Combined Heat and Power (CHP) as a Compliance Option under the Clean Power Plan

A Template and Policy Options for State Regulators

April 2016

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Executive Summary

Combined Heat and Power (CHP) is an important option for states to consider in developing compliance plans to meet their emission targets under the Clean Power Plan (CPP), which was finalized in fall 2015. Under the rule, states are required to submit initial plans (or a request for a two-year extension) to EPA by September 2016. This Template is designed to highlight key issues that states should consider when evaluating whether CHP could be a meaningful component of their compliance strategy. It demonstrates that CHP can reduce emissions and help states achieve their targets, at a lower cost compared to many other options.

The CPP contains a number of provisions that encourage states to include CHP in compliance planning. While state plans will reflect a variety of state-specific factors and determinations, this Template provides generic tools and methodologies needed to build CHP into compliance plans.

By producing both heat and electricity from a single fuel source, CHP can achieve significant energy savings and carbon emission reductions, compared to the separate generation of heat and power. These efficiency gains translate to economic savings and enhanced competitiveness for CHP hosts, and emissions reductions for the state. CHP is already a proven and cost-effective technology, representing 8 percent of electric capacity in the United States (and providing 12 percent of total power generation).[1] Projects already exist in all 50 states and significant technical and economic potential remains. CHP is a tested method for states and utilities to achieve their emission limits while advancing a host of ancillary benefits.

This Template outlines the key issues that any state must consider to incorporate CHP into its CPP plan. As such, it lays out a roadmap for states to capture the economic and environmental benefits of CHP.

First, it identifies a number of threshold questions that states need to address when developing their compliance plans. In particular, each state will need to determine:

1. Will it rely on “outside-the-fence” measures such as energy efficiency and renewable energy, rather than rely solely on the limited “inside the fence” options (e.g. power plant heat-rate improvements) to meet its emissions limits;
2. Will it pursue a rate-based or mass-based compliance path;
3. Will it assume any part of the emission reduction obligation directly (“state measures”), or will it impose the full responsibility on power plant owners; and,
4. Whether compliance with either rate or mass limits will be measured unit-by-unit, or fleet-wide, and whether to allow trading with other states.

Of these threshold questions, only one is critical to the decision of whether to include CHP in a state compliance plan. So long as the state determines that “outside-the-fence” measures can be used to support compliance of affected units, CHP is a valuable tool that can fare well under either a rate- or mass-based compliance approach. Indeed, when thermal output is properly accounted for, well-designed and properly operated CHP systems generate electricity at a lower effective emissions rate than most affected Electric Generating Units (EGUs) and lower than state targets emission rates under the CPP. As such, CHP can generate emission rate credits (ERCs) to help affected EGUs achieve compliance under rate-based emission-reduction plans.

[1] Nearly seventy percent of existing CHP capacity is fueled by natural gas, but CHP systems can be, and are, fueled by a wide variety of fuels including propane, biogas, process wastes, biomass and coal.

Alternatively, under a mass-based approach, CHP systems can reduce demand from the affected EGUs, lowering overall emissions and potentially earning emission allowances.

Second, this Template also examines how a CPP compliance plan that includes CHP would meet the “approvability” criteria EPA will use to evaluate state plans. These include:

1. Enforceable,
2. Quantifiable,
3. Verifiable,
4. Non-duplicative, and
5. Permanent.

Although these criteria are similar to the elements required in state implementation plans (SIPs) for National Ambient Air Quality Standards (NAAQS), the approvability criteria for CPP plans need not be identical and they are generally understood to be less demanding. In fact, EPA acknowledges that a substantive requirement in section 110(a)(2) [SIPs] is not an independent source of authority for the EPA to require the same for section 111(d) plan.[2] The Template demonstrates that a state plan that includes CHP is likely to fare very well under each of the approvability criteria.

Third, the Template recommends a process for states to follow if they wish to include CHP in their compliance plans. The steps in this process include:

- Survey CHP potential,
- Establish an interagency working group,
- Determine ways to generate value for CHP hosts,
- Inform large customers that CHP investments can earn ERCs or emission allowances,
- Adopt an established EM&V protocol,
- Build on existing efficiency and CHP programs, and
- Identify and remove barriers to CHP development.

Fourth this paper shows that CPP compliance is an important opportunity for states to provide economic value to their manufacturing sector and provide industry and businesses with an attractive way to participate in carbon emission reduction compliance.

The Appendices offer further exploration and details. In Appendix A, the Template identifies dozens of programs that states have already adopted to advance CHP and which could assist a state in deploying new CHP. The Appendix does not select a particular approach, but demonstrates the range of options that are available (both in terms of geography and nature of the policies). While policies that are successful in one state may not be suitable in another, Appendix A describes the history of these policies and provides resources to enable others to learn from their experience. The Appendix identifies three broad categories of programs (Financial Incentives, Regulatory Support – e.g., streamlined permitting, Creating Markets). In

[2] *See* U.S. EPA, Oct. 23, 2015, 80 *Fed. Reg.* 64662, 64853, Final Rule, “Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units” (distinguishing 110 authority from section 111(d)).

addition to a brief description of each successful program, it provides links to the enabling legislation or other resources.

Appendix B provides a more detailed discussion of the enforceability of CHP programs under the Clean Power Plan. It concludes that EPA is very unlikely to disapprove a CHP component of a state plan due to concerns about enforceability. It finds that EPA is likely to approve state plans that:

- Make reasonable assumptions about the performance of the CHP elements of the plan,
- Identify a party that is responsible for any state incentive programs designed to generate emission reductions or credits from CHP,
- Rely on established EM&V protocols, and
- Include correction or contingency mechanisms if projected strategies underperform.

Appendix C explores the CPP's approaches for crediting carbon dioxide emission reductions from CHP. This includes prorating electricity output (MWh) to emission reductions, with sample calculations for different types of technologies and fuel types (including biomass). Appendix C also includes discussion about options for determining what the CHP system is displacing (e.g., average grid emissions v. emissions during peak use).

Appendix D describes the general EM&V requirements for non-affected CHP under the Clean Power Plan and the detailed EM&V requirements included in the proposed rate-based model trading rule.

Appendix E provides a brief description and links to key publications about CHP.

This Template is designed to highlight key issues that states must consider when including CHP in their compliance plans. It demonstrates that CHP is a valuable approach for reducing emissions and helping states achieve their targets. While actual plans will vary dependent upon state-specific factors and determinations, this Template provides the tools and methodology that states will need to begin the process.

Introduction

EPA's final regulations to control Carbon Dioxide (CO_2) emissions from existing electric power plants (Clean Power Plan or CPP) provides a powerful new driver to advance the deployment of Combined Heat and Power (CHP). The final plan allows states to use "outside the fence" measures such as end-use efficiency and CHP as a means to achieve emissions targets. By producing both heat and power from a single fuel source, CHP is significantly more efficient than central power generation. CHP is a proven and demonstrated approach to lowering emissions, making U.S. manufacturers more competitive, and enhancing electric reliability. CHP can produce large blocks of low-cost energy and carbon savings. Strategies to increase deployment of CHP as part of a carbon-pollution reduction plan could be an attractive option for state air and energy regulators. New revenue generation opportunities or incentives associated with CO_2 reductions could help overcome some of the barriers that have historically restricted CHP development in commercial, institutional and industrial settings. For manufacturing entities and other large energy users, the CPP provides novel ways to offer and receive financial credit for the emissions benefits of CHP systems, in ways that complement more traditional state or utility efficiency programs. This paper provides guidance and technical assistance to states on how to design programs around industry needs that satisfy EPA's compliance requirements. Fortunately, best practices in technology, policies, programs and measurement and verification

(M&V) exist for CHP, and can be tailored for and adapted into state CPP compliance plans based on individual state needs.

This document summarizes how states and utilities can use CHP as a compliance option under the CPP, and how to design a CHP pathway that meets EPA requirements for state compliance plans. States and power plant owners have until September 2016 to submit initial plans or request a two-year extension. State agencies, large electric customer groups and others can use this period to popularize CHP as an effective CO_2 compliance option and establish mechanisms by which CHP can be recognized (and rewarded financially) as an emissions reduction strategy under the CPP.

The Final Clean Power Plan

On August 3, 2015, EPA released the final version of the Clean Power Plan, which, under the authority of the Clean Air Act's Section 111(d), regulates carbon dioxide (CO_2) emissions from existing power plants. The Clean Power Plan had been in development for several years. In 2007, the Supreme Court ruled in *Massachusetts v. EPA* that the EPA has the authority and the responsibility to regulate carbon emissions under the Clean Air Act. Six years later, on June 5, 2013, the Administration announced its Climate Action Plan, which, among other initiatives, included a Presidential Memorandum directing the EPA to work "expeditiously to complete carbon pollution standards for both new and existing power plants." One year later, on June 2, 2014, the EPA proposed the draft Clean Power Plan, which provided individual 2030 emissions reduction targets for all 50 states, cumulatively resulting in a projected 30 percent decrease in power sector emissions from 2005 levels by 2030.

The final Clean Power Plan calls for a 32 percent reduction in power sector emissions from 2005 levels by 2030, equivalent to 870 million short tons of CO_2, or the equivalent annual emissions resulting from the powering of 95 percent of U.S. homes. EPA states that the cuts in CO_2 emissions will also reduce emissions of harmful co-pollutants; by 2030, emissions of sulfur dioxide will be 90 percent lower and emissions of nitrous oxides will be 72 percent lower, compared to 2005 levels. EPA projects that in 2030, the final rule will have led to net benefits of $26 to 45 billion, avoided 3,600 premature deaths and 90,000 asthma attacks in children, and reduced the average American's yearly electricity bill by $84.

While the final rule is similar to the proposed rule, there are a number of key differences. The final goal is more aggressive than the proposed goal of 30 percent reductions, and cuts 70 million more tons of carbon. In order to achieve this goal, the EPA created a "glide path" with interim and final carbon emission performance rates for fossil fuel steam units (e.g. coal power plants) and for natural gas combined cycle units. To develop the emission performance standards, EPA identified the "best system of emission reduction" (BSER) for carbon pollution from power plants. The BSER for the Clean Power Plan are divided into three "building blocks," which represent the most effective existing strategies that can be used to reduce emissions from power plants:

- Building Block 1 - improving the efficiency of existing coal-fired power plants
- Building Block 2 - substituting low-emission natural gas electricity generation for high-emission coal-fired power plants
- Building Block 3 - substituting zero-emissions renewable electricity generation for high-emissions coal-fired power plants

The proposed rule included a fourth building block - demand-side energy efficiency, which EPA removed in setting state targets under the final Clean Power Plan. Most analysts believe it did so in order to strengthen the final rule's goal-setting framework against legal challenges, as the EPA has little legal authority to regulate a state's energy economy outside of power plants under this rule. However, EPA makes it clear in the final rule that this change does not affect states' ability to utilize energy efficiency, including CHP, as a robust compliance option. To the contrary, EPA has emphasized that energy efficiency is likely to serve as an integral component of, or complimentary policy to, many state compliance plans and identified a variety of energy-efficiency measures, programs, and policies that can count toward compliance, including utility and nonutility energy-efficiency programs, building energy codes, combined heat and power, energy savings performance contracting, state appliance and equipment standards, behavioral and industrial programs, and energy efficiency in water and wastewater facilities.[3]

To provide states with maximum flexibility in their compliance, EPA created reduction goals in three different formats, allowing each state to choose which format best suits its needs. The three formats are:

1. A rate-based state goal measured in pounds per megawatt hour (CO_2 pounds per MWh)
2. A mass-based state goal measured in total short tons of CO_2
3. A mass-based state goal with a new source complement measured in total short tons of CO_2. The "new source complement" is a separate allocation for emissions from fossil-fuel power plants that have not yet been constructed. This option allows states to streamline the regulatory processes for new and existing power plants and to address the problem that emissions from new sources could erode emission reductions from the final rule ("leakage").[4]

The proposed rule only included rate-based goals; the two mass-based goals were developed at the request of states. Mass-based goals are generally considered to be easier to plan and implement, and may make more sense for states participating in multi-state cap-and-trade programs. Rate-based goals, however, give states enjoying strong economic growth more flexibility. In any case, EPA's objective was to ensure the reductions in carbon emissions would be substantially the same.

In addition, the rule establishes uniform CO_2 performance rates for two specific EGU categories:

1. Fossil-fueled steam generating units (SGU) and integrated gasified combined cycles (IGCC), and
2. Stationary combustion turbine units. States can choose to comply using any one of these emissions targets.

Unlike the proposed rule, the final rule also allows states to select one of two types of implementation plans:

1. Emission standards plan, which requires states to create source-specific requirements to ensure that all affected power plants within the state meet the required emissions performance rates, and

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[3] *See*, e.g., U.S. EPA, 80 *Fed. Reg*. 64622, at 64902, October 23, 2015, "Carbon Emissions for Existing Stationary Sources: Electric Utility Generating Units; Final Rule" ("Electric generation from non-affected CHP units may be used to adjust the CO_2 emission rate of an affected EGU").
[4] 80 *Fed. Reg*. at 64822-64823.

2. State measures plan, which allows states to achieve their goal not only through source-specific emissions reductions, but through a mixture of measures implemented by the state, including installation of renewable energy, improvements in residential energy efficiency, etc.

No matter which type of plan a state selects, the state has the flexibility and autonomy to choose the emissions reductions strategies that are best suited to the energy, environmental and economic needs of the state. Additionally, if states choose to do so, the plan allows for them to work with other states using multi-state approaches such as emissions trading through a cap-and-trade program, like the Northeast's Regional Greenhouse Gas Initiative (RGGI).

States now have a little more time to prepare compliance plans. States are required to submit a final plan, or an initial submittal with an extension request (up to two years extension is possible), by September 6, 2016. If a state fails to submit a compliance plan, the EPA will implement its own federal plan.

The timeline for compliance with the rule has been pushed back to 2022, with the final compliance deadline remaining 2030 and thereafter. No CO_2 emissions reductions are required prior to 2022. In addition, states are required to meet a series of interim compliance goals in 2024, 2027, and 2029. Under the final rule, energy-efficiency improvements can count if they are installed after January 1, 2013 and will still be saving energy in 2022. These savings can continue to receive credit for each year during the 2022-2030 period in which they save energy.

The final rule allows a very limited opportunity for early action to accelerate investment in efficiency and reduce emissions before 2022. EPA has also proposed an early-credit option for states called the Clean Energy Incentive Program (CEIP) that awards early credit for low-income energy-efficiency programs and certain renewable energy projects implemented in 2020 and 2021. The program offers a two-to-one match for state energy-efficiency savings in order to jump-start these efforts in low-income communities. Efficiency measures during this period are only creditable in "low income communities" – to be defined later by EPA. The credits are capped under this early action program – 300 million tons of CO_2 - and the state must be participating in the CEIP. As written, CHP is not eligible for early-action credits.

As discussed above, the final rule establishes source-specific requirements on electric generating units (steam generating units and combustion turbines), directing all affected power plants within the state to meet their required emission performance rates. Under a rate-based approach, this traditional "stack-by-stack" approach creates clear incentives for EGU owners to pursue cost-effective strategies such as directly contracting for renewable energy, demand-side energy- efficiency savings or CHP with third-party deliverers or buying credits through regional or national registries. The final rule describes how these types of measures can generate "emission rate credits" (ERCs). ERCs are valued in terms of MWh reductions from affected EGUs. The adjusted emissions rate for an affected EGU is determined by adding ERCs to the denominator in the emission rate equation:

$$\text{EGU Adjusted Emission Rate} = \frac{\mathit{CO_2\ Emissions\ (lbs)}}{\mathit{(MWh\ Electricity\ Generation\ (MWh) + MWh\ ERC_{RE} + MWh\ ERC_{EE} + MWh\ ERC_{CHP})}}$$

In a rate-based pathway, this approach provides mechanisms for energy efficiency or CHP projects to sell ERCs to affected EGUs.

The final rule also allows states using the mass-based approach to help affected EGUs meet their emission targets by promoting increased deployment of efficiency and CHP, thereby reducing generation, and the resultant emissions, from affected EGUs. The efficiency measures themselves would not be federally enforceable, as long as the state had a federally enforceable backstop (e.g., the obligation would fall back on the affected EGUs if sufficient efficiency or CHP projects were not developed). In other words, the backstop mechanism would ensure that emissions from the fossil generation fleet are reduced; however, it would not impose a federally enforceable obligation on CHP owners who participate in a state measures program. States could incentivize these measures through various types of allowance allocation approaches.

