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The Clean Power Plan and Electricity Demand: Considering Load Growth in a Carbon-Constrained Economy

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The Clean Power Plan (CPP), finalized on August 3, 2015, establishes the first federal greenhouse gas emissions limits for the existing fleet of fossil fuel-fired power plants.[1] The rule, issued by the U.S. Environmental Protection Agency (EPA) under the Clean Air Act, establishes emissions guidelines for two categories of power plants and requires states to develop plans that establish performance standards that reflect those guidelines. States have multiple options regarding the form and design of the performance standards, including whether to apply mass-based or rate-based standards, and for mass-based plans, whether to cover only existing sources or to cover new sources as well. A variety of factors may influence state implementation decisions. For example, states may consider stakeholder preferences, administrative simplicity, whether their existing and planned fleets are well-positioned to comply with a certain approach, and implications for meeting future electricity demand.

Release of the Clean Power Plan marks a significant moment in U.S. climate policy, but a host of additional economic, technological, and regulatory factors are also driving significant change in the electricity sector, further complicating state regulatory decision making. Ensuring access to reliable and affordable electricity while protecting public health is a central goal of state regulation of electric utilities. Thus, expectations about the future of the electricity sector in general, and the future of electricity demand and emissions trajectories in particular, will likely play an important role in state CPP decisions.

This policy brief discusses load growth—rising electricity demand—in the context of CPP design choices and demonstrates that it may occur under either a rate-based or mass-based approach. It begins with a brief overview of the Clean Power Plan and state choices, including rate-based and mass-based performance standards. It then summarizes recent trends in load growth and carbon dioxide emissions in the U.S. electricity sector, showing how electricity demand growth in the United States has been low for more than a decade while the carbon intensity of electricity generation has declined.[2] Finally, it explores how both rate-based and mass-based plans can accommodate load growth and future emissions. Although no CPP approach limits electricity generation growth to meet new demand, rate-based approaches and mass-based approaches that cover only existing sources also allow emissions from new sources to increase. Mass-based plans that cover new sources would not limit electricity generation growth, but they would limit emissions from all covered sources.[3]

[1] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,661 (Oct. 23, 2015) [hereinafter CPP Rule], https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for- existing-stationary-sources-electric-utility-generating.

[2] U.S. Energy Info. Admin., Lower Electricity-related CO_2 Emissions Reflect Lower Carbon Intensity and Electricity Use (2014), https://www.eia.gov/todayinenergy/detail.cfm?id=18511.

[3] As set forth in the final rule, all rate-based plans cover only existing sources.

Overview of the Clean Power Plan

The Clean Power Plan, which covers steam-electric-generating units (EGU) (mostly coal) and stationary combustion turbines (natural gas combined cycle or NGCC), establishes emissions guidelines on the basis of the "best system of emission reduction" (BSER) (See Box 1). The rule provides the emissions guidelines in multiple forms, including rates measured in pounds per megawatt hour (i.e., a rate-based standard) and total tons of carbon dioxide emitted (i.e., a mass-based standard) (Table 1).[4] In the case of rate-based plans, the Clean Power Plan allows states to use either a subcategorized rate for each affected EGU category or a "blended" rate, which combines both affected EGU categories.[5] In the case of mass-based plans, the Clean Power Plan allows states to use a statewide mass-based goal or a statewide mass-based goal with a "new source complement," which would include new and existing units.[6] States considering a mass-based plan that covers only existing sources must address the potential for emissions leakage to new sources—that is, shifting of power generation and thus emissions from existing facilities covered by the rule to new sources that are not subject to the rule.[7]

Box 1. EPA Analysis of the Best System of Emission Reduction

The EPA calculates the emissions guidelines for existing sources on the basis of the BSER's three building blocks: (1) improved efficiency of existing coal plants (heat rate improvements), (2) shifting generation from existing steam units to existing NGCC units, and (3) increasing deployment of renewable energy. The EPA analyzed the building blocks' potential to reduce emissions on an interconnection-wide basis (Eastern Interconnect, Western Interconnect, and Electric Reliability Council of Texas Interconnect). It then chose the least stringent standard for steam units and NGCC units, respectively, in each time period, and applied it nationally.

