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EPA's Clean Power Plan: Implications for the Electric Power Sector

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Summary

On October 23, 2015, the Environmental Protection Agency (EPA) released the final version of regulations to reduce greenhouse gas (GHG) emissions from existing power plants (also referred to as electric generating units or EGUs by EPA). Since carbon dioxide (CO_2) from fossil fuel combustion is the largest source of U.S. GHG emissions, and fossil fuels are used for the majority of electric power generation, reducing CO_2 emissions from power plants plays a key role in the Administration's climate change policy. Under the provisions of the Clean Power Plan (CPP), states must prepare plans that reduce either total CO_2 emissions or emission rates at affected EGUs. When implemented, EPA projects the state plans will reduce CO_2 emissions from U.S. power generation approximately 32% by 2030 compared to 2005 levels.

EPA prepared state-specific CO_2 emissions rates based on newly established national performance standards and the state's existing power generation portfolio. A state must implement an EPA-approved plan to ensure that power plants individually, in aggregate, or in combination with other measures undertaken by the state, achieve the equivalent of the interim CO_2 emissions performance rates (over the "glide path" period of 2022 to 2029), and the final CO_2 performance rates, rate-based goals, or mass-based goals by 2030.

EPA based the national performance standards in the CPP on the best system of emissions reduction (BSER). In the final rule, BSER includes three ("inside the fence line") Building Blocks (BBs): BB 1 involves improving the heat rate (i.e., efficiency) of coal-fired steam EGUs. BB 2 substitutes generation from (lower-emitting) existing natural gas combined cycle (NGCC) units for generation from (higher-emitting) steam generating units. BB 3 has generation from new (zero-emitting) renewable energy generating capacity replacing generation from fossil fuel-fired generating units.

EPA has modeled potential implications of the CPP in its Regulatory Impact Analysis (RIA), and emphasizes demand-side energy efficiency (DSEE) as a potential low-cost option. While DSEE is not a part of the BSER (and is an "outside the fence" activity), EPA's RIA assumes DSEE can lower electricity demand and reduce electric system costs, thereby offsetting estimated electricity price increases. As a result, EPA projects lower average electricity bills nationally by 2030. EPA's RIA also estimates reduced electricity demand will lower natural gas consumption, even as more NGCC capacity may be called upon to back up increased intermittent and variable renewable electric generation. Increased dependence on renewable generation may require new transmission lines. Many of today's transmission projects awaiting regulatory approvals are intended to serve renewable electricity projects. It can take from 3 to 10 years to get the federal, state, and local permits to build a major electric transmission line; planning may need to begin now so that new lines will be in place for when they may be needed in the early 2020s. State decisions on the design and availability of DSEE programs may be crucial to attaining the levels of subscribership necessary to achieve the demand reductions projected in the RIA. For some states, attaining the levels of cost-effective DSEE projects needed to reduce CPP compliance costs may be a challenge, while for the top tier of states currently engaged in DSEE, the challenge may be identifying the next increment of cost-effective projects.

Going forward, EPA's GHG regulations may provide a basis for the evolution of the U.S. electric power sector. EPA has based the CPP on increasing renewables as the technology of choice for new power generation. EPA declares in the CPP that states and affected EGUs can essentially use whatever methods they choose to meet CO_2 emissions and emission-rate reductions in timeframes proposed, and in so doing, creates a plan it believes most states and affected EGUs may be able to comply with in the timeframe allowed. The overall costs of CPP compliance will not begin to be known until after state compliance plans are filed and implemented.

Contents

Figures

Contacts

Introduction

On October 23, 2015, the U.S. Environmental Protection Agency (EPA) released the final version of its regulations to reduce greenhouse gas[1] (GHG) emissions from existing power plants (also referred to as electric generating units or EGUs).[2] Since carbon dioxide (CO_2) from fossil fuel combustion is the primary source of GHG emissions, and fossil fuels are used for the majority of electric power generation, reducing CO_2 emissions from power plants plays a key role in the Administration's climate change policy. CO_2 emissions are linked to anthropogenic climate change,[3] and the EPA cites the Obama Administration's intent to address climate change concerns.[4]

Under the provisions of the Clean Power Plan[5] (CPP), most existing fossil fuel-fired electric power generation plants will be subject to state-specific targets to reduce carbon emissions. The combined state targets are expected to result in reducing CO_2 emissions from power generation in the United States approximately 32% by 2030 as compared to 2005 levels.[6]

To meet CPP goals, EPA has established a national CO_2 emissions performance rate for fossil fuel-fired electric steam generating units (generally, coal- and oil-fired power plants), and for stationary combustion turbines (generally, natural gas-fired combined cycle generating units). EPA is also giving each state a specific CO_2 emissions rate based on these national performance rates and the state's existing power generation portfolio.[7] EPA believes that the CPP will "protect human health and the environment by reducing CO_2 emissions from fossil fuel-fired power plants in the U.S."[8] Mandatory compliance with the CPP begins in 2022, with final compliance with state CO_2 emissions or emission rate targets set for 2030.[9]

This report presents an analysis of EPA's Clean Power Plan in the context of the electric power sector. The full implications of implementing the CPP are unlikely to be known until after the states file their compliance plans, which are due by September 6, 2016 (although an extension to 2018 is available to allow for the completion of stakeholder and administrative processes). The

[1] Greenhouse gases are any gases that absorb infrared radiation in the atmosphere. There are six greenhouse gases addressed by EPA regulatory actions: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated gases—sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs). Carbon dioxide is the most prevalent GHG produced by combustion of fossil fuels. See http://www.epa.gov/climatechange/ghgemissions/gases.html.

[2] For a discussion of the changes from the EPA's proposed Clean Power Plan, see CRS Report R44145, *EPA's Clean Power Plan: Highlights of the Final Rule*, by Jonathan L. Ramseur and James E. McCarthy.

[3] "Humans tap the huge pool of fossil carbon for energy, and affect the global carbon cycle by transferring fossil carbon—which took millions of years to accumulate underground—into the atmosphere over a relatively short time span. As a result, the atmosphere contains approximately 35% more CO_2 today than prior to the beginning of the industrial revolution. As the CO_2 concentration grows it increases the degree to which the atmosphere traps incoming radiation from the sun, which further warms the planet." CRS Report RL34059, *The Carbon Cycle: Implications for Climate Change and Congress*, by Peter Folger.

[4] Executive Office of the President, *The President's Climate Action Plan*, June 2013, http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.

[5] Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Final Rule," 80 *Federal Register* 64661-65120, October 23, 2015. (Hereinafter, CPP.)

[6] CPP, p. 64665.

[7] CPP, p. 64664.

[8] Ibid.

[9] CPP, p. 64666.

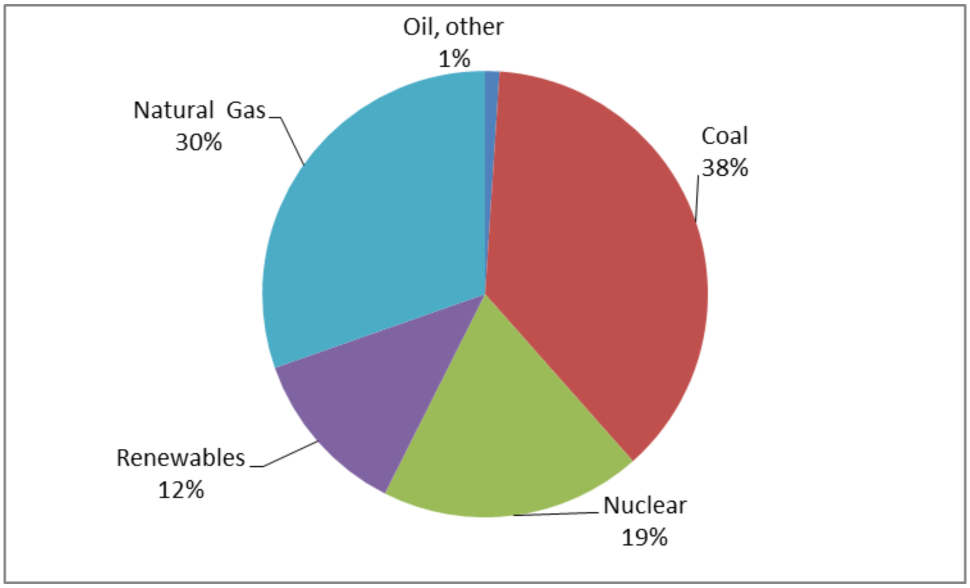
discussion of issues for Congress in this report will be focused on the implications of the CPP on electric power system reliability, the costs of electric power to customers, and the future structure of the electric utility industry which could result from implementation of state compliance plans.

Background

Burning fossil fuels to produce electricity results in the release of CO_2, and represents the largest source of GHG emissions in the United States. As shown in **Figure 1**, fossil fuel combustion was responsible for approximately 68% of electric power generation as of 2012. Coal was the fuel most used. Coal is also the fossil fuel which emits the most carbon dioxide per unit of electric power produced, averaging 216 pounds of carbon dioxide per million British thermal units (mmBTUs) of energy produced. By comparison, natural gas combustion releases about half the carbon emissions at 117 pounds of carbon dioxide per mmBTU of energy produced.[10]

Figure 1. U.S. Electricity Generation by Fuel, 2012

Trillion kiloWatt-hours per Year



Source: DOE, Annual Energy Outlook, 2014 Early Release, December 16, 2013, http://www.eia.gov/forecasts/aeo/er/early_elecgen.cfm.

Notes: Renewable electricity includes hydropower, wind, solar, and biomass power generation. "Other" includes other liquid fuels. Fossil fuels include coal, natural gas, and petroleum products such as oil and oil distillates.

In a 2007 decision, the Supreme Court found in *Massachusetts vs. EPA*[11] that GHG emissions were air pollutants which could be regulated under the Clean Air Act (CAA). EPA then moved in 2009 to declare that GHGs were a threat to public health and welfare in an "endangerment" finding, which served as a basis for subsequent actions from the agency.[12]

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[10] Energy Information Administration, "How Much Carbon Dioxide Is Produced When Different Fuels Are Burned?," June 4, 2014, http://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11.

[11] *Massachusetts v. EPA*, 549 U.S. 497, 529 (2007).

[12] U.S. Environmental Protection Agency, *Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act,* November 22, 2013, http://www.epa.gov/climatechange/endangerment/.