Finally, it is important to note that the final rule specifically calls out CHP as an approvable compliance option for states or utilities, stating that electric generation from non-affected CHP units may be used to adjust the CO_2 emission rate of an affected EGU (i.e., serve as a compliance option), as CHP units are low-emitting electric generating resources that can replace generation from affected EGUs. The rule prescribes how to "net-out" the incremental emissions from CHP in determining the ERCs for non-affected CHP used as a compliance measure (see Appendix C). The approach described takes into account the fact that a "non-affected CHP unit is a fossil fuel-fired emission source, and the fact that the incremental CO_2 emissions related to electrical generation from non-affected CHP units are typically very low," and requires an adjustment to the MWh output of the CHP system that reflects the incremental emissions at the project site.[5]

The rule also specifically states that electric generation from Waste Heat to Power (WHP) units may be used to adjust the CO_2 emission rate of an affected EGU (i.e., serve as a compliance option).[6] The rule notes that as long as there is no supplemental fuel use, there are no incremental CO_2 emissions associated with WHP power generation. As a result, the incremental electric generation output from the WHP facilities could be considered zero emitting for the purposes of meeting the emission guidelines, and the MWh of electrical output could be used to adjust the CO_2 emission rate of an affected EGU without adjustment. Where fossil fuel is used to supplement waste heat in a WHP application, MWh of electrical generation that can be used to adjust the CO_2 emission rate of an affected EGU must be adjusted or prorated based on the proportion of fossil fuel heat input to total heat input that is used by the WHP unit to generate electricity.

CHP Offers Significant Benefits

The CPP creates a new opportunity to stimulate investment in CHP for the mutual benefit of manufacturing, commercial and institutional building owners, electric utilities and power plant owners:

- CHP is a large, low-cost emission-reduction opportunity.
- CHP is often a less-expensive means to reduce power plant CO_2 emissions, compared to "inside the fence" options.
- A CHP pathway in a state compliance plan can help improve the productivity and competitiveness of a state's industrial and commercial base, enable industrial plants, commercial buildings and institutional campuses an opportunity to benefit financially from GHG reductions, and provide new revenue streams or other financial incentives to encourage investment in CHP.

[5] 80 *Fed. Reg.* at 64902.
[6] 80 *Fed. Reg.* at 64903.

- CHP investments tend to stabilize the industrial and commercial base in a service territory and can be utilized to help resolve electric transmission and distribution system problems that would otherwise require more expensive capital investment by electric utilities.
- CHP compliance pathways can align with existing state and utility programs to accelerate the deployment of CHP.

EPA, DOE and others have long recognized CHP's environmental, economic and reliability benefits. Appendix E provides an annotated collection of key materials on barriers and opportunities to CHP deployment.

CHP compliance pathways under the CPP could bring significant new financial value to encourage CHP investment by owners of manufacturing, commercial and institutional facilities. State compliance plans under the CPP can be designed to shorten the investment payback of CHP, provide customers with a hedge against rising electric power prices, and lower the overall cost of CO_2 controls for utilities and ratepayers.

CHP Is Already Fueling the American Economy

CHP has long played a key role in America's electricity system. Today, there are more than 4,200 CHP systems operating in the United States. (Figures 1 and 2). Combined, these projects produce nearly 83 gigawatts of clean and efficient power – the equivalent of more than 166 conventional power plants. This represents 8 percent of U.S. electric capacity and roughly 12 percent of U.S. generation. Nearly seventy percent of this existing installed capacity is fueled by natural gas, but CHP systems can be, and are, fueled by a wide variety of fuels including propane, biogas, process wastes, biomass and coal. Each year these systems avoid more than 1.8-quadrillion Btus of fuel consumption and 241-million metric tons of emissions, compared to what would occur from separate production of heat and power.

CHP systems operate under a wide variety of ownership structures, including systems owned by industrial facilities, CHP systems jointly operated and owned by industrial customers in partnership with utilities, and CHP systems operated by third-party independent power producers (IPP) who supply some combination of thermal energy and electricity to an industrial host and in some cases surplus electricity to the utility grid. Each of these ownership structures can be used to reduce emissions and produce tradable ERCs or emission allowances under EPA's CPP.

Figure 1. Existing CHP Capacity by State[7]

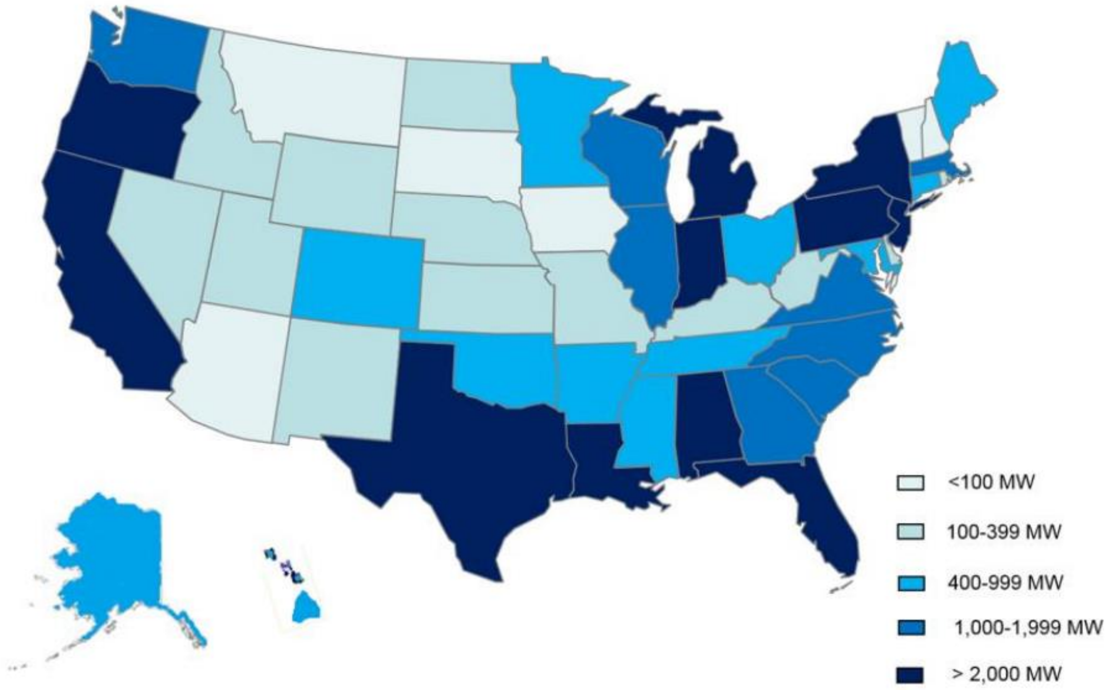
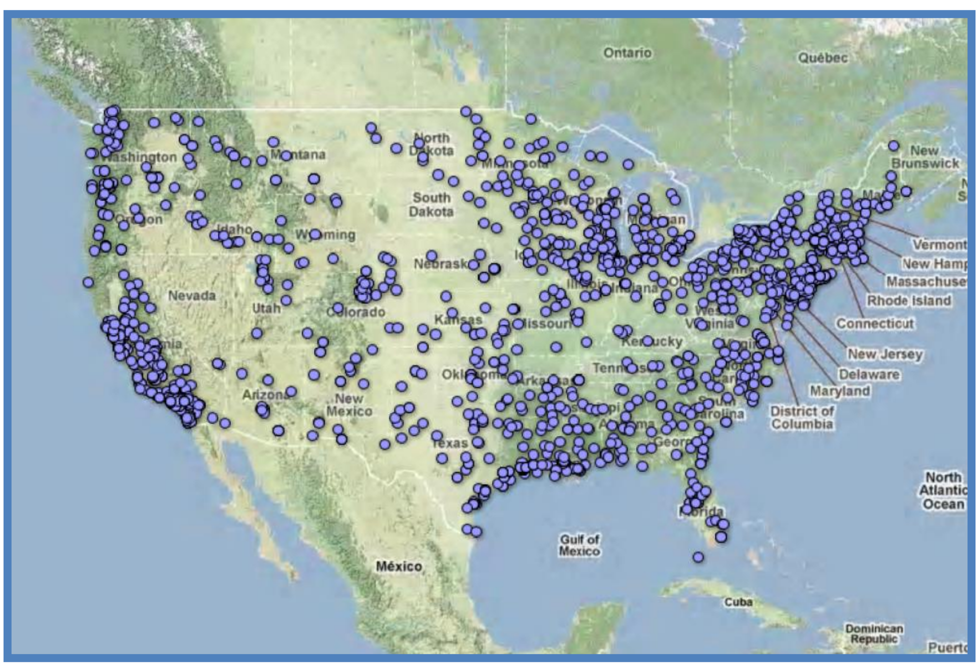


Figure 2. Existing CHP Installations (2014)[8]



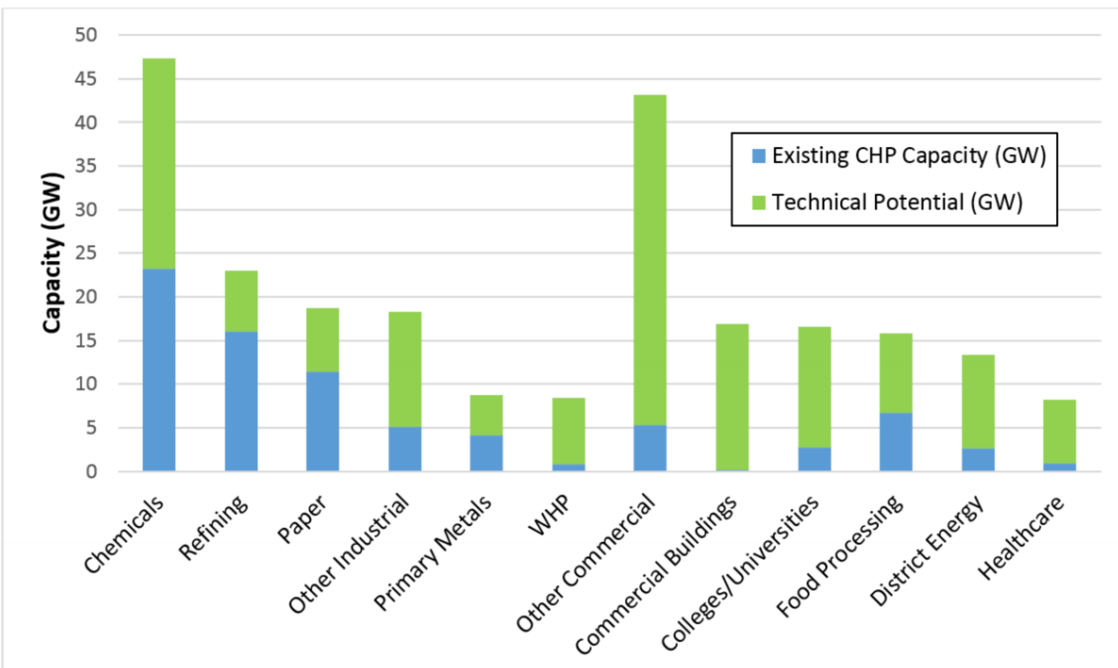
[7] U.S. DOE, "Combined Heat and Power (CHP) Technical Potential in the United States," March 2016, http://energy.gov/sites/prod/files/2016/03/f30/CHP Technical Potential Study 3-18-2016 Final.pdf.

[8] U.S. DOE CHP Installation Database. Maintained by ICF International. U.S. Installations as of December 31, 2014. https://doe.icfwebservices.com/chpdb/.

There Is Significant Opportunity to Increase CHP Deployment

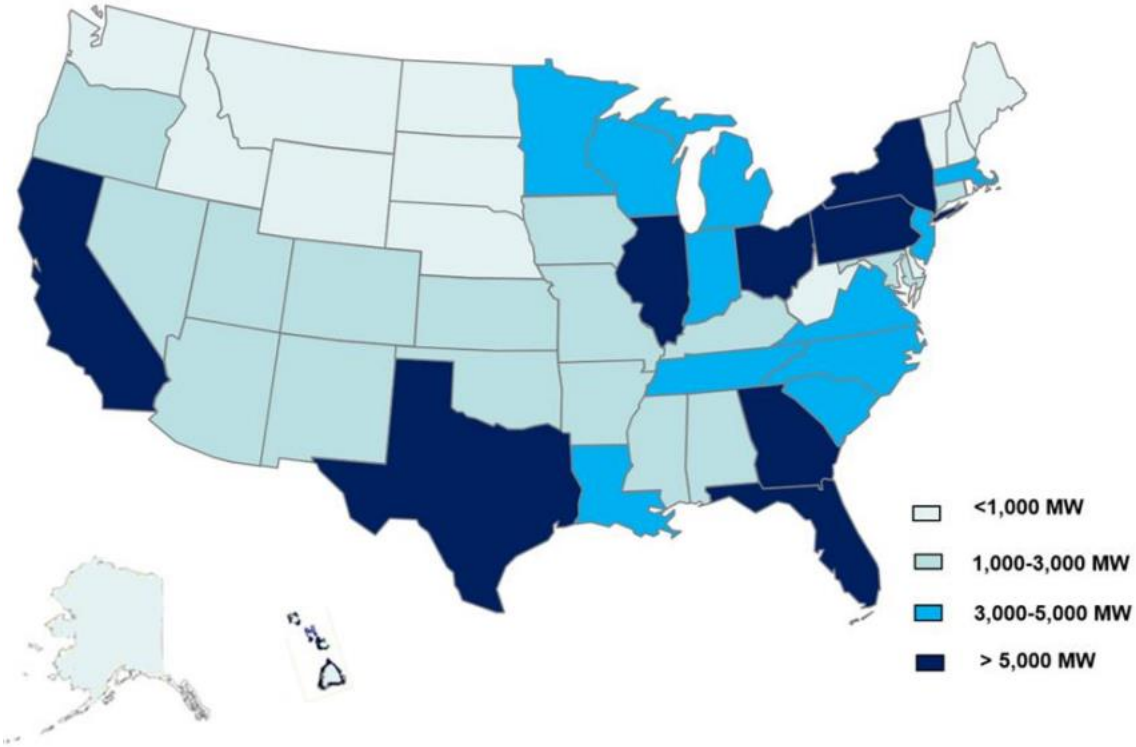
While CHP is already fueling America's factories, tremendous potential remains to increase deployment and make American businesses and institutions more competitive and resilient, while reducing emissions. The U.S. Department of Energy and EPA have identified as much as 149 gigawatts of remaining CHP technical potential – the equivalent of 298 conventional power plants. (Figure 3).[9] To date, U.S. CHP deployment has been concentrated in the industrial sector; however, tremendous opportunity remains in hospitals, universities, and multi-family housing, with future potential roughly equally divided between the commercial and industrial sectors. (Figure 3). Unlike other clean-energy sources, energy production from CHP systems is not limited to times when the sun is shining or the wind is blowing. CHP provides an available, reliable clean-energy solution for every state in the United States. (Figure 4). A recent report by the National Association of Clean Air Agencies (NACAA) identifies CHP as "one of the most cost-effective strategies for reducing CO_2 emissions economy-wide."[10] For this reason, it is a key option that states may consider when determining how to achieve CPP emission targets.

Figure 3. Remaining CHP Technical Potential by Sector[11]



[9] Note that technical potential provides an estimation of market size constrained only by technological limits — the ability of CHP technologies to fit customer energy needs. It does not include economic or other considerations relevant to a decision to invest in CHP.
[10] National Association of Clean Air Agencies (NACAA), May 2015, "Implementing EPA's Clean Power Plan: A Menu of Options," at 3-14, http://www.4cleanair.org/NACAA_Menu_of_Options.
[11] U.S. DOE, "Combined Heat and Power (CHP) Technical Potential in the United States," March 2016, http://energy.gov/sites/prod/files/2016/03/f30/CHP Technical Potential Study 3-18-2016 Final.pdf.

Figure 4. Remaining CHP Technical Potential by State[12]



CHP in the Clean Power Plan

In designing a compliance plan under the CPP, states initially need to make several threshold decisions that are independent of the question whether to include CHP in a compliance strategy:

1. The state needs to decide if it will rely, in part, on "outside-the-fence" measures such as energy efficiency and renewable energy, rather than rely solely on the limited "inside the fence" options (e.g. power plant heat rate improvements or fuel switching).
2. States need to decide if they will pursue a rate-based or mass-based compliance path.
3. Each state needs to decide if it is taking on any of the emission reduction obligation ('State Measures"), or if it will impose the full responsibility on power plant owners.
4. The state needs to decide whether compliance with either rate or mass limits will be measured unit-by-unit, or fleet-wide, and whether to allow trading with other states.

