available for sale if CO_2 allowance prices exceed certain price thresholds.[147] This Cost Containment Reserve would need to be analyzed and potentially modified to ensure the interim and final goals were met.[148] *Third*, like California, RGGI allows for the use of allowances awarded to GHG offset projects to be used to meet a specified portion of an affected source's compliance obligation. Thus RGGI states would also need to continue to track the extent to which affected EGUs use offsets for cap-and-trade program compliance.

VII. Interstate Coordination and Linking

A number of considerations may motivate states to coordinate or link their programs. For example, states may attempt to lower the compliance costs associated with the Clean Power Plan, better match the geographic scope of power transmission systems, and create a uniform price on carbon to level the playing field across states and to minimize trade exposure. States may also see value in creating larger markets that are deeper and more liquid, and/or leverage common systems, tools, and resources such as a tracking system, certain monitoring functions and the management of joint auctions as a way to reduce the administrative costs associated with the program.

A. Types of Multi-State Coordination

The Final CPP proposes two approaches that states may follow to coordinate their plans.[149] As a first approach, states may merge their individual state mass or rate goals, but the Final CPP requires that all states merging their goals use the same type of plan: emission standards or state measures. To combine rate-based goals, states must calculate the weighted average of each participating state emissions rate. For states that have adopted a mass-based plan, the joint goal is obtained by adding the mass-based performance goals of each participating state.[150] According to the Final CPP, RGGI is one example of states combining their individual goals. As a second option, states may retain their individual state goals, but agree to permit their regulated sources to use compliance instruments (*e.g.*, ERCs and allowances) issued by other states.

B. Multi-State Rate-Based Trading

The Final CPP allows states to incorporate multi-state rate-based trading of ERCs into their state plans.[151] However, such interstate trading is only permissible for states that impose rate-based limits for affected EGUs that are equal to the CO_2 emission performance levels in the Final CPP, so as to prevent arbitrage opportunities and ensure that all states issue ERCs on the same basis.[152] For example, states that implement EPA's subcategory-specific emission standards would be able to trade ERCs issued in other states that have adopted the same standard.[153] States implementing a multi-state rate-based plan with an emission standard based on the weighted average CO_2 emission rate, based on all participating states' goals would also be able to engage in multi-state rate-based trading.[154]

The Final CPP specifies three specific methods to link state plans with rate-based emission trading systems: (1) a "ready-for-interstate-trading" approach; (2) a specific bilateral or multilateral linkage; or (3) joint ERC issuance among states with materially consistent regulations. The first approach would essentially make states that adopt the forthcoming EPA model rule for rate-based trading systems presumptively eligible for interstate trading.[155] The second approach would allow states to incorporate specific linkages with other states into their state plans, provided that they demonstrate in their plans that they have compatible tracking systems.[156] Under the third approach, states with materially consistent regulations and a shared tracking system may jointly issue ERCs, coordinating their review of submissions for ERC issuance.[157]

C. Mass-Based Trading

The Final CPP identifies two potential approaches that states could use to create their state trading programs.

"Ready-for-Interstate-Trading"

The Final CPP allows a state to submit a "ready-for-interstate-trading" plan indicating that its emissions trading program will be administered using an EPA-approved or administered emission and allowance tracking system.[158] State plans using such a system will be deemed as ready for interstate linkages upon approval of the plan, and no additional EPA approval will be necessary in order to link trading programs or for affected EGUs to engage in trading pursuant to the plan.[159] Ready-for-interstate-trading plans must also indicate that the state will recognize the emission allowances issued by any other state with an EPA-approved plan and tracking systems as usable for compliance purposes.[160]

Bilateral or Multilateral Arrangements

Alternatively, the CPP allows a state to specify the other states from which it will recognize emission allowances as usable for compliance under its own trading program.[161] States utilizing this option must indicate in their implementing regulations that allowances from specified states will be recognized for compliance purposes, and the state plan must indicate how allowances will be tracked — either through a joint tracking system, an interoperable tracking system or an EPA-administered system. In addition, plans must address differences between the linked trading systems, including whether one program covers a broader set of emission sources than another, and whether each program is designed to meet a state mass-based goal for affected EGUs only or a mass-based goal plus the new source CO_2 emission complement.[162]

D. Reliability

EPA received a significant number of comments regarding the impacts the Proposed CPP could have on electric system reliability.[163] FERC also held a series of technical conferences on the subject, which led to FERC's five commissioners sending a letter to EPA on May 15, 2015 that described the reliability issues and recommendations discussed at these technical conferences.[164] In response to these comments, EPA included several features in the Final CPP that it concludes will ensure that the Final CPP does not interfere with the electric industry's ability to maintain the reliability of the nation's electricity supply.[165]

In EPA's view, the most important changes adopted in the Final CPP with respect to maintaining electric system reliability are moving the start of mandatory compliance from 2020 to 2022 and then phasing in achievement of state goals or emission performance rates over the subsequent eight-year period until 2030.[166] EPA asserts that states are given significant flexibility to address reliability issues as they arise, given that the states need only to meet their interim goal on average over the eight-year period.[167] EPA also cites the flexibility and variety of available measures engrained in the guidelines to comply with the Final CPP as providing states the ability to tailor their plans in a way to avoid reliability concerns.[168] In addition to these two features relating to flexibility and timing, EPA also included three new electric system reliability measures in the Final CPP:

- A requirement that states consider reliability issues during their plan development process
- A mechanism that allows a state to seek a revision to its approved plan in order to address unforeseen reliability impacts
- A reliability safety mechanism or valve to address emergency situations that threaten reliability[169]

Consideration of Electric System Reliability During State Plan Development

The Final CPP includes a requirement that each state demonstrate in its final plan submittal that it "considered" electric system reliability issues during the development of its plan.[170] EPA states that "one particularly effective way" to comply with this requirement is for the state to consult with its relevant RTO, independent system operator (ISO), or other planning authority during the development process and include documentation of this consultation in the final plan submittal.[171] Alternatively, EPA will allow states to provide other comparable support.[172] EPA also notes, however, that state plan submissions "will not be evaluated substantively regarding reliability impacts."[173]

State Plan Modifications

EPA has also provided states with the ability to seek expedited review of a proposed revision to a state's implementation plan in the event an electric system reliability issue is identified that cannot be addressed within the range of actions or mechanisms in the state's approved plan.[174] In order to qualify for expedited review, however, the state must document the reliability issue by providing a separate analysis of the reliability risk from the relevant RTO, ISO or other planning authority.[175] While EPA will prioritize review of plan revisions needed to address reliability issues, EPA will review requests for modification pursuant to the implementing regulation requirements in 40 C.F.R. Part 60.28 and undertake necessary notice and comment periods.[176]

Reliability Safety Valve

The reliability safety valve included in the Final CPP includes two features:

- A 90-day period during which the EGU needed to address a reliability concern will not be required to meet the emission standard established for it under a state plan, though it will be required to meet an alternative standard
- A subsequent period when the state must submit a revised state plan if the reliability concern continues beyond the first 90-day period and offset any excess emissions beyond what was authorized in the state's original plan[177]

Applicability. The reliability safety valve is available under limited circumstances set forth by EPA:

- The reliability emergency would be unforeseeable, brought about by an extraordinary, unanticipated, potentially catastrophic event
- The electricity grid would face some form of failure if the affected EGU did not operate
- The operation of the EGU resulted in emission levels in excess of those allowed under a state plan that imposes emissions constraints[178]

EPA also expressly states that it does not anticipate that EGUs operating under an emissions trading program will be able to meet these criteria,[179] which would likely significantly limit the availability of the reliability safety valve to the extent that a market mechanism is in place that allows for the monetization of CO_2 emission costs under an economic dispatch framework.

