JONES DAY | One Firm Worldwide℠

WHITE PAPER

August 2015

EPA Issues Clean Power Plan to Control Power Plant Carbon Emissions

At a White House ceremony on August 3, 2015, President Obama and the U.S. Environmental Protection Agency ("EPA") issued the Clean Power Plan ("CPP"), the administration's regulatory plan to reduce carbon dioxide ("CO_2") emissions from existing fossil fuel power plants to 68 percent of their 2005 levels by 2030. EPA seeks to impose the CPP on states that refuse to adopt it on their own and additional carbon emission standards for new, modified, and reconstructed sources. The CPP is expected to further reduce coal-fired power generation. It will further depress demand for coal and lead to additional economic distress and bankruptcy for companies in the coal mining sector. An open question is whether the government can be called upon for compensation for these losses.

The CPP represents the most far-reaching single action EPA has ever taken under the Clean Air Act ("CAA"). Far from simply regulating certain emissions from certain industrial sources, the plan essentially seeks to dramatically restructure the U.S. power system to reduce the contribution of coal from 36 percent of total generation capacity today to 27 percent over the next 15 years, while stimulating much broader deployment of renewable technologies as an alternative to both coal and natural gas. Indeed, opponents of the plan assert, and plan to argue in upcoming legal challenges, that many elements of the plan extend beyond the bounds of environmental regulation and simply exceed the authority Congress conferred on EPA in the CAA. EPA's attempt remake the power system will affect not only electricity producers and energy suppliers but also every sector of the economy that relies upon electricity by potentially affecting electricity's reliability and pricing.

EPA has relied on section 111(d) of the CAA as authority for the plan. That section does not permit direct regulation of existing power plant emissions but rather authorizes EPA to require state implementation plans based on the "best system of emissions reduction" that has been "adequately demonstrated" for the emissions at issue. In the CPP, EPA concludes that the best system for reducing CO_2 emissions from existing fossil fuel power plants consists of three "building blocks": (i) increasing the operational efficiency of such plants; (ii) shifting generation from higher emitting plants, generally coal-fired, to lower emitting plants, generally natural gas-fired; and (iii) increasing generation from "zero-emitting" energy sources, primarily wind and solar. As initially proposed by EPA in 2014, the plan included a fourth building block—improving demand-side energy efficiency, such as better insulation of homes and the use of LED light bulbs. Although energy efficiency is not a formal building block in the final version of the plan, EPA continues to emphasize the importance of the concept in the text.

Consistent with section 111(d), the plan does not directly regulate any existing sources. Instead, EPA has specified emission rates that each state in the continental U.S. must achieve by 2030 and a set of regulatory methods that the states may use to achieve those rates. While 2030 may seem a long way off, the requirements of the CPP will begin affecting states much sooner. Proposed plans must be submitted to EPA for review by September 6, 2016, and the final plans must be submitted within two years after that. In addition to the reductions that must be achieved by 2030, the plan establishes interim targets that must be achieved between 2022 and 2029.

EPA also proposed a "federal implementation plan that would be used to achieve the necessary reductions in states that either decline to participate or fail to submit a state implementation plan that EPA finds approvable." Emission trading, either within a single state or across multiple states, is not required by the final plan, but EPA strongly endorses the concept and encourages states to view emission trading as a market-based tool that allows emission reductions to occur in the most cost-effective manner. A group of nine northeastern states has already been administering an emission trading program for power plants, known as the Regional Greenhouse Gas Initiative, for six years and California began implementing a multisector cap-and-trade program several years ago. Moreover, EPA's proposed federal implementation plan for states that do not submit approvable state plans is based in large part on emission trading.

Predictable political battle lines were well-established even before the final CPP was released. A coal company and a group of 15 states, largely Republican-led, attempted to have the U.S. Circuit Court for the District of Columbia block the plan even before it was finalized, while a similarly sized group of states, largely Democrat-led, publicly supported EPA's proposal. While the D.C. Circuit deemed the legal challenge premature pending a final plan, that litigation will presumably resume as soon that the final plan is formally published in the Federal Register, probably in September. Trade groups and other states will likely file their own actions challenging the plan, while environmental groups and additional states will undoubtedly weigh in on the side of EPA.

In addition to arguments that the CPP's broad regulation of energy markets exceeds EPA's authority under the CAA, opponents have raised the more specific objection that EPA lacks authority to regulate power plant emissions under section 111(d), because EPA is already regulating such emissions under the Act's "air toxics" program. In a fascinating issue of statutory construction, this argument turns on the fact that the Senate and the House of Representatives passed different versions of the key language back in 1990, a discrepancy that Congress never resolved. It seems likely that the legality of the plan will ultimately be decided by the U.S. Supreme Court several years from now.

The CPP is 1,500 pages long, not counting its companion proposal for a federal implementation plan, which adds another 755 pages. In addition, EPA issued a 768-page final rule for new, modified, and reconstructed electric generating units ("EGUs"). In the following sections, we outline the structure, requirements, and legal issues associated with the two final rules and the proposed federal implementation plan. First, we examine new source performance standards for carbon emissions from new, reconstructed, and certain modified existing EGUs. Next, we move to the final rule regulating carbon emissions from existing EGUs analyzing the modified building blocks, subcategory-specific CO_2 emission performance rates, state plans, compliance timelines, the reliability safety valve, remaining useful lives of units, and environmental justice considerations. Finally, we summarize the federal implementation plan.