These choices will be determined by a number of factors that are beyond the scope of this guide. But clearly, as long as the state decides to rely in part on outside-the-fence measures, CHP can be an effective element of a broader compliance plan regardless of which other forks-in-the road are chosen.

EPA has established state targets in both a rate- and equivalent mass-based form. Under the former, the state must not exceed a certain level of emissions per unit of power generated by

[12] U.S. DOE, "Combined Heat and Power (CHP) Technical Potential in the United States," March 2016, http://energy.gov/sites/prod/files/2016/03/f30/CHP Technical Potential Study 3-18-2016 Final.pdf.

covered power plants (i.e., lbs/MWh). Under a mass-based approach, covered power plants (individually or collectively) may not exceed an aggregate emissions level (in tons) set by EPA. As noted above, the decision to pursue either a rate-based or mass-based approach is a threshold determination for each state. CHP is a viable compliance option under either approach.

CHP under a Rate-Based Approach

Under a rate-based approach, states will have specific emissions-rate targets (i.e., lbs CO_2/ MWh) that must be met over time. These targets may be applied to statewide power plant fleets, utility fleets, or individual power plants, depending how individual state compliance plans are structured. When thermal output is properly accounted, well-designed and properly operated CHP systems generate electricity at a lower effective emissions rate than most affected EGUs and at a rate that is lower than state targets under the CPP. Under EPA's final rule, CHP can generate ERCs that can help states, and or affected EGUs meet their emissions targets.

Under the CPP, the state may issue ERCs to measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs. These ERCs may then be used to adjust the reported CO_2 emission rate of an affected EGU when demonstrating compliance with a rate-based emission standard. For each submitted ERC, one MWh is added to the denominator of the reported CO_2 emission rate, resulting in a lower adjusted CO_2 emission rate.[13]

Under a rate-based approach, CHP generation and emissions savings data can be used to affect "corrections" to the denominator of the equations used to determine compliance with state CO_2 targets (as illustrated in Appendix C). Under the final rule, each state will be assigned an emission limitation representing the allowable average emission rate for all affected power generation in that state. To achieve the target, power plant owners must reduce the total emissions from power plants relative to the total amount of electric power generated. States can help power plant owners do this through programs that incentivize CHP investment and other energy-efficiency measures that are more cost- effective options compared to "inside the fence" measures such as power plant heat-rate improvements or repowering.

Grid connected[14] CHP systems installed after 2012,[15] which are not affected units, are eligible to generate ERCs.[16] WHP systems are also eligible.[17] The final rule sets forth the accounting

[13] 80 *Fed. Reg.* at 64834.
[14] 80 *Fed. Reg*. at 64897.
[15] 80 *Fed. Reg.* 64896. Only the quantified and verified MWh of electricity generation that a CHP system produces in 2022 may be applied toward adjusting a CO_2emission rate of an EGU. A MWh of generation from CHP systems that occurs in 2022 or a subsequent year may be carried forward (or ''banked'') and applied in a future year. For example, a MWh of renewable energy generation that occurs in 2022 may be applied to adjust a CO_2 emission rate in 2023 or future years, without limitation.
[16] "…a wide range of actions may be taken to adjust the reported CO_2 emission rate of an affected EGU in order to meet a rate-based emission standard and/or demonstrate achievement of a state CO_2 rate-based emissions goal. All of the measures described in this section will substitute for generation from affected EGUs or avoid the need for generation from affected EGUs, thereby reducing CO_2 emissions. This includes incremental NGCC and RE measures included in the EPA's determination of the BSER, as well as other measures that were not included in the determination of the BSER, such as other RE resources, demand-side EE, CHP, WHP, electricity transmission and distribution improvements, nuclear energy, and international RE imports connected to the grid in the contiguous U.S., as discussed elsewhere in this preamble." (emphasis added) 80 *Fed. Reg.* at 64895-6. *See also* 80 *Fed. Reg.* 64902

method for adjusting a CO_2 emission rate of affected sources in section VIII.K.1.[18] Under this method, MWh from zero- and lower-emitting resources are added to the denominator of an affected EGUs reported CO_2 emission rate, resulting in a lower adjusted CO_2 emission rate. This adjustment allows mass CO_2 emission reductions from CHP to be fully reflected in an adjusted CO_2 emission rate.[19]

This adjustment mechanism means that CHP systems can produce revenue for CHP investors that reflects the economic value of emissions reductions. This can occur in two ways:

1. Direct financial incentives to CHP developers from states or utilities to stimulate CHP investment, accompanied by assignment of ERCs to power plant owners, or
2. Market-based mechanisms that allow power plant owners (affected entities) to purchase certified ERCs that have been issued to CHP owners by states, typically from an emissions registry.

The issuance of ERCs requires both independent verifiers and an ERC tracking system.[20] Rate-based compliance plans must include:

- Provisions for issuance of ERCs by the state and/or its designated agent;
- Provisions to track ERCs, from issuance through submission for compliance; and
- The administrative process for submission of ERCs by the owner or operator of an affected EGU to the state, in order to adjust its reported CO_2 emission rate when demonstrating compliance with a rate-based emission standard.[21]

To demonstrate compliance with a rate-based emission standard, an affected EGU would report its CO_2 lbs/MWh emission rate to the state regulatory body, and surrender to the state any ERCs it wishes to use to adjust its reported emission rate. The state regulator would then cancel the submitted ERCs. The affected EGU would add the MWh the ERCs represent to the denominator of its reported CO_2 lbs/MWh emission rate to demonstrate compliance with its emission standard.[22]

(discussing the method to determine the number of MWh that may be used to adjust the CO_2 emission rate: "The accounting approach proposed in a state plan must take into account the fact that a non-affected CHP unit is a fossil fuel-fired emission source, as well as the fact that the incremental CO_2 emissions related to electrical generation from a non-affected CHP unit are typically very low. In accordance with these considerations, a non-affected CHP unit's electrical MWh output that can be used to adjust the reported CO_2 emission rate of an affected EGU should be prorated based on the CO_2 emission rate of the electrical output associated with the CHP unit (a CHP unit's 'incremental CO_2 emission rate') compared to a reference CO_2 emission rate."). The calculation method is also discussed in EPA's proposed "Model Rule." 80 *Fed. Reg.* 64966, at 64996, October 23, 2015, "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; Proposed Rule."

[17] 80 *Fed. Reg.* at 64902-3.

[18] 80 *Fed. Reg.* at 64895.

[19] *See* 80 *Fed. Reg.* at 64895 which includes a sample calculation.

[20] These requirements are described at 80 *Fed. Reg.* at 64906-907.

[21] 80 *Fed. Reg.* at 64904.

[22] *Id.*

CHP under a Mass-Based Approach

Under a mass-based approach, the state's rate-based emissions targets are converted into overall emissions limits expressed in terms of annual short tons of CO_2 released. EPA has included equivalent mass-based state emission targets in the final rule. Under a mass-based approach a state plan can rely on "state measures" and forms of emission allowance trading.

Under a state measures plan, a state would implement a suite of state measures that are adopted, implemented, and enforceable only under state law, and rely upon such measures to achieve the required level of CO_2 emission performance from affected EGUs. The state measures under this plan type could be measures involving entities other than affected EGUs.[23]

CHP deployment reduces the need for power generated from the grid, thereby lowering the emissions from affected EGUs. This emission reduction can be attributed to CHP under state or ratepayer incentive programs (a "state measure" element of a compliance plan), or the state could create an emission allowance and trading mechanism that "sets aside" or directly allocates CO_2 emission allowances to industrial entities who can sell them to power plant owners in state or regional cap and trade programs.[24]

If a state chooses to use an incentive program as a state measure to encourage CHP investment, it must also include a backstop mechanism that would impose tighter federally enforceable emission standards on affected EGUs in the event that the state program underperforms and the state fails to achieve its mass-based CO_2 goal.[25] Under a state measures plan, programs to incentivize CHP must be satisfactorily described in the supporting material for a state plan submittal. The supporting material would need to demonstrate that the CHP program meets the same integrity elements that would apply to federally enforceable emission standards. Specifically, the state plan submittal must demonstrate that the state measures are verifiable, enforceable, non-duplicative and permanent. See Appendix B for a discussion of these terms and requirements.

It does not appear that a backstop mechanism is necessary, however, where a state seeks to rely on CHP as a compliance mechanism by simply allocating emission allowances to CHP owners.

Is CHP Compatible with Criteria Used by EPA to Approve State Compliance Plans?

EPA's final rule identifies the general criteria it will use to evaluate and approve state compliance plans.[26] The criteria are different for rate-based and mass-based plans. Several of the criteria for approval are not germane to decisions to use CHP as a compliance option. In the discussion below and in Appendix B, we address enforceability and related criteria, as this requires particular attention when developing a CHP compliance module.

Enforceability

[23] 80 *Fed. Reg.* at 64836.
[24] Considerations and requirements for mass-based emission standards state plans are addressed in section VIII.J for the final rule. 80 *Fed. Reg.* at 64887, *et seq*.
[25] 80 *Fed. Reg.* 64836The requirements for the backstop are described in the final rule at 80 *Fed. Reg.* 64837.
[26] 80 *Fed. Reg.* 64843.

The final EPA rule clarifies how state plans can meet the enforceability criteria and strongly suggests that CHP elements of a state compliance plan satisfy this standard.

A compliance plan element has historically been deemed enforceable if the measure is mandatory and legal authority has been granted by legislation and/or regulations to the relevant governing body to enforce the measure.[27]

In general, a key to meeting the enforceability criteria under §111(d) is to identify a responsible party operating under state law, interagency agreements, regulatory requirements, contracts or other requirements to implement each emissions reduction measure (and in some cases to establish a backstop mechanism). Responsible parties might include the affected EGUs, the state, or even third parties (such as distribution utilities). For example, a state agency or utility responsible for implementing an incentive program to increase investment in CHP could be identified as the party responsible to carry out, evaluate and report on the effectiveness of the measure. Typically these entities will have a web of statutes, regulations, utility commission orders or contracts that establish commitments to carry out the measures relied on, or referenced in, the plan. CHP emission reductions are enforceable[28] because ERCs generated by, or allowances directly allocated to (or earned by) CHP systems are subject to a web of contractual requirements that ensure any failure to operate would not give rise to an ERC or an allowance in the first place. Moreover, many CHP systems are financed in part through state or utility incentive programs that have performance requirements in the documents giving rise to those incentives that are enforceable by the agencies or the utilities involved. If a CHP system contracted to sell ERCs or allowances to affected sources for compliance purposes, that sale would undoubtedly be described in binding contracts between the CHP operation and the purchaser (typically the owner of a power plant subject to the CPP).

Hence, while drafters of compliance plans need to identify an entity that is responsible for deploying CHP and develop corrective measures if that aspect of the plan underperforms, in most cases this will happen automatically as part of incentive or credit sales transactions.

It is important to note that a CHP measure or compliance module may help a state plan meet the enforceability criteria without necessarily being “federally” enforceable itself. A measure becomes federally enforceable when the state includes it in its formal compliance plan. But the final rule states that a state may rely on “state measures” (such as a CHP strategy) that are not

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[27] U.S. EPA, 2012, “Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans.”

[28] An emission standard or a state measure is enforceable if: “(1) It represents a technically accurate limitation or requirement and the time period for the limitation or requirement is specified; (2) compliance requirements are clearly defined; (3) the entities responsible for compliance and liable for violations can be identified; and (4) each compliance activity or measure is enforceable as a practical matter in accordance with EPA guidance on practical enforceability...In developing its CAA section 111(d) plan, to ensure that the plan submittal is enforceable and in conformance with the CAA, a state should follow the EPA’s prior guidance on enforceability.” 80 *Fed. Reg.* at 64850. Prior EPA guidance on enforceability includes:

1. September 23, 1987, memorandum and accompanying implementing guidance, ‘‘Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency,’’
2. August 5, 2004, ‘‘Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures,’’ and (3) July 2012 ‘‘Roadmap for Incorporating Energy Efficiency/ Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix F.’’

federally enforceable, as long as there is a commitment by the state to adjust its plan to address any emissions reduction shortfalls associated with the implementation of such measures or to implement "backstop" provisions, which involve tighter emission limits on EGUs to compensate for any shortfall.[29] (See Appendix B for a more complete discussion of backstop measures).

It is therefore not necessary to include all emission reduction measures in the *federally* enforceable portion of the state plan. In fact, states are more likely to be successful at incentivizing private entities to invest in cost-effective CHP projects if these programs and projects are *not* subject to the perceived risk of federal enforcement or citizen suits under the federal Clean Air Act. This can be accomplished using a "state measures approach," which makes the overall state target the federally enforceable provision in the state plan. Under such an approach, it is only the state emission rate target (or mass emission limit), and EGU-specific permit limitations, that constitute the federally enforceable elements in the state plan. A state's plan would demonstrate how it would achieve the targets through EGU-specific permit requirements, while referencing state measures, including CHP programs, that will help meet those limits. The programs themselves would not, therefore, be federally enforceable, but would give EPA sufficient confidence that the plan as a whole meets the general enforceability criteria of the EPA rule.

Since the emission targets in the state plan itself, rather than the individual elements of a compliance strategy, are ultimately enforceable,[30] end users that participate in a state or utility CHP program that generates credits for CPP compliance would not be subject to state or federal enforcement. As voluntary suppliers of emission reduction credits, their only obligations would be to satisfy the terms of legally binding emission credit sales contracts or agreements under which they receive financial incentives. Similarly, states will not face penalties if a CHP program does not deliver as expected. Rather, the state would monitor overall performance of each element in its strategy, periodically report progress to EPA, and if the overall mix of strategies is underperforming, it will make adjustments in programs and strategies or invoke backstop provisions to make up the short fall. Such adjustments need not be specific to the CHP elements of the plan. (See Appendix B for a more detailed discussion of enforceability).

Measurable, Quantifiable and Verifiable

The concept of enforceability is closely related to three other state plan approval criteria. State plans must detail how emissions reductions can be measured quantified and verified. These criteria can be easily met by CHP projects. Most CHP projects as a matter of standard business

[29] *See,* e.g., 80 *Fed. Reg.* at 64832 n. 782, 64842, & 64867.

[30] Under a state measures approach, a state compliance plan may project that a set of CHP incentives (managed by a state agency or under a utility DSM program) will achieve a certain amount of energy savings or CO_2 tonnage reductions. The state strategy is enforceable because it is based on a series of contractual agreements with entities that receive incentives or other financial support to invest in CHP. If those CHP incentives fail to produce the estimated energy savings, neither that state, nor participants in the program are subject to federal enforcement. It is the overall performance of a state plan that is federally enforceable, and if one strategy falls short it may be made up by over-performance from other plan elements, or by corrective measures (to improve the CHP strategy, or other elements of the compliance plan) taken in later years of the applicable three-year compliance period.

practice are metered and annual performance is monitored. A number of states have adopted standard protocols to evaluate CHP project performance (e.g., Massachusetts, New York, Maryland, California, Illinois, New Jersey) and many utilities have long experience with similar protocols under traditional demand-side management programs. Recognizing this, EPA explicitly identifies CHP as a compliance option for which EM&V is well established.[31] Section VIII.K of the CPP sets out specific considerations and requirements for state plans focused on rate-based emission standards. These include the basic accounting method for adjusting the reported CO2 emission rate of an affected EGU, as well as requirements for the use of measures to adjust a CO2 emission rate. These requirements include eligibility, accounting, and quantification and verification requirements (EM&V) for the use of CO2 emission reduction measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs in rate-based state plans. The rate-based model rule in the proposed Federal Implementation Plan (FIP) included specific EM&V requirements for non-affected CHP (see Appendix D). Where the state has assumed some part of the emission reduction obligation (via a "state measure"), any plan to achieve part of that reduction via CHP and industrial energy efficiency more broadly should include an EM&V plan and identify the responsible implementation entity.

In mass-based plans states will also need to detail how energy savings from CHP result in CO_2 emissions reductions. The EGU emission reduction impacts of CHP are similar to those of other end-use energy-efficiency measures. Like other energy-efficiency investments, CHP reduces demand – and thus the associated emissions – from affected EGUs. As such, the methodology used for crediting emission reductions caused by new and upgraded CHP[32] should be equivalent to the methodology used for crediting other end-use energy-efficiency measures. However, unlike end-use efficiency, implementation of CHP often results in incremental fuel use – and incremental CO_2 emissions – at the host facility (see Appendix C). CHP's efficiency and emission benefits derive from producing both electricity and useful thermal energy simultaneously from a single fuel source. There are accepted output-based emissions measures that account for both the thermal and electric outputs of the system and that appropriately account for the emissions benefits of CHP.