With regard to stationary sources of GHGs, EPA proposed new source performance standards (NSPS) in September 2013 for the control of CO_2 emissions from new electric power plants burning fossil fuels under CAA Section 111(b) regulations. These standards were finalized in October 2015.[13]

With the NSPS promulgated in October 2015,[14] EPA issued guidelines under CAA Section 111(d) for the control of CO_2 emissions from existing power plants burning fossil fuels. The standard of performance for existing sources is to reflect the degree of emissions limitation achievable through the application of the best system of emission reductions (BSER) that is "adequately demonstrated" and available to reduce pollution. The provisions under CAA 111(d) allow EPA to set goals, and gives states the responsibility for creating compliance plans which meet EPA's guidelines.[15]

EPA's Clean Power Plan for CO_2 Reduction

EPA's Clean Power Plan establishes interim and final CO_2 emission performance rates for fossil fuel-fired steam electric generating units and natural gas-fired combined cycle electric generating units.[16] Based on these performance rates, EPA calculated for each state a rate-based CO_2 emissions goal (measured in pounds of CO_2 per Megawatt-hour (lbs CO_2/MWh)) and a mass-based state goal (measured in total short tons of CO_2). A state must implement an EPA-approved plan to ensure that power plants individually, in aggregate, or in combination with other measures undertaken by the state, achieve the equivalent of the interim CO_2 emissions performance rates (over the "glide path" period of 2022 to 2029), and the final CO_2 performance rates, rate-based goals or mass-based goals by 2030.[17]

EPA outlines goals in the CPP for CO_2 reduction by establishing its best system of emissions reduction. The BSER is based upon three "building blocks" which EPA says are available to all affected EGUs,[18] either through direct investment or operational shifts or through emissions trading.[19]

[13] See EPA, "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units," 80 *Federal Register* 64509, October 23, 2015.

[14] 42 U.S.C. §7411(b).

[15] 42 U.S.C. §7411(d).

[16] CPP, p. 64664.

[17] CPP, p. 64673.

[18] "For the emission guidelines, an affected EGU is any fossil fuel-fired electric utility steam generating unit or stationary combustion turbine that was in operation or had commenced construction as of January 8, 2014 ... and that meets the following criteria, which differ depending on the type of unit. To be an affected source, such a unit, if it is a steam generating unit or integrated gasification combined cycle (IGCC), must serve a generator capable of selling greater than 25 MW to a utility power distribution system and have a base load rating greater than 260 GJ/h (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel). If such a unit is a stationary combustion turbine, the unit must meet the definition of a combined cycle or combined heat and power combustion turbine, serve a generator capable of selling greater than 25 MW to a utility power distribution system, and have a base load rating of greater than 260 GJ/h (250 MMBtu/h). Certain EGUs are exempt from inclusion in a state plan." See EPA, *Regulatory Impact Analysis for the Clean Power Plan Final Rule*, EPA-452/R-15-003, August 2015, http://www.epa.gov/airquality/cpp/cpp-final-rule-ria.pdf. (Hereinafter, RIA) RIA, p. 1-5.

[19] CPP, p. 64667.

> **Building Block 1**: Improving the heat rate[20] at affected coal-fired steam EGUs.
>
> **Building Block 2**: Substituting increased generation from lower-emitting existing natural gas combined cycle (NGCC) units for reduced generation from higher-emitting (primarily coal-fired) affected steam generating units.[21]
>
> **Building Block 3**: Substituting increased generation from new zero-emitting renewable energy generating capacity for reduced generation from affected fossil fuel-fired generating units.

All three building blocks are based on "inside the fence line" (i.e., EGU-focused) actions to reduce CO_2 emissions or emissions rates.[22]

EPA used the building blocks to create national performance rates for two subcategories of affected EGUs: fossil fuel-fired electric utility steam generating units and stationary combustion turbines. For fossil fuel-fired (i.e., mostly coal- and oil-fueled) steam generating units, an emission performance rate of 1,305 pounds of CO_2 per Megawatt-hour (lbs CO_2/MWh) is established. For stationary combustion turbines (identified by EPA as NGCC units), the performance rate is 771 lbs CO_2/MWh.[23] EPA believes that a transition period from 2022 to 2029 will allow for states to achieve these final performance rates by 2030.[24] In turn, EPA used the national performance rates to establish specific CO_2 reduction targets for each state based on each state's "historical blend" of fossil-fueled steam and NGCC generation. EPA believes that the ranges of CO_2 emissions reduction at coal, oil, and gas power plants can be achieved at a "reasonable cost" by application of the building blocks to a state's power generation portfolio.[25]

EPA is allowing states to choose how to meet their CO_2 emissions compliance goals, using rate-based goals (measured in lbs CO_2/MWh) or mass-based goals (measured in total short tons of CO_2). In addition, states can meet their goals using an emission standard plan or a state measures plan. The "emissions standard approach" is based on the EGU-specific requirements so that all affected EGUs will meet their emission performance rates or equivalent mass-based goals. States can also choose a "state measures approach" using a mixture of state-enforceable measures (such as a renewable electricity standard and programs for improvement of energy efficiency) to achieve (on aggregate) equivalent emissions or emission rate reductions. If a state measures approach is chosen, the plan must also include a "contingent backstop of federally enforceable

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[20] Heat rate is the efficiency of conversion from fuel energy input to electrical energy output often expressed in terms of British Thermal Units per kilowatt-hour (BTU/kWh).

[21] EPA is emphasizing a greater utilization of existing NGCC, not construction of new power plants in this Building Block.

[22] A fourth Building Block for demand-side energy efficiency in the proposed CPP was dropped from the final rule. EPA states that its "traditional interpretation and. implementation of CAA section 111 has allowed regulated entities to produce as much of a particular good as they desire provided that they do so through an appropriately clean (or low-emitting) process. While building blocks 1, 2, and 3 fall squarely within this paradigm, the proposed building block 4 does not. In view of this, since the BSER must serve as the foundation of the emission guidelines, the EPA has not included demand-side [energy efficiency] as part of the final BSER determination." CPP, p. 64738.

[23] See CPP, p. 64667.

[24] "Affected EGUs, individually, in aggregate, or in combination with other measures undertaken by the state, must achieve the equivalent of the CO_2 emission performance rates, expressed via the state-specific rate- and mass-based goals, by 2030." CPP, p. 64664.

[25] CPP, p. 64674.

emission standards for affected EGUs that fully meet the emission guidelines and that would be triggered if the plan failed to achieve the required emission reductions on schedule."[26]

States will also be able to formulate their own plans to reduce CO_2 emissions (as opposed to using the BSER), and can use an integrated resource plan[27] (IRP) or other method.[28] However, if they choose to implement their own plan they will have to include a timeline and process for reporting to ensure that the state's affected EGUs achieve the equivalent of the interim and final CO_2 emission performance rates between 2022 and 2029 and by 2030.[29]

States can also join existing or form new regional emission trading programs with other states for compliance purposes. EPA has promulgated each state's goal as a specific CO_2 mass goal[30] as a way for states to implement mass-based trading. Some states have expressed a view that mass-based trading has significant advantages over rate-based trading.[31]

States must decide whether to allow emissions trading, or require EGUs to meet specific CO_2 emission performance rates or a state "portfolio" measure, which can be rate- or mass-based. Depending on what the state plan allows, the owners of EGUs may be responsible for deciding how these requirements will be met (i.e., by application of the BSER or purchase of emission allowances).

EPA encourages investments in renewable electricity projects and demand-side energy efficiency (DSEE) in lower-income communities in 2020 and 2021. Under the Clean Energy Incentive Program (CEIP), established in the CPP final rule, EPA can award (a limited number of) matching allowances for renewable electricity projects that begin construction after participating states submit their final implementation plans. Energy efficiency projects in low-income communities are also eligible under the CEIP for double credits.

> Through this program ... states will have the opportunity to award allowances and [emissions rate credits (ERCs)] to qualified providers that make early investments in [renewable energy (RE)], as well as in demand-side [energy efficiency (EE)] programs implemented in low-income communities. Those states that take advantage of this option will be eligible to receive from the EPA matching allowances or ERCs, up to a total for all states that represents the equivalent of 300 million short tons of CO_2 emissions.[32]

Participation in the CEIP must be a part of the initial state CPP compliance submitted to EPA by September 6, 2016. This submission must outline all of the programmatic milestone steps necessary to achieve a state's compliance goals.

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[26] CPP, p. 64668.

[27] Generally, an IRP is a 10- to 20-year look forward at options for meeting future energy demand which is revisited typically every three to five years to help ensure the continued validity of the planning process.

[28] CPP, p. 64666.

[29] CPP, p. 64664.

[30] EPA calculates state specific mass-based goals as the product of the state-specific emission rate goal and the mass equivalent generation level. See Environmental Protection Agency, *Translation of the Clean Power Plan Emission Rate-Based CO_2 Goals to Mass-Based Equivalents*, Technical Support Document for Docket No. EPA-HQ-OAR-2013-0602, November 2014, http://www2.epa.gov/sites/production/files/2014-11/documents/20141106tsd-rate-to-mass.pdf.

[31] CPP, p. 64667.

[32] CPP, p. 64670.

The final state CPP implementation plan must be filed by September 6, 2018, with compliance with EPA-approved plans beginning in 2022. EPA has the authority to prescribe an implementation plan for any state that does not submit a plan or if EPA disapproves a state plan.[33]

Discussion of Clean Power Plan Elements

Electric power generation in the United States differs regionally, and largely reflects local resources, fuel costs, and availability of fuel supplies.[34] EPA recognizes that it will take time to implement compliance solutions to meet its proposed carbon pollution reduction plan. EPA is attempting to provide flexibility for state compliance with the CPP.

> States will have the flexibility to choose from a range of plan approaches and measures, including numerous measures beyond those considered in setting the CO_2 emission performance rates, and this final rule allows and encourages states to adopt the most effective set of solutions for their circumstances, taking account of cost and other considerations.[35]

While 2005 has been mentioned in broader U.S. policy terms for reductions in GHG emissions to 2030, it is not the year that EPA has used in its emissions reduction calculation. EPA chose 2012 as the year from which to establish a baseline for emissions reduction since that was the year for which it has the most complete state emissions, net generation, and capacity data for all affected EGUs. Some regard this as beneficial for many states since U.S. GHG emissions from EGUs have dropped 15% between 2005 and 2012, while others think it is not beneficial as early actors on clean energy do not get credit for CO_2 reductions in the timeframe from 2005 to 2012.[36]

Key elements of the CPP's approach and the potential implications for the electric grid are discussed in the following sections.

Best System of Emissions Reduction (BSER)

EPA has modeled opportunities for coal plant heat rate improvement, dispatch of more NGCC and fewer coal-fired power plants, and increased renewable electric power generation. The agency designated the three building blocks as the best system of emission reduction, and used the BSER to develop national EGU performance rates for steam and NGCC units.

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[33] "The purpose of the proposed federal plan is to establish requirements directly applicable to a state's affected EGUs that meet the emission performance levels in order to achieve reductions in carbon dioxide (CO_2) emissions in the case where a state or other jurisdiction does not submit an approvable plan. The stringency of the emission performance levels established in the final emission guidelines will be the same whether implemented through a state plan or a federal plan." See page 1-1, EPA, *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*, EPA-452/R-15-006, August 2015, http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-proposed-federal-plan-ria.pdf.

[34] Edison Electric Institute, *Different Regions of the Country Use Different Fuel Mixes to Generate Electricity*, 2014, http://www.eei.org/issuesandpolicy/generation/fueldiversity/Documents/map_fuel_diversity.pdf.

[35] CPP, p. 64665.