Process. In the event of a reliability emergency, the state must submit a notification to EPA within 48 hours.[180] Within seven days of submitting the initial notification, the state must submit a second notification describing the reliability concern in detail and explaining why the concern requires the relevant EGU to operate under a modified standard.[181] This second notification must also include a written concurrence by the relevant reliability coordinator or planning authority that confirms the existence of the reliability concern and supports the request to temporarily modify the EGU's emissions standard.[182] The affected EGU's emissions during this first 90-day period that exceed its obligations under the state plan will not be counted against the state's overall goal.[183]

If the reliability issue persists beyond 90 days, then the state must notify EPA at least seven days before the end of the 90-day period and then submit a revised plan "as expeditiously as possible."[184] The notification prior to the end of the 90-day period must include a second concurrence from the relevant reliability coordinator or planning authority confirming the continuing need for the EGU to operate beyond previously set limits.[185] After the initial 90-day period, emissions in excess of those authorized in the state's original plan will be counted against the state's overall goal.[186]

Coordination with FERC and DOE

Lastly, EPA notes that it will continue to coordinate with FERC and Department of Energy (DOE) during the implementation of the Final CPP.[187] While the Final CPP does not specify the exact roles that FERC or DOE will play, EPA does state that the coordination efforts among the three agencies will be based upon the relationships developed during the implementation of the Mercury and Air Toxics Standards (MATS).[188] More details regarding these coordination efforts are described in an August 3, 2015 document entitled "EPA-DOE-FERC Coordination on Implementation of the Clean Power Plan."[189]

E. Accounting for Renewable Energy Across State Lines

EPA acknowledges that "[w]henever CO_2 emission reduction measures, such as RE…, are implemented, the measure can affect EGU generation and CO_2 emissions across the regional grid."[190] Due to the complexity and interrelatedness of these impacts, such measures could be double-counted. Accordingly, the Final CPP requires states to "ensure that the emission reduction measures counted as part of meeting their plan requirements are not duplicative of any measures that are counted by another state, in order to avoid double counting of the MWhs of generation or energy savings that these measure [*sic*] produce."[191] EPA asserts that it has helped the states meet this requirement because the general accounting approaches for both mass-based and rate-based plans in the Final CPP have been "specifically designed to eliminate the risk of double counting of emissions reductions."[192]

In short, EPA believes that since the general accounting approaches modify only the denominator of an emissions rate (MWhs) and not the numerator (lbs of CO_2), "it is not possible for the real emission reductions prompted by any particular [RE] measure to be double-counted."[193] The CO_2 emission rate of an affected EGU or state would be adjusted by adding the MWhs of RE either is responsible for deploying to the denominator of its CO_2 rate, but the numerator would remain the same. EPA theorizes that since the numerator reflects reported stack emissions and will account for whether/how a RE measure reduced the affected EGU's generation and emissions, accounting for the state in which the RE originated or approximating exactly how it impacted the regional grid is unnecessary. This should be true so "long as it is assured that the MWhs of RE…are only being claimed by one affected EGU or state."[194]

Ensuring that only one state is claiming credit for the zero-emissions MWhs raises different issues depending on where a RE measure is located (rate- or mass-based state) and whether the RE is sunk within the state or exported. Mass-based plans rely exclusively on reported stack emissions for determining whether a mass-based CO_2 emission goal is achieved. This means that under a mass-based plan any emission reduction measures that are implemented automatically are accounted for in reduced stack emissions of CO_2 from affected EGUs, which avoids concerns about counting the same mass reductions in two different mass-based states.[195] Put another way, "zero-emitting MWhs from resources like RE…can serve load in the mass-based state and play a role in lowering compliance costs, but they play no direct role in mass-based compliance. As a result, no double-counting of emission reductions can take place."[196] In a rate-based plan, EPA states that "there needs to be an explicit adjustment of reported

CO_2 emission rates from affected EGUs, to reflect the measures that substitute low- or zero-emitting generation…for affected EGU generation. States with rate-based plans must demonstrate that measures used to adjust their CO_2 emission rate, such as RE…, are non-duplicative." Presumably, this demonstration would be made via ERC protocols.

However, concern remains about "foregone" emissions reductions where a RE measure is located in a mass-based state and an EGU in a rate-based state claims credit for the RE measure's MWhs. "In that scenario, expected CO_2 emission reduction actions in the rate-based state are foregone as a result of counting MWh that resulted in CO_2 emission reductions in a mass-based state" (*i.e.*, the RE served load in the mass-based state).[197] To minimize such forgone reductions, EPA is restricting the ability of rate-based states to claim RE located in mass-based states to situations where the generation in question "was intended to meet electricity load" in a rate-based state.[198] Such a situation would exist where there is a power delivery contract or power purchase agreement in which an entity in the rate-based state contracts for the supply of the MWhs in question.

VIII. Proposed Federal Implementation Plan

EPA also issued the Proposed FIP at the same time it released the final CPP. EPA proposed both rate-based and mass-based FIPs, and requested comment on whether it should approve one or both methods. EPA also proposed to use the rate-based and mass-based FIPs, with slight modifications, as model trading rules that states can adopt. By adopting a final model trading rule into its state plan, a state's plan would presumptively be approved by EPA. EPA intends to finalize one or both of the model trading rules in the summer of 2016.[199] This will allow states to incorporate the final model trading rule(s) into their state plans. EPA will wait to finalize an individual state FIP until after a state has failed to submit a plan, or after EPA does not approve a submitted state plan. The FIP for that individual state will incorporate both the substantive aspects of the final model trading rule(s) as well as any necessary modifications required for a particular state.[200]

Both the mass-based and rate-based federal plans share a general set of common features. These include interstate trading with other FIP states that are using the same type of plan, as well as trading with approved state plans that contain the required components to allow for linkage with the federal plan, and again only trading among plans of the same type (mass- or rate-based) is allowed to prevent leakage. The Proposed FIP outlines certain criteria for state plans to be allowed to trade with FIP states, primarily that the plan be approved, that the state uses the EPA credit tracking system and that the state meets the requirements for "ready-for-interstate-trading" finalized in the CPP. Both plans also include the CEIP. EPA also explains that because of the flexibility granted due to the trading, interim goals and extension of the initial compliance date, the reliability safety valve discussed above is not included in the proposals.

EPA proposes that an administrative appeals program be included, and proposes adopting the existing program for CAA trading in 40 C.F.R. Part 78. EPA notes that some modifications to Part 78 are required, but as the program was designed to address appeals from CAA trading programs, the revisions proposed are not significant.[201] Specific decisions that EPA proposes to include as reviewable under the program are included below.

A. Rate-Based Option

The rate-based plan relies on the standards set for natural gas and fossil-fuel fired generators, with staged performance goals in multi-year periods, set forth in Table 6. Covered EGUs that are above their required rates can comply by acquiring ERCs.

Table 6. Glide Path Interim Performance Rates (Adjusted Output-Weighted-Average Pounds of CO_2 Per Net MWh From All Affected Fossil Fuel-Fired EGUs)[202]

Technology	2022-2024	2025-2027	2028-2029	Final Rate
Fossil Fuel-Fired Electric Steam Generating Units	1,671	1,500	1,380	1,305
Stationary Combustion Turbines	877	817	784	771

Under the proposal, credits can be generated by covered EGUs that perform below their rates, by NGCC units, by nuclear generation (new capacity and uprates), and by certain types of renewable energy generators (specifically wind, solar, geothermal and hydro).[203] EPA proposes limiting the FIP credits to those technologies and approaches as they are the simplest to measure, and would be easily applied across a variety of jurisdictions. However, EPA also proposes additional mechanisms for ERC generation from additional energy efficiency and renewable energy technologies for inclusion in the model rule, and requests comment on whether those technologies should also be included in the rate-based federal plan.

EPA proposes highly detailed calculation mechanisms for each of the proposed credit generating technologies. Of particular note, under the proposal, NGCC units are both subject to the standard and also automatically generate credits (to represent the shift from the average fossil unit to gas units overall). Thus, as EPA details, an NGCC that performs worse than the standard could possibly be both generating credits (these are titled “gas switch” or “GS” credits by EPA) and require additional credits for compliance. While a unit cannot use its gas switch credits to fulfil its own compliance gap, it can sell the gas switch credits, and use that revenue to purchase credits for compliance purposes.[204]

EPA also proposes detailed program and planning requirements for measurement and verification. While the calculation, measurement and verification of ERCs is fairly straightforward for the Proposed FIP ERC generators, the mechanics become significantly more complicated for the additional ERC generators included in the proposed model trading rule. For example, EPA discusses the controversy surrounding the accounting methodology for biomass feedstocks, and indicates that for non-waste derived feedstocks some form of tracking and accreditation of the source biomass must be included in order to guarantee that the full lifecycle impact of the biomass is positive.[205] This framework at least initially appears similar to what is currently in place for the renewable fuel standard, or RFS, also administered by EPA. EPA requests comment on whether it should generate an initial list of “preapproved qualified biomass feedstocks” as well as a process for verifying additional feedstocks. EPA also proposes specific waste to energy, combined heat and power, and demand-side energy efficiency measurement and verification provisions for the model rule. In addition to considering whether EPA should include those technologies in the Proposed FIP, clients with a particular sector interest may wish to comment on the measurement protocols for particular technologies.