Non-Duplicative and Permanent

The final rule's criteria for state plan approval also requires that plan components achieve emission reductions that are non-duplicative and permanent. These terms may sound daunting, but as defined by EPA's final rule are easy for CHP measures to meet. CHP emission reductions are "permanent"[33] because CHP systems are long-lived capital investments that are financed and designed to operate for decades. Consequently, there is reasonable assurance that they will continue to produce energy and emission reductions though the 2022-2030 compliance period. While it is possible that a CHP system could fail to operate (e.g. due to the loss of a steam host or equipment failure), that eventuality is covered by state commitments to make corrections to plan elements that underperform, and in some cases to invoke backstop

[31] This recognition is reflected in a technical support document accompanying the proposed rule Technical Support Document (TSD) for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, State Plan Considerations, Docket ID No. EPA-HQ-OAR-2013-0602 June 2014, at 47-49.

[32] Upgraded CHP units refers to expansion or efficiency improvements to existing CHP systems.

[33] An emission standard or a state measure is permanent "if the emission standard must be met for each applicable compliance period." 80 *Fed. Reg.* at 64850, 64852.

emission reductions at affected power plants. The risk of CHP failure is therefore not a basis on which to reject a CHP element of a state plan.

CHP emission reductions are "non-duplicative"[34] so long as the state has an ERC or allowance tracking mechanism to ensure that any credits generated by a CHP system are not claimed twice. State plans will all include mechanisms to ensure the integrity of the emission allowance allocation system and a process to issue ERCs. Those provisions will satisfy the "non-duplicative" criteria for any CHP compliance module.

Steps Toward a CHP Compliance Module

The following are key steps a state can take to evaluate and configure a CHP compliance module:

Steps to Establish a CHP Compliance Pathway

1. Assess the CHP emissions reduction potential and experience under existing policy supports
2. Build on existing programs and/or create new options for large energy-intensive businesses
3. Clearly inform large customers that CHP investments they can earn revenues to support CHP investment, through either incentives, carbon emission rate credits ("ERCs") or allowance allocations
4. Adopt an Evaluation, Measurement and Verification (EM&V) protocol
5. Estimate energy savings or emission reductions to be achieved from CHP
6. Identify barriers to CHP investment and apply appropriate programs and policies policy changes to overcome the barriers

Survey CHP Potential and Build on Existing State and Utility CHP Programs

A first step to including CHP in a state CPP compliance plan is to collect information on the CHP potential in a state or utility service territory. Most states will have access to studies and databases that quantify the commercial, institutional and industrial base and associated thermal loads.[35] A variety of public and private organizations have already produced both national and state-specific estimates of CHP potential, which can inform this assessment.[36]

Next, the state must gain an understanding of existing state or utility programs to support CHP development. The fastest and most effective way to integrate CHP into CPP compliance is establish or expand existing state or utility CHP programs. Many states have already adopted policies to advance CHP investment (Appendix A),[37] often in the form of state or utility programs that incentivize CHP investment and/or reduce barriers to market development. Such policies and programs can take various forms: cash grants to offset capital costs, performance incentives tied to electric output, low-cost financing, streamlined permitting and interconnection

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[34] An emission standard or a state measure is non-duplicative if it is not already incorporated in another state plan." 80 *Fed. Reg.* at 64850, 64852.

[35] *See,* e.g*.,* DOE State Energy Database System.

[36] *See,* e.g., "The Opportunity for Combined Heat and Power in the United States", American Gas Association, 2013, https://www.aga.org/opportunity-chp-us; "Assessment of the Technical and Economic Potential for CHP in Minnesota", Minnesota Department of Commerce Division of Energy Resources, 2014, http://mn.gov/commerce/energy/images/CHPTechnicalandEconomicPotential.pdf.

[37] *See also* EPA CHP Policy Portal, http://www.epa.gov/chp/policies/database.html. Note that Appendix A profiles a wide range of existing policies, however, inclusion in the Appendix does not reflect an endorsement of a particular approach. Moreover, not every policy will be appropriate in each state.

standards, and tax credits. States without existing incentives can adopt successful programs from other states, modified to appeal to the particular mix of industrial customers and thermal loads.

Where a state plans to use utility or state-based incentives, it will generally be helpful to establish multi-agency teams to coordinate actions and establish a clear division of labor. The text box above shows one way to assign roles among participating agencies – though many other combinations are possible.

Illustrative Interagency Division of Responsibilities for a CHP Module

Public Utility Commission

- Approve utility or state-based incentives
- Address cost recovery for utility programs
- Address regulatory barriers to CHP

State Air Quality Agency

- Write and submit plan
- EPA Point of contact
- Under mass-based compliance system, manage set aside for CHP
- Agreements with other states on cross-state credit trade or ownership
- Manage any corrective actions

State Energy Offices

- Forecast MWh or CO_2 impacts (provide to air quality staff)
- Develop and define EM&V plan
- Outreach to CHP host community
- Monitor progress and report results
- Host registry or certification mechanism for CO_2 reduction credits

Evaluate Options for Large Customers to Earn Tradable Emission Rate Credits or CO_2 Allowances

States must adopt special mechanisms in their state plans to make CHP an effective compliance option. An investment in CHP does not automatically generate a compliance value under the CPP. However, CHP can provide states and power plant owners with large and low-cost compliance options.

Under a rate-based compliance approach, new investment in CHP systems will not lower the emission rate of power plants subject to the CPP. But power plant owners can purchase ERCs from CHP hosts that are used to reduce the effective emission rate of power plants. Hence it is essential that states create mechanisms to allow CHP to generate credits to validate the emission reduction claim. One approach is to create a registry where ERCs are recorded and verified, similar to the registries currently in use to verify and track Renewable Energy Credits ("RECs"). Each state plan should include mechanisms by which ERCs are created and traded.

Under a rate-based plan, once the basic mechanism for creation of ERCs is created, states or utilities could create "standard offers" to purchase emission reduction credits from industrial, commercial or institutional customers who make investments in CHP.[38] This model can work either with CHP units owned by industrial power customers or by CHP systems that are owned and operated by third-party independent power producers (IPP) that operate a CHP system on an industrial site with thermal energy and electricity being supplied to the industrial host. The compensation for and transfer of emissions rate credits can be done either as an element of a state or utility CHP incentive program, or where such programs do not exist, as a separate, market-based mechanism involving a bilateral transaction between affected EGUs and CHP investors.

Under a mass-based compliance approach, new CHP investment will reduce the total amount of CO_2 emitted from affected power plants, but no financial credit will flow to the investor unless: 1) states "set-aside" or directly allocate CO_2 emission allowances to CHP project owners from the pool of available allowances; or 2) traditional state or utility incentive grants are structured to reward CHP owners for the CO_2 compliance value of the CHP investment. Under a set aside or direct allocation approach (option 1 above), the industrial customers could gain emission allowances without participating in a utility-led energy-efficiency program. Under a mass-based system, affected EGUs will be allowed to emit a set number of tons consistent with the state emission target (expressed in tons/year). States will establish a permit system that requires affected EGUs to hold and retire a specific number of allowances each year – with one allowance representing each ton of CO_2 emitted. The power plant owners will receive allowances in several ways. A state could auction the allowances, or could allocate them directly to power plant owners. To reward CHP investors for the carbon-reduction effect of their facilities, the state could hold back, or "set-aside" a limited number of allowances from those that are auctioned or directly assigned to power plant owners. Those allowances could then be given to CHP owners, who could sell them to power plant owners. Alternatively proceeds from allowance auctions can be used for financial incentives for new CHP investment.

The standard offer and set-aside mechanisms described above may be especially important in states where industrial customers have opted-out of state or utility incentive programs or where such programs do not exist.

It will be difficult to estimate the financial value of ERCs and allowances generated or earned by CHP systems until states have drafted compliance plans and emission trading markets mature. Even after the regulatory mechanisms are in place, the price of emission rate credits may be hard to predict. This suggests that states might combine multiple strategies to incentivize CHP. An example of this hybrid approach would be to establish or continue traditional forms of performance-based CHP incentives (e.g. those run by the New York State Energy Research & Development Authority),[39] and allow the incentive recipients to earn associated ERCs or allowances that can be sold to supplement the value of traditional program incentives. The state program administrator could then periodically adjust the traditional incentive payments (up or

[38] Utilities can also consider partnerships in which shared ownership or operation of a new CHP system could help meet both utility and customer needs at lower cost than separate power generation and thermal systems. As described in the Menu of Options (Appendix A), several utilities have already pursued such partnerships.

[39] Such incentives are based on how well the system actually performs – considering performance factors such as annual electricity generation (kWh), overall fuel conversion efficiency (FCE), or summer-peak demand reduction (kW).

down) to reflect the value that CHP investors will be able to secure from the sale of the emission rate credits into CO_2 compliance markets. This would create a stable, ongoing revenue stream that would help attract large industrial, commercial and institutional customers to make CHP investments. Under this scenario, in order to avoid double counting, the state would not take credit for the CO_2 emission reduction value of its CHP incentive program as a "state measures" in a mass-based CPP compliance plan.

We emphasize that state plans must explicitly establish pathways by which power plant owners and CHP hosts can trade ERCs or emission allowances through set asides or direct allocations, ERC crediting/registry mechanisms, and other compliance plan provisions that make it clear that CHP owners can earn credit for reducing CO_2 emissions from the electric sector. Absent such measures, CHP hosts will not necessarily be compensated for their investments.

Adopt an Evaluation, Measurement and Verification (EM&V) Protocol

Any CHP pathway will require accurate measurement of the performance and efficiency of installed CHP systems. Most operators of CHP systems routinely measure these values as part of their standard approach to monitoring and evaluating project performance. States that have implemented CHP incentive programs including New York, Massachusetts, New Jersey and Maryland have developed detailed EM&V protocols that include standards for specific CHP system parameters including meter types, meter placement, data collection frequency and performance calculations. These protocols can be readily adopted as part of a state's CPP compliance plan.[40] Section VIII.K of the CPP sets out the basic accounting method for adjusting the reported CO2 emission rate of an affected EGU under a rate based plan, as well as requirements for the use of measures to adjust a CO2 emission rate. These requirements include eligibility, accounting, and quantification and verification requirements (EM&V) for the use of CO2 emission reduction measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs in rate-based state plans. The rate-based model rule in the proposed Federal Implementation Plan (FIP) includes specific EM&V requirements for non-affected CHP (see Appendix D).

Estimate Energy Savings and Emission Reductions

Based in part on the CHP potential studies and experience with utility and state-based incentive programs, the state should make a realistic estimate of energy savings and emission reductions

[40] As part of this, a state might create a registry and certification process to make it easier to record and trade credits or allowances generated or earned by CHP operation. This will help reduce the cost and uncertainty associated with data collection. EM&V can be a complex process; however, if the state simplifies the process and inspires confidence that the credits and compliance revenues will flow back to large customers, more facilities might choose to invest in CHP. Under such a certification mechanism, a state agency or third-party verification agent might carry out the EM&V for the CHP host. A registry, like those currently used to track Renewable Energy Credits (RECs) for RPS compliance (and for voluntary renewable energy markets), could be used to certify and track emission rate credits in ways that prevent double-counting of emission reductions or energy produced.

that they expect the CHP strategy to produce.[41] These estimates will feed into the broader portfolio of emission-reduction strategies included in the state compliance plan.

Identify and Remove Barriers for CHP Development

Finally we note that CHP projects face a host of market, regulatory and business barriers that impact project costs and customer decisions.[42] At the same time, traditional regulatory structures governing electric utilities are giving way in many states to new approaches that place greater value on distributed generation, pollution control, and load reduction. As new forms of distribution system management and electric transmission products emerge, there will be opportunities to craft regulatory changes, and utility-support programs that combine CO_2 reduction value with electric system reliability or cost-control benefits (e.g. capacity and "ancillary services") to reduce the market, regulatory and business barriers to expanded CHP deployment. An important step to make CHP a viable CO_2 compliance option is to identify these barriers, bring them to the attention of the utility regulators, and to seek necessary policy changes. There are numerous examples of programs and actions implemented in various states that can serve as starting points for potential state programs and regulatory changes (Appendix A).[43]

Suggested Elements of a CHP Compliance Pathway

A state should consider a number of template elements when incorporating CHP in a CPP compliance plan. Different levels of rigor may be required depending on the compliance plan approach adopted by the state:

1. Overview of Combined Heat and Power
   a. Definition of CHP and CHP measures as part of a compliance plan
   b. Efficiency, emissions and economic benefits of CHP
   c. Potential of CHP deployment (market sectors, MWs, timing)
   d. Role of CHP in a state compliance plan

2. CHP as a compliance option
   a. How CHP produces emissions reductions at affected EGUs
   b. Assumptions around CHP deployment, savings, and compliance estimates

3. Quantification of emission savings potential
   a. Methodology for calculating electricity demand reductions, and associated CO_2 savings, attributable to CHP
   b. Data assumptions and sources
   c. Potential emission reductions from CHP, including a timeline for those reductions

4. Implementation

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[41] These estimates should be conservative, especially in the early years. CHP investments require considerable planning and construction time (and may need to be timed to correspond with capital investment or production cycles).

[42] Oak Ridge National Laboratory, 2008, "Combined Heat and Power: Effective Energy Solutions for a Sustainable Future", http://info.ornl.gov/sites/publications/files/Pub13655.pdf; DOE-EPA, 2012, "Combined Heat and Power: A Clean Energy Solution," http://energy.gov/sites/prod/files/2013/11/f4/chp_clean_energy_solution.pdf.

[43] *See also* EPA CHP Policy Portal - https://www.epa.gov/chp/dchpp-chp-policies-and-incentives-database.

a. Status of and experience with CHP deployment in the state
    i. Current and projected prices for natural gas and electricity
    ii. Technical resources available to support CHP development
b. Identify barriers to implementing CHP and Potential Solutions
    i. Up-front costs for the user
    ii. Permitting and siting
    iii. Utility interface
        a. Interconnection
        b. Standby tariffs
        c. Sale of excess power
    iv. Lack of awareness
    v. Undeveloped sales and service infrastructure
    vi. Lack of institutional capacity to support interested users
c. Program elements and policy actions that would increase CHP implementation (opportunities both within and outside of rate-payer based programs)
    i. Financial assistance
    ii. Regulatory support
    iii. Creating markets
d. Entities responsible for implementation

5. Monitoring and reporting
    a. Process by which the state would monitor and evaluate progress of any CHP "state measure"
    b. Identify applicable EM&V protocols used as part of any CHP State Measure, registry or allowance allocation mechanism
    c. State entities responsible for monitoring and evaluation
    d. Sources of data and relevance (fuel input, net electricity generation, net useful thermal energy recovery)
    e. Process for data monitoring and reporting as needed for any state measure, registry or allowance allocation mechanism

6. Enforceability (in general, the state plan is enforceable, but individual measures are not)
    a. Entities responsible for program implementation
    b. Entities with jurisdiction to enforce CHP compliance measures
    c. Process for enforcing CHP compliance measures
    d. Corrective actions and shortfall remedies available to the state

7. Verification and quantification
    a. Verification process for electricity savings attributable to CHP
    b. Entities responsible for verifying electricity savings
    c. Process for reporting and verifying electricity savings
    d. Process for quantifying emissions reductions

Conclusion

CHP can make significant contributions to state compliance with carbon emission reductions under EPA's CPP. The decision to include CHP as a compliance option rests with states, utilities, and key stakeholders. The benefits of including CHP in state compliance plans would accrue to power plant owners, large electric customers, gas and electric utilities, and the general public. CHP is completely compatible with the purpose and structure of EPA's CPP regulation. Over the next 12 to 18 months, utilities, end-users, CHP advocates and state agencies should work together to craft CHP compliance mechanism to reduce electric sector demand and CO_2 emissions.

Appendix A
Combined Heat and Power:
A Menu of Options to Support Deployment[44]

Table of Contents

The Table of Contents identifies a sampling of successful policies that states have adopted to encourage deployment of Combined Heat and Power (CHP). As illustrated in the following pages, successful policies have been adopted in virtually all states and are not limited by geography or politics. This list is not intended to be prescriptive. Policies that are successful in one state may not be suitable in another. Instead, these policies reflect the wide array of options available to states to advance CHP as part of their Clean Power Plans and provide some initial background and resources to enable others to learn from their experience. EPA maintains a comprehensive overview of CHP policy profiles in its CHP Policies and Incentives Database

[44] Note that for many of these policies, CHP may be eligible alongside other clean or renewable energy sources. Thus, the listed policies may support CHP because it is among eligible resources.