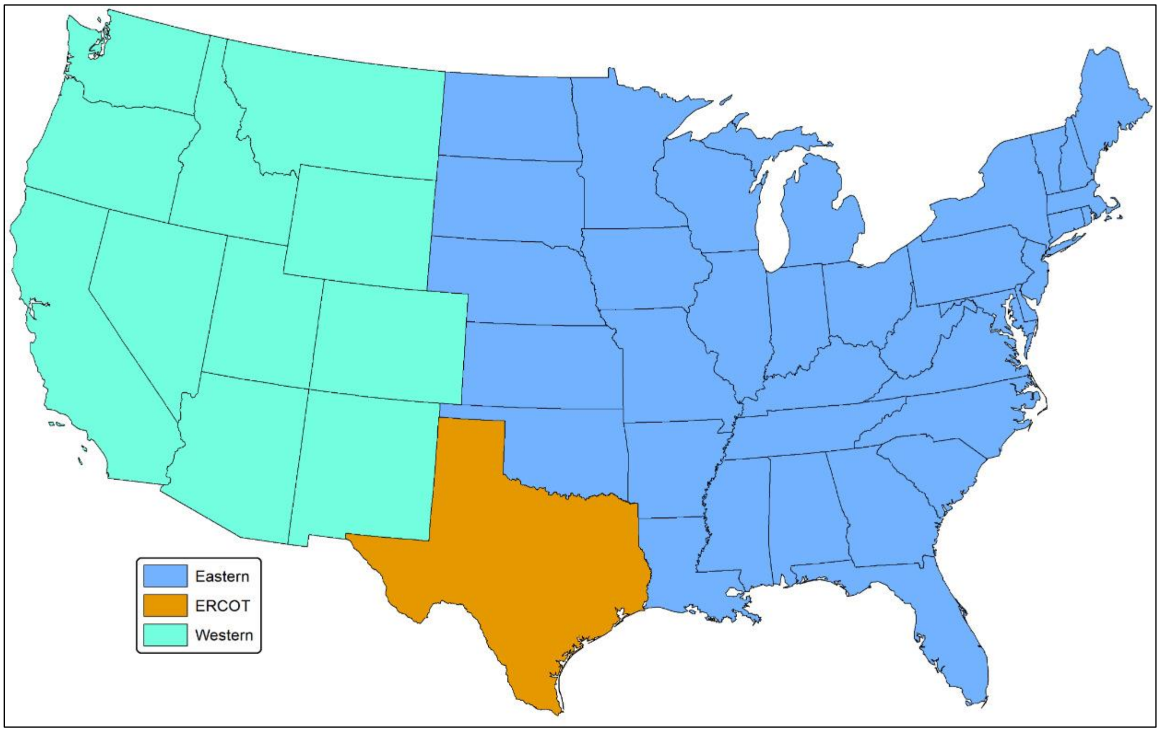
[36] Matthew Philips, "EPA Did the Power Industry a Big Favor by Using 2005 Levels," *Bloomberg BusinessWeek*, June 2, 2014, http://www.businessweek.com/articles/2014-06-02/epa-did-the-power-industry-a-big-favor-by-using-2005-levels.

Improving Heat Rate at Affected Coal-Fired Steam Electric Generating Units (EGUs)

EPA recognizes that increasing power plant efficiency by equipment upgrades and heat rate improvements[37] is a way for EGUs to reduce CO_2 emissions, and quantifies what it estimates is possible on a U.S. regional interconnection-wide basis (see **Figure 2**).[38]

> EPA has determined that a "conservative estimate of the potential heat rate improvements ... that EGUs can achieve through best practices and equipment upgrades is a 4.3-percent improvement in the Eastern Interconnection, a 2.1-percent improvement in the Western Interconnection and a 2.3-percent improvement in the Texas Interconnection.[39]

Figure 2. Illustrative Map of ERCOT, and the Eastern and Western Interconnection Regions



Source: EPA's Regulatory Impact Analysis (RIA), p. 3-10.

Notes: The area of responsibility of the Electric Reliability Council of Texas (ERCOT) does not coincide with the state boundaries of the state of Texas.

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[37] "These heat rate improvement measures include best practices such as improved staff training, boiler chemical cleaning, cleaning air preheater coils, and use of various kinds of software, as well as equipment upgrades such as turbine overhauls. These are measures that the owner/operator of an affected coal-fired steam EGU may take that would have the effect of reducing the amount of CO_2 the source emits per MWh." CPP, p. 64727.

[38] "These three network interconnections are the Western Interconnection, comprising the western parts of both the U.S. and Canada (approximately the area to the west of the Rocky Mountains), the Eastern Interconnection, comprising the eastern parts of both the U.S. and Canada (except those part of eastern Canada that are in the Quebec Interconnection), and the Electric Reliability Council of Texas (ERCOT) Interconnection, comprising most of Texas." RIA, p. 2-9.

[39] CPP, p. 64789.

Using less fossil fuel to generate the same amount of electricity at a facility will generally reduce its carbon emissions.[40] Those affected EGUs which have done the most to reduce their heat rate will tend to be closer to EGU's CO_2 performance emission rate.[41]

> These heat rate improvement measures include best practices such as improved staff training, boiler chemical cleaning, cleaning air preheater coils, and use of various kinds of software, as well as equipment upgrades such as turbine overhauls. These are measures that the owner/operator of an affected coal-fired steam EGU may take that would have the effect of reducing the amount of CO2 the source emits per MWh ... These heat rate improvements are a low-cost option that fit the criteria for the BSER, except that they lead to only small emission reductions for the source category.[42]

EPA expects that many coal-fired EGUs operating in 2030 will have made the investments required to improve unit heat rates.

> The majority of existing coal boilers are projected to adopt the aforementioned heat rate improvements. Of the 183 GW of coal projected to operate in 2030, EPA projects that 99 GW of existing coal steam capacity (greater than 25 MW) will improve operating efficiency (i.e., reduce the average net heat rate) under the rate-based approach by 2030. Under the mass-based approach, EPA projects that 88 GW of the 174 GW of coal projected to operate in 2030 will improve operating efficiency by 2030.[43]

New Source Review

The New Source Review P.L. 94-163[44] (NSR) program was designed to prevent the degradation of air quality from the construction of new facilities or modification of existing facilities which have potentially harmful emissions. Efficiency improvements to power plants that reduce regulated pollutants theoretically should not trigger NSR requirements, unless the improvements result in an increase in emissions (e.g., because the modified, more efficient plant operates for more hours).

EPA recognizes that CPP compliance plans could lead to an affected EGU making physical or operational changes. These changes could result in the unit being dispatched (i.e., scheduled for operation) more often, and cause an increase in the unit's annual emissions, possibly triggering NSR. However, EPA expects this to be a rare occurrence.[45]

Rebound Effects

The EPA is also aware of the potential for "rebound effects" from improvements in heat rates at individual EGUs. A rebound effect could occur if an improvement in an EGU's heat rate caused a reduction in variable operating costs. This would make the EGU more competitive relative to other EGUs, resulting in the EGU's generating more power. Nonetheless, EPA believes that a combined approach utilizing all three building blocks would alleviate the concern.

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[40] A discussion of potential improvements at coal-fired power plants is presented in CRS Report R43343, *Increasing the Efficiency of Existing Coal-Fired Power Plants*, by Richard J. Campbell.

[41] CPP, p. 64790.

[42] CPP, p. 64727.

[43] RIA, p. 3-24.

[44] NSR was established by Congress as part of the 1977 Clean Air Act Amendments (P.L. 95-95), and is codified in Sections 165-169 of the act. NSR requires pre-construction permits and the application of Best Available Control Technology at new major sources of air pollution, and at major modifications of existing major sources.

[45] CPP, pages 64919 to 64920.

> Combining building block 1 with the other building blocks addresses this [rebound effect] concern by ensuring that owner/operators of affected steam EGUs as a group would have appropriate incentives not only to improve the steam EGUs' efficiency but also to reduce generation from those EGUs consistent with replacement of generation by low- or zero-emitting EGUs. While combining building block 1 with either building block 2 or 3 should address this concern, the combination of all three building blocks addresses it more effectively by strengthening the incentives to reduce generation from affected steam EGUs.[46]

An increase in CO_2 emissions associated with an EGU's increase in generation output could offset the reduction in the EGU's CO_2 emissions caused by the decrease in its heat rate and rate of CO_2 emissions per unit of generation output. The extent of the offset would depend on the extent to which the EGU's generation output increased (as well as the CO_2 emission rates of the EGUs whose generation was displaced).[47]

Shifting Power Generation from Coal-Fired EGUs to Existing NGCC Units

EPA states that more frequent use of power plants that produce fewer CO_2 emissions (per MWh) will result in less carbon pollution. Dispatching higher efficiency, less carbon-intensive natural gas combined cycle units more would accomplish this goal.[48]

EPA also states that existing NGCC dispatch could be augmented with an increase in NGCC utilization rates, concluding that an annual average utilization rate of 75% on a net summer basis is "a conservative assessment of what existing NGCC plants are capable of sustaining for extended periods of time."[49] The increase in the utilization rate essentially would be accomplished over a glide path of annual increases in NGCC dispatch over the interim period from 2022 to 2029.[50] EPA concludes that the existing natural gas pipeline supply and delivery system would be capable of "supporting the degree of increased NGCC utilization potential" needed for this building block.[51] However, others might disagree with this conclusion, noting that in areas which use natural gas for residential and commercial heating, there could be competition on existing lines for natural gas delivery.[52]

EPA considers the phased increase in utilization of existing NGCC capacity to be a less expensive option to conversion of coal power plants to natural gas.[53]

Similarly, EPA is not emphasizing the construction of new NGCC units due to costs compared to other BSER options.[54] In the context of the BSER, EPA views construction and operation of zero-emitting renewable electric generating capacity as a preferable alternative to new NGCC.[55] New NGCC would also result in additional CO_2 emissions (compared to other BSER options).

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[46] CPP, p. 64748.

[47] CPP, pp. 64748-64749.

[48] CPP, p. 64745.

[49] CPP, p. 64799.

[50] CPP, pp. 64797-64798.

[51] CPP, p. 64800.

[52] Energy Information Administration, *Northeast and Mid-Atlantic Power Prices React to Winter Freeze and Natural Gas Constraints*, January 21, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=14671.

[53] CPP, p. 64728.

[54] CPP, p. 64729.

[55] "Because of the likelihood of CO_2 emissions for decades, the overall net emission reductions achievable through the construction and operation of new NGCC are less than for the measures including in the BSER, such as increased (continued...)

It should be noted that Building Block 2 incorporates reduced generation from steam EGUs,[56] while Building Block 3 incorporates reduced generation from all fossil fuel-fired EGUs.[57]

Increasing Generation from New Zero-Emitting Renewable Energy

Reducing power generation from coal-fired EGUs and replacing the capacity with power from lower- or zero-emitting EGUs is a way to reduce CO_2 emissions from the utility power sector.[58] EPA states that renewable energy technologies have been deployed in increasing amounts over the last few years.