NEW SOURCES, RECONSTRUCTED SOURCES, AND MODIFIED SOURCES

Concurrently with the issuance of the final rule regulating carbon emissions from existing EGUs, EPA issued a final Carbon Pollution Standards rule ("CPS Rule"), establishing a new source performance standard ("NSPS") for carbon emissions from new, reconstructed, and certain modified EGUs. The NSPS standard is established pursuant to section 111(b) of the CAA and identifies the best system of emission reduction ("BSER"), which is then used to establish a final standard of performance.

Applicability of the NSPS Carbon Emissions to EGUs

To be subject to the NSPS carbon emission standards, the units must have a base load rating greater than 250 MMBtu/hr of fossil fuel (either alone or in combination with any other fuel) and serve a generator capable of selling more than 25 MW of electricity to a utility power distribution system. Exempt units include those with permits that limit annual net-electric sales below specified standards, municipal waste combustors, commercial or industrial waste incineration units, and those using primarily non-fossil fuels with permit conditions limiting the use of fossil fuels below specified standards. The EGUs also must have commenced construction after January 8, 2014 or reconstruction or modification after June 18, 2014.

Carbon Emission Standards for Coal-Fired Units[1] Subject NSPS

The final standards of performance (along with BSER) for new, modified, and reconstructed EGUs firing coal are summarized in the table below:

Generating Units	BSER	Final Standards of Performance
New Fossil Fuel-Fired Steam Generating Units or Integrated Gasification Combined Cycle ("IGCC") Units	Efficient new supercritical pulverized coal utility boiler implementing partial carbon capture and storage ("CCS")	1,400 lb CO_2/gross MWh
Modified Fossil Fuel-Fired Steam Generating Units or IGCC	Most efficient generation at the affected EGU achievable through a combination of best operating practices and equipment upgrades	Sources making modifications resulting in an increase in CO_2 hourly emissions of more than 10 percent are required to meet a unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no more stringent than: 1,800 lb CO_2/gross MWh for sources with heat input of more than 2,000 MMBtu/hr OR 2,000 lb CO_2/gross MWh for sources with heat input of 2,000 MMBtu/hr or less.
Reconstructed Fossil Fuel Fired Steam Generating Units or IGCC	Most efficient generating technology at the affected source (supercritical steam conditions for the larger; and subcritical conditions for the smaller)	Sources with heat input greater than 2,000 MMBtu/hr are required to meet an emission limit of 1,800 lb CO_2/gross MWh. Sources with heat input of 2,000 MMBtu/hr or less are required to meet an emission limit of 2,000 lb CO_2/gross MWh.

Although the final rule identifies CCS as BSER for new units, the final standard of performance increased to 1,400 pounds of CO_2 per megawatt hour (gross) from 1,100 pounds of CO_2 in the proposed rule. EPA indicated that the change reflects reconsideration of the costs to implement CCS.

EPA used the SaskPower Boundary Dam Unit #3 project in Estevan, Canada, as an example of a commercial-scale fully integrated post-combustion CCS project at a coal-fired plant to demonstrate that partial CCS is a viable, cost-effective technology that can be used to establish BSER. Although EPA claims that the Boundary Dam project alone is sufficient to support EPA's position that CCS is technologically feasible, EPA also discussed a number of other CCS projects in the final preamble, including projects that received funding from the United States Department of Energy.[2]

In a further change from the proposed rule, regulated units that are modified such that their emission increase is 10 percent or less are not subject to the NSPS for new, modified, and reconstructed units. These units with small modifications will remain subject to the standards for existing units discussed below. The emission limit for reconstructed sources was finalized as proposed.

The new source standard for these units (1,400 lb CO_2/MWh) turns out to be higher than the numerical standard for existing sources (1,305 lb CO_2/MWh), which is discussed elsewhere in this *White Paper*. The numbers by themselves imply that existing sources can be controlled better than new sources. In truth, the existing source standard is more stringent only because it regulates the average CO_2 emissions of all generation on the grid, while the new source standard does not extend beyond the boundaries of a particular regulated unit. This odd regulatory result seems to encourage existing sources to shift into the new source category, and it forced EPA to address that possibility in the development of mass-based emission targets and trading programs in the CPP.

Carbon Emission Standards for Natural-Gas Fired Units Subject to NSPS

The final standards for natural-gas fired units are:

Generating Units	BSER	Final Standard of Performance
New or Reconstructed* Base Load Natural Gas Stationary Combustion Turbines	Efficient natural gas combined cycle ("NGCC") technology	1,000 lb CO_2 per MWh of gross energy output or 1,030 lb of CO_2 of net energy output
Non-Base Load Natural Gas Stationary Combustion Turbines	Clean Fuels	120 lb CO_2/MMBtu
New or Reconstructed Multi-Fuel (less than or equal to 90% natural gas) Combustion Turbines	Clean Fuels	120 to 160 lb CO_2/MMBtu for multifuel-fired units, depending on the percentage of natural gas actually used.

*New combustion turbines are those commencing construction on or after January 8, 2014. Reconstructed turbines are those commencing reconstruction on or after June 18, 2014.

One significant change from the proposed rule is a reorganization of the way that units are categorized. In the proposed rule, the units were categorized into small and large combustion turbines based on whether the base load rating was greater than 850 MMBtu/h. In the final rule, the units are categorized into base load and non-base load units based on capacity factor—whether the net electric sales from the units are greater or less than 50 percent of the design efficiency multiplied by potential electric output. In addition, a new category was created for units that combust fuel consisting of 90 percent or less of natural gas.