The Clean Power Plan also allows states to implement tradable performance standards under either a rate- or mass-based approach, including "trading-ready" plans that allow trading of compliance instruments across state borders without formal interstate agreements. Under this approach, states that use a common or linked tracking system and the same definition of their tradable instruments—"allowances" in a mass-based approach and "emission rate credits" in a rate-based approach—could enable power plant operators within those states to buy or sell tradable instruments across state borders.[8] To help facilitate interstate emission trading, the EPA proposed mass-based and rate-based trading-ready model rules, which it plans to finalize by summer 2016.[9] The final model rules will be presumptively approvable, meaning that the EPA will approve any state plan components drawn from them.

Table 1. Summary of state plan options and implications for electricity demand and emissions trajectory

Form of Performance Standard	Limits Load Growth?	Limits Emissions from New Sources?
Subcategorized Rate	No	No
Blended Rate	No	No
Mass-Based Existing-Sources-Only Goal	No	No
Mass-Based Goal with New Source Complement	No	Yes*

*In the case of a mass-based plan that covers new sources and that allows interstate trading of emissions allowances, purchases of allowances from other states represent an additional supply of allowances that would allow in-state emissions to grow.

[4] CPP Rule, 80 Fed. Reg. at 64,811–19 (codified at 40 C.F.R. pt. 60, tbls. 1–4).
[5] *Id.* at 64,811–19 (codified at 40 C.F.R. pt. 60, tbls. 1–2).
[6] *Id.* at 64,811–19 (codified at 40 C.F.R. pt. 60, tbls. 3–4).
[7] *Id.* at. 64,822–23 (codified at 40 C.F.R. § 60.5790(b)(5)).
[8] *Id.* at 64,708, 64,835–37 (codified at 40 C.F.R. § 60.5750(d)).
[9] 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, 80 Fed. Reg. 64,966 (Oct. 23, 2015) (codified at 40 C.F.R. pts. 60, 62, 78), [hereinafter Proposed Federal Plan & Model Rules], http://www.gpo.gov/fdsys/pkg/FR-2015-10-23/html/2015-22848.htm.

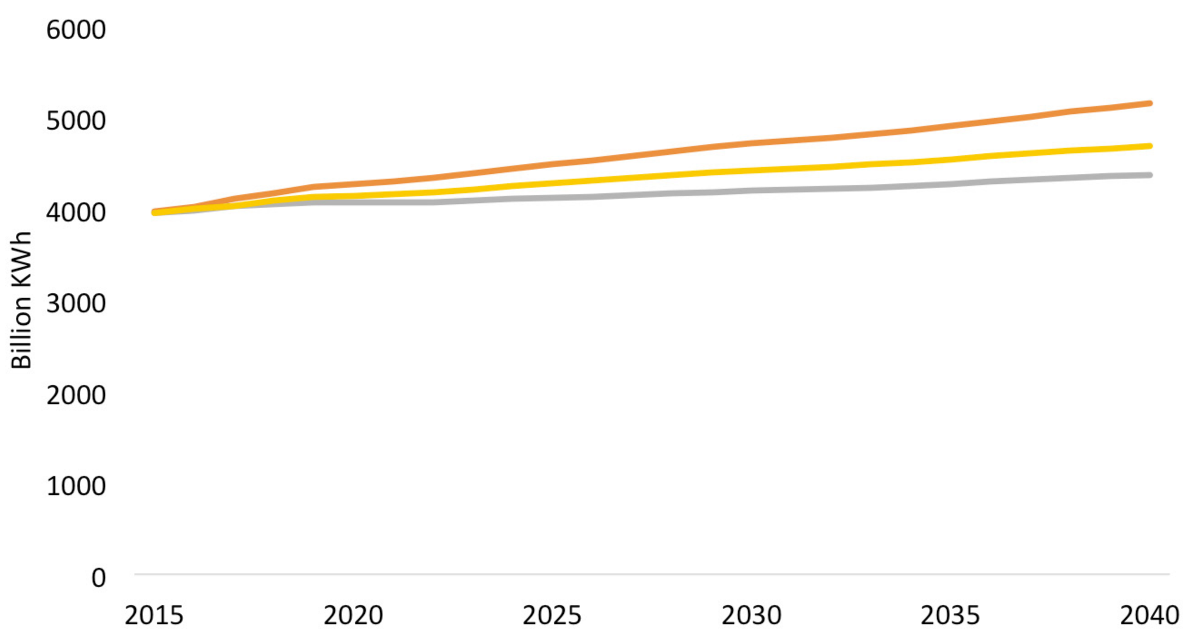
As noted above, many considerations will likely factor into state implementation choices, such as stakeholder preferences, administrative simplicity, and implications for meeting future electricity demand. Additionally, uncertainty about future electricity demand and resource costs (such as the price of natural gas) could influence state implementation decisions.