> Many affected EGUs are already planning on deploying significant amounts of RE according to their integrated resource plans (IRPs). Electric utilities use [integrated resource planning (IRP)] to plan operations and investments over long time horizons. These plans typically cover 10 to 20 years and are mandated by public utility commissions (PUCs).[59]

EPA quantified potential renewable energy levels in 2030 in terms of the three interconnection regions.[60] EPA modeled the potential for renewable energy technologies to be deployed in increasing amounts during the interim period (2022 to 2029) based on historical deployment levels to replace fossil-fired EGU capacity. Assumptions were made to include projected future capacity factors[61] for renewable electric generation, and increased potential for future deployment based on historical five-year bands of average capacity changes.[62] As a result, EPA projects that implementation of the CPP may result in renewable energy making up 28% of total generating capacity by 2030 (in both the mass-based and rate-based scenarios) as compared to its base case projection of 25% renewables.[63]

(...continued)

generation at existing NGCC capacity, which would be expected to reach the end of its useful life sooner than new NGCC capacity, or construction and operation of zero emitting RE generating capacity. We view the production of long-term CO_2 emissions that otherwise would not be created as inconsistent with the BSER requirement that we consider the magnitude of emissions reductions that can be achieved. For this reason, we are not including replacement of generation from affected EGUs through the construction and operation of new NGCC capacity in the final BSER." CPP, p. 64730.

[56] "Compared to the base case, existing coal steam capacity is, on average, projected to operate at a lower capacity factor for both illustrative plan approaches. Under the illustrative rate-based plan approach, the average 2030 capacity factor is 69 percent, and under the mass-based approach, the average capacity factor for existing coal steam is 75 percent. Existing natural gas combined cycle units, which are less carbon-intensive than coal steam capacity on an output basis, operate at noticeably higher capacity factor under both illustrative plan approaches, on average. The utilization of existing natural gas combined cycle capacity is lower than the BSER level of 75 percent on an annual average basis in these illustrative plan approaches, reflecting the fact that, in practice, the most cost-effective CO_2 reduction strategies to meet each state's goal may not require that each building block be achieved in entirety." RIA p.3-24

[57] CPP, p. 64724.

[58] "The [renewable energy] technologies used to quantify building block 3 generation levels are onshore wind, utility-scale solar [photovoltaic (PV)], concentrating solar power (CSP), geothermal and hydropower. Each of these technologies is a utility-scale, zero-emitting resource." CPP, p. 64807.

[59] CPP, p. 64805.

[60] CPP, p. 64807.

[61] "The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period." See http://www.eia.gov/tools/glossary/index.cfm.

[62] CPP, p. 64808.

[63] RIA, Table 3-12. Note that according to the Energy Information Administration, hydro and other renewables were (continued...)

As regards the potential for power generation, EPA's analysis[64] projects that this increased renewable capacity (hydro and non-hydro) will represent 20% of projected total electricity generation (for both the rate- and mass-based scenarios) in 2030, as compared to 18% in the base case. This represents relatively small increases from the RIA based case in 2020, wherein renewables (hydro and non-hydro) represent approximately 17% of total generation in all cases (base case and the rate- and mass-based scenarios).[65]

EPA acknowledges that the intermittency and variability of some renewable electric technologies are seen as a potential hindrance to large-scale deployment,[66] but states there is adequate time to build infrastructure (potentially including new pipelines and fast ramping natural gas units) to back up renewable generation.[67] However, unlike some, EPA does not consider the need for large-scale electricity storage as essential for the growth of renewable electricity to levels comparable to utility-scale fossil or nuclear generation.

> The phase-in period would allow for additional time to complete potential infrastructure improvements (e.g., natural gas pipeline expansion or transmission improvements) that might be needed to support more use of existing natural gas-fired generation, and provides states with the increased ability to coordinate actions taken under building block 2 with actions taken under building block 3 (deployment of new renewable capacity).[68]
>
> ... Storage can be helpful but is not essential for the feasibility of RE deployment because there are many sources of flexibility on the grid. DOE's Wind Vision and many other studies have found an array of integration options (e.g., large balancing areas, geographically dispersed RE, weather forecasting used in system operations, sub-hourly energy markets, access to neighboring markets) for RE beyond storage. Storage is a system resource, as its value for renewables is a small share of its total value. Increasing regional coordination between balancing areas will increase operational flexibility.[69]

Nevertheless, EPA expects states and utilities will encounter few if any problems in connecting the expected increase in amounts of (variable or intermittent) renewable electricity into the grid. EPA concedes, however, that operational and technical upgrades (including new transmission lines) may be needed for non-dispatchable[70] renewable energy technologies.

(...continued)

10% of total net summer electric generating capacity in 2005, and 13% of total net electricity capacity in 2010. Renewable electricity is projected to grow through 2030, even without the CPP requirements. See http://www.eia.gov/electricity/capacity/.

[64] See RIA, Table 3-12.

[65] "In both [rate-based and mass-based] scenarios, total generation declines relative to the base case as a result of the reduction in total demand attributable to the demand-side energy efficiency applied in the illustrative scenarios, by 5 percent in 2025 and 8 percent in 2030." RIA, p. 3-25.

[66] "EGUs using technologies with relatively low variable costs, nuclear units, are for economic reasons generally operated at their maximum output whenever they are available. Renewable EGUs such as wind and solar units also have low variable costs, but the magnitude and timing of their output generally depend on wind and sun conditions rather than the operators' discretion. In contrast, fossil fuel-fired EGUs have higher variable costs and are also relatively flexible to operate. Fossil fuel-fired EGUs are therefore generally the units that operators use to respond to intra-day and intra-week changes in demand." CPP, p. 64795.

[67] In the simplest terms, solar power only generates electricity when the sun is shining, and wind power only generates electricity when the wind blows. Therefore these intermittent or variable renewable sources of power are made into "firm" electricity by increasing dispatch of power from (usually) natural gas-fired sources of generation when the renewable sources ebb.

[68] CPP, p. 64798.

[69] CPP, p. 64810.

[70] Since variable or intermittent renewable electricity technologies have their output controlled by the natural variability

(continued...)

> Grid operators are reliably integrating large amounts of RE, including variable, non-dispatchable RE today-.... **Operational and technical upgrades to the power system may be required to accommodate high levels of variable, non-dispatchable RE like wind and solar over longer time periods**; however, the penetration levels cited above have been achieved without negative impacts to reliability due in large part to low-cost measures such as expanded operational flexibility and effective coordination with other regional markets.[71] (**Emphasis added.**)
>
> The potential range of new transmission construction is within historical investment magnitudes ... Incremental grid infrastructure needs can be minimized by repurposing existing transmission resources. Transmission formerly used to deliver fossil-fired power to distant loads can – and is – being used to deliver RE without new infrastructure.[72]

Additional concerns have been raised that the expected retirement of many older coal plants will impact the provision of ancillary services.[73]

> Ancillary services are those that ensure reliability and support the transmission of electricity from generation sites to customer loads. Such services may include load regulation [i.e., the ability to maintain a constant voltage level], spinning reserve [i.e., generating capacity held in reserve which is running and synchronized to the electric system but not exporting power to the system], non-spinning reserve [i.e., generating capacity not currently running but capable of providing power to the system within a specified time], replacement reserve [i.e., generation held in reserve that requires a longer start-up time], and voltage support [i.e., generators providing reactive power to help move electricity over distances in alternating current systems].[74]

EPA asserts that some renewable energy technologies are capable of filling this gap, with the assistance of appropriate regulatory measures.

> New variable RE generators can provide more electrical power grid support services beyond just energy. Modern wind turbine power electronics allow turbines to provide voltage and reactive power control at all times. Wind plants meet a higher standard and far exceed the ability of conventional power plants to "ride-through" power system disturbances, which is essential for maintaining reliability when large conventional power plants break down. Xcel Energy sometimes uses its wind plants' exceedingly fast response to meet system need for frequency response and dispatchable resources. Utility-scale PV can incorporate control systems that enable solar PV to contribute to grid reliability and stability, such as voltage regulation, active power controls, ramp-rate controls, fault ride through, and frequency control. Solar generation is capable of providing many ancillary services that the grid needs but, like other generators, needs the proper market signals to trade energy generation for ancillary service provision.[75]

(...continued)

of the energy resource (e.g., the sun or the wind), intermittent output usually results. As such, these resources cannot be dispatched solely based on electric system requirements and are considered non-dispatchable resources.

[71] CPP, p. 64809.

[72] CPP, p. 64810.

[73] Some older power plants are transitioned to providing ancillary services as an alternative to full retirement.

[74] See EIA Glossary at http://www.eia.gov/tools/glossary/index.cfm.

[75] CPP, p. 64810.

Nuclear Power

EPA recognizes that renewable energy and nuclear generating capacity, as sources of lower- or zero-CO2 emission power, can potentially replace more carbon-intensive generation from affected EGUs. Therefore, EPA had originally considered including nuclear generation (from nuclear units under construction) in the CPP, and considered incentives to help existing nuclear generation which may be at risk of early retirement due to electricity market prices.[76] But, in the final CPP, EPA chose not to include generation from units under construction in the BSER because such generation does not actually reduce existing levels of CO_2 emissions from affected EGUs.[77]

EPA has also chosen not to include a BSER component in the final CPP to help preserve existing at-risk nuclear generation.[78] EPA acknowledges that while existing generation helps make current CO_2 emissions lower, existing generation "will not further lower CO_2 emissions below current levels."[79] EPA points to the potential for other options to reduce CO_2 emissions from affected EGUs.

> There are numerous other measures that are available to at least some affected EGUs to help assure that they can achieve their emission limits, even though the EPA is not identifying these measures as part of the BSER. These measures include demand-side [energy efficiency] implementable by affected EGUs; new or uprated nuclear generation; renewable measures other than those that are part of building block 3, including distributed generation solar power and off-shore wind; combined heat and power and waste heat power; and transmission and distribution improvements.[80]

EPA concludes that, in comparison to renewable electricity generating technologies, "investments in new nuclear units tend to be individually much larger and to require longer lead times."[81] EPA will, however, allow "emission reductions attributable to generation from the units to be used for [CPP] compliance."[82]

Emissions Trading

EPA conceived of national uniform standards for existing EGUs, in part, to facilitate emissions trading as a CPP compliance choice.[83] EPA views emissions trading as a cost-effective means of

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[76] "Exelon and Entergy are among US power generators facing rising pressures to close some of their nuclear plants, as a result of lower electricity prices, competition from cheap gas, and sometimes political opposition." Ed Crooks, "Uneconomic US Nuclear Plants at Risk of Being Shut Down," *Financial Times*, February 19, 2014.

[77] CPP, p. 64901.

[78] CPP, p. 64902.

[79] CPP, p. 64729.

[80] CPP, p. 64735.

[81] CPP, p. 64737.

[82] "With respect to existing nuclear units, although again we believe that other refinements in the final rule would address the concern about disparate impacts on particular states, we acknowledge that we lack information on shutdown risk that would enable us to improve the estimated 5.8 percent factor for nuclear capacity at risk of retirement. Further, based in part on comments received on another aspect of the proposal –- specifically, the proposed inclusion of existing RE generation in the goal-setting computations –- we believe that it is inappropriate to base the BSER in part on the premise that the preservation of existing low- or zero-carbon generation, as opposed to the production of incremental, low- or zero-carbon generation, could reduce CO_2 emissions from current levels." CPP, p. 64737.