Another change from the proposed rule is that no emission standards have been finalized for modified natural-gas fired units because EPA was "less confident" that all smaller combustion turbines, particularly those constructed prior to 2000, could meet the finalized standard if they undertook a modification.[3] EPA indicated that the modified sources would continue to be regulated as existing sources and subject to the CPP standards discussed below.

CPP REGULATION OF CARBON EMISSIONS FROM EXISTING SOURCES

EPA issued the final CPP rule establishing interim and final CO_2 emission performance rates for two subcategories of affected EGUs: coal/oil fuel units and natural gas units. Additionally, the CPP establishes three forms of interim and final statewide goals for states to use in implementing the performance standards: (i) rate-based state goals, (ii) mass-based state goals, and (iii) mass-based state goals with a new source complement. States are responsible for developing and implementing plans to ensure that EGUs in the respective states meet the interim and final goals through EPA-approved approaches.

EPA's authority to regulate CO_2 emissions from existing sources stems from CAA section 111(d). In 1990, the House and the Senate adopted conflicting versions of amendments to section 111(d) that were not ultimately reconciled in a Conference Committee before the legislation was signed into law. The House version prohibits EPA from regulating industrial *sources* under section 111(d) if those sources, or source categories, are subject to regulation under section 112. The Senate version prohibits regulation of *pollutants* under section 111(d) that are already regulated as hazardous air pollutants ("HAP"). Thus, the House version appears to prevent regulation of the same source under both sections 111(d) and 112, while the Senate version appears to prevent regulation of the same pollutants under sections 111(d) and 112. In the 2005 Clean Air Mercury litigation and again in the 2014 proposed rule, EPA interpreted the conflicting language as follows: "where a source category has been regulated under CAA section 112, a CAA section 111(d) standard of performance cannot be established to address any HAP listed under CAA section 112(b) that may be emitted from that particular source category."[4]

In the CPP, EPA has taken the position that section 111(d) contains an exclusion that prohibits the regulation under CAA section 111(d) of air pollutants that are regulated under CAA section 112, labeling this the "Section 112 Exclusion."[5] EPA argues that the two versions of the 1990 amendments are not "properly read as in conflict"[6] and that "the Section 112 Exclusion does not bar the regulation under CAA section 111(d) of non-HAP from a source category, regardless of whether that source category is subject to standards for HAP under CAA section 112."[7] EPA changed its interpretation based on reading the House version in the context of the larger statutory scheme that distinguishes between regulation of HAP and criteria air pollutants subject to National Ambient Air Quality Standards ("NAAQS"), but that contains "no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare."[8] Within this larger statutory structure, EPA interprets section 111(d) as intended to cover pollutants that are not regulated under either the criteria pollutant/NAAQS provisions or the HAP regulated under section 112."[9]

EPA Uses Building Blocks to Set BSER: Shift From Four Building Blocks to Three

The CPP uses BSER to set CO_2 emission performance rates for affected existing EGUs. Initially, EPA proposed using four "building blocks" to determine BSER: (i) improving the heat rate of existing coal-fired power plants; (ii) shifting electricity generation from higher-emitting coal-fired power plants to lower-emitting natural-gas emitting power plants; (iii) increasing electricity generation by zero-emitting renewable energy sources; and (iv) increasing state demand-side energy efficiency efforts. The final rule, however, shifts to a three building block analysis, preserving blocks 1–3 but not block 4.[10] Therefore, the final rule focuses on supply-side measures to reduce emissions and does not rely on state demand-side energy efficiency. Further, the final rule refines these three building blocks in response to improved data and public comments.

Block 1: Heat Rate Efficiency Improvements. Under building block 1, the proposed CPP Rule assumed a national 6 percent improved efficiency at all coal-fired units. Comments expressed a concern, however, that the methodology used to calculate this heat rate yielded an inflated figure due to equipment upgrades. In response, EPA has adjusted its analysis under the final rule and determined that it would be reasonable for coal-fired plants, through best practices and equipment upgrades, to reduce their CO_2 emissions by improving heat rate efficiency by 4.3 percent in the Eastern Interconnection, 2.1 percent in the Western Interconnection, and 2.3 percent in the Texas Interconnection. Had EPA conducted the final rule analysis at a national level, rather than regional, it would have arrived at a national heat rate reduction figure of 4.0 percent. Therefore, the regional analysis employed in the final rule results in a less stringent standard for the Western and Texas Interconnections, but a slightly more stringent standard for the Eastern Interconnection.[11]

Block 2: Shifting Electricity Generation from Existing Coal Plants to Existing Natural Gas Plants. The initial BSER analysis assumed that natural gas units could operate at 70 percent of their "nameplate capacity"—the designed capacity of a power plant as manufactured. However, comments indicated that this "nameplate capacity" did not reflect real operating conditions; rather, they suggested that EPA use a "net summer capacity factor" instead, which is based on data about how a unit actually performs. Net summer capacity is the maximum output that generating equipment can supply to a system load at the time of summer peak demand (June 1 through September 30). The net summer capacity reflects a reduction in capacity due to electricity use for stations or auxiliaries.