(dCHPP). This Appendix highlights a subset of those policies that are recognized as being the most successful. A list of all state policies cited herein is provided at the end of Appendix A.

Financial Assistance

While CHP systems offer long-term economic savings, they require a substantial up-front economic investment. Some developers and project hosts are often looking for projects with an eighteen-month pay-back period, but a large-scale CHP installation may take 7-10 years to see a return on investment. Policies that provide financial support can help reduce this initial hurdle and help projects “pencil out.”

CHP costs vary depending on the prime mover and the capacity of the installed system, with average capital costs ranging from $1,200 to $4,000 per kilowatt depending on technology, size and site conditions.[45] Total installation cost of a 3-megawatt CHP system can range from $5.7 million to over $10-million dollars.[46] Due to economies of scale, larger systems are cheaper to install per kilowatt than smaller units. Since industrial CHP applications are likely to be substantially larger than commercial installations (due to high heat loads and significant on-site electricity demand), these systems may be more cost-effective. In fact, the vast majority (86 percent) of existing capacity is in the industrial sector.[47] Maintenance costs will likewise vary by type, size and engine speed of the system.

Despite the up-front investment required, CHP systems provide significant long-term economic savings by reducing purchased electricity demand and insulating hosts from volatile electricity prices. Return on investment will vary depending on the technology type, location, price of electricity and fuel, among other variables. Because these factors vary by project, CHP system owners report payback periods ranging from 1.5 years to 12 years, with a large number of opportunities anticipating payback between 5 to 10 years.”[48] Favorable financial policies can help reduce this payback period and make CHP projects more attractive investments.

Financial incentives like the federal Investment tax credit can reduce up-front costs, thereby lowering the payback period. States can also offer additional financial incentives for CHP projects in the form of rebates, grants, loans, and tax deductions.[49]

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[45] EPA, Sept. 2014, “Catalog of CHP Technologies,” at Table 2-4, http://www.epa.gov/chp/documents/catalog_chptech_full.pdf (reporting capital costs ranging from $1,200 to $4,300/ kW – small microturbine on the small side, large gas turbine on the high side of range – dependent on prime mover and size).

[46] *Id.,* Tables 3-4 and 3-5.

[47] ICF, 2015, Combined Heat and Power Installation Database, http://www.eea-inc.com/chpdata/index.html.

[48] AGA, May 2013, “The Opportunity for CHP in the United States,” at Table ES-1 (reporting approximately 35 GW of projects with a payback between 5 to 10 years compared to 6.4 GW with a payback of less than 5 years given current technology costs and electricity prices), https://www.aga.org/sites/default/files/sites/default/files/media/the_opportunity_for_chp_in_the_united_states_-_final_report_0.pdf.

[49] ACEEE, “Policies and Resources for CHP Deployment: Financial Incentives,” http://www.aceee.org/sector/state-policy/toolkit/chp/financial-incentives.

States and utilities have adopted a wide variety of financial supports for CHP, including:

- State **grants**, **loans**, and **utility rebates**.
- State **bonds**.
- **Commercial PACE programs** that allow building owners to receive full financing for eligible energy-saving measures, repaid as a property tax assessment for up to 20 years.
- Discounted **utility** rates.
- State **tax credits** or **favorable tax treatment** (e.g., exempting CHP investments from property or income tax).

State Grants, Loans and Utility Rebates

A variety of grants and low-interest loans exist to help finance clean-energy investments, including CHP. These programs may be financed by utilities as part of their compliance with portfolio standards. By reducing upfront costs, such programs lower the payback period for eligible projects.

Alabama – The Energy Division of the Alabama Department of Economic and Community Affairs administers the AlabamaSAVES revolving loan fund program, which includes a budget of $50 million dollars. Revolving Loan Funds are structured so that the repayment of a loan is recycled to be loaned out again in support of another project, providing a continuous source of loan funds. The interest rate is one percent and the loan length is a maximum of 10 years. Closing costs are 1.75 percent of loan origination fee. The loans may be used to purchase and install equipment for renewable-energy systems and energy-efficient fixtures and retrofits installed on property owned and/or operated by an eligible business. CHP is considered an eligible technology under this program, with loans ranging from $50,000 to $4-million.

Arizona – Southwest Gas' Arizona Smarter Greener Better Distributed Generation program offers its customers rebates ranging from $400-$500 per kW of installed capacity (up to 50 percent of the cost of the qualifying project) as part of its energy-efficiency program. The Company offers incentives to qualifying commercial and industrial facilities that install efficient CHP systems. Incentives vary based upon the efficiency of the installed system. The minimum efficiency for all systems is 60 percent. Contractors are also encouraged to participate in the program. A partial rebate is provided after the equipment is purchased, following the submission of the project application and the engineering study. The utility then verifies the installation, operation, and energy savings before providing the remainder of the rebate.

California – The Self Generation Incentive Program (SGIP) provides incentives to renewably fueled and fossil-fueled CHP systems. All of California's major investor-owned utilities participate. The maximum incentive is $5 million with a minimum 40 percent customer investment. Eligible system size is capped at 3 MW and must meet a 60 percent minimum efficiency requirement. The incentive is $1.13 per watt for renewably fueled CHP and $0.46 per watt for conventional CHP systems.

Connecticut – In 2014, the Connecticut Department of Energy and Environmental Protection (DEEP) released a draft Integrated Resource Plan proposing to offer incentives of up to $450/ kWh for up to 160 MW of new CHP capacity in the state. The incentives will decline over time, as the state's deployment goals are met.

Connecticut also offers low-interest loans (one percent below the customer's applicable rate, not greater than prime rate) to support the installation of customer-side distributed resources (including CHP systems larger than 50 kW). The minimum loan size is $1,000,000 for a program total of $150-million.

Section 7 of Public Act No. 12-148 requires the Connecticut Department of Energy and Environmental Protection (DEEP) to establish a $15 million Microgrid Grant and Loan Program to support distributed energy generation at critical facilities. Critical facilities are defined as, "any hospital, police station, water treatment plant, sewage treatment plant, public shelter, or correctional facility, any commercial area of a municipality, a municipal center…" The loans are to be used for the cost of design, engineering, and interconnection of microgrid systems. Recipients of funding must submit an annual report to DEEP and the Connecticut Public Utilities Regulation Authority about the status of the recipient's microgrid project. An initial round of grants was issued in 2013 under the Microgrid Grant and Loan Program. A new round of grants was announced in October 2014.

Illinois - In June 2014, the Illinois Department of Commerce and Economic Opportunity (DCEO) established a pilot program that provides cash incentives, up to $2 million, for individual CHP projects in Illinois public sector facilities. Incentives are performance-based and are paid out at various phases of the project (design, construction, and production). For Conventional CHP systems to qualify, the minimum measured performance level must be an annual energy efficiency of 60 percent high-heating value (HHV) with at least 20 percent of the system's waste heat energy output in the form of useful thermal energy utilized in the facility.

Maryland - In September of 2012, Baltimore Gas and Electric (BGE) launched a Combined Heat and Power pilot program as part of the BGE Smart Energy Savers Program. The CHP program provides incentives to industrial and commercial customers who install efficient (>65 percent higher-heating value) CHP systems. Incentives are partly performance based and provided for design, installation, and construction to offset costs developers face throughout the process. In September 2013, BGE received approval from the Maryland PSC to expand this program, due in large part to the positive reception that BGE received from its commercial and industrial customers. The program now offers an additional $10 million in funding (It had originally been approved for $2 million). These Programs were approved by the PSC in Order No. 84955 as part of a combined filing (case numbers 9153 through 9157) in which Maryland's Electric Utilities applied for approval of their Energy Efficiency, Conservation and Demand Response Programs pursuant to the EMPOWER Maryland Energy Efficiency Act of 2008. Accordingly, in addition to BGE, First Energy, PEPCO, Delmarva and Southern Maryland Electric Cooperative offer similar CHP incentive programs. The Maryland Energy Administration (MEA) launched a complementary CHP grant program in July 2015. The program will target eligible industrial facilities and critical infrastructure facilities. Grantees will receive $425/kW to $575/kW, based on the size of the CHP system, with a maximum per project cap of $500,000. To be eligible CHP systems must have an anticipated annual efficiency of at least 60 percent, on a Higher Heating Value (HHV) basis.

Massachusetts –The Mass Save CHP program was created to implement the Green Communities Act of 2008, which recognizes CHP as an energy-efficiency measure eligible for utility incentives. The program offers in-state CHP system-owners incentives to increase deployment. The incentives are tiered (ranging from $750 to $1,200), with larger incentives (covering up to 50 percent of installed costs) given to the most efficient systems. Incentives are also offered to cover up to 50 percent of the cost of feasibility studies.

New Jersey – In the wake of Superstorm Sandy, New Jersey created the Energy Resilience Bank (ERB) with the goal of investing in long-term recovery strategies focused on critical facilities and enhancing energy resilience. The ERB will finance the design, acquisition, construction, and installation of distributed energy resources at certain critical facilities. Financing includes both grant funding and longer term, low-interest loans. Grants and forgivable loans will be offered to address up to 40 percent of unmet funding needs, while low-interest, amortizing loans will be available for the remaining 60 percent of unmet funding needs. Both fossil-fueled and renewably fueled CHP systems are eligible for the program.

New York – Established in 2013, the CHP Accelerator program is sponsored by NYSERDA and provides incentives for the installation of pre-qualified, pre-engineered CHP systems by pre-approved CHP system installers (see system catalog for listings). Eligible project sizes range from 0.05 to 1.3 MW. The maximum incentive per project is $1.5-million, with a total program budget of $20-million. All incentive payments are made through the CHP system vendor.

Ohio – Dayton Power & Light launched a CHP rebate program in 2015. Qualified projects will receive a rebate based on rated design capacity ($100/ kW) and kWh generated ($0.08/ kWh) during the first year the project is commissioned. Generation rebates will be paid in two installments at 6 and 12 months; capacity will be paid upon project completion. Rebates are based on the final cost of the project, and will be limited to 50 percent of the total design and construction cost, with a total cap of $500,000/ project. Eligible projects must have an annual energy efficiency of 60-percent high-heating value (HHV) and a payback period based on electricity cost savings of less than 7 years.

Oregon – NW Natural's CHP Solicitation Program provides financial incentives to encourage its customers to install efficient CHP systems as a means to lower carbon emissions. NW Natural will pay customers $30 per metric ton of CO_2-equivalent reduced through the use of CHP approved through the program. Eligible systems must be at least 10 percent more efficient than a combined cycle gas turbine. Only measured and verified emissions reductions are eligible for the incentives, which will be paid quarterly for 10 years after the system becomes operational. NW Natural is hoping this program will support the reduction of 240,000 MTCO2(e) per year through 2020. Reaching this goal will support the deployment of 80 to 120 MW of CHP.

Bonds

Through state bonding authorities, a bond (financial security) may be issued by state and local authorities as a way for agencies to borrow money at low-cost to invest in operational endeavors and projects, including clean energy and CHP.

Hawaii – The Hawaii Department of Business, Economic Development, and Tourism issues Green Infrastructure Bonds to help developers of clean-energy installations (including CHP) on commercial or residential properties secure low-cost financing. The bond proceeds will be used to fund the on-bill financing program being developed by the Public Utilities Commission. Bondholders will be repaid with funds collected from the state Public Benefits Fund.

Minnesota – In 2012, Minnesota policymakers approved $64.1 million in bonding that will allow the University of Minnesota to make improvements to its campus infrastructure. Of that $64.1 million, $10 million is being dedicated to a CHP project, designed to replace current coal furnaces.

New Mexico – New Mexico's Energy Efficiency and Renewable Energy Bonding Act authorizes up to $20 million in bonds, backed by the State's Gross Receipts Tax, to be issued to finance energy efficiency and renewable energy improvements in state government and school buildings. The bonds are exempt from taxation by the state. Projects financed with the bonds will be paid back to the bonding authority using the savings on energy bills. At the request of a state agency or school district, the New Mexico Energy, Minerals and Natural Resources Department will conduct an energy assessment of a building to determine specific efficiency measures which will result in energy and cost savings. A state agency or school district may install or enter into contracts for up to 10 years for the installation of energy-efficiency measures on the building identified in the assessment. Any type of renewable energy system and most energy-efficiency measures, including energy recovery and CHP systems, are eligible for funding.

Commercial PACE Programs

Property Assessed Clean Energy (PACE) financing is an innovative way to finance energy-efficiency upgrades to buildings. Interested property owners evaluate measures that achieve energy savings and receive 100 percent financing, repaid as a property-tax assessment for up to 20 years. This allows property owners to pursue qualifying energy-efficiency upgrades with no up-front costs.

California – The California Statewide Community Development Authority's CaliforniaFIRST Program is a finance program for non-residential properties. The program allows property owners to finance the installation of energy and water improvements and pay the amount back on their property tax bill. Eligible projects include renewable energy generation projects using fuel cells and energy-efficiency projects involving "cogeneration furnaces". A property owner can finance the equipment, labor, design, audit, permits and engineering of a project. The minimum amount that can be financed is $50,000. The maximum financing amount is dependent on the property value. Current outstanding debt plus CaliforniaFIRST financing amount must be less than the property value plus the value of the financed projects. Repayment periods will range from 5-20 years, depending on the expected useful life of the financed improvements and terms negotiated with lender.

Connecticut – C-PACE allows commercial, industrial or multi-family property owners to access 100 percent up-front, long-term financing for energy-efficiency and clean energy improvements on their properties through a special assessment on the property tax bill, which is repaid over a period of years (up to 20 years). Although there is no financing minimum, C-PACE is best suited for capital improvements over $150,000. CHP is highlighted as a recommended measure for industrial property owners. To qualify, projects must result in an energy savings-to-investment ratio greater than 1 over the lifetime of the assessment term and be permanently affixed to the building or property.

Michigan – The City of Ann Arbor offers Property Assessed Clean Energy (PACE) financing to commercial and industrial property owners for energy efficiency and/or renewable energy projects, including CHP, that range in size from $10,000 to $350,000. Financing will be conducted by pooling the assessments and issuing a bond once the pool reaches $1 million. The interest rate is expected to be less than 5 percent. CHP systems and biomass thermal systems must include the appropriate air pollution controls. The project costs cannot exceed 20 percent of the property's State Equalized Value, and the lien to value of the property cannot exceed 99 percent of twice the State Equalized Value. Projects must demonstrate that energy savings will be greater than the cost of the project and will undergo a voluntary special assessment as part of the application process.

Discounted Natural Gas Rates

Gas utilities can encourage CHP investments by offering reduced rates to CHP hosts.

California – California natural gas utilities can provide natural gas to qualified cogeneration systems under the same distribution rates offered to large electric utilities per Order Number 92792 and Public Utilities Code (PUC) Section 218.5. This is a significant discount over the distribution rates charged to non-CHP commercial and industrial uses. Eligible CHP facilities must operate at 42.5 percent efficiency (i.e., minimum PURPA efficiency).

New York – Since 2003, New York customers using natural gas for distributed generation including CHP have been able to qualify for discounted natural gas delivery rates. In April 2003, the New York Public Service Commission (NYSPC) issued procedures for developing gas-delivery rates that the local gas distribution companies (LDCs) would exclusively apply to gas-fired distributed generation (DG) units.

Pennsylvania – Philadelphia Gas Works offers discounted gas rates for commercial and industrial customers who use natural gas in any combination of cooling, heating and power production.

New Jersey – New Jersey Natural Gas offers a discounted gas rate for residential and commercial customers with distributed generation. South Jersey Gas offers a special rate designed to incentivize CHP applications.

Favorable Tax Treatment

Tax policies can significantly affect the economics of investing in new onsite power generation equipment such as CHP. Several states have instituted specific tax exemptions and tax credits to promote the deployment of efficient CHP projects.

Connecticut – Connecticut municipalities are authorized, but not required, to offer a property tax exemption lasting up to 15 years for qualifying CHP systems installed on or after July 1, 2007. Municipalities that adopt an ordinance to provide such an exemption may require a payment in lieu of taxes from the property owner. Owners of CHP systems located in commercial, industrial, residential, multi-family residential, and agricultural facilities where the facility capacity does not exceed the electricity load for the location are eligible.