[83] CPP, p. 64742.

compliance with the CPP, and while rate-based trading is possible, it has designed mass-based state goals specifically to facilitate trading.[84]

In general, while in some cases it may be cheaper to build new units than buy emissions credits,[85] economic studies indicate that emissions trading can potentially create a financial incentive to reduce emissions by affording owners of affected EGUs the opportunity to buy or sell emissions products (e.g., rate-based emission *credits* or mass-based emission *allowances*) to or from other affected EGUs.[86]

> With emissions trading, an affected EGU whose access to heat rate improvement opportunities, incremental generation from existing NGCC units, or generation from new RE generating capacity is relatively favorable can overcomply with its own standard of performance and sell rate-based emission credits or mass-based emission allowances to other affected EGUs. Purchase of the credits or allowances by the other EGUs represents cross-investment in the emission reduction opportunities, and such cross-investment can be carried out on as wide a geographic scale as trading rules allow.
>
> The regions we have determined to be appropriate for the regionalized approach in the final rule are the Eastern, Western, and Texas Interconnections.[87]

With the CPP, EPA provides support for a regional (or possibly a national) comprehensive CO_2 market to develop with these new credits and allowances, alongside or including other commodities such as renewable energy credits (which result from prior investments in CO_2 reduction technologies). In particular, in its federal plan proposal, EPA included "model rules" for both rate- and mass-based programs so that states have the option to adopt a consistent approach to emissions trading.[88] EPA affirms that it will support states in tracking emissions (and allowance and credit programs) in order to ensure the validity of CO_2 emission reduction strategies.[89]

Emissions trading was originally developed in the 1970s to address sulfur dioxide emissions, and a program to address climate change is already active in the nine states that comprise the Regional Greenhouse Gas Initiative (RGGI).[90] As the nation's first mandatory cap-and-trade program for GHG emissions, the RGGI cap-and-trade system applies only to CO_2 emissions from electric power plants with capacities to generate 25 MW or more. The RGGI emissions cap took effect January 1, 2009, based on an agreement signed by the governors of states participating in RGGI in 2005, and is generally considered to be an effective program.[91] Those that favor a cap-and-trade system argue that, among other features, it is preferable to a carbon tax or other means of regulation, because of the potential flexibility of the system and the certainty of the amount of

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[84] CPP, p. 64675.

[85] "States, and the industries they embody, can also set up trading platforms to exchange carbon credits amongst themselves. Those able to meet emissions requirements can sell credits to those unable to do so. It may be cheaper, though, to install new technologies than to buy credits." Ken Silverstein, *Clean Power Plan Formalized*, Public Utilities Fortnightly, August 3, 2015, http://www.fortnightly.com/fortnightly/clean-power-plan-formalized?page=0%2C1.

[86] CPP, p. 64741.

[87] CPP, p. 64739.

[88] CPP, p. 64833.

[89] CPP, p. 64839.

[90] For a discussion of RGGI, see CRS Report R41836, *The Regional Greenhouse Gas Initiative: Lessons Learned and Issues for Congress*, by Jonathan L. Ramseur.

[91] A cap is set on emissions, and a limited number of permits are created up to the level of the cap. A single permit corresponds to a set level of emissions requiring entities to hold generally one permit for every ton of emissions they produce. A price on pollution is set by trading in the permits.

pollution that is avoided. Others have criticized cap-and-trade programs because some features may limit the fairness or effectiveness of the program, such as the issuance of free emissions permits to large emitters, or the use of emissions offsets to allowances for pollution reduction projects in developing countries.

Issues Related to Compliance Strategies

In the CPP, EPA presents potential answers to questions on CO_2 reduction the electric power sector might ask with respect to timeframe, timeline, and choices that are available for compliance by EGUs. The CPP thus sets out a vision for a greater proportion of electric power production coming from natural gas and renewable energy generation, and less from coal-fired power plants, with specific goals for carbon emissions reduction proposed for 2030. However, some outstanding issues remain with regard to potential implementation of the CPP.

Electric System Reliability

EPA addresses concerns as to how the CPP might affect electric grid reliability by including several provisions to help assure system reliability.[92] With the inclusion of a "safety valve" provision, EPA recognizes that there may be a need for a power plant to continue operations resulting in "excess emissions" if an emergency situation arises which could compromise electric system reliability. EPA therefore allows a 90-day reprieve from CO_2 emission limits, but only in an emergency situation. Such emergency situations are not expected to include severe weather, as EPA states in the CPP that extreme weather events are of "short duration and would not require major—if any—adjustments to emission standards for affected EGUs or to state plans."[93]

EPA has also implemented a formal memorandum of joint understanding on maintaining electric system reliability with the Department of Energy and the Federal Energy Regulatory Commission so as to coordinate efforts while the state compliance plans are developed and implemented. The memorandum expresses the joint understanding of how the agencies will cooperate, monitor, implement, share information, and resolve difficulties that may be encountered.[94]

Transmission Queues and Renewables Development

The transmission system itself is aging and in need of modernization.[95] The grid is stressed in many regions because the system is being used in a manner for which it was not designed.[96] More transmission capacity will likely be needed to handle potentially more transmission transactions under the EPA proposal. Much of the transmission system was built by individual electric utilities to serve their own power plants. New power plants or increased utilization of existing NGCC capacity may require upgraded transmission facilities and potentially new natural gas

[92] CPP, p. 64671.

[93] CPP, p. 64878.

[94] *EPA-DOE-FERC Coordination on Implementation of the Clean Power Plan*, August 2015, http://www.ferc.gov/media/headlines/2015/CPP-EPA-DOE-FERC.pdf.

[95] Dwayne Stradford, *The Revitalization, Modernization of the Aging Transmission System*, Electric Light and Power, January 1, 2012, http://www.elp.com/articles/2012/01/the-revitalization-modernization-of-the-aging-transmission-system.html.

[96] Transmission of power was originally a function of a single, vertically integrated company moving power from power plants to consumers of electricity. But with the growth of wholesale power markets, the grid is being used to transport huge amounts of power in multiple transactions with the result that the system can become stressed at times.

infrastructure to provide fuel. Increased dependence on renewable generation will likely require new transmission lines, and many of today's transmission projects awaiting regulatory approvals are intended to serve renewable electricity projects.

It can take anywhere from 3 to 10 years to get the federal, state, and local permits in place to build a major electric transmission line.[97] If additional transmission capacity is required, planning would likely need to begin soon to get new lines in place for when they would be needed in the early 2020s.

The Federal Energy Regulatory Commission (FERC) has identified public policy requirements (such as state renewable portfolio standards) as drivers which should be elevated to the level of reliability[98] when it comes to approving new transmission projects in its Order No. 1000, *Transmission Planning and Cost Allocation*.[99] Such treatment is essentially intended to shorten the time for transmission line approval and permitting across multiple state jurisdictions. Actual implementation of regional Order No. 1000 compliance plans will demonstrate whether the regime for transmission planning and cost sharing will achieve FERC's goals.

Maintaining Fuel Diversity

Arguably, a central focus of the EPA's CPP proposal is on coal-fired power plants, with each of the three building blocks centering on either coal plant efficiency, reduced coal unit dispatch to lower emissions, or displacement of coal with renewable generation. The age and condition of coal-fired power plants are key considerations in a decision to upgrade or modify plants, or retire plants. Power plants in Regional Transmission Organization (RTO) regions operate in competitive environments where a power plant's operating and maintenance costs are not guaranteed recovery. Additional costs for plant upgrades may not be cost-effective under RTO electricity market regimes or prices, and state implementation plans for EPA's CPP may also result in differing requirements within RTO regions for competitive generators. Capacity markets designed to incentivize the construction of new generation in regions with competitive markets have had mixed results. New power plants will most likely be built in regions of the country with traditional regulation using tools like integrated resource planning, and rules allowing cost recovery from ratepayers for approved investments.[100]

EPA's CPP could potentially mean increased natural gas consumption under two of the three legs of the BSER stool. Building Block 2 would shift the dispatch of power generators to lower-emitting sources by increasing the scheduled operation of higher efficiency natural gas combined cycle units. Scheduling these plants more often would be expected to result in higher natural gas consumption.[101] In addition, Building Block 3 requires the use of more zero-emitting renewable

[97] "Permitting time for a major transmission line has doubled from 3-4 years to 10 years or more (particularly for environmental and land use reviews and approvals)." Alison Silverstein, *Transmission 101*, National Association of Regulatory Utility Commissioners, April 20-21, 2011, http://www.naruc.org/Grants/Documents/Silverstein%20NCEP%20T-101%200420111.pdf.

[98] Previously, a tiered system of transmission priorities existed wherein projects to maintain or improve reliability were given precedence.

[99] See discussion of Order No. 1000 in CRS Report R41193, *Electricity Transmission Cost Allocation*, by Richard J. Campbell and Adam Vann.

[100] Generally, an Integrated Resource Plan is a 10- to 20-year look forward at options for meeting future energy demand which is revisited typically every three to five years to help ensure the continued validity of the planning process.

[101] "Given that significant underutilized NGCC exists in various U.S. regions, the possibility of further shifting from coal base load plants to natural gas intermediate capacity exists. A recent study by the Massachusetts Institute of Technology in 2011 noted that the existing U.S. NGCC generation fleet had an average capacity factor of (continued...)

generation sources, which in many parts of the United States may require more natural gas consumption in fast-ramping power plants to make variable renewable electric generation more firm (i.e., provide power as renewable electric generation ebbs).

However, increasing the use of natural gas for power generation raises some concerns, as deliverability and price volatility issues have emerged as recently as this past winter with the demand spikes associated with the Polar Vortex cold weather events.[102] Recovery of costs from the Polar Vortex of January 2014 proved to be an issue for some utilities.[103]

FERC is working to improve coordination between the electricity and natural gas industries.[104] Major pipelines or local distribution companies have firm deliveries usually scheduled during nomination cycles,[105] and often release unused natural gas to secondary markets.[106] Electricity generators in competitive markets, where dispatch of generation is not certain, frequently obtain their natural gas from secondary markets. The utilization of more NGCC capacity (especially in the competitive markets) may require changes in the way fuel is obtained so that power generation can be guaranteed. More cost-effective, natural gas storage facilities may be required for electric power production purposes, if greater natural gas use for power generation is expected. However, the regulatory regime (i.e., Regional Transmission Organization markets or traditional regulation) in place will likely have a bearing on what choices are available to natural gas generators with regard to gas storage options or contracting for firm capacity vs. the "just-in-time" manner of natural gas deliveries traditionally available to power generators.

The electric utility industry values diversity in fuel choice options since reliance on one fuel or technology can leave electricity producers vulnerable to price and supply volatility. EPA expects additional retirements of coal-fired power plants, with some new NGCC capacity likely built to replace retiring coal capacity.[107] Nuclear power plants are also aging. Some plants expected to be in operation in the 2020 to 2030 timeframe could face premature retirement for a variety of reasons ranging from plant age to competitive electricity market fundamentals (wherein cost recovery is not guaranteed) or other conditions. Unless electricity storage capacity is increased or

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approximately 41%, while its design capacity allowed such plants to operate at 85%. The MIT study looked at a scenario across selected regions of the United States which mimicked the 'full dispatch' of existing natural gas combined cycle plants. The study concluded that under such a scenario (while noting that transmission constraints exist), there is 'sufficient surplus NGCC capacity to displace roughly one-third of U.S. coal generation, reducing CO_2 emissions from the power sector by 20%.'" See CRS Report R42950, *Prospects for Coal in Electric Power and Industry*, by Richard J. Campbell, Peter Folger, and Phillip Brown. (Hereinafter CoalProspects.)