B. Mass-Based Option

The mass-based FIP would be a trading program that: (1) establishes an aggregate emissions limit, specifying the maximum amount of emissions authorized from affected EGUs included in the program; and (2) creates allowances that authorize a specific quantity of emissions. The aggregate emissions limit for a state is its statewide mass-based emission goal as specified in the Final CPP. The total number of allowances created must equal the aggregate emissions limit. Each facility with affected EGUs in the program must surrender allowances covering the EGUs' emissions during each compliance period. If a facility were to fail to surrender sufficient allowances, then the facility would be charged two allowances for each allowance it is short.[206] Moreover, EGU owners and operators would be subject to civil penalties for each violation in accordance with the CAA, with each ton of unauthorized emissions and each day of the compliance period involved constituting a violation of the CAA.[207]

A facility with affected EGUs may use allocated allowances, buy allowances from, or transfer or sell allowances to, other affected EGUs or other entities that participate in the market — including those in other states with mass-based FIPs or EPA-approved, mass-based state plans. Any party (*e.g.*, brokers) could participate in the allowance market. Allowances would be assigned a vintage year and could be used during the compliance period applicable to the allowance's vintage year or a later compliance period. Allowances could be "banked" (*i.e.*, carried over for future use), but not "borrowed" (*i.e.*, bringing forward future allowances for use in an earlier compliance period).[208] Unlike in California's cap-and-trade program, the mass-based FIP would allow the use of allowances from future years *within* each compliance period (*e.g.*, if the first compliance period covers years 2022 through 2024, a vintage 2024 allowance could be used to cover a ton emitted in 2022).

The compliance periods in the mass-based FIP would be the same as in the Final CPP: 2022-2024; 2025-2027; 2028-2029; and successive two year compliance periods commencing in 2030. EPA would evaluate compliance only after the end of a compliance period. Unlike in RGGI and California's cap-and-trade program, EPA is not proposing to implement intervening compliance requirements (*e.g.*, California requires 30% coverage of a source's emissions in the prior year).[209]

A state covered by the mass-based FIP could adopt its own approach to allowance allocation. This means that states could, for example, administer allowance auctions, allocate allowances to RE, demand-side EE, and/or load-serving entities. However, if a state does not choose to do so, EPA would distribute the allowances as outlined in the Proposed FIP. EPA is proposing to allocate allowances based on EGUs' historical generation, minus "set-asides" primarily designed to address "leakage" (*i.e.*, shifting of generation to new sources not covered by the trading program).

In particular, EPA proposes to allocate the historic-generation-based portion of the allowances to individual affected EGUs based on each affected EGU's share of the state's historic generation, using average 2010-2012 generation levels as a baseline.[210] EGUs essentially would receive a pro rata share of a state's aggregate emissions limit that generally would be determined prior to the start of the entire program. Since this approach hinges on historical generation and not historical emissions, low emitting EGUs are rewarded.[211] EPA is taking comment on alternate allocation methods, including approaches using source-category division, historic heat input, historic emissions data, projected or observed future activity, and "updating" allocations based on future activity.[212]

EPA also proposes three allowance set-asides:

- ***Clean Energy Incentive Program***. This set-aside would be of first compliance period allowances only. The rules governing eligible projects for this set-aside would be the same as for the CEIP in the Final CPP.

- ***Output-Based Allocation***. This set-aside would be for NGCC only (not steam generating units) and start in the second compliance period and continue for each compliance period thereafter. A portion of the total allowances within each mass-based federal plan state would be allocated to existing NGCC units based, in part, on their generation in the previous compliance period. EPA would calculate the size of the set-aside as 10% of the NGCC capacity in the state, multiplied by the hours in a year, multiplied by the allocation rate for the set-aside. The allocation rate would be the emission rate standard for new NGCC units under 111(b) (*i.e.*, 1,030 lbs CO_2/MWh-net).

- ***Renewable Energy***. This set-aside would be for developers of in-state RE projects that provide capacity incremental to 2012, and would be implemented in all compliance periods. Eligible RE technologies include on-shore wind, solar, geothermal power and hydropower. EPA is taking comment on the inclusion of other RE measures, incremental nuclear, demand-side EE measures, CHP and any other emission reduction measures. For the purpose of this set-aside, 5% of allowances would be reserved from the aggregate emissions limit of each state.

As EPA does not have authority to regulate new fossil fuel-fired sources under CAA Section 111(d) and therefore cannot cover new sources under the mass-based trading program, the latter two set-asides are designed to address leakage to new sources. EPA believes the Output-Based Allocation set-aside would provide an incentive for owner/operators of eligible EGUs to generate more in order to receive more allowances. EPA expects the RE set-aside to lower the marginal cost of production of incentivized clean energy technologies.

Table 7. Allowance Movement Timing Under the Mass-Based FIP

Compliance Period	Allowance Transfer Compliance Deadline	Eligible Vintages for Surrender	Allowance Allocation Deposit Date	Output-Based Allocation (Set-Aside #2) Distribution Date	RE Allocation (Set-Aside #3) Distribution Date
2022 – 2024	May 1, 2025	2022 – 2024 CEIP	June 1, 2021	N/A	Dec. 1, 2021 Dec. 1, 2022 Dec. 1, 2023
2025 – 2027	May 1, 2028	2025 – 2027 Pre-2025 CEIP	June 1, 2024	November 1, 2025	Dec 1, 2024 Dec. 1, 2025 Dec. 1, 2026
2028 – 2029	May 1, 2030	2028 – 2029 Pre-2028 CEIP	June 1, 2027	November 1, 2028	Dec. 1, 2027 Dec. 1, 2028
2030 – 2031 (two-year periods after)	May 1, 2032	2030 – 2031 Pre-2030 CEIP	June 1, 2029	November 1, 2030	Dec. 1, 2029 Dec. 1, 2030

Table 8. Qualifying Technologies for ERC Generation Under Each Plan

	Rate-Based FIP	Rate-Based Model Rule	CEIP
Technologies that qualify to generate credits under each plan			
Over-Performing Covered EGUs	✓	✓	
Natural Gas Combined Cycle	✓	✓	
Nuclear (New and Expanded Capacity)	✓	✓	
Wind and Solar	✓	✓	✓
Geothermal and Hydro		✓	
Biomass		✓	
Distributed Renewables		✓	
Demand-Side Energy Efficiency		✓	✓*
Combined Heat and Power		✓	

***must be deployed in low income communities**

Actions Reviewable Under the Proposed Administrative Appeal Mechanism

EPA has proposed certain actions under each of the rate- and mass-based plans that will be reviewable through the administrative process offered under 40 C.F.R. Part 78.

Rate-based decisions proposed by EPA that may be administratively appealed include decisions on:

- Eligibility applications for ERCs
- Numbers of ERCs generated
- Transfers of ERCs
- Disallowance of ERCs for compliance
- Emissions excesses requiring 2-for-1 administrative penalties
- Deduction or surrender of ERCs for compliance
- Accreditation of independent verifiers

Mass-based plan decisions proposed by EPA that may be administratively appealed include decisions on:

- Applications for set-aside allowances
- Allocation of allowances to affected EGUs
- Allocation of allowances from set-asides
- Transfers of allowances
- Finalization of emissions data
- Compliance penalties for excess emissions

IX. Looking Forward

The Final CPP is an historic regulation that will have wide-ranging implications nationally and internationally. In this section, we address some potential impacts on private sector power generation and international climate change negotiations as well as examine the legal risk to the Final CPP.

A. Private Sector Implications

The Final CPP will have long-term implications for private sector interests involved in power generation. We outline potential implications for merchant generation and clean energy technology providers (hereafter "Cleantech").

Merchant Generation

Efficiencies Created by Trading Programs. From a merchant generator perspective, the Final CPP is an improvement over the Proposed CPP to the extent that the Final CPP more clearly points states toward the development of one or more multi-state trading platforms for ERCs or allowances. A trading platform will facilitate the monetization of CO_2 emission costs and create market conditions that will efficiently increase the utilization of NGCC units and utility-scale renewable energy generation to meet the goals set forth in Building Blocks 2 and 3, respectively, as the relative costs of operating fossil-fuelled steam EGUs (predominantly coal-fired EGUs) increase. This more efficient approach to implementing the Final CPP will benefit all affected EGUs by providing increased flexibility and reducing overall compliance costs. A trading platform will also allow affected EGUs to more easily implement Building Block 2, because EGUs will be able to trade credits/allowances rather than find counterparties and negotiate contracts to shift generation from fossil-fuelled steam EGUs to more efficient NGCCs.