Providing reliable and affordable power is a central tenant of state electricity regulation and is vital to citizens' economic and social well-being. Thus, the need to meet future demand at an affordable price will likely play a role in state implementation decisions. All state plan pathways under the Clean Power Plan allow generation to grow to meet any increase in demand, but covering both existing and new units under a mass-based plan would effectively limit emissions from the state's electricity sector. Thus, assumptions and projections about load growth and emissions will likely play a major role in many states' implementation choices. Although accurately projecting load growth is difficult, actual load growth in the United States has been low for a decade and consistently below official projections.

Recent Trends in Electricity Demand and Electricity Sector Carbon Dioxide Emissions

The U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2015 (AEO 2015) Reference Case—which does not reflect the Clean Power Plan—projects 0.7% annualized growth through 2040, assuming gross domestic product (GDP) grows at a rate of 2.4% (Figure 1).[10] Actual annualized growth was 0.3% per year from 2004 to 2014 for national electricity generation from all sectors (Figure 2).[11] During the same time period, total retail electricity sales fell in multiple states, including Connecticut, Maine, Massachusetts, Rhode Island, Vermont, New Jersey, Michigan, Ohio, Delaware, Maryland, and Kentucky.[12]

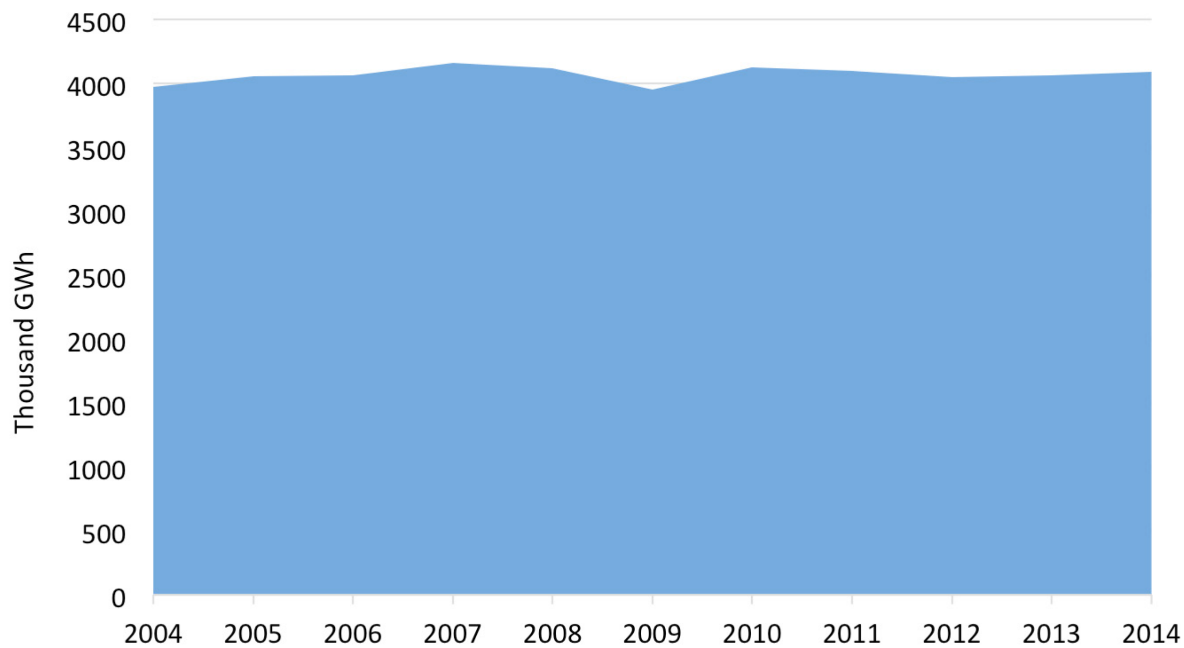
Figure 1. Projected net U.S. generation: Electricity plants, all sectors, 2015–2040