In response to these comments, the building block 2 analysis of the final rule assumes an annual average utilization rate of 75 percent of net summer capacity for natural gas units, rather than 70 percent of nameplate capacity. The rule states, however, that generally a net summer capacity factor appears higher compared to a corresponding nameplate capacity factor because net summer capacity reflects a lower amount of total generation achievable by the unit in practice. Therefore, according to EPA, the 75 percent net summer figure is "similar" to the 70 percent nameplate figure used in the proposal.[12]

The final rule concludes that the 75 percent is "technically feasible" by relying on the following statistics: (i) in 2012, roughly 15 percent of natural gas plants operated at annual utilization rates of 75 percent or higher on a net summer basis; and (ii) on a seasonal basis, approximately 30 percent of plants operated at 75 percent or higher rate on a net summer basis across the entire season, and a "significant number" of plants had achieved utilization rates of greater than 90 percent for "shorter, but still sustained periods of time."[13] The final rule acknowledges that these plants idle or operate at much lower capacity factors during the spring and fall, when electricity demands are typically lower, but goes on to state that:

> Nonetheless, the data clearly demonstrate that a substantial number of existing NGCC [natural gas combined cycle] plants have proven the ability to sustain 75 percent utilization rates for extended periods of time. We view this as strong evidence that increasing the annual average utilization rates of existing NGCC units to 75 percent on a net summer basis would be technically feasible.[14]

The final rule also notes that in 2012 roughly 10 percent of plants operated at annual utilization rates of 80 percent or higher on a net summer basis, and that the 75 percent figure is therefore a "conservative estimate" of the operating capacity existing plants are capable of achieving.[15] The fact that EPA relies on a fairly low percentage of plants that were able to achieve a 75 percent or greater utilization rate for seasonal (or shorter) periods of time raises doubt as to the achievability of the 75 percent figure for all plants on an annual basis.

Block 3: Shifting Generation from Existing Coal Plants to Renewables. Under building block 3, the BSER analysis in the proposed rule initially included provisions based on increasing nuclear electricity generation in addition to other renewable generation, such as wind and solar. The final rule, however, does not include existing or under-construction nuclear power plants. This change was in response to comments expressing the concern that the inclusion of nuclear power in the analysis would result in overly stringent goals for states in which nuclear plants were under construction. An additional concern was that the analysis did not account for potential delays in the completion of nuclear plants.[16]

Electricity generation from new or updated nuclear plants can, however, still be incorporated into state plans and count toward compliance with the emission standards. Therefore, while electricity generation by under-construction nuclear plants did not factor into setting the CO_2 emission goal, new or updated nuclear generation can count toward meeting the goal.[17] This approach seems to provide greater flexibility for states, at least those with new or updated nuclear plants, to meet the emission goals.

Removal of Block 4: Replacing Demand Side Management Requirements with Clean Energy Incentive Program. In place of the proposed building block 4 incorporating demand-side energy efficiency into the BSER determination, the CPP Rule establishes the Clean Energy Incentive Program ("CEIP"). EPA eliminated the use of demand-side energy efficiency in developing BSER and emission performance rates for both the coal and natural gas subcategories, since requiring such beyond-the-fenceline measures arguably does not fall within EPA's CAA section 111 authority.[18] Under the voluntary CEIP, eligible demand-side energy efficiency projects are those that reduce end-use energy demand during 2020 and 2021. EPA will award matching energy reduction credits to states that award early action credits, up to a limit equivalent to 300 million tons of CO_2 emissions.

EPA Establishes Subcategory-Specific CO_2 Emission Performance Rates Based on the Building Blocks

The final rule goes on to set subcategory-specific CO_2 emission performance rates. The two subcategories are: (i) fossil fuel-fired electric steam generating units (coal- and oil-fired power plants) and (ii) natural gas-fired combined cycle generating units. The initial CPP proposal set state emission performance rates, rather than technology-specific performance rates.[19] Comments expressed concern that this approach would lead to inconsistency by creating different incentives for the same technology class depending on the state in which the unit was located. Comments further expressed concern that not providing technology-specific requirements was inconsistent with EPA's previous interpretation of § 111(d). In response, the final rule establishes subcategory-specific emission performance rates that are identical across units within a subcategory regardless of where in the contiguous United States the unit is located.[20] However, EPA did attempt to preserve some of the flexibility of state plans and provided alternate statewide rate-based and mass-based goals, discussed below.

EPA applied the three building blocks analysis to all of the fossil fuel units and all of the natural gas units in each of the three regions discussed above. This produced regional emission rates for each subcategory. From there, EPA chose the most readily achievable rate from each subcategory to arrive at the emission performance rates for the country that represent the BSER. EPA repeated this analysis for each year 2022–2030. The rates for years 2022–2029 were averaged together to create the interim rate. The rate for year 2030 becomes the final emission performance rate for that year forward.[21] The interim rates are intended to allow for reasonable deployment and scaling up of BSER technologies.[22]

The interim and final emission performance rates are presented in the form of adjusted output-weighted-average CO_2 emission rates that the affected units could achieve through application of the BSER. The emission rates are expressed in terms of net rather than gross output. This means that the output is measured at the point of delivery to the transmission grid, rather than at the point of generation. The difference between net and gross output is the electricity used by the plant itself to operate auxiliary equipment such as fans, pumps, motors, and pollution control devices.[23]

These emission performance rates were then applied to all affected sources in each state to determine individual statewide rate-based and mass-based goals. Each state has a different goal based on its particular mix of affected sources.[24] States can demonstrate compliance with specific statewide goals through different state plan approaches discussed below.

