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# Long-Term GHG Reduction Rule To Change Nature Of EPA

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Law360, New York (August 01, 2014, 11:10 AM ET) -- On July 29, the Subcommittee on Energy and Power of the House Energy and Commerce Committee held a hearing, "FERC [Federal Energy Regulatory Commission] Perspectives: Questions Concerning EPA's [U.S. Environmental Protection Agency's] Proposed Clean Power Plan and Other Grid Reliability Challenges."

The hearing addressed the controversial June 18, 2014, EPA proposal to engage in its most far-reaching actions to date for reducing domestic greenhouse gas emissions.[1] The proposal is projected by the EPA to reduce emissions from electric generating units by 30 percent below a 2005 baseline by 2030. The proposed rule would implement the EPA's authority under Section 111(d) of the Clean Air Act to require states to submit plans to reduce carbon dioxide emissions from fossil fuel-fired EGUs.

Although the proposal nominally aims to reduce emissions from existing power plants, in order to meet the EPA's prescribed GHG reduction goals, states would have to implement measures far "beyond the fence" of existing plants. The proposed rule sets state emission rate standards based on the quantified extent to which the EPA assumes that each state can: (1) shift energy production from EGUs fired by coal to those fired by natural gas, nuclear and renewable energy sources and (2) implement demand-side energy efficiency measures.

Thus, the rule represents a potential shift from the EPA's traditional role as an environmental regulator (i.e., governing what comes out of power plants) to that of an energy regulator (i.e., governing the mix of electricity sources used to meet our nation's power needs). This shift may test the limits of state and EPA regulatory authority.

**Section 111(d)**

Section 111(d) of the CAA requires the EPA to promulgate regulations requiring states to submit plans establishing standards of performance for existing sources that emit an air pollutant that is not a criteria pollutant under Section 108 of the CAA or a hazardous air pollutant under Section 112 when a new source performance standard under Section 111(b) would apply to that source if it were new. The EPA already has proposed carbon dioxide standards for new and modified and reconstructed fossil fuel EGUs in separate rulemakings.[2] Since GHGs are neither a criteria pollutant nor a Section 112 hazardous air pollutant, the EPA now is proposing to extend its Section 111 GHG regulatory program to include existing power plants. The existing source standards also depend on the existing of a new source performance standard applicable to GHGs for the same source category.

Section 111(a) defines a standard of performance as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction" that has been "adequately demonstrated" taking into account cost and other factors. In the rule package, the EPA proposes what it considers to be the "best system of emission reduction" for existing fossil fuel plants, emissions rate limits for fossil fuel plants in each state based on implementation of this system and requirements for state plans that incorporate these limits, including a schedule for state implementation.

**Best System of Emission Reduction**

Perhaps the most controversial aspect of the proposed rulemaking is the EPA's definition of the best system of emissions reduction. EPA defines this system as a combination of four building blocks:

1. efficiency improvements at existing coal plants;
2. changes to how electricity is dispatched that results in greater reliance on natural gas plants, taking into account the capacity of natural gas combined cycle units;
3. increased use of renewable and nuclear energy and avoided reductions in nuclear use; and
4. demand-side energy efficiency programs.

Of these three, only the first involves controls at the source itself and would account by the EPA's estimate for up to a six percent reduction in GHG emissions compared to a 2005 baseline. The remaining measures accounting for the vast majority of emissions reductions require reducing utilization of coal-fired plants and replacing that power through reliance on alternative generation or reliance on measures to reduce demand for the generation altogether. In so doing, these measures go far beyond the source to measures largely outside of the sole control of a power plant operator. Changes to how electricity is dispatched, increasing the supply of alternative energy sources and implementation of demand-side energy efficiency programs would require states to assert regulatory authorities beyond the area of environmental regulation and into the sphere of energy regulation.

The EPA does not require that each state rely on each of these four building blocks in its state plan. Indeed, the EPA explains as an alternative framework for its legal authority that it may simply treat reductions in utilization at coal-fired plants — essentially a required derate of capacity — commensurate with the amount of power that could be generated by replacement natural gas or renewable sources or the generation of which could be avoided due to demand-side management as an appropriate emission standard.