[102] FERC, *2014 Winter 2013-2014 Operations and Market Performance in RTOs and ISOs*, AD14-8-000, April 1, 2014, http://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf.

[103] Veronique Bugnion, *The Polar Vortex Wreaks Havoc on Utility Bills*, Energy Collective, January 31, 2014, http://theenergycollective.com/vbugnion/334481/polar-vortex-wreaks-havoc-utility-bills.

[104] FERC, *Natural Gas—Electric Coordination*, June 2014, http://www.ferc.gov/industries/electric/indus-act/electric-coord.asp.

[105] A "nomination" is a request for a physical quantity of gas under a specific purchase, sales or transportation agreement or for all contracts at a specific point. Standard times are established during a day or month when volumes for deliveries of natural gas can be scheduled.

[106] "The natural gas industry generally follows the scheduling cycles adopted by the [North American Energy Standards Board (NAESB)], which FERC regulations incorporate by reference. The NAESB standards set a nationwide natural gas operating day (Gas Day), beginning at 9:00 a.m. CCT [Central Clock Time] and ending at 9:00 a.m. CCT the following day. Current regulations provide for a minimum of four standard nomination cycles over that 24-hour period with a 'Timely Cycle' and 'Evening Cycle' for nominations closing in the prior day and two 'Intra-Day' nominations during the Gas Day." See http://www.vnf.com/2311.

[107] CPP, pp. 64729-64730.

other concepts developed, natural gas will likely be used to smooth the variable output of some renewable electricity technologies. The developing potential for a heavier reliance on natural gas for power generation is a concern for many in the power sector.[108]

EPA's Regulatory Impact Analysis

EPA, for its part, states that its CPP can help preserve fuel diversity goals. The agency has modelled potential implications of the CPP in its Regulatory Impact Analysis (RIA) for the Clean Power Plan Final Rule.

The RIA presents two scenarios designed to achieve these goals (which it calls the "rate-based" illustrative plan approach[109] and the "mass-based" illustrative plan approach),[110] which are designed to reflect state and affected EGU approaches to CPP compliance.[111] However, in both the rate-based and mass-based scenarios, each plan is assumed to have identical levels of demand-side energy efficiency (DSEE) (represented as megawatt-hour (MWh) demand reductions and associated costs). Each scenario assumes that affected EGUs within each state comply with state goals without exchanging a compliance instrument (i.e., emission rate credits or allowances) with sources in any other state.[112]

Role of DSEE in the RIA

EPA therefore expects that DSEE will be a major tool in CPP compliance strategies, even though it is not a part of the BSER. The RIA applies its "illustrative DSEE" assumptions to the rate- and mass-based scenarios to arrive at electricity demand reductions.[113] As a result, EPA is expecting DSEE to lead to a significant reduction in electricity demand, resulting in a moderation of potential CPP compliance costs.

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[108] FERC, *Natural Gas - Electric Coordination*, October 2015, http://www.ferc.gov/industries/electric/indus-act/electric-coord.asp.

[109] "In the rate-based illustrative plan approach analyzed in this RIA, the affected EGUs within each state are required to achieve an average emissions rate that is less than or equal to the state goals for each state." RIA, p.3-8.

[110] "The mass-based scenario presented in this chapter includes a 5 percent set-aside of allowances that would be allocated to recognize deployment of new renewable capacity, which is represented by lowering the capital cost of new renewable capacity in a compliance period by the estimated value of the allowances in the set-aside in that period." RIA, p. 3-10.

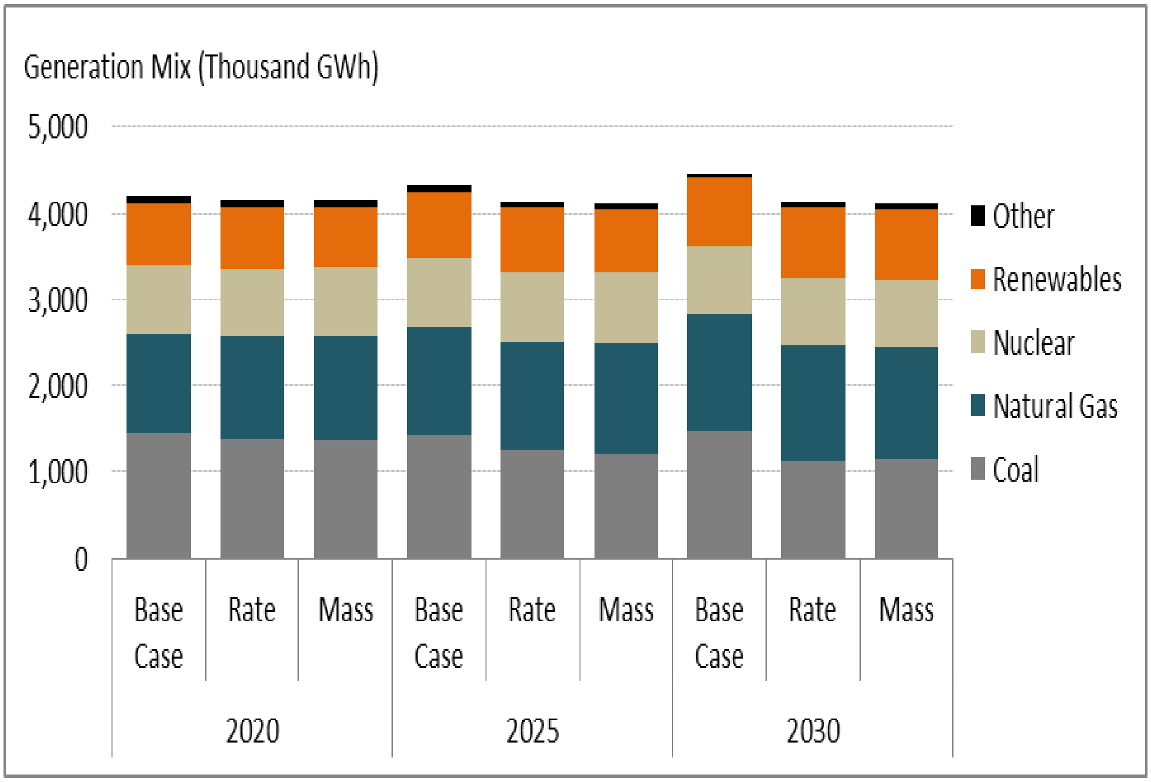
[111] "For the CPP, the analysis and projections for the year 2025 reflect the impacts across the power system of complying with the interim goals, and the analysis and projections for 2030 reflect the impacts of complying with the final goals. In addition to the 2025 and 2030 projections, modeling results and projections are also shown for 2020. There is no regulatory requirement reflected in the 2020 run-year in [the modelling analysis], consistent with the final rule." RIA, p. 3-12.

[112] RIA, p. ES-4.

[113] According to EPA, this "demand-side energy efficiency plan scenario" represents a level of performance that has already been demonstrated or is required by policies (e.g., energy efficiency resource standards) of leading energy efficiency implementing states, and is consistent with a demonstrated or required annual pace of performance improvement over time. RIA, p. 3-13.

Figure 3. EPA's Projection of the Future Electric Generation Mix

From CPP Scenario Analysis



Source: CRS from RIA, Table 3-11.

Notes: Amounts in Thousand GigaWatt-hours (GWh).

Figure 3 illustrates the generation mix in EPA's RIA scenarios. Total power generation declines relative to the base case in both scenarios due to DSEE by 5% in 2025, and 8% in 2030. The scenarios thus present a case for a reduced overall need for power generation infrastructure relative to the RIA's base case.[114] EPA projects in 2030 that:

- under the **rate-based scenario**, coal-fired power generation could decline 23% from the base case, while existing NGCC increases by 18%, with non-hydro renewable electric generation increasing by 9% in 2030, and
- under the **mass-based scenario**, coal-fired generation is projected to decline 22% from the base case in EPA's RIA, while existing NGCC generation increases 5% relative to the base case. Relative to the base case, generation from non-hydro renewables increases 8% in 2030.[115]

EPA's RIA modeling estimates from 29 GW (under the rate-based scenario) to 38 GW (under the mass-based scenario) of coal-fired units could be rendered "uneconomic to maintain" and potentially retire by 2030 relative to the base case, representing between 14% and 19% of existing

[114] "Detailed information and documentation of EPA's Base Case ... including all the underlying assumptions, data sources, and architecture parameters can be found on EPA's website at: http://www.epa.gov/powersectormodeling." RIA, p. 3-2.

[115] RIA, pp. 3-25-3-26.

coal capacity.[116] The expected reduction in energy demand from DSEE will also slow installation of new natural gas combined cycle generation, with only new non-hydro renewable generation expected to grow.[117]

Potential Impacts on Electricity Prices in RIA

EPA's RIA looks at the implications to electricity prices and impacts on electricity rates in the context of its mass-based and rate-based scenarios.

Under the Energy Policy Act of 2005 (P.L. 109-58), *economic dispatch* is defined in Section 1234 as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." EPA's CPP recognizes that *security constrained economic dispatch* assures reliable and affordable electricity.[118] While some dispatch of renewable generation is prioritized in some markets (assuming the resource is available), economic dispatch is generally the rule.[119] Dispatch of intermittent renewables may also require the operation of higher cost natural gas units to firm up power (and thus compensate for the ebb and flow of the wind or solar resource). Moreover, in competitive markets, power plants are generally scheduled to operate under an economic dispatch regime whereby the generating units with the lowest electricity price offers are dispatched first, subject to reliability, security, and environmental considerations.

However, some observers say that EPA's CPP essentially proposes an *environmental dispatch* regime[120] for power plant operation under Building Blocks 2 and 3. The primary goal of environmental dispatch is to prioritize use of "cleaner" power generating units (i.e., which emit the least pollutants) by scheduling these plants to operate as much as possible to serve load demands. This could result in changes to the rules for dispatch order in some markets based first on emissions and then on other criteria, in perhaps a "security constrained *environmental* dispatch" regime. Cost could potentially be relegated to a tertiary role under a "clean and reliable electricity" system.

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[116] RIA, p. 3-30.

[117] RIA, pp. 3–31-3–32.

[118] "Security Constrained Economic Dispatch has two components—economic generation of generation facilities and ensuring that the electric system remains reliable." CPP, p. 64693.

[119] "The exact order of dispatch varies across the United States, depending on such factors as fuel costs, availability of renewable energy resources, and the characteristics of local generating units. The type of generators with the lowest variable costs are nuclear, hydroelectric, and renewable power (wind and solar). For economic and technical reasons, nuclear plants in the United States are almost invariably operated as baseload units at maximum output. While wind and solar plants have very low operating costs, their availability is limited by the availability of the resource (i.e., whether the wind is blowing or the sun is shining). Some electric power systems dispatch these variable resources, others do not, and wind generators are sometimes curtailed to keep electric supply in balance with demand.... While variable operating costs are the primary driver of the dispatch decisions made by an electric power system operator, other factors can lead to deviations from the hypothetical economic dispatch curve presented above. Power plant startup times and ramp rates; air permit requirements; electric transmission system constraints that require non-economic dispatch of generating units for system reliability purposes; and the preference of operators to avoid cycling nuclear units are several other factors that play a role in dispatch decisions." See Energy Information Administration, *Electric Generator Dispatch Depends on System Demand and the Relative Cost of Operation*, August 17, 2012, http://www.eia.gov/todayinenergy/detail.cfm?id=7590.