Distinguishing Between Mass-Based Targets and Mass-Based Targets with a New Source Complement

Under the CPP, a mass-based goal is a total CO_2 emission goal for all of a state's affected EGUs. To meet the mass-based goal, a state could require individual affected EGUs to meet a specified mass emission standard or implement a market-based emission budget trading program.[25] EPA also anticipates the possibility of a mass-based goal with a new source complement that would include mass-based CO_2 emission standards for new fossil fuel-fired EGUs. Under this approach, an emission budget trading program could include affected existing EGUs and new fossil fuel-fired EGUs. Requirements for affected EGUs would be federally enforceable, while requirements for new fossil fuel-fired EGUs would be state-enforceable. To this end, EPA has set mass-based goals with a new source complement for each state.[26]

Role of States in Achieving Performance Standards

In the CPP, EPA does not establish a single nationwide policy for reducing CO_2 emissions but instead establishes state-specific CO_2 goals that are intended to reflect each state's mix of affected EGUs as well as guidelines for the development, submittal, and implementation of state plans that establish emission standards or other measures to implement CO_2 emission reductions. For each state (except for Washington, D.C. and Vermont, which do not have any fossil fuel power plants, and Alaska and Hawaii, which have grid issues that exempt them from participation for now), the CPP sets rate-based (lb/MWh) CO_2 goals that are the weighted aggregate of the emission performance rates for such state's EGUs. Each state's goal is also expressed as a CO_2 mass (in short tons of CO_2) goal. States must achieve the equivalent of the CO_2 emission performance rates, expressed via the state-specific rate-based or mass-based goals by 2030.

While states do not have control over their emission targets, they can decide how to meet them. States have the option of choosing between an "emission standards approach" and a "state measures approach."[27] Under the emission standards approach, the state places all of the requirements directly on the affected EGUs by establishing emission standards for its affected EGUs that are sufficient to meet the state's rate-based or mass-based goal. Under the state measures approach, the state can rely on state-implemented measures imposed on entities other than affected EGUs in conjunction with federally enforceable source-specific standards on affected EGUs to meet its mass-based goal. In writing a plan for a state measures approach, a state can select from several options, including switching from coal to natural gas, building renewable energy resources, or reducing consumers' electricity demand, among other things. However, if a state chooses a state measures approach, it must use its mass-based goal (not the rate-based goal), and its plan must provide for a federally enforceable backstop that would be triggered if the plan fails to achieve the required reductions on schedule.

Perhaps most importantly, states can also trade carbon emission credits with other states—effectively enacting a cap-and-trade regime at the state level. EPA concurrently proposed a model rule along with the final rule that, according to EPA, "paves the way" for states to implement mass-based trading.[28] A state plan using this model rule would be "presumptively approvable" by EPA.[29] While states are not required to engage in a collaborative emission trading system, EPA has provided multiple mechanisms to promote multistate collaboration:[30]

- States may submit multistate plans that address the affected EGUs in a group of states.
- States may coordinate plan implementation with other states through the interstate transfer of emission rate credits ("ERCs") or emission allowances without having to submit a joint plan.
- An individual state can submit a "ready-for-interstate-trading" plan that provides for the use of a CO_2 allowance issued by another state to comply with its plan but does not have to identify the states with which it will coordinate.

Given EPA's discussion about the broad support that it received in the comments for multistate trading collaborations and the many mechanisms provided in the final rule to implement such collaborations, it is clear that EPA seeks to encourage more collaborative state and regional trading partnerships like the Regional Greenhouse Gas Initiative in the future.

All state plans under the CPP must include the following components: (i) a description of the plan; (ii) applicability of state plans to affected EGUs; (iii) demonstration that the plan submittal is projected to achieve the state's CO_2 emission performance rates or state CO_2 goal; (iv) monitoring, reporting, and recordkeeping requirements for affected EGUs; (v) state recordkeeping and reporting requirements; (vi) public participation and certification of hearing on state plan; and (vii) supporting documentation. States must also provide documentation demonstrating that they have considered electric system reliability in developing their plans.

Disparate Impacts on States. The CPP affects each state differently, and the state goals may prove easier for certain states to meet than others. Indeed, 16 states will have more stringent targets to reduce CO_2 than those in EPA's original proposal last year. According to EPA's Janet McCabe, Acting Assistant Administrator for EPA's Office of Air and Radiation, this change is based on the cheaper costs of renewable energy sources such as wind and solar and the fact that certain states could easily source clean power from neighboring states if they did not have the capability to generate it themselves. "In the original proposal, we looked at each state in isolation," said McCabe. "In the final rule, we have opened it up so we could look at capacity for renewables and natural gas across the region." The result: Thirty-one states' goals were reduced, but tougher CO_2 emission reduction goals for other states make the CPP more ambitious than the original proposal.

Wyoming, Pennsylvania, North Dakota, Kentucky, West Virginia, Indiana, Missouri, and Kansas will have to reduce their CO_2 emissions the most, compared with the original proposal. In contrast, some of the states that rely less on coal-fired electricity, such as California, Nevada, and Oregon, are well-positioned to comply with the new regulations. Some state officials who oppose the rule have said they are considering not submitting a plan at all to EPA. Any state that does not file a plan, or submits one that is unworkable under the federal rule, will be subject to an EPA-imposed federal plan.

Timetables for State Plan Submittal and Review.[31] In response to comments and to provide more flexibility for states to develop their plans, EPA is allowing for a two-year extension for states to submit a final plan. States must submit either a final plan or an initial submittal with a request for an extension by September 6, 2016. The initial submittal must identify final plan approaches under consideration, explain why the state needs additional time, and demonstrate how the state has been engaging with the public for development of the final plan.32 If EPA grants the extension, the state must submit a progress report on September 6, 2017 and submit a final plan on September 6, 2018.33 EPA will then have 12 months to review and approve each final plan.