New Jersey – In 2009, New Jersey established a sales and use tax exemption for the purchase of natural gas and utility service for on-site cogeneration facilities.

New Mexico – New Mexico offers a 6 percent tax credit for qualifying clean-energy projects, including “recycled energy.” Any unused credit may be carried forward for up to 10 years. The tax credit amount is capped at $60 million. Recycled energy is defined to include projects that convert the otherwise lost energy from the exhaust stacks or pipes to electricity without combustion of additional fossil fuel." Qualifying projects must be smaller than 15 MW.

North Carolina – North Carolina offers a tax credit equal to 35 percent of the cost of eligible renewable energy property (including CHP fueled by non-renewable fuels) placed into service in North Carolina during the taxable year. There is a maximum of $10,500 per installation for CHP systems or certain other renewable-energy systems used for a non-business purpose. There is a maximum of $2.5 million per installation for all CHP systems (as defined by Section 48 of the U.S. Tax Code) and biomass applications used for a business purpose, meaning the useful energy generated by the property is offered for sale or is used on-site for a purpose other than providing energy to a residence. Renewable-energy equipment expenditures eligible for the tax credit include the cost of the equipment and associated design; construction costs; and installation costs less any discounts, rebates, advertising, installation-assistance credits, name-referral allowances or other similar reductions provided by public funds. Eligible systems must be placed in service before the end of 2015.

Ohio – Ohio may provide a 100 percent sales and use tax exemption for certain tangible personal property for industrial and commercial property owners. Qualifying energy conversion facilities are those that are used for the primary purpose of converting natural gas or fuel oil to an alternate fuel or power source. Thermal efficiency improvement is defined as "the recovery and use of waste heat or waste steam produced incidental to electric power generation, industrial process heat generation, lighting refrigeration or space heating."

The Ohio Air Quality Improvement Tax Incentives Act also allows a 100 percent exemption from the tangible personal property tax (on property purchased as part of an air quality project), real property tax (on real property comprising an air quality project), a portion of the corporate franchise tax (under the net worth base calculation), and sales and use tax (on the personal property purchased specifically for the air quality project only) for outstanding bonds issued by OAQDA. Furthermore, interest income on bonds and notes issued by OAQDA is exempt from state income tax (and may be exempt in certain cases from the federal income tax). OAQDA provides assistance for new air quality projects in Ohio for both small and large businesses. Such assistance extends to any energy efficiency or conservation project.

Regulatory Support

CHP installations are complex projects, which trigger a variety of air and utility commission permitting requirements. States can encourage projects by offering regulatory assistance – by supporting developers and users through the process, relaxing permit requirements for “straightforward” projects, and by adopting standardized interconnection processes and rate design that recognizes the potential benefits of natural gas CHP to electric and gas systems.

State and utility regulations can encourage CHP by offering:

- **Technical assistance** to help guide developers through the permitting process
- **Streamlined permitting** for small to mid-size projects
- Federal and state environmental regulations that support CHP through their specific inclusion or with **output-based limits** for thermal and electrical outputs

- Transparent and uniform technical standards, procedures, and agreements governing **interconnection** to the grid
- **Rates** that reflect actual costs and benefits of CHP systems on electric and natural gas systems

Technical Assistance

New York – The New York State Energy Research and Development Authority's (NYSERDA) Flex Tech Program provides New York State industrial, commercial, institutional, government, and nonprofits with technical assistance to help them make "informed energy decisions." The goal of the FlexTech program is to increase the productivity and economic competitiveness of facilities by identifying and helping assist with the development of certain energy-efficiency projects, including CHP. The program provides cost-sharing (up to $1-million) for a range of studies, including CHP project classification studies and industrial process efficiency analysis. For CHP project classification studies, site-specific technical requirements and economic feasibility of installing natural gas-fired CHP are assessed. To be eligible, the proposed CHP system must be less than 50 MW, more than 60 percent efficient, and use at least 75 percent of the produced electricity on site.

United States – DOE offers a variety of technical support for industrial facilities:

DOE funds seven regional CHP Technical Assistance Partnerships (TAPs) throughout the United States. The TAPs help end-users consider CHP, WHP or district energy in their facility, including assisting project development from initial CHP screening to installation. TAPs also provide market opportunity analyses and general education and outreach about CHP benefits to state and local policy makers, regulators, energy end-users, trade associations and others.

DOE supports Industrial Assessment Centers at 24 universities around the country. These centers provide complementary energy audits for small and mid-size manufacturers to identify opportunities to improve productivity, reduce waste, and save energy. IACs typically identify more than $130,000 in potential annual savings opportunities for every manufacturer assessed, nearly $50,000 of which is implemented during the first year following the assessment. The IAC's have conducted over 16,000 assessments since their inception in 1976. A searchable database allows facilities to search recommendations by facility type, recommendations, and assessment center.

Streamlined Air Permitting

CHP installations must comply with a host of federal, state, and local zoning, environmental, health and safety requirements at the site. These include rules on air and water quality, fire prevention, fuel storage, hazardous waste disposal, worker safety and building construction standards. This requires interaction with various agencies including fire districts, air districts, and water districts and planning commissions, many of which may have no previous experience with a CHP project. Air permitting, in particular, can be challenging for CHP projects both in meeting required limits if the benefits of thermal output are not recognized, and in the complexity and time needed for permitting. A number of states have addressed these concerns by instituting permit-by rule for qualifying CHP projects or by streamline the standard permitting process.

Connecticut – Connecticut's distributed generators rule (Sec. 22a-174-42) streamlines the air permitting process for eligible systems that produce both electric and thermal energy. The rule explicitly mentions CHP and any systems that are more than 55 percent efficient, have a nameplate capacity less than 15 MW, a power-to-heat ratio is between 0.15 and 4.0, and that produce fuel for non-emergency use are eligible. The rule provides a thermal credit based on the avoided emissions of the displaced boiler. Eligible systems may operate without applying for or receiving a stand-alone permit.

New Jersey – New Jersey offers two general permits for CHP, one for combustion turbines and another for reciprocating engines. Both permits require participating systems to have total design efficiency greater than or equal to 65 percent. Each includes four different sets of fuel and emission limits, depending on system size and how the source plans to operate the equipment.

Texas – In 2012, Texas established a permit by rule for natural gas CHP systems that meet certain size and performance criteria. The rule applies to NOx and CO emissions from CHP systems. The streamlined process expedites permitting for natural gas-fired CHP systems that are less than 15 MW and where thermal output is more than 20 percent of the total energy output. The compliance calculation accounts for the thermal output of CHP units by converting the measured steam output (Btu) to an equivalent electrical output (MWh) through the "equivalence approach." Credit is given at the rate of 1.0 MWh for each 3.4 million Btu of heat recovered. Notably, gas-fired CHP systems are subject to less demanding requirements than standard power generation limits. For systems less than or equal to 8 MW, NOx emissions are limited to 1 lb/MWh and CO emissions are limited to 9 lb/MWh. NOx limits are more demanding for larger systems (between 8 and 15 MW). Such systems are limited to 0.7 lb/MWh. The streamlining has had a significant impact on permitting. As an example, the Texas PBR allowed a CHP system to obtain an air permit in just 4 to 6 weeks. Prior to PBR, the average time was typically over a year.

Output-Based Emission Standards

Lack of recognition of CHP's efficiency benefits in environmental regulations can be a particular issue in permitting. Higher efficiency generally means lower fuel consumption and lower emissions of all pollutants. Nevertheless, most U.S. environmental regulations have historically established emission limits based on heat input (lb/MMBtu) or exhaust concentration (parts per million [ppm]). These input-based limits do not recognize or encourage the higher efficiency offered by CHP. Nor do they account for the pollution prevention benefits of efficiency in ways that encourage the application of more efficient on-site generation. Moreover, since CHP generates both electricity and thermal energy on-site, it can potentially increase on-site emissions even while it reduces the total overall emissions throughout the air shed. One approach to address these issues is through the use of output-based regulations, which set emission limits based on the total useful energy output (including both thermal and electric) that a system produces (e.g., lbs/MWh). Recent Clean Air Act rules have been written as output-based standards. Many states are likewise adopting output-based standards. Such standards acknowledge that the additional useful energy output was generated in a manner generally cleaner than the separate generation of electricity and thermal energy. CHP systems fare well under this approach because it credits both the thermal and electric energy they produce. This can encourage additional deployment.

California – In September 2007, the California Resources Board amended its Distributed Generation Certification Regulation, which specifies the emissions regulations that particular generators are subject to. Applicable to distributed generation units manufactured after

January 1, 2003, the amended rule indicates that CHP units that meet a minimum efficiency requirement may take a thermal credit against their emissions for NOx, CO VOCS and PM, equivalent to 1 MWh per 3.4 million Btus. To be eligible, CHP systems must perform at greater than 60-percent efficiency (high-heating value).

Connecticut – In 2005, Connecticut's Distributed Generators Rule established output-based emissions limits (lb/MWh) for NOX, PM, CO, and CO_2 from small, distributed generation systems that are less than 15 MW in capacity, including CHP systems. The rule allows a CHP system to account for its secondary thermal output using the avoided emissions approach. A CHP system can take into account the secondary thermal output if at least 20 percent of the fuel's total recovered energy is thermal and at least 13 percent is electric, with a resulting power-to-heat ratio between 4.0 and 0.15. The design system efficiency must be at least 55 percent.

Delaware – Delaware has output-based emissions regulations for NOx, PM, CO and CO_2 from eligible generators (Delaware Regulation No. 1144: Control of Stationary Generator Emissions). Qualifying systems must be at least 55 percent efficient and at least 20 percent of the fuel's total recovered energy must be thermal and 13 percent electric (corresponding to an allowed power-to-heat ratio between 4.0 and 0.15). Systems that satisfy these requirements receive a thermal credit based upon the emissions that would have been created by separate generation of the thermal energy (i.e., the "avoided emissions approach"). Under this approach, credit is calculated for CHP systems using the following formula: Credit (lbs/MWh emissions) = boiler limit (lbs per MMBtu)/boiler efficiency x 3.413/power to heat ratio.

Texas – In 2001, Texas adopted a standard permit to facilitate CHP deployment for systems under 10 MW. The permit relies on an output-based standard to measure NOx emissions. As noted above, Texas adopted a permit by rule process for CHP in 2012 that likewise relies on an output-based standard. A CHP system can take into account the secondary thermal output if the heat recovered equals at least 20 percent of the total heat energy output of the CHP system.

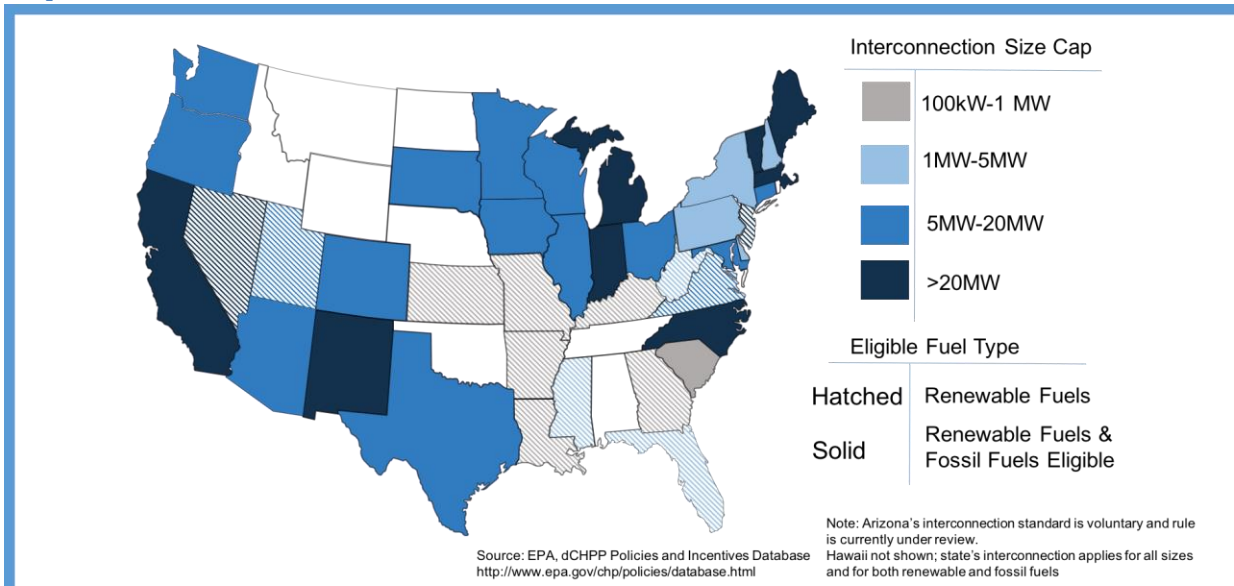
Interconnection Rules

Facilities with CHP systems usually require supplemental and/or standby/back-up service from the utility to provide power needs over and above the output of the CHP system and during periods when the system is down due to routine maintenance or unplanned outages. Interconnection rules detail the technical requirements and procedural process by which an electric-generating unit is connected to the grid. These standards are needed to ensure that both the end-user and the utility's reliability and safety needs are taken into account. A key to CHP's ultimate market success is the ability to safely, reliably, and economically interconnect with the utility grid system. The current lack of standard uniformity in interconnection rules makes it difficult for equipment manufacturers to design and produce modular packages, and reduces the economic incentives for on-site generation. Predictable interconnection rules based on industry technical standards and application processes that limit financial uncertainty and delays can encourage CHP projects. To date, PUCs in more than 40 states have developed interconnection rules that extend to CHP systems; however, these rules vary considerably from one state to another. (Figure A-1). Some are limited to renewably fueled CHP. Others allow interconnection for only a subset of smaller projects (e.g., up to 100 kW), while some encourage deployment by streamlining interconnection for projects up to 10 MW. States may also want to consider the impacts of regional coordination of interconnection procedures to standardize practices.

Considerations to Ensure Consistent Interconnection Rules[50]

1. Interconnection fees commensurate with system size,
2. Streamlined procedures with simple decision-tree screens (allowing faster application processing for smaller systems),
3. Practical technical requirements (often based on existing technical standards));
4. Standardized, simplified application forms and contracts;
5. A dispute resolution procedure to resolve disagreements;
6. The ability for larger (20 MW and larger) CHP systems to qualify; and
7. The ability for on-site generators to interconnect to both radial and network grids.

Figure A-1 States with Standardized Interconnection Processes



* Updated as of April 2016

California – California was among the first states to establish a standard interconnection policy for distributed generation. Approved in 2000, Rule 21 applies to CHP and other distributed generation systems up to 10 MW. It has been adopted as a model by all three major investor-owned utilities, and follows the established technical guidelines of the IEEE 1547 interconnection standard. In September 2012, the California Public Utilities Commission enacted several major changes to Rule 21 for the first time since 2000. Changes include a "fast

[50] SEE Action, 2013, "Guide to the Successful Implementation of State Combined Heat and Power Policies," at xi and 13-17, https://www4.eere.energy.gov/seeaction/system/files/documents/see_action_chp_policies_guide.pdf, (hereinafter "SEE Action 2013").

track" application process for systems that meet certain size standards, as well as several detailed study options for larger facilities.

Illinois – In August 2007, Illinois enacted legislation (S.B. 680) requiring the Illinois Commerce Commission (ICC) to establish standards for net metering and interconnection for renewable energy systems by April 1, 2008. Although S.B. 680 only requires the promulgation of interconnection standards for "eligible renewable generating equipment," the ICC developed four tiers of interconnection standards for all distributed generation up to 10 megawatts (MW). The ICC is also considering legislation that would explicitly address CHP. Final interconnection standards were adopted by the ICC in August 2008. In March 2010, the ICC established interconnection standards for Large Distributed Generation Facilities, or those over 10 MW.

Maryland – In June 2008, the Maryland PSC adopted interconnection standards that include CHP up to 10MW and applies to both fossil-fueled and renewable- fueled systems. The rule applies to all types of utilities and has four tiers to determine the level of technical screens, review procedures, and timelines based on the size and type of equipment. Standardize interconnection agreements are available on the PSC renewable portfolio website for all levels of interconnection agreement.

Michigan – Michigan's interconnection standard (Case # U-1375) delineates five separate tiers of interconnection, and covers systems of all sizes with the largest interconnection tier for systems 2 MW systems and above. Both fossil-fueled and renewably fueled CHP systems are eligible for standardized interconnection. However, utilities are the final arbiters of which types of systems and sizes are suitable for their distribution systems. Fees for interconnection range from $75 to $500, depending on system size, and liability insurance is required for systems that are larger than 150 kW.