Increased Demand for Renewables. Utility-scale renewable energy generation, particularly wind and solar EGUs, will benefit from increased demand pull in both the near-term and long-term as they will be viewed as assets to facilitate compliance with the Final CPP. In the near-term, wind and solar EGUs could have additional demand pull as a result of the incentives set forth in the CEIP, while in the long-term all utility-scale renewable generation will assist states to comply with the Final CPP.

Increased Demand for NGCC Units – Building Block 2 calls for an increase in the total output of the existing NGCC fleet by over 50% by 2027 compared to 2012 levels, creating an increased demand for output from these units.

Cleantech

EPA's Final CPP represents a significant market opportunity for Cleantech companies, although not all technologies and projects will qualify. Depending on a state's implementation choices, there are a variety of potential options to increase market share and monetize the benefits of Cleantech. Under the Final CPP, qualifying RE and EE are expected to play a major role in meeting the emissions goals set by EPA. However, which technologies qualify will vary on a state-by-state basis, and may change over time. As the Proposed FIP and model rules are likely to be applied in a number of states, states and technology providers have a strong interest in commenting on the ERC generation eligibility and allowance allocation set-aside methodology provisions included.

Beyond the core set of qualifying renewables, there are several Cleantech technologies that EPA has recognized may generate emissions reductions, but are not in the Proposed FIP, and in some cases not in the model trading rules. Biomass, waste to energy, combined heat and power and demand side energy efficiency are all technologies in the model rule, but not the Proposed FIP. Other clean technologies were not included in the model rule, such as energy storage. However, there remain opportunities to change what is included in each proposed plan, and also to advocate with states to include additional technologies beyond those included in the EPA proposals. Technologies, such as energy storage, that directly reduce the emissions of affected EGUs will also be able to participate by that route, regardless of their explicit inclusion elsewhere.

Consideration for Cleantech companies. As Cleantech companies evaluate the Final CPP and the FIP proposal, the first question to answer will be if their particular technology is eligible across all of the proposed federal plan and model trading rule options, and for the CEIP. Depending on how the technology is treated by the different proposals, clients may wish to argue for their technology to be included. As different technologies are treated differently under the mass-based and rate-based plans, clients may also consider advocacy at the state and federal level in favor of either plan. For example, a CHP system in a rate-based state can generate ERCs by demonstrating the emission reduction benefits of using thermal output. In a mass-based state CHP does not have the same opportunity to generate ERCs, but a state could potentially allocate (*i.e.,* set aside) allowances to CHP projects. Cleantech companies should also consider how the timing and eligibility requirements of the CPP will mesh with existing programs, including tax credits, renewables portfolio standards and energy efficiency standards.

In addition to commenting on the inclusion of particular technologies in the Proposed FIP and the model trading rules, Cleantech clients should consider how the benefits of their technologies can best be measured, and whether EPA has included appropriate measurement systems in its proposed rules. Beyond grid-scale renewables, the measurement and verification of Cleantech benefits presents a significant challenge to EPA and the implementing states. To the extent that industry-wide standard methods for measurement and verification can be developed and presented to EPA and the states, the implementing agencies may be more willing to include additional technologies, even if those technologies are not connected to the grid with revenue-grade meters.

B. Role of the CPP in U.N. Climate Negotiations

The US will consider the Final CPP materially important to its role in the United Nations Framework Convention on Climate Change (UNFCCC) talks that will take place in Paris in December 2015 (COP 21).[213] The UNFCCC parties previously agreed to develop and submit Intended Nationally Determined Contributions (INDCs) by the first quarter of 2015 so that the parties would be in a position to adopt a final, binding agreement at COP 21. INDCs are the voluntary contributions of each party/nation to achieve the UNFCCC's objectives. Use of INDCs allows the UNFCCC parties to take into account each nation's capacities, relative responsibilities and national circumstances.

The US submitted its INDC in March 2015, which provides in pertinent part: "The United States intends to achieve an economy-wide goal of reducing its greenhouse gas emissions by 26%-28% below its 2005 level in 2025 and to make best efforts to reduce its emissions by 28%."[214] Since the electricity sector is the largest source of GHG emissions in the US,[215] the Proposed CPP was prominently identified in the INDC as a source of emissions reductions. Notably, the Final CPP's and the INDC's goals do not align temporally. The INDC targets 2025, while the Final CPP imposes both interim and final (2030) reduction goals. Accordingly, the Final CPP's interim targets have greater significance in the face of the US' international commitments.

EPA is candid about the importance of the Final CPP to the US INDC: "This final rule demonstrates to other countries that the U.S. is taking action to limit GHG emissions from its largest emission sources, in line with our international commitments. The impact of GHGs is global, and U.S. action to reduce GHG emissions complements and encourages ongoing programs and efforts in other countries."[216] According to some models, the Final CPP could account for almost half of the total reductions in the INDC.[217] Reliance on the Final CPP carries concomitant risk for the US. If the Final CPP were to be invalidated, there would be serious questions concerning the viability of the US INDC, potentially destabilizing progress toward an international climate agreement.

C. Legal Risk

The Final CPP's scope and impact are unprecedented and the Final CPP will almost certainly be reviewed by the D.C. Circuit and the US Supreme Court. Indeed, a group of 15 state attorneys general already filed a petition with the D.C. Circuit on August 13, 2015 requesting an emergency stay of the rule. How broadly courts will view EPA's authority is yet to be determined. Latham & Watkins LLP is not at this time expressing any final view as to the likelihood that the Final CPP might be determined upon judicial review to be legally deficient on any ground. We note that, over the last 40 years, EPA has used 111(d) to regulate only four pollutants from five source categories,[218] and no federal court has reviewed, in any meaningful way, EPA's interpretation of its Section 111(d) authority.[219]

Extended Deadlines and Prospects for a Stay

The Final CPP includes two important timing changes that likely decrease the chances that the rule's opponents will obtain a stay of the rule during the inevitable litigation. *First*, although the Final CPP kept the September 6, 2016 initial state plan submission deadline, under the Final CPP any state is eligible for a two-year extension until September 6, 2018. Under the Proposed CPP, only multi-state plans were eligible for the two-year extension. *Second*, EPA extended the compliance deadline from 2020 to 2022. The extended compliance deadline makes greatly increases the difficulty for affected entities to argue that a stay is needed to maintain the status quo during litigation.

Beyond the Fence Line/Source-Based Rule

Including "outside the fence" building blocks in the BSER, such as dispatch shifts and reliance on generation by sources other than regulated EGUs (*i.e.*, renewables), and the indirect regulation of state energy programs are novel uses of EPA's authority under Section 111(d). As such, some observers have questioned whether EPA has overstepped its legal bounds by requiring power plants to be responsible for emission reductions through means that are "outside the fence," *i.e.* for reductions beyond the heat rate improvements they can achieve on site by addressing their own equipment and operations. On its own terms, Section 111 applies to "stationary sources" of an air pollutant. Some, including Latham & Watkins, have noted that a regulation that requires emission reductions outside of a source's own equipment and operations (*i.e.*, outside the fenceline) would be impermissible because it would require reductions that are beyond a source's control. The novel legal question the final CPP poses is whether under Section 111 EPA can require reductions of an EGU that are beyond its fenceline ***if*** the Final CPP ensures that the state plan provides the source with a means of accessing outside-the-fenceline reductions — that is, that a source can obtain such reductions through the ERC trading program provided in EPA's final rule. EPA would argue that such a state plan essentially brings the energy system emission reductions WITHIN the source's control, thus satisfying the Act's requirement that the required BSER emission reductions be determined as both feasible and affordable *from the perspective of the regulated source*. The Proposed CPP seemed clearly deficient in meeting this potential test because, among other provisions, it failed to require that state plans assure EGU access to the outside-the-fenceline reductions.