Source: AEO 2015.
Note: In the High Economic Growth case, GDP grows at 2.9% and annualized electricity generation grows at 1%. In the Low Economic Growth case, GDP grows at 1.8% and annualized electricity generation grows at 0.04%.

[10] U.S. EIA, *Annual Energy Outlook 2015: Electricity Generation*, Apr. 14, 2015 https://www.eia.gov/forecasts/aeo/section_elecgeneration.cfm.
[11] U.S. EIA, *Electricity Data Browser: Net Generation from Electricity Plants for All Sectors, Monthly*, http://www.eia.gov/electricity/data/browser (last visited Nov. 4, 2015).
[12] Total retail sales include sales to the industrial, commercial, residential, transportation, and other sectors. U.S. EIA, *Electricity Data Browser, Retail Sales of Electricity, Annual*, http://www.eia.gov/electricity/data/browser/#/topic/5?agg=0,1&geo=vvvvvvvvvvvvo&endsec=vg&linechart=ELEC.SALES.US-ALL.A&columnchart=ELEC.SALES.US-ALL.A&map=ELEC.SALES.US-ALL.A&freq=A&ctype=linechart&ltype=pin&maptype=0&rse=0&pin= (last visited Nov. 23, 2015).

Figure 2. Net U.S. generation: Electricity plants, all sectors, 2004–2014



Source: U.S. EIA.

According to the Energy Information Administration, the current trend of declining growth in electricity demand reflects declining population growth, market saturation of major appliances, increasing efficiency of appliances and other equipment, and shifts toward relatively less energy-intensive industry.[13] Other studies have similarly projected tepid future demand growth as a result of structural changes in the economy.[14] Absent the rapid introduction of new electricity-consuming devices, such as electric vehicles, the Energy Information Administration does not expect a sharp increase in demand growth.[15]

While electricity demand has continued to grow at a declining rate, electricity sector carbon dioxide (CO_2) emissions have dropped. For example, in North Carolina, CO_2 emissions fell almost 20% from 2005 to 2014 as NGCC generation replaced coal generation (Figure 3). The AEO 2015 Reference Case projects that the carbon intensity of generation will continue to decrease through 2040: total generation increases annually at 0.8% while electricity sector CO_2 emissions increase at 0.2% per year.[16] At the same time, the Reference Case shows that coal capacity decreases from 300 gigawatts (GW) in 2012 to 255 GW in 2022, reflecting a shift toward lower-emitting generation sources.[17]

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[13] U.S. EIA, *U.S. Economy and Electricity Demand Growth Are Linked, but Relationship Is Changing*, Mar. 22, 2013, https://www.eia.gov/todayinenergy/detail.cfm?id=10491.