[120] U.S. Congress, House Committee on Energy and Commerce, Subcommittee on Energy and Power, *FERC Perspectives: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges*, Testimony of the Honorable Philip D. Moeller, 113th Cong., July 29, 2014.

The increased availability of natural gas has recently resulted in lower prices for wholesale electricity, with a general expectation that wholesale prices will remain relatively low for the next few years.[121] However, there is concern that shifting to an environmental dispatch regime could potentially result in increased electricity prices to consumers, depending on the generation resource mix employed. Under the CPP, without regional plans or agreements, RTOs may be faced with decisions on generator dispatch that take into account various state plans for meeting emissions targets rather than the lowest acceptable offers to serve load.[122]

EPA, for its part, says that states and affected EGUs are essentially free to embark on any strategy (in addition to the BSER) to reduce CO_2 emissions in meeting CPP emissions reduction requirements. EPA views emissions trading as a cost-effective means of compliance with the CPP, and has designed mass- and rate-based state goals specifically to facilitate trading as a compliance strategy. It views the RIA scenario analysis emphasizing DSEE as presenting a conservative estimate of potential CPP compliance costs, as it does not include emissions trading.[123]

Potential for Reduction of CPP Compliance Costs Using DSEE

In its RIA for the CPP final rule, EPA assumes DSEE levels attained by the top state achievers are a model for what can be reasonably achieved by other states.

> For the illustrative demand-side energy efficiency plan scenario, electricity demand reductions for each state for each year are developed by ramping up from a historical basis to a target annual incremental demand reduction rate of 1.0 percent of electricity demand over a period of years starting in 2020, and maintaining that rate throughout the modeling horizon. Nineteen leading states either have achieved, or have established requirements that will lead them to achieve, this rate of incremental electricity demand reduction on an annual basis. Based on historic performance and existing state requirements, for each state the pace of improvement from the state's historical incremental demand reduction rate is set at 0.2 percent per year, beginning in 2020, until the target rate of 1.0 percent is achieved.[124]

EPA thus expects that any increase in natural gas combined cycle capacity and thereby natural gas consumption will be muted by a projected decrease in energy demand (under the RIA DSEE illustrative scenario): the use of natural gas as a power generation fuel is expected to decrease about 1% in 2025 and 2030 (under the rate-base scenario), and as much as 4.5% (under the mass-based scenario) by 2030.[125]

EPA's model indicates that the decline in electricity demand shown by its RIA scenario analysis will lead to a reduction in average electricity bills.[126] EPA asserts that the combination of reduced electricity rates, reduced electric system costs,[127] and lower demand from its RIA analysis will translate directly into reduced consumer electricity bills by 2030.

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[121] See EIA, Natural Gas Section, at http://www.eia.gov/forecasts/archive/aeo13/source_natural_gas_all.cfm#netexporter.

[122] Electric Reliability Coordinating Council, *The Clean Power Plan Endangers Electric Reliability: RTO and ISO Market Perspectives*, November 28, 2014, http://www.hks.harvard.edu/hepg/Papers/2015/EPG%20FERC%20Filing.pdf.

[123] RIA, p. ES–8.

[124] RIA, p. 3–13.

[125] RIA, p. 3–33.

[126] See Table 3–22 in RIA.

[127] "The results show that annualized expenditures required to supply enough electricity to meet demand decline by $18 (continued...)

> The electricity price changes ... combine with the significant reductions in electricity demand applied in the illustrative approaches to affect average electricity bills. Under the illustrative rate-based plan scenario, EPA estimates an average monthly bill increase of 2.7 percent in 2020 and an average bill decrease of 3.8 percent in 2025 and 7 percent in 2030. Under the mass-based scenario, EPA estimates an average bill increase of 2.4 percent in 2020 and an average bill decrease of 2.7 percent in 2025 and 7.7 percent in 2030. These reduced electricity bills reflect the combined effects of changes in both average retail rates (driven by compliance approaches taken to achieve the state goals) and lower electricity demand (driven by demand-side energy efficiency).[128]

However, electricity prices are affected by a number of factors which vary regionally across the country based on power generation mix, fuel costs, fuel availability, regulatory regime (i.e., competitive market or traditional rate setting by a state or local body), and adequacy and age of infrastructure to name a few factors.[129] While EPA expects changing such price determinants will have an impact on electricity prices, EPA does not expect that these impacts will be significant. When averaged across regions, EPA projects an increase under the mass-based scenario "in the national average (contiguous U.S.) retail electricity price of 2 percent in 2025 and 0.01 percent in 2030."[130]

State decisions on the design and availability of DSEE programs will be crucial to attaining the levels of subscribership necessary to achieve the cost reductions projected in EPA's RIA analysis. The development of further national standards for energy efficient appliances promulgated by DOE standards[131] may help achieve the levels of DSEE seen by the RIA as a low-cost CPP compliance option. For some states, attaining the levels of cost-effective DSEE projects needed to reduce CPP compliance costs may be a challenge. For the top tier of states engaged in DSEE, the challenge may be where to look for the next increment of cost-effective projects.[132] EPA has quantified the projected annualized costs of its illustrative DSEE scenario at $2.1 billion to $2.6 billion in 2020, $16.7 billion to $20.6 billion in 2025, rising to between $26.3 billion and $32.5 billion in 2030.[133] EPA understands that a large portion of the costs for DSEE programs are likely to be passed back to electric utility customers in electricity rates.[134] EPA also recognizes that

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billion (rate) and $21 billion (mass) from the base case in 2030. This incremental decline is a net outcome of two simultaneous effects that move in opposite directions. First, imposing the CO_2 constraints represented by each illustrative plan scenario on electric generators would, other things equal, result in an incremental increase in expenditures to supply any given level of electricity. However, once electricity demand is reduced to reflect demand-side energy efficiency improvements, there is a substantial reduction in the expenditures needed to supply a correspondingly lower amount of electricity demand." RIA, p. 3–23.

[128] RIA, p. 3–40.

[129] The RIA has projected ranges in 2030 by region in Table 3–21.

[130] RIA, p. 3–35.

[131] "The authority to develop, revise, and implement minimum energy conservation standards for appliances and equipment was established by Congress in Part B of Title III of the Energy Policy and Conservation Act (EPCA), , as amended.... " See U.S. Department of Energy, *Statutory Rules and Authorities*, 2015, http://www.energy.gov/eere/buildings/statutory-rules-and-authorities.

[132] For a discussion of possible DSEE opportunities for states, see Sara Hayes, Garrett Herndon, and James P. Barrett, et al., *Change Is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution*, American Council for an Energy-Efficient Economy, E1401, April 29, 2014, http://aceee.org/research-report/e1401.

[133] Ranges in estimate represent differences in rate-based vs. mass-based scenarios. See RIA, p. 3–15.

[134] RIA, p. 3-16.

measurement and verification of DSEE programs will be critical to achieving real reductions in electricity demand, and has issued draft guidelines for public input.[135]

Given the CPP's focus on the three legs of the BSER (representing potential actions by EGUs inside the fence line), the EPA's inclusion of demand-side energy efficiency (representing actions outside the fence line) in the RIA does not clarify the costs of the BSER.[136] One might expect EPA to focus its estimate of CPP compliance costs in the RIA using the "best system of emissions reduction." EPA lists the BSER options, states that DSEE is no longer a part of the BSER (since it is not something that EGUs can effect inside the fence line), and then includes DSEE in its RIA to show how CPP compliance costs can be managed and minimized by states and EGUs. EPA does not analyze the cost or other implications of BSER implementation without concomitant DSEE implementation.

For example, Building Block 3 replaces affected EGU capacity with renewable electricity. EPA projects an increase in renewables will result under the CPP, rising to an estimated 28% of total generation capacity by 2030.[137] The mechanism for much of the past growth in renewable electric capacity has been state Renewable Portfolio Standard (RPS) requirements. While EPA observes that the cost of renewable electricity is declining in many areas,[138] increasing renewable energy may require a continuation or expansion of state RPS policies which require a mandate for load-serving electric utilities to procure renewable electric generation. In most state jurisdictions, these electric utilities pass the costs of procuring renewable energy through to electric rate payers. Expanding renewable energy may therefore be a challenge in some state jurisdictions, if this means an increase in costs for ratepayers. In some states, utilities are excused from RPS requirements if these costs exceed specified limits.[139] EPA's RIA nominally addresses the cost questions associated with new renewables deployment, implying that DSEE is a lower cost option to Building Block 3 of its BSER. Some state authorities may need to revisit RPS policies to allow for harmonization with state CPP policies.

Overall Estimated Costs and Benefits of the CPP

EPA has estimated overall annualized compliance costs (in the electricity demand reduction framework of the RIA illustrative rate-based vs. mass-based scenario analysis) as ranging from $1.4 billion to $2.5 billion in 2020, $1.0 billion to $3.0 billion in 2025, and $5.1 billion to $8.4 billion in 2030.[140] However, the actual overall costs of CPP compliance will not begin to be known until after state compliance plans are filed and implemented.

[135] EPA, *Evaluation Measurement and Verification (EM&V) Guidance for Demand-Side Energy Efficiency*, August 3, 2015, http://www2.epa.gov/sites/production/files/2015-08/documents/cpp_emv_guidance_for_demand-side_ee_-_080315.pdf.

[136] "In the rate-based approach, energy efficiency activities are modeled as being used by EGUs as a low-cost method of demonstrating compliance with their rate-based emissions standards. In the mass-based approach, energy efficiency activities are assumed to be adopted by states to lower demand, which in turn reduces the cost of achieving the mass limitations." RIA, p. ES–4.

[137] As opposed to the RIA Base Case estimate of 25% renewable capacity in 2030 (for both Hydro and Non-Hydro renewables) per Table 3-12. RIA, p. 3–31.

[138] CPP, p. 64804.

[139] Brendan Pierpont, *Renewable Portfolio Standards—The High Cost of Insuring Against High Costs*, Climate Policy Initiative, December 2012, http://climatepolicyinitiative.org/2012/12/17/renewable-portfolio-standards-the-high-cost-of-insuring-against-high-costs/.

[140] RIA, p. 3–22.

EPA states throughout its analysis of CPP compliance costs that it has focused on what it considers the least expensive options. EPA now considers previously discussed alternatives, such as carbon capture and storage, conversion from coal to natural gas firing, and coal gasification, as too costly compared to other measures (i.e., DSEE or possibly emissions trading).

> Specifically, as described in the proposal, the EPA also considered co-firing (including 100 percent conversion) with natural gas, a measure that presented itself in part because of the recent increase in availability and reduction in price of natural gas, and the industry's consequent increase in reliance on natural gas.... The EPA also considered implementation of carbon capture and storage (CCS).... The EPA found that some of these co-firing and CCS measures are technically feasible and within price ranges that the EPA has found to be cost effective in the context of other GHG rules, that a segment of the source category may implement these measures, and that the resulting emission reductions could be potentially significant. However, these co-firing and CCS measures are more expensive than other available measures for existing sources.[141]

EPA states "[f]or this rulemaking, we were only able to quantify the climate benefits from reduced emissions of CO_2 and the health co-benefits associated with reduced exposure to $PM_{2.5}$ and ozone," projecting annual health- and climate-related benefits of $34 billion to $54 billion by 2030.[142] EPA cites potential CPP benefits in reducing asthma attacks and potential premature deaths by reducing air pollution.