The EPA does, however, calculate emission rate goals (in terms of pounds of carbon dioxide produced per megawatt hour of fossil fuel electricity generation) for the years 2020 and 2030 assuming that each state will implement these four building blocks. Under the EPA's proposal, states would be able to use these building blocks or other tools, such as multistate cap-and-trade programs, to achieve the emission rate goals. However states choose to proceed, though, "beyond-the-fence" measures or some system to make up for a forced derate of coal-fired plants appear necessary to meet the EPA's standards.

**Requirements for State Plans**

The EPA is requiring that states submit their plans to meet the prescribed emissions rate goals by June 30, 2016. If a state is unable to complete a plan by that date, the EPA is requiring that the state submit an initial submittal by the deadline along with justification for the delay that includes a demonstration of steps taken to date by the state to prepare a final plan. If a state chooses to put forward an initial submittal rather than a final plan, the state would have until June 30, 2017, to submit a final plan or June 30, 2018, if it is participating in a multistate compliance plan. State plans must provide for the achievement of: (1) an interim emission target that must be met on an averaged basis between 2020 and 2029 and (2) the final target in 2030.

Each final plan must contain, among others, the following elements:

- identification of affected entities;
- description of plan approach and geographic scope;

- identification of state emission performance level;
- demonstration that plan is projected to achieve the required emission performance level;
- identification of emission standards;
- identification of monitoring, reporting and recordkeeping requirements;
- identification of milestones; and
- identification of backstop measures.

The EPA proposes to assess the adequacy of state plans based on four criteria, whether: (1) a state plan contains enforceable measures that reduce EGU GHG emissions; (2) these enforceable measures are projected to achieve emission performance equivalent to or better than the applicable state-specific emission rate goal; (3) the GHG emission performance is quantifiable and verifiable and; (4) the plan includes a process for state reporting of plan implementation, outcomes and corrective measures.

**Problems with Implementation**

States with a current generation mix that would require displacement of coal-fired power in order to achieve the EPA targets would face a potential host of problems. For example, each state does not have a single utility that owns all of the power plants and can select which ones to run based on meeting the EPA's proposed standards. Rather, in many parts of the country, multistate regional transmission organizations dispatch generating facilities on a least-cost basis to serve demand within the region. There is no state-by-state dispatch of power plants, nor ready means to accommodate such an approach.

While the proposal allows for the submission of multistate plans that might align better within regional transmission organizations, it is not clear that states have the legislative or regulatory authority to enter into such plans and then place specific dispatch requirements on regional transmission organizations. Moreover, the proposal to displace the dispatch of coal-fired resources with natural gas-fired ones does not fully account for the pressures already faced by the increase in natural gas generation spawned by abundant and inexpensive natural gas that has occurred without a corresponding increase in pipeline infrastructure to deliver the fuel reliably. Given the cold weather during the polar vortex this past winter, FERC and grid operators already have been addressing significant reliability issues caused by this increased reliance on natural gas. Furthermore, due to transmission constraints in some areas, local generation must be dispatched to serve local needs, and this local generation could be a coal-fired plant.

The FERC commissioners who testified at the Energy and Power Subcommittee hearing — all of whom were appointed or reappointed by President Obama — emphasized some of the challenges that regional transmission organizations might face if the EPA rules are finalized in their current form. In particular, Commissioner Moeller highlighted challenges in increasing the dispatch of natural gas plants from the current average of 55 percent to 70 percent, one of the "building blocks" proposed by the EPA.

As noted above, currently power is dispatched under an economic dispatch system, where power that is most economical is dispatched to meet market demands. Commissioner Moeller indicated that the EPA proposal could be viewed as a shift to an environmental dispatch system, where environmental attributes at least partially determine the form of power dispatched. To accommodate this change, the commissioner suggested that transmission organizations might need to implement fees on coal power, which would cause a shift to natural gas production while allowing transmission organizations to continue to use an economic dispatch methodology.