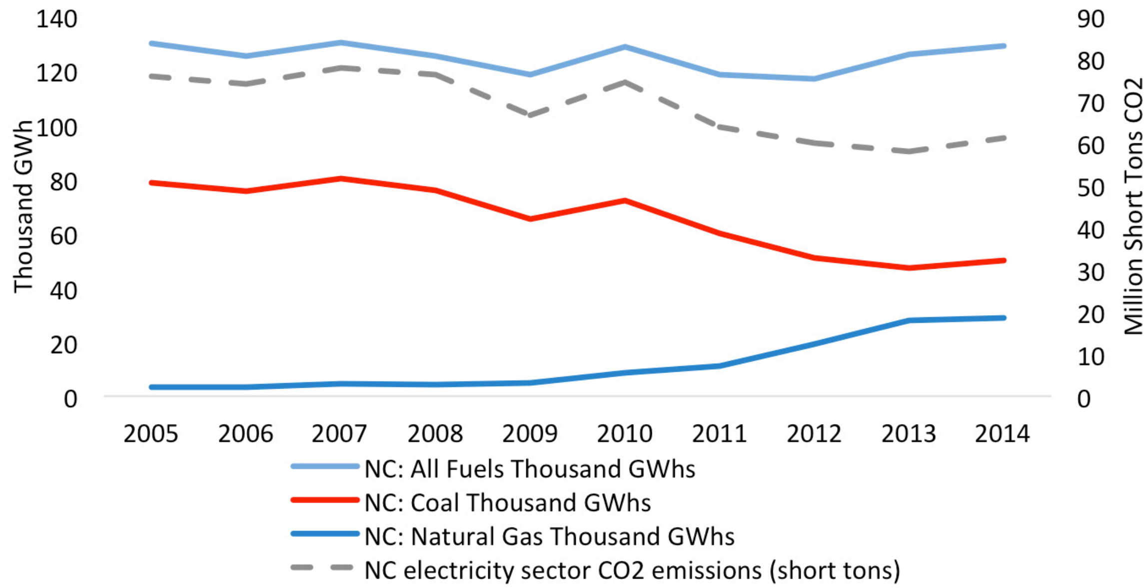
[14] *See, e.g.*, Bradley T. Ewing et al., *Disaggregate Energy Consumption and Industrial Output in the United States*, 35 Energy Policy 1274 (2007); Ahmad Faruqui & Eric Shultz, Brattle Group, *Demand Growth and the New Normal: Five Forces Are Putting the Squeeze on Electricity Consumption*, Pub. Utilities Fortnightly, Dec. 2012; Internat'l Energy Agency, Worldwide Trends in Energy Use and Efficiency: Key Insights from IEA Indicator Analysis 17 (2008); Reed Landberg, *These Three Trends have Radically Redefined the Energy Market*, Bloomberg Business, Oct. 14, 2015; Paresh Kuma Narayan & Arti Prasad, *Electricity Consumption—Real DGP Causality Nexus: Evidence from a Bootstrapped Causality Test for 30 OECD Countries*, 36 Energy Policy 910, 917 (2008); James E. Payne, *On the Dynamics of Energy Consumption and Output in the United States*, 86 Applied Energy 575, 577 (2009).

[15] U.S. EIA, *supra* note 13.

[16] *Id.*

[17] The Reference Case deals with electricity-sector coal capacity. *See* U.S. EIA, *Annual Energy Outlook 2015* (2015), http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf [hereinafter AEO 2015].

Figure 3. North Carolina generation and CO_2 emissions 2005–2014



Note: For generation data, see U.S. EIA, "Electricity Data Browser," *supra* note 11. For emissions data, see U.S. EPA, "Air Markets Program Data" (accessed November 4, 2015), http://ampd.epa.gov/ampd.

Although meeting load growth with lower-emitting sources could be technically feasible, states also have to balance the cost of these resources. Expectations about the relative costs of different electric-generating technologies depend on factors such as future fuel prices, subsidies, and technological advancements. As part of the AEO 2015, the Energy Information Administration released an analysis of the levelized cost of new generation resources coming online in 2020 (Table 2).[18] In this analysis, the levelized cost of new wind generation is approximately equal to or below the cost of new NGCC generation without federal subsidies for new wind.[19] However, the expected cost of new NGCC generation varies widely, depending on expectations about its capacity factor and about future fuel prices (Table 3).[20] With federal subsidies, wind and solar prices—especially in areas where these resources can generate the majority of electricity—have reached historic lows in recent years.[21] In 2014 and 2015, utility-scale solar power purchase agreements in the Southwest reached $40/MWh.[22] Similarly, the average levelized long-term price of wind in power purchase agreements signed in 2014 was $23.5/MWh; most of these agreements are associated with projects located in the central plains.[23]