EPA pushed back the interim reduction period to begin on January 1, 2022. The interim period will run from 2022–2029. States must meet interim goals in 2022–2024, 2025–2027, and 2028–2029. States can either adopt EPA's proposed interim emission performance rates or adapt each goal to accommodate the timing of the state's expected reductions, provided that the state's interim goal does not exceed eight years.[34] The final CO_2 performance rates or equivalent statewide mass- or rate-based goals must still be met no later than 2030.

In the final rule, EPA added a program, called the Clean Energy Incentive Program ("CEIP"), to incentivize early investment in renewable energy and energy efficiency projects.[35] States can set aside allowances or generate ERCs to eligible projects for the MWh those projects generate or the end-use energy savings they achieve in 2020 and/or 2021. EPA will match state-issued early action allowances and ERCs up to an amount that represents the equivalent of 300 million short tons of CO_2 emissions. A portion of this pool will be reserved for solar and wind projects, and another portion will be reserved for energy-efficiency projects in low-income communities. In order to participate in the program, a state must include a nonbinding statement of intent in its final plan or initial submittal to participate in the program by September 6, 2016.[36] EPA discusses the CEIP in the proposed federal plan and will address design and implementation details in a subsequent action.[37]

Reliability Safety Valve

In an effort to create additional flexibility and avoid potential grid reliability issues, EPA has introduced provisions in the final rule, including a "safety valve" provision, designed to allow states more time and ability to monitor and maintain reliability. Prior to the announcement of the final rule, several groups and states, including North American Electric Reliability Corporation ("NERC"), an international regulatory authority established to evaluate and improve the reliability of the bulk power system in North America, expressed concern that the CPP would compromise electronic system reliability. Specifically, NERC noted that implementation of the CPP would:

- Accelerate an ongoing fundamental shift in the generation resource mix toward greater use of gas and renewables, which presents reliability challenges as new resources have different essential reliability service characteristics than the current generation fleet;
- Change the use of the remaining coal-fired generating fleet from baseload to seasonal peaking, potentially eroding plant economics and operating feasibility; and
- Cause energy and capacity to shift to gas-fired generation, requiring additional infrastructure and pipeline capacity. NERC proposed that more time would be needed to develop coordinated plans to address shifts in generation and corresponding transmission reinforcements to address proposed CPP CO_2 interim and other emission targets.

EPA appears to have taken some of these concerns into account when it promulgated the final CPP Rule. For example, EPA pushed back the compliance date to 2022 from 2020, made reliability one of the issues states must consider in their compliance plans, and allowed the states to modify their plans if reliability becomes a problem. Additionally, the safety valve provision allows states in emergency situations to notify EPA, which can approve a short-term modification to a state's compliance plan for a 90-day period under which an affected power plant will not be required to meet the emission standard established under the state plan, but rather meet an alternative emission standard. Additionally, the affected power plant can continue to operate under the alternate emission standard after the 90-day period, if necessary.

Remaining Useful Life

Under the CAA, EPA must allow states to consider "among other factors, the remaining useful life of the existing source …" when applying an emission standard under section 111(d).[38] In the proposed rule, EPA said that state goals would inherently allow enough flexibility for states to account for the remaining useful lives of existing EGUs.[39] EPA therefore proposed that remaining useful life would not be a valid basis for any state to deviate from its proposed goal, notwithstanding the provision in section 111(d) on state discretion.[40]

Notwithstanding EPA's assertion, the state goals in the proposed rule assumed that many coal-fired units would retire before the end of their useful lives.[41] Numerous public comments expressed concern that the proposed goals were not achievable without these premature unit retirements. Commenters also noted that retiring units prematurely would, in many cases, result in stranded investments, as many companies have already made significant improvements to units that would need to shut down in order to comply with the proposed state goals.

In the final rule, EPA again claims that the "inherent flexibility" of the state goals approach will allow states to consider remaining useful life, saying that states can "select a form of standards (e.g., marketable credits or permits, retirement of certain older facilities after their useful life, etc.) that avoids or diminishes concerns about facility-specific factors such as remaining useful life."[42] EPA also believes that its revisions to the state goals and the interim goal deadline (2022 instead of 2020) will ensure that states really can, in practice, consider the remaining useful lives of existing EGUs as section 111(d) requires. The final rule includes a "stranded assets analysis" that defines the useful life of a coal-fired unit or a major retrofit as its "book life," or the period over which the assets are depreciated for financial reporting purposes.[43] The use of an accounting concept to evaluate whether states have flexibility to consider the remaining useful life units is a controversial aspect of the final rule.

Environmental Justice: Requirement to Meaningfully Engage Communities During Initial and Final Plan Submittal

Using EPA's environmental justice mapping and screening tool, EJSCREEN, EPA has conducted a proximity analysis for demographic information on the communities located within a three-mile radius of each affected power plant in the U.S. The analysis demonstrates that a higher percentage of communities of color and low-income communities live near power plants than national averages. EPA expects its environmental justice analysis to inform states as they meaningfully engage with communities and other stakeholders during the initial and final plan submittal processes. Specifically, EPA will require states to "provide information to the agency about the community engagement they have undertaken and the means by which they intend to involve vulnerable communities and other stakeholders as they develop their final plan."[44] While this data requirement lacks an obvious enforcement mechanism, EPA has established an incentive for states to meaningfully engage with communities. In order to qualify for a two-year extension for submission of final plans, the rule requires that states demonstrate how they are meaningfully engaging vulnerable communities and other interested stakeholders as part of their public participation process.