New Hampshire – The New Hampshire Public Utilities Commission (PUC) established standardized interconnection rules for net-metered systems up to 1 MW in January 2001. Systems that connect to the grid using inverters that meet IEEE 1547 and UL 1741 safety standards do not require an external disconnect device. While utilities cannot require customers to purchase or maintain property insurance or comprehensive personal liability insurance, the customer-generator assumes all risks and consequences associated with the absence of a switch. Utilities may not require customer-generators to perform additional tests, or pay for additional interconnection-related charges. The New Hampshire standards apply to natural gas-fired CHP (in addition to renewable fuels), though CHP can only contribute up to 4 MW under the aggregate net-metering capacity limit of 50 MW. The rule further sets efficiency requirements for eligible CHP systems (greater than 80 percent for systems less than 30 kW and 65 percent for systems between 30 kW and 1 MW).

Washington – The Washington Utilities and Transportation Commission has adopted interconnection standards for distributed generation systems, including CHP (regardless of fuel type), up to 20 MW in size. The standards apply to the state's investor-owned electric utilities, but not to municipal utilities or electric cooperatives. Two separate tiers for interconnection exist; the first tier applies to systems smaller than 300 kW. The second tier applies to systems between 300 kW and 20 MW, and generally follows the interconnection standards promulgated by the Federal Energy Regulatory Commission (FERC).

Standby Rates

Facilities with CHP systems usually require supplemental and/or standby/back-up service from the utility to provide power needs over and above the output of the CHP system and during periods when the system is down due to routine maintenance or unplanned outages. Electric utilities often assess specific standby charges to cover the additional costs the utilities incur as they continue to provide generating, transmission, or distribution capacity (depending on the structure of the utility) to supply backup power when requested (sometimes on short notice). These fees vary widely by state, region, and utility; however, they are generally designed to cover: (1) backup power that may be needed during an unplanned generator outage, (2) maintenance power during scheduled repairs, (3) supplemental power for customers whose onsite power does not meet all of their energy needs, (4) economic replacement power in the event that grid power costs less than onsite generation, and (5) a transmission and distribution charge to provide electricity in any of these circumstances.[51] The level of these charges is often a point of contention between the utility and the consumer, and can, without proper oversight, create unintended and important barriers to CHP.

Utility rates may consider allocating the total cost of service for a utility to recover costs from customer classes, reflecting each class's use of the system. This principle of "cost causation" is implemented through rate designs that allocate cost based on measurable customer characteristics. Demand charges are often higher than actual costs because of the use of "ratchets," meaning the utility continues to apply some percentage (often as high as 100 percent) of the customer's highest peak demand in a single billing month up to a year after its occurrence. The use of ratchets can be controversial, as some view them as increasing the equity of fixed-cost allocation, while others view them as barriers to economic applications by CHP customer. Although demand ratchets may be appropriate for recovering the cost of delivery, they arguably do not reflect cost causation for shared distribution and transmission facilities.

While rates can act as a deterrent to installing new CHP systems, these charges are needed to allow utilities to recover costs they incur to provide supplemental, backup, and maintenance services. Below are some considerations such that utilities may recover appropriate fixed costs without deterring projects.

Considerations to Establish Rates that Recognize the Potential Benefits of Natural Gas CHP to Electric and Natural Gas Systems[52]

1. Utilities and PUCs may adopt an "as-used" demand charge to reflect the actual cost a CHP system places on the utility, rather than basing fees on prices during peak demand.
2. Utilities may allow CHP customers to purchase all of their backup power at market prices.
3. Generation, transmission, and distribution charges can be unbundled to provide transparency to customers and enable appropriate and cost-based standby rate design

[51] *Id.,* at 7-11.

[52] Regulatory Assistance Project, 2014, "Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States," http://www.raponline.org/document/download/id/7020; *see also* SEE Action 2013, at 11.

4. Avoidance of demand ratchets. Instead, customer-generators may pay for non-dedicated distribution facilities only when they are actually purchasing backup or maintenance power in a particular month."

Connecticut – The Connecticut Department of Environmental Protection (DEEP) is developing a pilot program to promote CHP by limiting the demand charge electric companies impose on qualifying systems (between 0.5 and 5 MW). Projects selected to participate in the pilot program shall not be required to pay the demand charges pursuant to the distribution demand-ratchet provision of firm service due to an outage of service of such project. If the project experiences an outage longer than 3 hours, the demand charge must be based on daily demand pricing pro-rated from standard monthly rates. The cumulative capacity for projects participating in the program is limited to 20 MW and eligible projects can continue the terms of the pilot program for 10 years.

Georgia (Georgia Power) – Georgia Power provides a standby rate that incorporates many of the best practices noted above. Customers can contract for either firm or interruptible standby capacity to replace onsite generation when the system is not in service. Customers must provide notification to the utility within 24 hours of taking firm backup power. In the event of an unplanned outage, customers must provide notice to Georgia Power within 30 minutes of beginning service. Scheduled maintenance service (for planned outages) must be scheduled 14 days in advance. Maintenance power is available as firm service during the off-peak months and as interruptible service during peak months. Customers may also purchase supplemental power (i.e., to augment what is produced onsite) at the same rates as other customers. While there are no ratchets, demand charges are subject to a “standby demand adjustment factor,” which adjusts the billed standby demand once a customer uses backup service for more than 876 hours during the most recent 12-month period. This provides an incentive for a customer to use standby service as efficiently as possible.

New York – In 2001, the New York Public Service Commission established guidelines for utilities requiring that investor-owned utilities in New York make their standby rates reflective of actual costs. In the guidelines, the PSC states that "Cost based standby delivery rates should provide neither a barrier nor an unwarranted incentive to customers contemplating the installation of DG [distributed generation]."

ConEdison’s standby tariff is entirely demand based and does not employ a ratchet. Under guidelines established by the New York Public Services Commission, ConEdison’s standby rates reflect a cost-based rate based on the cost of providing delivery service to meet the customer’s maximum demand for delivery service at a given time. The company assesses a demand charge based on the actual demand recorded each day, with rates varying by season and time of day—peak versus off-peak. Standby rates do not apply to customers whose on-site generation capacity is less than 15 percent of their maximum demand.

Oregon (Portland General Electric) – Portland General Electric’s (PGE) standby tariff is attractive because it does not employ a ratchet, but instead applies an as-used on-peak demand charge to CHP systems. Under this approach, an assumed outage only affects the demand charge in the month that the outage occurs and does not reduce the electric savings from the CHP system in other months. The PGE approach includes several features that support on-site generation:

- Transmission, distribution and generation charges are separated, and within these categories, the rates are further unbundled, thus increasing transparency.
- This rate does not have a demand ratchet so outages do not have an exaggerated effect on the cost.
- The fixed standby demand charges impose only a modest cost when compared to the savings provided by a CHP system.

Creating Markets

At 83 gigawatts nationwide, CHP deployment falls far short of its technical potential. States can adopt policies to signal hosts and developers that these projects are desirable and that they represent a key part of the state's long-term economic and environmental strategy.

States can help create a market for clean and efficient electricity through:

- **State portfolio standards** that require utilities to obtain a certain amount of the electricity they sell from specified sources (including CHP or waste heat to power) and/or achieve specified reductions in electricity consumption.
- Requiring consideration of CHP when **critical infrastructure** is built or renovated.
- Policies that **ease restrictions on electricity sales** from CHP systems.
- **Feed-in tariffs** that guarantee a minimum return for surplus electricity.
- State policies allowing for the **remuneration for excess electricity generated** by CHP units to be made available on the local electric grid.
- **Clean-power purchasing commitments** challenging the state to lead by example and deploy a set amount of clean or renewable power.

State Portfolio Standards

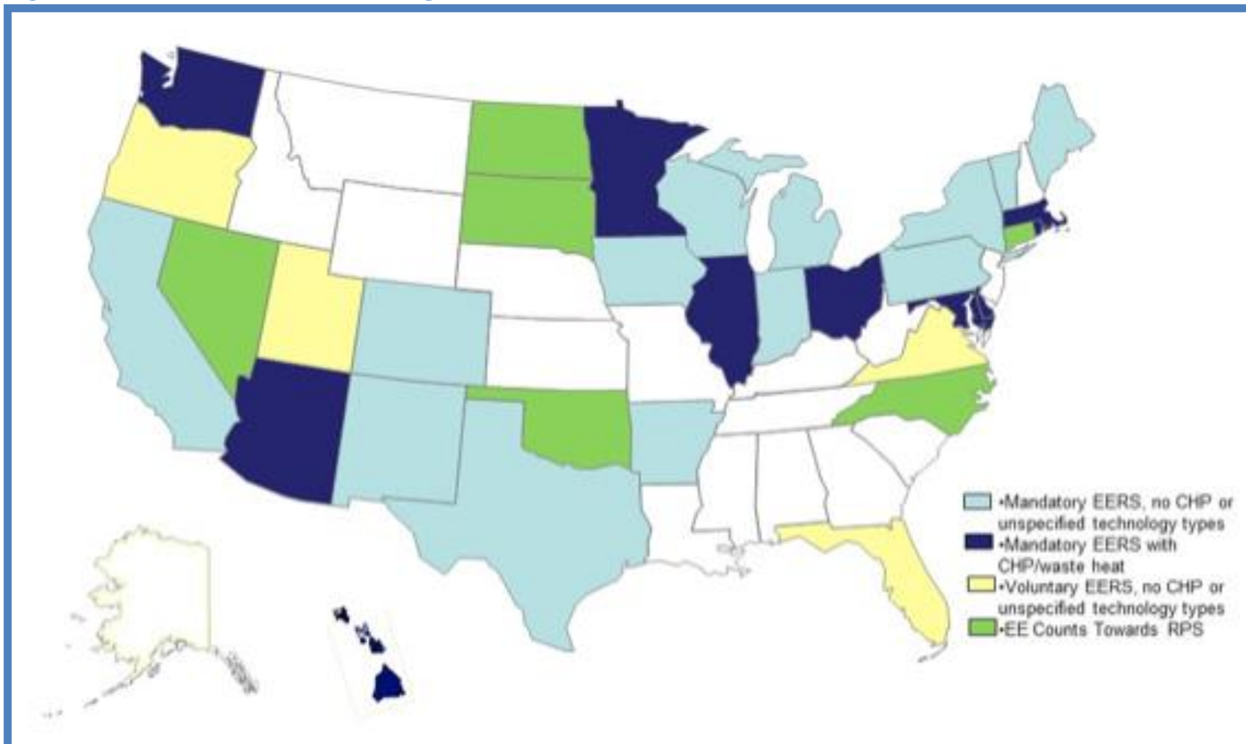
Many states have developed portfolio standards to increase the adoption of renewable energy generation, energy efficiency, and other clean energy technologies. (Figure A-2). Portfolio standards require utilities and retail energy suppliers (mostly electricity and sometimes gas) to procure a certain minimum quantity of eligible energy (typically from renewable sources and other specified supply-side resources) or achieve a minimum amount of energy-efficiency savings (typically from demand-side efficiency measures, but these could include CHP).

Portfolio standards can stimulate market and technology development to help clean energy sources become economically competitive with conventional forms of electric power. In this way, portfolio standards can help overcome barriers and create demand for such sources, enabling states to capture their energy-saving, environmental, and economic benefits. Recognizing CHP as an eligible technology benefits utilities by expanding the options that they can use to achieve the standard.

Considerations for CHP in EERS[53]

1. Explicitly identify CHP and/ or waste heat to power (WHP) as an eligible technology in state portfolio standards (RPS or EERS),
2. Provide consistent terminology and definitions for CHP and WHP,
3. Establish a reasonable minimum efficiency threshold to ensure energy savings without excluding certain systems,
4. Set separate and distinct targets for CHP within the Standard to encourage diversity of supply, and
5. Utilize appropriate calculations to credit the appropriate output (electric and thermal) from a CHP system.

Figure A-2. States with EERS Program for CHP or Waste Heat to Power[54]



Arizona – [Renewable Energy Standard](): In 2006, the ACC approved the Renewable Energy Standard and Tariff (REST), which requires 25 percent of covered utilities' electricity to come from renewable sources by 2025. The standard specifically includes renewably fueled CHP as an eligible resource (i.e., systems fueled with biomass or biogas). Both the electric and thermal outputs of CHP systems are credited. The thermal output from CHP is credited at a conversion rate of 3,415 Btus = 1 Renewable Energy Certificate (REC), and electricity from CHP is credited at a conversion of 1 kWh = 1 REC.

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[53] SEE Action 2013, at 31-26.

[54] EPA, Feb. 2015, "Portfolio Standards and the Promotion of Combined Heat and Power," at 8, http://www.epa.gov/chp/documents/ps_paper.pdf.

Energy Efficiency Resource Standard**:** On December 18, 2009 the ACC ordered that all investor-owned utilities and rural electric cooperatives achieve 1.25 percent annual savings as a percent of the retail energy sales in the prior calendar year, ramping up to 2 percent beginning in 2014. By 2020, the state should reach 20 percent cumulative savings, plus up to a 2 percent credit for peak demand reductions from demand response programs, for a total standard of 22 percent. Utilities can count energy supply from CHP systems that do not qualify under the state's Renewable Energy Standards towards the standard.

Massachusetts – In 2009, the Massachusetts Department of Energy Resources established an Alternative Energy Portfolio Standard (APS) (per Senate Bill 2768). The APS requires that 5 percent of a supplier’s (both regulated distribution utilities and competitive suppliers) retail sales must come from alternative energy sources by December 31, 2020. An alternative energy source is defined as one that generates electricity using CHP (regardless of fuel type), gasification with capture and permanent sequestration of carbon dioxide, flywheel energy storage, paper-derived fuel sources, or energy-efficient steam technology. The vast majority of this requirement has been met through CHP. This requirement is distinct from the state RPS. CHP and other eligible projects can receive credits, referred to as "APS Alternative Energy Certificates (AECs)," for 1 MWh of electrical energy output or for thermal output (using a conversion factor of 3,412 thousand Btus = 1 MWh). The AECs "earned by a CHP Unit represent the energy saved (in MWh) by operating the Unit as a CHP Unit as compared to separately operating an on-site thermal plant while drawing electricity from the grid" (i.e., the alternative emissions approach).

The Energy Efficiency First Fuel Requirement requires electric and gas utilities to prioritize cost-effective energy efficiency and demand reduction resources over supply resources and orders utilities to submit three-year plans outlining how they will meet the requirement. Demand side resources include energy efficiency, load management, demand response and generation that is located behind a customer's meter including a CHP system with an annual efficiency of 60 percent or greater, with the goal of 80 percent annual efficiency for CHP systems by 2020. The 3-year plans established a statewide electricity savings target of 2.4 percent in the year 2012. A separate goal associated with the Energy Efficiency Resource Standard (EERS) rebate program (also known as the Mass Save program) created a savings target of 25 percent of electric load by the year 2020 with demand side resources. All CHP systems are eligible for the Mass Save program, which establishes three tiers of incentives for utility customers who are considering energy-efficiency upgrades in conjunction with a CHP system.

Washington – Washington's Renewable Energy Standard requires that all types of electric utilities that serve more than 25,000 customers in the state generate 15 percent of their electric load from new renewables by the year 2020 and to undertake all cost-effective energy conservation, including CHP. Of Washington's 62 utilities, 17 are considered qualifying utilities, representing about 84 percent of Washington's load. High-efficiency CHP, owned and used by a retail electric customer to meet its own needs may be counted toward conservation targets. Thermal energy from CHP is credited at a conversion of 3.413 Btus per kWh. One REC = 1 MWh. Distributed generation (DG), defined as a "generation facility or any integrated cluster of such facilities" with a capacity of <5 MW, may be counted as double the facility's electrical output if the utility owns the facility, has contracted for the distributed generation and the associated Renewable Energy Certificate (RECs), or has contracted to purchase only the associated RECs." Renewably fueled CHP systems smaller than 5 MW are eligible under the

RPS. Fossil-fueled CHP systems are eligible as a conservation measure. High-efficiency CHP units must have a useful thermal output above 33 percent.

Critical Infrastructure

Because many CHP systems can function in island mode, they can remain operational during extreme weather events, which may compromise the electric grid. This capability makes CHP particularly desirable for critical infrastructure. Critical infrastructure refers to facilities that, if incapacitated, would have a substantial negative impact on national or regional security, economic operations, or public health and safety. These applications include hospitals, water and wastewater treatment facilities, financial institutions, police and security services, and places of refuge (e.g., universities, government buildings, convention centers, sports arenas and hotels).