The Final CPP, however, includes several changes that shore up the agency's legal defense. *First*, EPA changed the form of the standards so that they are now truly "source" performance standards and not state energy system standards. *Second*, EPA removed the most legally vulnerable Building Block — Building Block 4 (demand-side EE) — from the BSER analysis. It would have been difficult to argue that EE was within the control of the generator, even through an ERC program, given the remaining uncertainties regarding EE credit generation and enforcement. Indeed, by removing Building Block 4, EPA has made BSER an entirely "supply-side" determination and thus brought the emission performance standard, in form, much closer in character to a regulated EGU. *Third,* EPA establishes a preapproved ERC generation and trading platform that ensures power plants can buy credits in the marketplace to comply with their emissions limits. This addition is critical given that nearly every power plant will be a "structural buyer" — *i.e.*, it will need to purchase ERCs to comply because its permit limit will be much tighter than it can achieve purely through on-site heat rate improvements. So, while it remains to be seen whether a reviewing court will allow the Final CPP to "connect the dots" between the affected EGU and outside-the-fenceline reduction measures to satisfy a "control" test, which otherwise would have restricted regulation to within the fenceline, EPA has at least facially met that test through the ERC trading platform now contained in the Final CPP.

Whether the D.C. Circuit or the Supreme Court will entertain the "connect the dots" control argument may be influenced by the context for EPA's rulemaking. EPA's action is among those that directly respond to the Supreme Court's general direction in *Massachusetts v. EPA*[220] and the Court's specific acknowledgement of the agency's authority to use Section 111 in *American Electric Power Co., Inc. v. Connecticut*.[221] EPA will argue that applying Section 111 in the "traditional," inside-the-fenceline, manner would yield only trivial reductions (*i.e.*, the ~2% in Building Block 1), while a more systems-wide approach offers the material benefits the Court may acknowledge as warranted for such a large contributor sector. The final rule offers an approach that both delivers material benefits and brings compliance within a manner of "control" (*i.e.* through ERC trading) to the regulated source. No other approach could deliver such benefits while at least facially staying within legal parameters. On the other side of the balance is the view of the Supreme Court 5-4 majority in *UARG* that the Court will be disinclined to defer to EPA when the effect of its interpretation is to significantly expand EPA's jurisdiction.[222] The outcome of the case ultimately may depend on the extent to which the Court sees EPA's interpretation as a logical extension of its previous construction of the Clean Air Act as requiring EPA to regulate GHGs in a meaningful manner once EPA makes endangerment and contribution findings.

CAA Section 111 vs. Section 112

Opponents of the CPP have argued that the rule is invalid because EPA cannot regulate power plant emissions under both Section 111(d) and Section 112 of the CAA.[223] There are two competing versions of Section 111(d) which were amended and approved into law without being reconciled.[224] The House version of Section 111(d) appears to prevent EPA from regulating any "*source category,"* including any power plant that is also subject to regulation under Section 112 of the CAA. The Senate version of Section 111(d), however, does not mention source categories and may only bar EPA from regulating *hazardous air pollutants* under both Section 111(d) and Section 112 of the CAA. EPA argues the House and Senate amendments should be read to have the same meaning in the context of the Final CPP — "the Section 112 [e]xclusion does not bar the regulation under CAA section 111(d) of non-[hazardous air pollutants] from a source category, regardless of whether that source category is subject to standards for HAP under CAA section 112."[225]

Of relevance to this debate, the Supreme Court struck down the MATS rule because EPA failed to consider costs in determining whether to regulate the power sector in *Michigan v. EPA*. The MATS rule was promulgated under Section 112 and the decision may have consequences for legal challenges to the CPP. The Supreme Court's reversal of the MATS rule gives EPA an opportunity to sidestep the issue entirely, avoiding subjecting its interpretation of Section 111(d) to judicial scrutiny of the interplay between 111(d) and Section 112. That is, were EPA to allow vacatur of the rule, this issue could be moot. However, EPA has indicated that it is inclined to push for remand rather than vacatur of MATS.

D. Opportunities to Engage and Comment

EPA will take public comments on the Proposed FIP and the model state plans and CEIP included therein. The comment period will commence upon publication of the Final CPP and Proposed FIP in the Federal Register, which can often take a month or longer after issuance. In addition to engagement with the Proposed FIP rulemaking process, interested parties will want to monitor and engage with state regulators as the states develop their compliance strategies.

Annex A

Annex A. Statewide Rate-Based CO_2 Emission Performance Goals (Adjusted Output-Weighted-Average Pounds of CO_2 per Net MWh from All Affected Fossil Fuel-Fired EGUs)[226]

State	Interim Goal - Step 1	Interim Goal - Step 2	Interim Goal - Step 3	Interim Goal	Final Goal
Alabama	1,244	1,133	1,060	1,157	1,018
Arizona*	1,263	1,149	1,074	1,173	1,031
Arkansas	1,411	1,276	1,185	1,304	1,130
California	961	890	848	907	828
Colorado	1,476	1,332	1,233	1,362	1,174
Connecticut	899	836	801	852	786
Delaware	1,093	1,003	946	1,023	916
Florida	1,097	1,006	949	1,026	919
Georgia	1,290	1,173	1,094	1,198	1,049
Idaho	877	817	784	832	771
Illinois	1,582	1,423	1,313	1,456	1,245
Indiana	1,578	1,419	1,309	1,451	1,242
Iowa	1,638	1,472	1,355	1,505	1,283
Kansas	1,654	1,485	1,366	1,519	1,293
Kentucky	1,643	1,476	1,358	1,509	1,286
Lands of the Fort Mojave Tribe	877	817	784	832	771
Lands of the Navajo Nation	1,671	1,500	1,380	1,534	1,305
Lands of the Uintah and Ouray Reservation	1,671	1,500	1,380	1,534	1,305
Louisiana	1,398	1,265	1,175	1,293	1,121
Maine	888	827	793	842	779
Maryland	1,644	1,476	1,359	1,510	1,287

* Excludes EGUs located in Indian country within the state

State	Interim Goal - Step 1	Interim Goal - Step 2	Interim Goal - Step 3	Interim Goal	Final Goal
Massachusetts	956	885	844	902	824
Michigan	1,468	1,325	1,228	1,355	1,169
Minnesota	1,535	1,383	1,277	1,414	1,213
Mississippi	1,136	1,040	978	1,061	945
Missouri	1,621	1,457	1,342	1,490	1,272
Montana	1,671	1,500	1,380	1,534	1,305
Nebraska	1,658	1,488	1,369	1,522	1,296
Nevada	1,001	924	877	942	855
New Hampshire	1,006	929	881	947	858
New Jersey	937	869	829	885	812
New Mexico*	1,435	1,297	1,203	1,325	1,146
New York	1,095	1,005	948	1,025	918
North Carolina	1,419	1,283	1,191	1,311	1,136
North Dakota	1,671	1,500	1,380	1,534	1,305
Ohio	1,501	1,353	1,252	1,383	1,190
Oklahoma	1,319	1,197	1,116	1,223	1,068
Oregon	1,026	945	896	964	871
Pennsylvania	1,359	1,232	1,146	1,258	1,095
Rhode Island	877	817	784	832	771
South Carolina	1,449	1,309	1,213	1,338	1,156
South Dakota	1,465	1,323	1,225	1,352	1,167
Tennessee	1,531	1,380	1,275	1,411	1,211
Texas	1,279	1,163	1,086	1,188	1,042
Utah*	1,483	1,339	1,239	1,368	1,179

* Excludes EGUs located in Indian country within the state

State	Interim Goal - Step 1	Interim Goal - Step 2	Interim Goal - Step 3	Interim Goal	Final Goal
Virginia	1,120	1,026	966	1,047	934
Washington	1,192	1,088	1,021	1,111	983
West Virginia	1,671	1,500	1,380	1,534	1,305
Wisconsin	1,479	1,335	1,236	1,364	1,176
Wyoming	1,662	1,492	1,373	1,526	1,299

Annex B

Annex B. Statewide Mass-Based CO_2 Emission Performance Goals (Adjusted Output-Weighted-Average Tons of CO_2 from All Affected Fossil Fuel-Fired EGUs)[227]