In addition to the dispatch issues, Commissioner Moeller also discussed the tension between the state-centric approach of the EPA regulations and regional structure of energy markets, and hypothesized that the agency's requirements could serve as a cap on energy use in 2030. Commissioner Clark added that the EPA regulatory system could restrict state flexibility in meeting energy requirements because after a state submits its compliance plan to the EPA, it would need to obtain the agency's permission to deviate from that plan. In addition, a number of commissioners highlighted the challenges noted above in bolstering natural gas pipeline infrastructure to meet increased demand due to the EPA rule. According to these commissioners, significant financing hurdles are impeding pipeline construction, and these hurdles will need to be addressed using policy, legislative or regulatory means in order for the projected increased reliance on natural gas to be able to occur.

The timing of the EPA's rulemaking also creates difficult uncertainties. The EPA's final rule, if it resembles the proposal, is sure to be the subject of a litigation challenge. If promulgated as planned in June 2015, appeals in the D.C. Circuit and U.S. Supreme Court might take as long as four to five years to resolve. Meanwhile, states would be required to proceed with adopting their plans by that time, assuming no stay of their obligations is issued. In regions with forward-capacity markets, generators generally contract to supply capacity three years in advance, and this precipitates a "must-offer" requirement during the delivery year. Grid operators rely on this supply to be available to keep the lights on. Accordingly, the timing of litigation and implementation could cause confusion in such markets for 2020. To the extent states use an averaging approach to meeting the interim standards in the 2020-2029 period, they will have to make up for shortfalls in emissions reductions in 2020 with increased reductions at a later time within that window.

**EPA's Authority**

The EPA has long been anticipated to take a very aggressive approach to its authority under Section 111(d) to adopt as BSER for greenhouse gases from power plants requirements that go beyond controls that can be implemented at the source itself. This is for the simple reason that a program limited to standards that impose requirements to control emissions only at the plant would be limited, in the absence of mature carbon sequestration and storage technology, to energy efficiency measures that cannot achieve major reductions. Thus, even prior to this proposal, debate has largely focused on whether the statutory definition of BSER is broad enough to encompass a "system" that basically requires that the plant not utilize its capacity such that other sources substitute for the plant's production or that demand for the plant's production be controlled.

The limits of EPA authority may become further apparent in the scenario where a state fails to submit a plan. In such a situation, Section 111(d)(2)(A) allows the EPA to create its own federal implementation plan for the state. It is not clear how the EPA would exercise such authority as a matter of federal law. For example, opponents of EPA plans may argue that Congress did not intend to allow the agency to regulate the dispatch of electricity through Section 111. Even an EPA requirement that coal-fired plants materially reduce their capacity utilization raises a host of energy regulatory and reliability concerns. The same argument could be made for EPA requirements to build a particular mix of future energy sources or the implementation of demand-side energy controls. And, even if the EPA has such authority, the question remains as to whether the agency has the capacity and expertise to govern electricity markets. After all, the implementation of the building blocks will require policy choices that affect the very reliability of each state's power grid.

In addition to the EPA's authority over energy markets, some have questioned whether the agency will ultimately have authority to issue the Section 111(d) rule at all. The EPA's Section 111(d) rule is premised on regulation of the same source category and pollutant under Section 111(b). The EPA's

Section 111(b) rules for new power plants have not yet been finalized. When they are, they will certainly be subject to legal challenge. If they are overturned, the EPA will arguably no longer have the authority to issue the Section 111(d) rule.

Regulation of existing power plant carbon dioxide emissions under Section 111(d) of the CAA would be unprecedented in its scope and complexity. Significant questions remain as to the legal authority of the EPA's proposal, as well as the mechanics of how such a proposal will be implemented. As currently structured, the EPA potentially would be assuming a role in the dispatch of power plants and imposing a requirement to assume such a role on the states, a role the EPA and states may neither want nor be fully equipped to handle.

[1] 79 Fed. Reg. 34,380.
[2] 79 Fed. Reg. 1,430 (Jan. 8, 2014); 79 Fed. Reg. 34,960 (June 18, 2014).

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