[18] Levelized cost of electricity (LCOE) is a measure that attempts to express the cost of electricity generation from different technologies (e.g., coal, natural gas, solar)—which may have different upfront costs, variable operation and maintenance costs, and useful lives—on a comparable basis.
[19] U.S. EIA, *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015*, June 3, 2015, http://www.eia.gov/forecasts/aeo/electricity_generation.cfm. Levelized cost estimates for new nuclear, wind, and solar generation are highly sensitive to capital cost assumptions. Other analyses, such as a recent Lazard study, assume lower capital costs for new wind and solar photovoltaic generation, resulting in lower levelized costs of electricity. *See* LAZARD, LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS VERSION 8.0 (2014), https://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf.
[20] A unit's capacity factor is the ratio of its actual power output to its potential power output over a defined period (i.e., if it were possible to continuously operate at full nameplate capacity).
[21] Congress recently extended the existing federal tax credits for wind and solar. *See* Consolidated Appropriations Act of 2016, H.R. 2029-797, 114th Cong. § 301(a)(1) (2016) (enacted) (extending the credit for wind energy facilities to 2020); *id.* § 303(a) (extending the solar energy credit to 2022).
[22] M. BOLINGER & J. SEEL, LAWRENCE BERKELEY NATIONAL LABORATORY, UTILITY SCALE SOLAR 2014 (2015), https://emp.lbl.gov/sites/all/files/lbnl-1000917.pdf.
[23] R. WISER & M. BOLINGER, LAWRENCE BERKELEY NATIONAL LABORATORY, 2014 WIND TECHNOLOGIES MARKET REPORT (2015), https://emp.lbl.gov/sites/all/files/lbnl-188167.pdf.

Table 2. AEO 2015 regional variation in levelized cost of electricity for new generation online in 2020

	Minimum	Average	High
NGCC	70.4	75.2	85.5
Advanced NGCC	68.6	72.6	81.7
Advanced nuclear[a]	91.8	95.2	101
Wind	65.6	73.6	81.6
Solar PV[b]	89.3	114.3	175.8

[a] Assumed to be online in 2022.
[b] Includes permanent 10% investment tax credit.

Table 3. Variation in levelized cost of NGCC with different capacity factor and fuel cost assumptions

75% Capacity Factor		50% Capacity Factor	
Fuel cost ($/MMBtu)	LCOE ($/MWh)	Fuel cost ($/MMBtu)	LCOE ($/MWh)
7.29	66.36	7.29	74.27
6.00	57.49	6.00	65.4
5.00	50.61	5.00	58.51
4.00	43.71	4.00	51.62
3.00	36.82	3.00	44.74

Source: IECM 9.1, 11-4-15.
Note: All dollars are 2012 $. Assumes wet cooling tower, two turbines, default financing.

As the above discussion illustrates, the implications for meeting future growth with additional fossil generation may be an important factor in states' choice of plan pathway, depending on expectations about future electricity demand and resources that states will use to meet that demand. Even if electricity demand growth remains low nationally, growth rates in some states or service territories may outpace the national average. Whether meeting future growth with non-emitting sources is cost effective depends on future fuel prices, construction costs, and a host of other factors. Therefore, evaluating a range of plausible scenarios could help inform implementation choices.

Implications for Clean Power Plan Implementation

Given that states can meet electricity demand growth with a wide variety of resources—including new and existing fossil sources but also non-emitting sources such as nuclear, renewables, and demand-side energy efficiency—no Clean Power Plan pathway limits load growth. States can accommodate additional demand with less emissions-intensive resources. For example, in states with new nuclear capacity, total generation can increase while displacing significant fossil generation and reducing emissions. Similarly, in states that displace coal generation with efficient NGCC units—which emit CO_2 at approximately one-third the rate of existing coal units—fossil generation can grow while emissions decrease (relative to a 2012 baseline). The following sections expand on the implications for load growth under rate-based and mass-based plans.