PROPOSED FEDERAL IMPLEMENTATION PLAN

On August 3, 2015, EPA also published its proposed federal plan ("federal implementation plan" or "federal plan") for implementing the emission guidelines for existing sources, as required under the CPP. If the final plan is adopted as a final rule, EPA will enforce it against covered EGUs in states that do not adopt their own state implementation plans. EPA also intends that the federal plan will be a model for states to use in developing their own implementation plans. For this reason, EPA intends to adopt two final model federal rules in the summer of 2016, before the September 2016 deadline for states to submit their own plans. A state plan based on one of the model federal rules will be presumptively approvable (subject to the state's satisfaction of other requirements). EPA will promulgate an individual federal plan, based on a model rule, for each state that fails to submit a plan or receive approval for its plan.

The proposed federal plan includes both a rate-based model trading rule and a mass-based model trading rule. EPA intends to select one of these two approaches for all federal plans promulgated for individual states. A single approach, according to EPA, will "enhance the consistency of the federal trading program, achieve economies of scale through a single, broad trading program, ensure efficient administration of the program, and simplify compliance options for affected EGUs."[45] Although EPA will accept comments on the choice between types of rules, it describes the mass-based approach as more "straightforward," given agency and industry experience with existing mass-based trading programs in other sectors.[46]

Mass-Based Model Trading Rule

Under the proposed mass-based rule, EPA will set an aggregate emission limit on statewide CO_2 emissions from covered EGUs and require those EGUs to surrender allowances sufficient to offset their own emissions during each compliance period. The aggregate emission limit for a state would be the state's mass-based emission goal under the CPP rule. One allowance permits the emission of one short ton of CO_2 during a compliance period equal to or later than the vintage of the allowance. The compliance periods would be the same as under the CPP: two three-year periods and a two-year period for the Interim Period (2022–2029), and two-year periods during the Final Phase (2030 and beyond). EPA does not propose to evaluate compliance on an intervening basis within any compliance period (unlike California's cap-and-trade program).

EPA proposes to distribute allowances within each state in an amount equal to that state's aggregate emission limit. Each covered EGU would be allocated a share of those allowances in the same proportion as its share of its state's CO_2 emissions, based on historical data for the years 2010 to 2012. This allocation would be reduced to provide for several small set-asides of allowances for use in connection with specified incentive programs. Retiring units would continue to receive allocations for several years after closure, to reduce the operator's incentive to keep an EGU operating in order to continue receiving its allocation. As an alternative to EPA's allocation method, states operating under the federal plan may request approval of their own method of distributing allowances.

Emission allowances may be transferred, purchased, and sold. They also may be banked for future use in "unlimited" amounts, but EPA does not propose to allow operators to "borrow" from future allocations of allowances. The proposed model mass-based rule also would allow interstate trading of allowances in linked state systems using the federal plan. The aggregate emission limit for such a multistate system would be the sum of the aggregate emission limits for each participating state.

Covered EGUs under the federal plan would be required to report data on CO_2 emissions by January 1, 2022, with subsequent quarterly reporting.

Rate-Based Model Trading Rule

Under the proposed rate-based rule, an EGU must achieve a stack emission rate less than or equal to the federally enforceable rate-based emission standard (CO_2 emissions per unit of energy output), or apply ERCs to bring its rate into compliance. An ERC represents one MWh of electric generation (or reduced electricity use) with zero associated CO_2 emissions. Thus, ERCs may be used to achieve compliance with the applicable rate-based emission standard by increasing an EGU's reported energy output without corresponding increase in reported emissions, thereby reducing its reported emission rate.

EPA would limit issuance of ERCs to certain categories of EGUs—EGUs reporting below the applicable emission rate standard and new natural gas combined cycle units—and to certain renewable and nuclear energy providers. Like allowances under the mass-based rule, ERCs may be transferred, purchased, sold, and banked (without quantity limit or expiration) but may not be "borrowed" from future compliance periods.

JUDICIAL REVIEW

Many parties will challenge the CPP in the D.C. Circuit and perhaps other venues. The broad outlines of those challenges are well-established and were discussed in our *Commentaries* on the proposed rule and the Supreme Court's last greenhouse gas rule decision. The final rules do little to change the landscape that confronts supporters and opponents of the rule. The key issues on which litigants are likely to focus include:

- **Anti-Commandeering.** Under well-settled federalism principles, the federal government is not permitted to commandeer state governments to implement federal policy. *New York v. United States*, 505 U.S. 144, 161 (1992). Commandeering may exist where a state is given no meaningful choice over whether or not to accept implementation of a federal regulatory program. *Nat'l Fed'n of Indep. Bus. v. Sebelius*, 132 S. Ct. 2566, 2660 (2012).

- **Impact of MATS Rule.** The existence of the Mercury and Air Toxics Standards ("MATS") for EGUs could deprive EPA of authority to use section 111(d) for existing EGUs. The outcome of this argument depends on the interpretation of different language for Section 111(d) adopted in the House and the Senate in 1990 without being reconciled by the conference committee. In the final rule, EPA sought to bolster its position that MATS does not deprive EPA of authority to proceed with the CPP.

- **Outside the Fenceline.** The CPP does not represent a traditional EPA approach to setting emission standards. For example, the focus of building block 2 is on what capacity factor natural gas units are capable of achieving, not on what CO_2 emission rates they actually have achieved. Similarly, there is no discussion of whether any single existing coal-fired *source* has actually achieved the CO_2 emission rate set by EPA. These departures from the Agency's traditional standard-setting methods will certainly be challenged.