State	Interim Goal - Step 1	Interim Goal - Step 2	Interim Goal - Step 3	Interim Goal	Final Goal
Alabama	66,164,470	60,918,973	58,215,989	62,210,288	56,880,474
Arizona*	35,189,232	32,371,942	30,906,226	33,061,997	30,170,750
Arkansas	36,032,671	32,953,521	31,253,744	33,683,258	30,322,632
California	53,500,107	50,080,840	48,736,877	51,027,075	48,410,120
Colorado	35,785,322	32,654,483	30,891,824	33,387,883	29,900,397
Connecticut	7,555,787	7,108,466	6,955,080	7,237,865	6,941,523
Delaware	5,348,363	4,963,102	4,784,280	5,062,869	4,711,825
Florida	119,380,477	110,754,683	106,736,177	112,984,729	105,094,704
Georgia	54,257,931	49,855,082	47,534,817	50,926,084	46,346,846
Idaho	1,615,518	1,522,826	1,493,052	1,550,142	1,492,856
Illinois	80,396,108	73,124,936	68,921,937	74,800,876	66,477,157
Indiana	92,010,787	83,700,336	78,901,574	85,617,065	76,113,835
Iowa	30,408,352	27,615,429	25,981,975	28,254,411	25,018,136
Kansas	26,763,719	24,295,773	22,848,095	24,859,333	21,990,826
Kentucky	76,757,356	69,698,851	65,566,898	71,312,802	63,126,121
Lands of the Fort Mojave Tribe	636,876	600,334	588,596	611,103	588,519
Lands of the Navajo Nation	26,449,393	23,999,556	22,557,749	24,557,793	21,700,587
Lands of the Ute Tribe of the Uintah and Ouray Reservation	2,758,744	2,503,220	2,352,835	2,561,445	2,263,431
Louisiana	42,035,202	38,461,163	36,496,707	39,310,314	35,427,023
Maine	2,251,173	2,119,865	2,076,179	2,158,184	2,073,942

* Excludes EGUs located in Indian country within the state

State	Interim Goal - Step 1	Interim Goal - Step 2	Interim Goal - Step 3	Interim Goal	Final Goal
Maryland	17,447,354	15,842,485	14,902,826	16,209,396	14,347,628
Massachusetts	13,360,735	12,511,985	12,181,628	12,747,677	12,104,747
Michigan	56,854,256	51,893,556	49,106,884	53,057,150	47,544,064
Minnesota	27,303,150	24,868,570	23,476,788	25,433,592	22,678,368
Mississippi	28,940,675	26,790,683	25,756,215	27,338,313	25,304,337
Missouri	67,312,915	61,158,279	57,570,942	62,569,433	55,462,884
Montana	13,776,601	12,500,563	11,749,574	12,791,330	11,303,107
Nebraska	22,246,365	20,192,820	18,987,285	20,661,516	18,272,739
Nevada	15,076,534	14,072,636	13,652,612	14,344,092	13,523,584
New Hampshire	4,461,569	4,162,981	4,037,142	4,243,492	3,997,579
New Jersey	18,241,502	17,107,548	16,681,949	17,426,381	16,599,745
New Mexico*	14,789,981	13,514,670	12,805,266	13,815,561	12,412,602
New York	35,493,488	32,932,763	31,741,940	33,595,329	31,257,429
North Carolina	60,975,831	55,749,239	52,856,495	56,986,025	51,266,234
North Dakota	25,453,173	23,095,610	21,708,108	23,632,821	20,883,232
Ohio	88,512,313	80,704,944	76,280,168	82,526,513	73,769,806
Oklahoma	47,577,611	43,665,021	41,577,379	44,610,332	40,488,199
Oregon	9,097,720	8,477,658	8,209,589	8,643,164	8,118,654
Pennsylvania	106,082,757	97,204,723	92,392,088	99,330,827	89,822,308
Rhode Island	3,811,632	3,592,937	3,522,686	3,657,385	3,522,225
South Carolina	31,025,518	28,336,836	26,834,962	28,969,623	25,998,968
South Dakota	4,231,184	3,862,401	3,655,422	3,948,950	3,539,481
Tennessee	34,118,301	31,079,178	29,343,221	31,784,860	28,348,396
Texas	221,613,296	203,728,060	194,351,330	208,090,841	189,588,842

* Excludes EGUs located in Indian country within the state

State	Interim Goal - Step 1	Interim Goal - Step 2	Interim Goal - Step 3	Interim Goal	Final Goal
Utah*	28,479,805	25,981,970	24,572,858	26,566,380	23,778,193
Virginia	31,290,209	28,990,999	27,898,475	29,580,072	27,433,111
Washington	12,395,697	11,441,137	10,963,576	11,679,707	10,739,172
West Virginia	62,557,024	56,762,771	53,352,666	58,083,089	51,325,342
Wisconsin	33,505,657	30,571,326	28,917,949	31,258,356	27,986,988
Wyoming	38,528,498	34,967,826	32,875,725	35,780,052	31,634,412

* Excludes EGUs located in Indian country within the state

Annex C

Annex C. New Source Complements to Mass Goals[228]

State	New Source Complements (Short Tons of CO_2)		Mass Goals* + New Source Complements (Short Tons of CO_2)	
	Interim	Final	Interim	Final
Alabama	856,524	755,700	63,066,812	57,636,174
Arizona	1,424,998	2,209,446	34,486,994	32,380,196
Arkansas	411,315	362,897	34,094,572	30,685,529
California	2,846,529	4,413,516	53,873,603	52,823,635
Colorado	1,239,916	1,922,478	34,627,799	31,822,874
Connecticut	135,410	119,470	7,373,274	7,060,993
Delaware	78,842	69,561	5,141,711	4,781,386
Florida	1,753,276	1,546,891	114,738,005	106,641,595
Georgia	677,284	597,559	51,603,368	46,944,404
Idaho	94,266	146,158	1,644,407	1,639,013
Illinois	818,349	722,018	75,619,224	67,199,174
Indiana	939,343	828,769	86,556,407	76,942,604
Iowa	298,934	263,745	28,553,345	25,281,881
Kansas	260,683	229,997	25,120,015	22,220,822
Kentucky	752,454	663,880	72,065,256	63,790,001
Louisiana	484,308	427,299	39,794,622	35,854,321
Maine	40,832	36,026	2,199,016	2,109,968
Maryland	170,930	150,809	16,380,325	14,498,436
Massachusetts	225,127	198,626	12,972,803	12,303,372
Michigan	623,651	550,239	53,680,801	48,094,302
Minnesota	286,535	252,806	25,720,126	22,931,173
Mississippi	410,440	362,126	27,748,753	25,666,463
Missouri	668,637	589,929	63,238,070	56,052,813
Montana	421,674	653,801	13,213,003	11,956,908
Nebraska	216,149	190,706	20,877,665	18,463,444

* The state mass CO_2 goals can be found in Table 13 in *Section VII*

State	New Source Complements (Short Tons of CO_2)		Mass Goals* + New Source Complements (Short Tons of CO_2)	
	Interim	Final	Interim	Final
Nevada	770,417	1,194,523	15,114,508	14,718,107
New Hampshire	71,419	63,012	4,314,910	4,060,591
New Jersey	313,526	276,619	17,739,906	16,876,364
New Mexico	527,139	817,323	14,342,699	13,229,925
New York	522,227	460,753	34,117,555	31,718,182
North Carolina	692,091	610,623	57,678,116	51,876,856
North Dakota	245,324	216,446	23,878,144	21,099,677
Ohio	949,997	838,170	83,476,510	74,607,975
Oklahoma	581,051	512,654	45,191,382	41,000,852
Oregon	453,663	703,399	9,096,826	8,822,053
Pennsylvania	1,257,336	1,109,330	100,588,162	90,931,637
Rhode Island	70,035	61,791	3,727,420	3,584,016
South Carolina	344,885	304,287	29,314,508	26,303,255
South Dakota	46,513	41,038	3,995,462	3,580,518
Tennessee	358,838	316,598	32,143,698	28,664,994
Texas	5,328,758	8,516,408	213,419,599	198,105,249
Utah	981,947	1,522,500	27,548,327	25,300,693
Virginia	450,039	397,063	30,030,110	27,830,174
Washington	531,761	824,490	12,211,467	11,563,662
West Virginia	602,940	531,966	58,686,029	51,857,307
Wisconsin	364,841	321,895	31,623,197	28,308,882
Wyoming	1,185,554	1,838,190	36,965,606	33,472,602
Lands of the Navajo Nation	809,562	1,255,217	25,367,354	22,955,804
Lands of the Uintah and Ouray Reservation	84,440	130,923	2,645,885	2,394,354
Lands of the Fort Mojave Tribe	37,162	57,619	648,264	646,138
Total	**33,717,871**	**41,187,289**	**1,878,255,620**	**1,709,291,348**

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Endnotes

[1] U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (proposed Aug. 3, 2015) (pre-publication version) [Docket ID No. EPA-HQ-OAR-2013-0602] ***available at*** http://www.epa.gov/airquality/cpp/cpp-final-rule.pdf (hereinafter Final CPP).