EPA's major push for CO_2 emissions reduction is to address climate change, with emissions from power plants constituting the largest source of U.S. CO_2 emissions.

> The purpose of this rule is to protect human health and the environment by reducing CO2 emissions from fossil fuel-fired power plants in the U.S. These plants are by far the largest domestic stationary source of emissions of CO2, the most prevalent of the group of air pollutant GHGs that the EPA has determined endangers public health and welfare through its contribution to climate change.[143]

Thus, the goal of the CPP is to establish standards for existing power plants in order to significantly reduce CO_2 emissions. However, the potential for the CPP to affect climate change factors such as global temperature or sea-level rise is open to debate. It is unclear how the EPA's estimated economic benefits of the CPP are represented in terms of physical climate change factors.

CPP Implementation Issues

There are potential implementation issues associated with the CPP. For example, state-specific compliance plans geared to individual state needs may complicate the interstate coordination necessary for reliability purposes. The individual state compliance plans required by EPA's CPP may have to be submitted to multiple entities and jurisdictions (i.e., state public utility commissions, Regional Transmission Organizations, the North American Electric Reliability Corporation, and FERC) at a number of deliberative levels before a compliance plan can be finalized.[144] This may result in delays to compliance filings.[145]

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[141] CPP, p. 64727.

[142] Total combined climate benefits and health co-benefits for the rate-based approach. CPP, p. 64928.

[143] CPP, p. 64664.

[144] See CoalProspects, "Electricity Reliability—State and Market Inputs."

[145] State plans must be submitted to the EPA in 2016, though an extension to 2018 is available to allow for the (continued...)

Implementation may also be affected by EGU retirements. Many fossil-fueled power plants do more than just generate electricity. Many coal power plants likely to face retirement decisions provide ancillary services such as voltage support and frequency regulation to the grid. EPA recognizes that some renewable energy technologies are capable of filling this gap, with the assistance of appropriate regulatory measures. However, additional retirements of coal-fired capacity may also affect reserve margins, potentially impacting reliability during weather-related outages or periods of temperature extremes. Some renewable electricity technologies face performance challenges in periods of sub-optimal weather, but when employed in a distributed generation configuration, they may add a measure of resiliency to the grid.

Another concern may be inclement weather. Incidents of more extreme weather appear to be occurring, and will need to be planned for when considering the types of future generation which may need to be built to assure electric system reliability.[146] EIA recently estimated that a total of 60 GigaWatts of coal capacity would retire by 2020, with 90% of these retirements taking place by 2016 "coinciding with the first year of enforcement for the Mercury and Air Toxics Standards."[147] Much of this capacity scheduled for retirement was dispatched during the recent Polar Vortex, adding concern from some on how the grid will meet power demands in future weather extremes.[148]

Yet another concern may be the ability of states and electric utilities to acquire the levels of (utility-scale) renewable electricity in EPA's projections. EPA's CPP proposal arguably relies on state-implemented renewable portfolio standards and energy efficiency resource standards going forward. However, many state renewable portfolio standards and goals are scheduled to expire in the 2015 to 2020 timeframe, with more expired by 2025.[149] And many state RPS policies with mandatory requirements have cost caps to ensure that the targets can be met cost-effectively. Similarly, many state energy efficiency resource standards are expiring by 2020,[150] and may need to be revisited by state authorities to harmonize goals with state CPP plans.

Related Congressional Actions

Several bills have recently been introduced in Congress specifically addressing the EPA's Clean Power Plan or GHG restrictions from coal-fired power plants in general.

H.R. 3056, the "Stop the EPA Act of 2015," would, among other actions, amend the Congressional Review Act (P.L. 104-121) to require congressional approval of major rules issued by EPA. The bill would also nullify EPA's existing major rules unless EPA resubmits them for congressional approval, and would lower the annual economic threshold from $100 million to

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completion of "stakeholder and administrative processes." CPP, p. 64664.

[146] See CRS Report R42696, *Weather-Related Power Outages and Electric System Resiliency*, by Richard J. Campbell.

[147] Energy Information Administration, "AEO2014 Projects More Coal-Fired Power Plant Retirements by 2016 Than Have Been Scheduled," February 14, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=15031.

[148] Matthew L. Wald, "Coal to the Rescue, but Maybe Not Next Winter," *The New York Times*, March 10, 2014, http://www.nytimes.com/2014/03/11/business/energy-environment/coal-to-the-rescue-this-time.html?_r=0.

[149] Database of State Incentives for Renewables and Efficiency, *Renewable Portfolio Standard Policies*, March 2013, http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

[150] American Council for an Energy-Efficient Economy, *State Energy Efficiency Resource Standards*, April 2014, http://www.aceee.org/files/pdf/policy-brief/eers-04-2014.pdf.

$50 million for a rule to be deemed a major rule. The Government Accountability Office would be required to estimate the economic cost imposed by EPA's rules.

H.R. 2637, the "Coal Country Protection Act" or the "Protecting Jobs, Families, and the Economy from EPA Overreach Act," would, among other actions, prevent the EPA from promulgating any regulation limiting or prohibiting CO_2 emissions from a new or existing power plant, and would prevent any such regulation or guidance from having any force or effect until the U.S. Labor Department has certified the event will not result in job losses; the Congressional Budget Office has certified no loss in the U.S. gross domestic product will result; the EIA has certified there will not be a resultant increase in electricity rates; and, FERC and North American Electric Reliability Corporation will certify the reliability of electricity delivery under the regulation or guidance.

H.R. 2042, the "Ratepayer Protection Act of 2015," would, among other actions, relieve states from requirements to adopt or submit a state plan, and shield states from becoming subject to a federal plan that addresses CO_2 emissions from fossil fuel-fired electric utility generating units. The governor would be required to notify EPA that implementing such a plan would have a "significant adverse effect" on the state's residential, commercial, or industrial electricity ratepayers, or have a "significant adverse effect" on the reliability of the state's electricity system. Any deadlines for mandatory compliance with such provisions would be subject to an extension period beginning 60 days after the notice of promulgation of a final rule in the *Federal Register*, ending after the date any judicial review or judgment becomes final and is no longer subject to further appeal or review in all actions. The bill passed in the House on June 26, 2015.

H.J.Res. 71, a resolution of congressional disapproval under the Congressional Review Act[151] (CRA), was advanced by the House Committee on Energy and Commerce, Energy and Power Subcommittee on November 3, 2015, regarding the EPA's NSPS (published at 80 *Federal Register* 64510 on October 23, 2015) stating that "such rule shall have no force or effect."

H.J.Res. 72, a resolution of congressional disapproval under the CRA, was advanced by the House Committee on Energy and Commerce, Energy and Power Subcommittee on November 3, 2015, regarding the EPA's CPP (published at 80 *Federal Register* 64662 on October 23, 2015) stating that "such rule shall have no force or effect."

S. 1324, the "Affordable Reliable Electricity Now Act of 2015," would, among other actions, require the EPA to establish separate standards of performance for GHG emissions from coal-fired and natural gas-fired electric utility power plants. Such standards of performance must have been achieved by commercially operating plants, on average, for at least one continuous 12-month period (excluding planned power outages) by "each of at least 6 units within that category" (exclusive of results from demonstration units). Before EPA could issue, implement, or enforce any proposed or final rule for CO_2 emissions from existing fossil fuel-fired electric utility generating units, EPA would be required to issue state-specific model plans demonstrating "with specificity" how each state can meet the required GHG emissions reductions under the rule. States would not be required to adopt or submit a state plan, or become subject to a federal plan for any such proposed or final CO_2 emissions reduction plan from fossil fuel-fired electric utility generating units, if the governor of a state notifies the EPA that implementing such a plan would have a "negative effect" on the state's electricity ratepayers, on the reliability of the state's electricity system or on the "economic growth, competitiveness, and jobs in the State." The bill

[151] 5 U.S.C. §§801-808.

was reported in the Senate by the Environment and Public Works Committee on October 29, 2015.

S.J.Res. 24, a resolution of congressional disapproval under the CRA, was introduced and referred to the Senate Committee on the Environment and Public Works on October 26, 2015, regarding the EPA's CPP (published at 80 *Federal Register* 64662) stating that "such rule shall have no force or effect."

Concluding Comments

EPA declares in the CPP that states and affected EGUs can use whatever methods they choose to meet the applicable CO_2 emissions or emission rate reductions in the timeframes proposed. In so doing, EPA creates a plan that, according to EPA, allows most states and affected EGUs to be able to comply within the timeframe allowed. States and electric utilities already using integrated resource planning may choose to stay with this methodology. Larger, vertically integrated utilities generally have options within all three BSER Building Blocks. They tend to have large and, as a general matter, somewhat diverse generation fleets. For their higher-emitting units, they have opportunities to use measures which reduce unit CO_2 emission rates via heat rate improvements, co-firing, or fuel switching. EPA's modeling results suggest that fuel diversity can be maintained under the RIA scenario analysis while increasing the amount of power generation from zero-emission renewable electricity technologies. While the CPP could further diversify the national fuel generation mix by increasing generation from renewable electricity (including hydro) to 28% of capacity, EPA recognizes that even companies that have traditionally depended upon coal to supply the majority of their generation are already diversifying their fleets, increasing their opportunities for re-dispatch.

Going forward, EPA CO_2 regulations may provide a basis for the evolution of the U.S. electric power sector. EPA recognizes that the grid and many of its fossil-fueled power plants are aging and provides input via the CPP as to how a future national system focused on cleaner energy choices could be powered. Further technologies may emerge in the CPP compliance timeframe to increase power generation options, and some of these technologies may have the potential to lower the costs of producing and delivering electricity. Meeting the goals of EPA's CPP may, in effect, require less power generation from coal-fired power plants, or perhaps outright retirements of coal-fired generation. Considering the average age of the coal-fired power plant fleet, more retirements are likely when the costs of efficiency improvements or upgrades are weighed against other options in compliance plans.

In its final rule, EPA has largely calculated the CPP compliance obligations based on increasing renewable generation as the technology of choice for new power generation, emphasizing less fossil-fueled generation (including generation fueled by natural gas). This focus on renewables may, by its nature, eventually lead to a grid composed of distributed generation "cells" functioning in a cellular, interconnected manner with traditional transmission lines as its backbone. Such a design may be inherently more reliable than today's power plant-to-transmission-to-distribution model, as it focuses on serving smaller service areas whose characteristics can be designed for, and minimizes large-scale outages.

Implementing compliance plans will not come without real costs or making hard choices for the states and electric utilities who will have to work together to find an acceptable compromise. Some states and electric utilities may potentially face challenges in complying with CPP goals. The potential implications for reliability and the ultimate financial costs of the CPP will become clearer as state compliance plans are filed, and implementation plans become known.

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