These challenges will proceed through the D.C. Circuit with a high likelihood that the Supreme Court ultimately will resolve them. If the timeline for the MATS challenges can be taken as a guide, a Supreme Court decision could be expected in 2018, after the final state plans have to be submitted to EPA. This timeline will prompt opponents of the CPP to consider alternatives to waiting for the Supreme Court. The need for states to act in response to the CPP could present opportunities to litigate CPP issues in state courts.

Even if the validity of the CPP is affirmed in court, that may not be the end of litigation about it. Some EGUs and coal mines that are forced out of business by the CPP could seek compensation from the government for their losses. Cases suggest that the government is required to provide compensation when a regulation deprives a person of all economically beneficial use of its property or otherwise goes too far in interfering with investment-backed expectations. *Lucas v. South Carolina Coastal Council*, 505 U. S. 1003 (1992); *Penn Cent. Transp. Co. v. New York City*, 438 U.S. 104, 124 (1978).

CONCLUSION

Together, the final rules for new and existing sources and the proposed Federal Plan will significantly shift the status quo. The final rules establish EPA's strong preference for and a path forward for a comprehensive CO_2 emission trading scheme for EGUs, which could result in additional regional programs like the Regional Greenhouse Gas Initiative in the Northeast and Mid-Atlantic. EPA's new rules also create some incentive for states that do not want to be subject to EPA's proposed Federal Plan to develop their own state plans.

Although EPA has extended the compliance timeframe for states to develop their compliance plans, the timeline will still force many public utility commissions and utility companies to immediately expend significant resources to integrate the federal requirements into already established state energy planning such as integrated resource planning. Furthermore, even if expected legal challenges are at least partially successful, the lag between judicial review and the time needed for states to implement the final rules will likely result in a similar situation to that of the Mercury Air Toxics Rules, where states and power companies have already spent billions to comply with a rule that may ultimately be vacated.

As Congress attempts to weigh in, the regulatory scheme for electricity generation may be further complicated as new compromises are struck between the balance of state and federal authority to regulate electricity generation. In addition to heralding significant changes for the U.S. electrical generation system, the new rules signal significant implications for other industries, such as commercial aviation, which are on EPA's radar as large sources of greenhouse gases.

LAWYER CONTACTS

For further information, please contact your principal Firm representative or one of the lawyers listed below. General email messages may be sent using our "Contact Us" form, which can be found at www.jonesday.com/contactus/.

Mary Beth Deemer
Pittsburgh
+1.412.394.7920
mbdeemer@jonesday.com

John A. Rego
Cleveland
+1.216.586.7542
jrego@jonesday.com

Thomas M. Donnelly
San Francisco
+1.415.875.5880
tmdonnelly@jonesday.com

Danielle M. Varnell
Washington
+1.202.879.4696
dvarnell@jonesday.com

Gerald P. Farano
Washington
+1.202.879.4691
gfarano@jonesday.com

Charles T. Wehland
Chicago
+1.312.269.4388
ctwehland@jonesday.com

G. Graham Holden
Atlanta
+1.404.581.8220
ggholden@jonesday.com

Casey F. Bradford
Atlanta
+1.404.581.8119
cbradford@jonesday.com

Kevin P. Holewinski
Washington
+1.202.879.3797
kpholewinski@jonesday.com

Daniel L. Corbett
San Francisco
+1.415.875.5885
dcorbett@jonesday.com

Nancy MacKimm
Houston
+1.832.239.3776
nmackimm@jonesday.com

Jennifer M. Hayes
Pittsburgh
+1.412.394.7992
jhayes@jonesday.com

Jane K. Murphy
Chicago
+1.312.269.4239
jkmurphy@jonesday.com

ENDNOTES

1 These units are generally those that use solid coal to power steam generating units or gasified coal to power integrated gasification combined cycle ("IGCC") units.
2 Section 15962(i) of the Energy Policy Act of 2005 states that no technology can be considered adequately demonstrated for purposes of establishing BSER if the project receives assistance under the Energy Policy Act.
3 CPP Rule at 566.
4 CPP Rule at 245.
5 *Id.* at 244.
6 *Id.* at 247.
7 *Id.*
8 *Id.* at 249.
9 *Id.*
10 *Id.* at 283.
11 *Id.* at 650-57.
12 *Id.* at 711-12.
13 *Id.* at 712.
14 *Id.* at 712-13.
15 *Id.* at 713.
16 *Id.* at 385-88.
17 *Id.* at 387-88.
18 *See id.* at 389.
19 *Id.* at 771-72.
20 *Id.* at 772.
21 *Id.* at 803-18.
22 *Id.* at 772-73.
23 *Id.* at 777-79.
24 *Id.* at 818-19.
25 *Id.* at 892.
26 *Id.* at 1178-80, Table 14.
27 *Id.* at 32-33.
28 *Id.* at 29.
29 *Id.* at 34.
30 *Id.* at 911-12.
31 Alaska, Guam, Hawaii, Puerto Rice, and the District of Columbia are not required to submit a state plan. Id. 10-11.
32 CPP Rule at 37-8.
33 *Id.* at 1002.
34 *Id.* at 30.
35 *Id.* at 865.
36 *Id.* at 870.
37 *Id.* at 76.
38 CAA § 111(d)(1)(B).
39 79 Fed. Reg. 34,830, 34,925-26 (June 18, 2014).
40 *Id.*
41 *Id.* at 34,953 (projecting that 30–50 gigawatts of coal-fired generation "may be uneconomic to maintain" as a result of the proposed rule).
42 CPP Rule at 1085.
43 *Id.* at 1093-94.
44 *Id.* at 1324.
45 Federal Plan at 26.
46 *Id.*