[2] U.S. Environmental Protection Agency, "Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units" (proposed Aug. 3, 2015) (pre-publication version) [Docket ID No. EPA-HQ-OAR-2013-0495] ***available at*** http://www.epa.gov/airquality/cpp/cps-final-rule.pdf (hereinafter Final NSPS).

[3] 42 U.S.C. §7411, *et seq*.

[4] U.S. Environmental Protection Agency, "Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations" (Aug. 3, 2015) [EPA-HQ-OAR-2015-0199] ***available at*** http://www.epa.gov/airquality/cpp/cpp-proposed-federal-plan.pdf (hereinafter Proposed FIP).

[5] U.S. Environmental Protection Agency, "Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (June 2, 2014) (pre-publication version) [EPA-HQ-OAR-2013-0602] ***available at*** http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf (hereinafter "Proposed CPP"); ***see also*** U.S. Environmental Protection Agency, "Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units" (proposed June 2, 2014) (pre-publication version) [EPA-HQ-OAR-2013-0603] ***available at*** http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13725.pdf (hereinafter "Modified and Reconstructed Sources Rule").

[6] Final CPP at 22-23.

[7] *Id.* at 28-29; 775, Table 11.

[8] Regulatory Impact Analysis for the Proposed Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendments to Framework Regulations (Aug. 2015) (hereinafter Regulatory Impact Analysis) at 1-14, ***available at*** http://www.epa.gov/airquality/cpp/cpp-proposed-federal-plan-ria.pdf (last accessed Aug. 10, 2015).

[9] *Id.* at 841-843, Table 12.

[10] In an August 4, 2015 presentation, EPA included a flow chart with a third rate-based model described as a "different rates" approach. We understand this approach to be functionally the same as a "state measures" approach because it allows the state to modify the applicable EGU rates, presumably by shifting some of the state's burden from individual EGUs to another emission reduction strategy (*e.g.*, EE).

[11] *Id.* at 843-844.

[12] *Id.* at 22-23.

[13] *Id.*at 28-30.

[14] *Id.* at 272-3.

[15] *Id.* at 92.

[16] Regulatory Impact Analysis at ES-9.

[17] *See* Final NSPS at 9-10.

[18] Final NSPS Preamble at 438-39.

[19] *Id.* at 566-68.

[20] *Id.* at 274-76. For states that adopt a rate-based state plan, Section 111(b) sources would automatically be excluded since the Section 111(b) rule sets the emission rates for those sources. Under a mass-based state plan, states are allowed to include Section 111(b) sources in their state plans to avoid leakage.

[21] *Id.* at 1037-38, 1483-86.

[22] *Id.* at 1314.

[23] EPA has defined "base load natural gas-fired units" as units actually burning over 90% natural gas, and which make net sales of electricity in excess of their design efficiency (not to exceed 50%) multiplied by their potential electric output. "Non-base load gas-fired units" also burn over 90% natural gas, but make net electricity sales equal to or less than their design efficiency multiplied by potential electric output. "Multi-fuel-fired units" are units which burn 90% or less natural gas. *Final NSPS* at 466-67.

[24] *Id.* at 15-16.

[25] *Id.* at 1154-55.

[26] *Id.*

[27] *See Utility Air Reg. Group. v. EPA*, 134 S. Ct. 2427 (2014) (hereinafter UARG).

[28] Final NSPS at 601-24.

[29] *Final CPP* at 33.

[30] *Id.* at 34.

[31] *Id.* at 35-36.

[32] *Id.* at 37.

[33] *Id*. at 38.

[34] *Id*. at 40.

[35] *Id*. at 38-39.

[36] *Id*. at 39.

[37] *Id*. at 1002.

[38] *Id*. at 420.

[39] *Id.* at 879.

[40] *Id.* at 880; 902-907.

[41] *Id.* at 668.

[42] *Id.* at 725.

[43] *Id.* at 769.

[44] *Id.* at 661.

[45] *Id.* at 663.

[46] *Id.* at 661-663.

[47] *Id.* at 668.

[48] *Id.* at 667-668.

[49] *Id.* at 667.

[50] Id. See *generally* at 688-731.

[51] Final CPP at 703-704.

[52] *Id.* at 708.

[53] *Id.* at 708, 713-714.

[54] *See id.* at 705-706, 711.

[55] *Id.* at 705.

[56] *Id.* at 705-706.

[57] *Id.* at 706-707

[58] *Id.*

[59] *Id.* at 708.

[60] *Id.* at 711.

[61] *Id.*

[62] *Id.*

[63] *Id.* at 712.

[64] *Id.* at 709-710.

[65] Calculations based on data provided by EPA in Table 7 on page 708 of the Final CPP.

[66] Final CPP at 715-716.

[67] *Id.* at 717.

[68] *Id.* at 718.

[69] EPA suggests that affected fossil-fuelled steam EGUs can use Building Block 2 to comply with the Final CPP by shifting generation to affiliated lower emitting EGUs (to the extent applicable), reducing generation and purchasing replacement power or procuring generation from separately owned, lower emitting EGUs. *Id*. at 7-5-6.

[70] *Id.* at 696.

[71] *See id.* at 153-154.

[72] Final CPP at 731.

[73] *Id*. at 735.

[74] *Id*.

[75] *Id*. at 738.

[76] *Id*. at 738-739.

[77] *Id*. at 739.

[78] *Id*. at 750.

[79] *Id*. at 751.

[80] *Id*.

[81] *Id*. at 752-53.

[82] *Id*. at 752.

[83] *Id*. at 753.

[84] *Id*. at 753.

[85] *Id*.

[86] *Id*. at 761.

[87] *Id*.

[88] *Id*.

[89] *Id*. at 761-762.

[90] *Id.* at 760-61, Table 10.

[91] U.S. Environmental Protection Agency, Translation of the Clean Power Plan Emission Rate-Based CO_2 Goals to Mass-Based Equivalents, Docket ID: EPA-HQ-OAR-2013-0602-22187.

[92] Final CPP at 843-844, Table 13

[93] *Id*. at 892.

[94] Martin T. Ross, Brian C. Murray and David Hoppock, The Clean Power Plan: Implications of Three Compliance Decisions for U.S. States, Nicholas Institute, Working Paper, NI WP 15-02 (May 2015), *available at* https://nicholasinstitute.duke.edu/sites/default/files/publications/ni_wp_15-02_full_pdf.pdf (last accessed August 18, 2015).

[95] *Id*. at 1253-1254; Proposed FIP at 125.

[96] *Id*. at 882-4.

[97] *Id.* at 1213.

[98] *Id.* at 1261

[99] *Id.* at 1278

[100] *Id.* at 1260-1261

[101] *Id*. at 1261-62

[102] *Id.* at 1262-1263.

[103] *Id.*at 1267-68; Proposed FIP at 628-630.

[104] *Id.*at 1273

[105] Final CPP at 1270; *see, e.g.*, California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to Allow for the Use of Compliance Instruments Issued by Linked Jurisdictions, Cal. Code Regs. Section 95970 et. seq.

[106] Final CPP at 1257; 1269

[107] The Final CPP contemplates a role for independent registries in administering a rate-based trading program. For example, the Final CPP would allow EPA to delegate the authority to issue ERCs on the state's behalf to third party "agents." Final CPP at 1268-69.

[108] Final CPP at 1270-1271, 1273.

[109] *Id.* at 1275-1276.

[110] *Id.* at 1276.

[111] *Id.*

[112] *Id.*

[113] *Id.* at 1277.

[114] *Id.*

[115] *Id.* at 1278.

[116] New EGUs would be covered by Section 111(b) standards and, as such, are allowed to be excluded.

[117] Final CPP at 882 and 1196, but EPA has circulated documents suggesting that such plans would not be ready for interstate trading.

[118] Final CPP at 893 and 896.

[119] Final CPP at 1172-1173.

[120] California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to Allow for the Use of Compliance Instruments Issued by Linked Jurisdictions, Cal. Code Regs. tit. 17, §95802(a)(336).

[121] *Id.* at 834.

[122] *Id.* at 1175; 1193.

[123] *Id.* at 1183.

[124] *Id.* at 1175-1176.

[125] *Id.* at 1184.

[126] *Id.* at 1194-1195.

[127] *Id.* at 488.

[128] *Id.* at 1218.

[129] *Id.* at 1283, n.1004.

[130] *Id.* at 1245-1246.

[131] *Id.* at 1194-1195.