Considering Load Growth in a Rate-Based State Plan

As stated above, affected EGUs in any state that chooses a rate-based standard would demonstrate compliance on the basis of pounds of CO_2 emitted per adjusted megawatt hour-net during each compliance period.[24] States may apply the national subcategorized rates for steam and NGCC units (see Table 4) or their state-specific blended rate.[25] States using the subcategorized rates can choose to be trading ready. Trading under a blended-rate approach requires formal agreements with other states. An EGU can comply with a rate-based standard by acquiring emissions rate credits (ERCs), which

[24] CPP Rule, 80 Fed. Reg. at 64,781–82 (codified at 40 C.F.R. § 60.5880).
[25] *Id*. at 64,811–19 (codified at 40 C.F.R. pt. 60, tbl. 1).

represent one emissions-free megawatt hour (MWh) of electricity that is added to the denominator of the emissions rate equation (see Box 2).[26]

Table 4. Interim and final subcategorized emissions rates in lbs/MWh

Technology	2022–2029	Final Rate
Steam	1,534	1,305
Stationary combustion turbine	832	771

Box 2. Affected EGU ERCs Accounting Example

The number of ERCs that an affected unit earns or owes would equal the difference between the unit's actual emissions rate and the relevant standard multiplied by its generation according to the following formula:

ERCs = (EGU standard – EGU operating rate)/EGU standard * generation

The following examples demonstrate how to determine the number of ERCs earned or owed by an affected EGU under the proposed rate-based federal plan and model rule.

Example 1:

An NGCC facility with an average emissions rate of 750 that generates 1,000 MWh in a final compliance period with the final NGCC compliance standard of 771:

ERCs = (771 -750)/771 * 1000

= (21/771) * 1000

= 27.2 or **27 ERCs earned**

Example 2:

An NGCC facility with an average emissions rate of 800 that generates 1,000 MWh in a final compliance period with the final NGCC compliance standard of 771:

ERCs = (771-800)/771 * 1000

= (-29/771) *1000

= -37.6 or **38 ERCs owed**

In general, three categories of electricity resources can earn ERCs: (1) affected EGUs that perform below their applicable rate; (2) zero-emitting electricity resources online in 2013 or later, including eligible renewable energy projects and new and uprated nuclear capacity; and (3) under a subcategorized rate-based approach, all affected NGCC units, which earn a special type of credit called a gas-shift ERC.[27] With the exception of gas-shift ERCs, which only affected steam units can use for compliance, all ERCs would be mutually exchangeable.[28]

Rate-based compliance can accommodate load growth in several ways. First, efficient existing EGUs can increase their output. If these sources perform below the compliance rate, they also generate ERCs, which higher-emitting affected sources can use for compliance.[29] Second, states can build or expand zero-generating electricity sources, such as renewables and nuclear. Like existing units that beat their rate, these resources can supply additional electricity generation and ERCs.

[26] *Id*. at 64,811–19 (codified at 40 C.F.R. § 60.5790(c)(1)).

[27] A gas-shift ERC (GS-ERC) should incentivize increased use of existing NGCC units. Under a blended-rate approach, existing natural gas units facing the same rate as coal units would provide a similar incentive for efficient natural gas units to increase generation.

[28] CPP Rule, 80 Fed. Reg. at 64,950 (codified at 40 C.F.R. § 60.5795(a)(2)–(b)); id. at 64,993 (codified at 40 C.F.R. § 62.16434).

[29] ERCs can be "banked"—saved for use in a later compliance period—without limit.

Third, affected EGUs that emit above their compliance rate can also increase generation as long as they acquire sufficient ERCs to comply on the basis of their adjusted rate. Finally, because a rate-based approach under the CPP covers only existing fossil units, new fossil units can meet future demand. New sources will need to comply with the current new source performance standards, but most new NGCC plants already meet the standard for natural gas plants (1,000 lbs/MWh-gross).[30]

Considering Load Growth in a Mass-Based State Plan

In general, mass-based emissions regulations limit total emissions from covered sources over a period of time (i.e., compliance period). Mass-based emissions trading programs establish a total emissions budget for each compliance period and create a number of "allowances" equal to the total budget; each allowance represents one ton of emissions. Affected EGUs must surrender one allowance for each ton of emissions during a compliance period. The fixed number of allowances maintains total emissions within the budget. Affected unit owners, and in many cases other market participants, can buy and sell allowances, thereby enabling the market to determine the lowest-cost compliance path across all affected EGUs.[31]

States considering mass-based plans have the choice to cover only existing sources or to include new sources under an expanded emissions budget, termed the "new source complement."[32] The mass-based existing source budgets for each state are intended to allow growth in emissions from existing sources equivalent to the growth possible under a subcategorized rate-based compliance approach.[33] Although mass-based state plans that cover only existing sources must include an EPA-approved mechanism to address the risk of leakage to new sources, as a practical matter, both generation and emissions from new sources can increase without limit. There is no forward-going requirement to limit generation or emissions from new sources or to demonstrate that leakage is not occurring under a mass-based plan that covers only existing units.

The new source complement is intended to capture emissions growth beyond that built into the existing-source-only budgets, and covering new sources limits total emissions—but not generation—from all covered sources.[34] Thus, covering new sources may limit states' ability to meet future growth with additional fossil generation, depending on expectations about future demand and the resources that would likely meet that demand. However, states could still accommodate load growth with zero-emitting resources, such as renewables or nuclear.

Trading and Growth in CPP Plans

Finally, in both rate- and mass-based approaches, whether and to what degree a state plan allows interstate trading of compliance instruments shapes implications for meeting future load with additional fossil generation within a state. Power plant operators in a state that participates in interstate trading would have access to a supply of credits (rate) or allowances (mass) in other states, which may not be experiencing the same amount of growth. Thus, interstate trading is another avenue for states to accommodate load growth.

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[30] The Clean Air Act requires the Environmental Protection Agency to review and, if appropriate, revise the NSPS at least every eight years. Clean Air Act Amendments of 1990 §111(b)(1)(B),42 U.S.C. § 7411(b)(1)(B).

[31] In a mass-based emissions trading system, sources will reduce their emissions (subject to operational constraints) if the cost of doing so is below the market price of an allowance. Sources with emissions reduction costs that are higher than the market price of an allowance will buy allowances to comply with the mass cap, minimizing costs for both individual affected units and the system as a whole.

[32] *See* Sarah Adair & David Hoppock, Nicholas Inst. for Envtl. Policy Sols., *New Sources and the Clean Power Plan: Considerations for Mass-Based Plans* (Dec. 2015), https://nicholasinstitute.duke.edu/climate/publications/new-sources-and-clean-power-plan-considerations-mass-based-plans.

[33] U.S. EPA, CO_2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule 21 (Aug. 2015), http://www3.epa.gov/airquality/cpp/tsd-cpp-emission-performance-rate-goal-computation.pdf.

[34] U.S. EPA, New Source Complements to Mass Goals Technical Support Document for CPP Final Rule (Aug. 2015), http://www3.epa.gov/airquality/cpp/tsd-cpp-new-source-complements.pdf.

Conclusion

Although recent trends in electricity generation indicate declining demand growth and CO_2 intensity, future demand is uncertain, and determining which technologies are the most efficient will depend on a host of factors, including fuel prices, technological innovation, and future regulations. In the context of the Clean Power Plan, both rate-based and mass-based plans can accommodate load growth (Table 5). Rate-based plans and mass-based plans that cover only existing sources can also accommodate emissions growth. Considering a range of plausible futures may inform choices about plan design, such as the choice of rate or mass and the choice to cover or not cover new sources under a mass-based plan.

Table 5. Summary of opportunities to meet future electricity demand under rate- and mass-based plans

Rate-based	Increase generation from existing EGUs that perform at or better than the applicable rate.
	Use ERCs from low- or zero-emitting sources to accommodate generation above existing units' rate.
	Increase generation from new renewable or nuclear units.
	Build new fossil units that meet the new source standards and operate outside the CPP.
Mass-based covering only existing units	Increase generation from lower-emitting or non-emitting sources.
	Build new fossil units that meet the new source standards and operate outside the CPP.
	If trading is allowed, purchase additional allowances from outside the state.
Mass-based with New Source Complement	Increase generation from lower-emitting or non-emitting sources.
	If trading is allowed, purchase additional allowances from outside the state.

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