[132] *See Id.* at 1225; *see also Id.* at 1310 ("Rate-based states are not allowed to claim demand-side EE or any other emission reduction measures that were not included in the determination of the BSER located in mass-based states for ERC issuance. While this limits rate-based sources' access to additional resources, providing that access would result in a risk of foregone [GHG emissions] reductions.").

[133] *See Id.* at 1287-88.

[134] *Id.* at 874.

[135] *Id.* at 898 ("The EPA believes the state measures plan type will provide states with additional latitude in accommodating existing or planned programs that involve measures implemented by the state, or by entities other than affected EGUs, that result in avoided generation and CO2 emission reductions at affected EGUs. This includes market-based emission budget trading programs that apply, in part, to affected EGUs, such as the programs implemented by California and the RGGI participating states in the Northeast and Mid-Atlantic, as well as RE and demand-side EE requirements and programs, such as renewable portfolio standards (RPS), EERS **[**Energy Efficiency Resource Standard**]**, and utility- and state-administered incentive programs for the deployment of RE and demand-side EE technologies and practices.").

[136] *Id.* at 899.

[137] *See Id.* at 900.

[138] *Id.* at 903.

[139] *Id.* at 1190-91.

[140] *See* California Air Resources Board, Clean Power Plan Proposed Rule (111(d)) (Sept. 2014) Discussion Paper *available at* http://www.arb.ca.gov/cc/powerplants/meetings/discussion_paper.pdf.

[141] Notably, California's 2012 baseline was adjusted from 698 lbs CO2/Net MWh in the Proposed CPP to 963 lbs CO2/Net MWh in the Final CPP to be more representative. As such, the goal weakening is not quite as extensive as it initially appeared.

[142] However, state policies designed to accelerate the deployment of electric vehicles to meet both criteria pollutant and GHG emission reduction mandates are likely to result in the need for more generation capacity. If these policies succeed in electrifying much or all of the transportation sector, compliance with the Final CPP may prove more challenging and/or more complex for California.

[143] Final CPP at 629.

[144] *Id.* at 1177.

[145] *See id.* at 1193-94, n.924.

[146] *See* Regional Greenhouse Gas Initiative, Second Control Period Interim Adjustment for Banked Allowance Announcement (March 17, 2014), *available at* http://www.rggi.org/docs/SCPIABA.pdf.

[147] Final CPP at 1192, n. 992.

[148] *See* Regional Greenhouse Gas Initiative, 2015 CO_2 Allowance Allocation (July 15, 2015), *available at* https://www.rggi.org/docs/CO2AuctionsTrackingOffsets/Allocation/2015_Allowance-Allocation.pdf.

[149] Final CPP at 911-912.

[150] *Id.* at 916.

[151] *Id.* at 1291.

[152] *Id.*at 1291-1292.

[153] *Id.* at 1291-1292; Proposed FIP at 228.

[154] Final CPP at 1292.

[155] *Id.* at 1293-1294.

[156] *Id.* at 1294.

[157] *Id.* at 1294-1295.

[158] *Id.* at 1196-98.

[159] *Id.* at 1197.

[160] *Id.* at 1198.

[161] *Id.*

[162] *Id.* at 1198-99.

[163] *Id.* at 48-51, 76-78; *see generally id.* at 1103-1140.

[164] *Id.* at 60-61. Letter from the Federal Energy Regulatory Commission (FERC) to Janet McCabe, Acting Asst. Adm'r EPA (May 15, 2015) is available at http://www.ferc.gov/media/headlines/2015/ferc-letter-epa.pdf.

[165] Final CPP at 48-51.

[166] *Id.* at 77.

[167] *Id.*

[168] *Id.*

[169] *Id.* at 49-50.

[170] *Id.* at 1112.

[171] *Id.* at 1118-1119.

[172] *Id.* at 1119-1120.

[173] *Id.* at 1120, n. 870.

[174] *Id.* at 1120-1122.

[175] *Id.* at 1121-1122.

[176] *Id.*

[177] *Id.* at 1122-1123.

[178] *Id.* at 1125.

[179] *Id.* at 1125-26.

[180] *Id.* at 1126.

[181] *Id.* at 1126-1127.

[182] *Id.* at 1127.

[183] *Id.* at 1128.

[184] *Id.* at 1128-1130.

[185] *Id.* at 1129.

[186] *Id.* at 1129-1130.

[187] *Id.* at 1113, 1130-1131.

[188] *Id.* at 1131.

[189] EPA-DOE-FERC Coordination on Implementation of the Clean Power Plan (Aug. 3, 2015) *available at* http://www.ferc.gov/media/headlines/2015/CPP-EPA-DOE-FERC.pdf.

[190] Final CPP at 1297.

[191] *Id.* at 1302.

[192] *Id.* at 1302.

[193] *Id.* at 1304.

[194] *Id.* at 1305.

[195] *See id.* at 1302-1303.

[196] *Id.* at 1307.

[197] *Id.* at 1307.

[198] *Id.* at 1308.

[199] Proposed FIP at 48-49.

[200] *Id.* at 52-53.

[201] *See id.* at 104.

[202] *Id.* at 127, Table 6.

[203] *Id.* at 128-129, 144.

[204] *Id.* at 139-141.

[205] *See* Proposed FIP, at 148-49.

[206] *Id.* at 329.

[207] *Id.*

[208] *Id.* at 233-234.

[209] *Id.* at 239-240.

[210] *Id.* at 251-252.

[211] Further detail on EPA's proposed allocation approach is provided in the Allowance Allocation Proposed Rule TSD, which should be available in the docket, but was not at the time this *White Paper* was published. The affected-EGU-level allocations resulting from this approach purportedly are provided in the docket in an appendix to the TSD.

[212] *See* Proposed FIP at 259-260.

[213] The climate talks are the 21st session of the Conference of the Parties and the 11th session of the Conference of the Parties serving as the meeting of the Parties to the Kyoto Protocol, commonly referred to as COP 21 and CMP 11.

[214] United Nations Framework Convention on Climate Change (UNFCCC), United States Cover Note to Intended Nationally Determined Contribution (INDC), *available at* http://www4.unfccc.int/submissions/INDC/Published%20Documents/United%20States%20of%20America/1/U.S.%20Cover%20Note%20INDC%20and%20Accompanying%20Information.pdf (last visited August 15, 2015).

[215] *See* EPA, Power Plants are the Single Largest Source of Carbon Pollution, *available at* http://www2.epa.gov/sites/production/files/2014-05/ghg-chart.png, *see also* EPA, By The Numbers: Cutting Carbon Pollution From Power Plants, *available at* http://www.epa.gov/airquality/cpp/fs-cpp-by-the-numbers.pdf.

[216] Final CPP at 189.

[217] Karl Hausker et al., Delivering on the U.S. Climate Commitment: A 10-Point Plan Toward A Low-Carbon Future (May 2015) (Working Paper) (World Resources Institute), *available at* http://www.wri.org/publication/delivering-us-climate-commitment-10-point-plan-toward-low-carbon-future.

[218] The categories are "phosphate fertilizer plants (fluorides), sulfuric acid plants (acid mist), primary aluminum plants (fluorides), kraft pulp plants (total reduced sulfur) and municipal solid waste landfills (landfill gases)." *See* EPA, Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units, 9-10 (June 2014) available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602-legal-memorandum.pdf (hereinafter Legal Memorandum).

[219] Legal Memorandum at 10.

[220] *See Massachusetts v. Environmental Protection Agency*, 549 U.S. 497 (2007).

[221] *See American Electric Power Co.,Inc. v. Connecticut, 564 U.S.* ___ No. 10-174, slip op. (June 20, 2011).

[222] *UARG* 134 S. Ct. at 2444 ("The fact that EPA's greenhouse-gas-inclusive interpretation of the PSD and Title V triggers would place plainly excessive demands on limited governmental resources is alone a good reason for rejecting it; but that is not the only reason. EPA's interpretation is also unreasonable because it would bring about an enormous and transformative expansion in EPA's regulatory authority without clear congressional authorization.").

[223] Comments of Laurence H. Tribe and Peabody Energy Corporation, 79 Fed. Reg. 34830 (June 18, 2014).

[224] Robert R. Nordhaus & Ilan W. Gutherz, Regulation of CO2 Emissions from Existing Power Plants Under § 111(d) of the Clean Air Act: Program Design and Statutory Authority, Environmental Law Institute, 44 ELR 10366 (May 2014).

[225] Final CPP at 247.

[226] Final CPP at 841-843, Table 12.

[227] *Id.* at 843-844, Table 13.

[228] *Id.* at 1178-1180, Table 14.