CHP systems have many advantages over back-up generators.[55] First, CHP systems tend to be more reliable because they are designed for continuous operation rather than emergency use. While generators are only tested periodically, CHP systems are more likely to be properly maintained and operated by trained staff. During the blackout of 1993, half of New York's 58 metropolitan hospitals had failures in their backup generators. The lack of electricity allowed 145-million gallons of raw sewage to be released from a Manhattan pumping station. Even when functioning properly, back-up generators only provide electricity; whereas, CHP provides thermal needs (heating, cooling, chilled water) as well. Finally, back-up generators run of diesel, while the vast majority of CHP systems run on natural gas, greatly reducing their emissions.

These reliability benefits have been demonstrated during a number of extreme weather events. While 8.5-million residents in New Jersey, New York, and Connecticut lost power and heat during Hurricane Sandy, facilities with CHP systems kept their electricity on and heat flowing. A notable example is South Oaks Hospital on Long Island, a 350,000 square foot facility that includes an acute psychiatric hospital, a nursing home, and an assisted living center. During the storm and its aftermath, the hospital maintained full power through the use of its 1.3-megawatt CHP system. Hurricane Sandy is not the only instance when CHP has demonstrated resiliency. In 1994, Mississippi Baptist Medical Center in Jackson, MS, chose to install a 4.3-megawatt CHP system. Eleven years later, during Hurricane Katrina, the 646-bed hospital was the only hospital in the Jackson area to remain 100 percent operational during and after the storm. These resiliency benefits have led several states to adopt policies that encourage greater deployment.

New York – In 2014, New York adopted the [Community Risk and Resiliency Act](), which adopts many of the recommendations issued by Governor Cuomo's NYS 2100 Commission, the purpose of which was to develop more resilient infrastructure systems in the wake of Hurricane Sandy. The NYS 2100 Commission recommended evaluating combined heat and power and distributed generation projects to improve resiliency of the grid. The act also requires the New York Department of Environmental Conservation and the New York Department of State to provide guidance to help communities implement the act, including the use of resiliency measures.

[55] ICF, 2013, "Combined Heat and Power: Enabling Energy Resilient Infrastructure for Critical Facilities," http://www.harc.edu/sites/default/files/documents/projects/CHP%20Critical%20Facilities.pdf.

Texas – In the wake of several major natural disasters that disabled the grid for extended periods, Texas law (Energy Security Technologies for Critical Government Facilities) requires all government entities to identify government-owned buildings and facilities that are critical in an emergency situation and to obtain a feasibility study to consider the technical opportunities and economic value of implementing CHP. Subsequent law (Texas HB 1864) requires this assessment to consider whether the expected energy savings associated with such a system would exceed the costs of the system. This requirement extends to critical facilities that are operational 6,000 hours per year with a peak electric load exceeding 500 kW. The analysis should be based on a potential CHP system with greater than 60 percent efficiency that can provide 100 percent of a facility's critical electricity needs and sustain emergency operations for at least 14 days.

Easing of Restrictions on Electricity Sales

The definition of contiguous property may restrict the sale of excess electricity generated by a CHP facility host to a nearby end-user. Under most current regulatory policies, entities that sell power across public easements are deemed regulated utilities. As a consequence, the sale of electricity by on-site generation, such as CHP is – as a practical matter – restricted to end-users on the host's property or contiguous property. Expanding the definition of what is considered contiguous property to include end-users who take thermal energy from a CHP host provides the host with a potential revenue stream from the sales of electricity.

New Jersey – The New Jersey Cogeneration Bill of 2009 allows CHP systems to "wheel power" to their district energy thermal customers, regardless of whether they are separated by an easement, a street, another building, or a utility-owned right-of-way. New Jersey law defines the CHP facility and its thermal customers as "contiguous." This expanded definition creates a much larger market for electricity from CHP systems, without converting CHP hosts to regulated utilities. The legislation also allows the CHP host to use existing electricity distribution infrastructure at the standard prevailing tariff rate, which is important for enabling district energy systems with CHP.

Texas – HB 2049, which was signed into law in June 2013, clarifies language in the Texas Utility Code to allow CHP facilities to sell electricity and heat to any customer located near the CHP facility. Previously, CHP facilities could only sell electricity to one customer—the electricity service provider. Enactment of HB 2049 opens the market for selling electricity, and thereby has the potential to facilitate the adoption of CHP, particularly for plants that are interested in selling excess CHP power.

Feed-in Tariffs

When CHP systems are optimally sized to match the thermal load of a facility, they may produce excess electricity that cannot be used on-site. Feed-in-tariffs (FIT) allow CHP generators to execute standard-offer contracts to sell electricity to utilities at a fixed rate for an extended period. This provides greater investor certainty for CHP projects and improves the competitive position of CHP in the market by providing an additional revenue stream for projects with excess power capability. While not very prevalent in the U.S., FITs are used in Europe both for renewable and clean distributed generation (including CHP). FITs generally establish a cap on total on-site generation capacity, to create a market for surplus electricity from systems designed for maximizing efficiency without allowing large power projects optimized for power output. FITs can be tied to the current price of natural gas and pay CHP owners at a rate slightly above the market rate for excess electricity, with a gradual decrease in payment over time. This reduces the cost these systems place on the utility as the host recoups its investment. FIT prices may be set high enough to attract the types and amounts of generation desired, while protecting consumers from paying more than needed to achieve generation targets.

Considerations for Feed-in Tariffs and CHP[56]

1. FIT payments may be tied to the current price of avoided fuel and set sufficiently high to allow for an attractive return on investment for CHP owners.
2. Contracts may be set for a long enough period to provide investor confidence.
3. Tariffs may account for environmental, social, and grid-reliability benefits of CHP systems.[7]

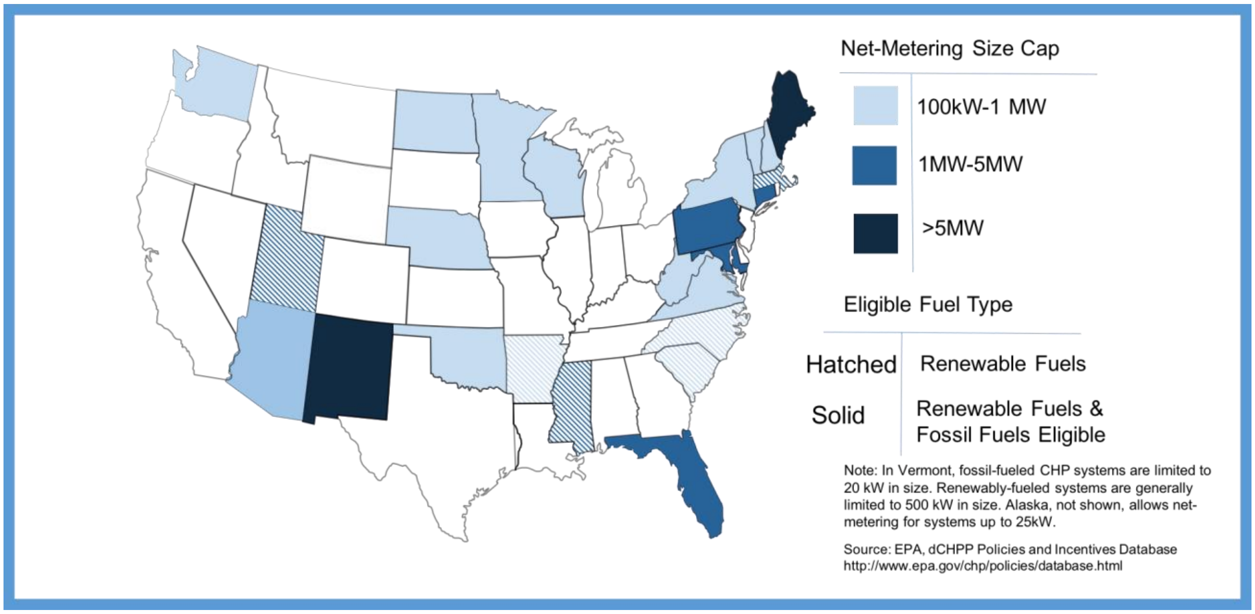
California – In 2006, the state legislature directed the California Public Utilities Commission (CPUC) to have investor owned utilities establish appropriate tariffs for sale of excess power from CHP systems up to 20 MW (AB 1613). In 2008, the CPUC approved three standard-form contracts for purchasing excess electricity from CHP systems of varying sizes: (1) a standard contract for systems with a capacity up to 20 MW; (2) a simplified contract for systems that export no more than 5 MW; and (3) a further simplified contract for systems with a capacity of less than 500 kW. The contract terms are for up to 10 years, with fixed purchase rates throughout the contract term based on the costs of a new combined–cycle gas turbine operating as a baseload resources. Additional compensation is provided for CHP systems located in grid-constrained areas to encourage distributed generation to help avoid grid-system failure. Qualifying systems must be in operation after January 2008, have NOx emissions less than 0.07 lb/MWh, and operate at or above 62 percent total efficiency.

Net Metering

A CHP system's efficiency benefits are maximized when it is sized to match the thermal load. When the thermal load at the site is large, the system may produce surplus electricity. Under wholesale net-metering policies, customers install a second meter on their property, which tracks the on-site generated electricity exported to the grid and utilities remunerate customers for net excess generation at the utility's wholesale avoided cost rate. Such policies provide an additional financial incentive for larger systems and helping those projects pencil out. Where net metering is prohibited, electricity cannot be returned to the grid, and CHP hosts and developers may undersize their systems – foregoing potential economic and environmental benefits. While 43 states have adopted net-metering laws, CHP is only eligible for net metering in 24 of these states (Figure A-3). Even where net-metering for CHP is allowed, stringent size caps may prevent systems from realizing their full potential. Moreover, net-metering fees may create additional costs for the CHP system owner and discourage deployment. CHP installations require a significant up-front investment. Net-metering rules reduce the payback period for those systems by allowing owners to generate revenue. This allows owners to make long-term investments with confidence.

[56] SEE Action 2013, at 20-30.

Figure A-3. States with CHP Net-Metering Policies



* Updated as of April 2016

Considerations for Net-Metering and CHP Deployment[57]

1. Explicitly recognize CHP as an eligible net-metering technology,
2. Increase the size cap on eligible CHP projects to greater than 2 megawatts,
3. Allow system owners to roll over net-metering credits from year to year, and
4. Eliminate burdensome fees.

Maryland – Maryland's net-metering law has been expanded several times since it was originally enacted in 1997. In their current form, the rules apply to all investor-owned utilities (IOUs), electric cooperatives and municipal utilities. Residents, businesses, schools or government entities with systems that generate electricity from micro-CHP (less than 30 kW in capacity) are eligible for net metering, regardless of fuel type. The law permits outright ownership by the customer-generators as well as third-party ownership structures (e.g., leases and power purchase agreements). The provisions allowing for micro-CHP systems (H.B. 1057) and certain third-party ownership structures (S.B. 981) have been in effect since July 2009. In 2011 the law was expanded to require utilities to develop a standard tariff for net metering (S.B. 380). Net metering is available statewide until the aggregate capacity of all net-metered systems reaches 1,500 MW (~8 percent of peak demand). Net excess generation (NEG) is generally carried over as a kWh credit at the retail rate, for 12 months. Compensation for any NEG remaining in a customer's account after a 12-month period is paid to the customer at the commodity energy supply rate.

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[57] American Council for an Energy-Efficient Economy, "Net Metering," http://aceee.org/topics/net-metering, visited Mar. 16, 2015; International Renewable Energy Council and The Vote Solar Initiative, 2013, "Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures," at 12, http://freeingthegrid.org/wp-content/uploads/2013/11/FTG_2013.pdf.

Minnesota - Minnesota's net-metering law, enacted in 1983 and expanded in 2013,[58] applies to all investor-owned utilities, municipal utilities and electric cooperatives. Today, all "qualifying facilities" up to 100 kW in capacity under the federal Public Utility Regulatory Policy Act of 1978 (PURPA) are eligible. There is no limit on statewide capacity, though IOUs may request a cumulative generation limit once generation has reached 4 percent of annual retail electricity sales. For smaller systems (up to 40 kW), each utility must compensate customers for customer net excess generation (NEG) at the "average retail utility energy rate," defined as "the total annual class revenue from sales of electricity minus the annual revenue resulting from fixed charges, divided by the annual class kilowatt-hour sales." This rate is basically the same as a utility's retail rate. Larger systems (40-100 kW) can be compensated at either an avoided-cost rate or as a kWh credit. Both fossil-fueled and renewably fueled CHP systems are eligible for net-metering.

New Hampshire - The New Hampshire Public Utility Commission amended its net-metering rules in 2012 to include CHP systems up to 1 megawatt. Though the rules vary slightly for each customer-type and size, they include several features that benefit CHP. CHP may account for a maximum of 4 MW of the state's 50 MW aggregate net-metering limit. This allows CHP hosts to size their systems to match their thermal load and sell surplus electricity back to the grid. Eligible CHP systems must meet an efficiency requirement (65-80 percent, depending upon system size). Any customer's net excess generation during a billing cycle is credited to the customer's next bill and carried forward indefinitely. At the end of a 12-month period, customers may choose to receive payment for any excess generation at the utility's avoided-cost rate. Both fossil-fueled and renewably fueled CHP systems are eligible for net-metering. Each utility's net-metering tariff must be identical, with respect to rates, rate structure and charges, to the tariff that under which the customer would otherwise take default service from the utility.

Washington - Washington's net-metering law, originally enacted in 1998, applies to systems up to 100 kilowatts (kW) in capacity. All customer classes are eligible, and all utilities—including municipal utilities and electric cooperatives—must offer net metering. Net metering is available on a first-come, first-served basis until the cumulative generating capacity of net-metered systems equals 0.25 percent of a utility's peak demand during 1996. This limit increased to 0.5 percent on January 1, 2014. Both fossil-fueled and renewably fueled CHP systems are eligible for net metering.

Power Purchase Agreements

Power Purchase Agreements (PPA) provide the host customer power (and heat) at a discounted rate, with no capital requirement. A third-party investor and/or developer owns and operates the CHP system and enters into a long-term power contract with the host. PPAs offer a number of benefits to CHP hosts: because they do not require any up-front cost or capital, they can be cash-flow positive from day one, they offer predictable energy pricing and serve as a hedge against electricity prices, they reduce system performance or operating risks, and do not have maintenance costs.

[58] Note that many of the features described here will not take effect until rules are enacted for H.F. 729 at the PUC. Pending those changes, net metering is limited to systems up to 40 kW in size.

Connecticut – Connecticut Natural Gas and Southern Connecticut Gas have designed and tested a zero-capital program, which was designed to help spur third-party CHP ownership with customers interested in on-site CHP. The program would encourage five- or ten-year power purchase agreements (PPAs) between customers and the third-party developers and owners. Under this model, CNG/SCG's parent UIL would be able to enjoy the benefits of CHP on its electric system without having to own the CHP systems, which it is not permitted to do under current market rules. CNG/SCG also explored developing an unregulated subsidiary that could legally own these generation assets.

Utility Participation in CHP Markets

A key policy option for increasing installed CHP capacity may be to allow incumbent natural gas and electric utilities to participate in CHP markets. Utility participation may take many forms. A utility could own CHP facilities directly on the customer side of the meter, provide packages of services to customers who own their own CHP, or it could incorporate combined heat and power solutions into ratepayer-funded efficiency programs. Today, utilities are constrained in the provision of CHP services. Most do not have the regulatory approval to build and own CHP facilities – nor do most have the flexibility to negotiate custom service packages for customers who own their own CHP systems. This represents a significant barrier to the growth of cost-effective CHP because incumbent utilities are uniquely positioned to facilitate new CHP development. Utilities understand CHP technology, which has been present in the market about as long as central station power supply. They generally are very familiar with their customers' process needs and concerns. Utilities may be in a unique role to assume the risk and responsibility of installing and maintaining a complex energy system so that the customer can concentrate on its primary mission or business. They may also be able to accept longer paybacks and lower internal rates of return than their customers. Direct support could involve investments in equipment and infrastructure over a long investment horizon – a proposition that aligns with the utility business model.

Pennsylvania (Philadelphia Gas Works) – Understanding that the up-front costs of CHP can be a hurdle to market development, Philadelphia Gas Works (PGW), the municipal gas utility in Philadelphia, works with commercial and industrial customers on a case-by-case basis to provide an incentive in an amount up to the up-front capital cost for small and mid-size CHP systems (70 kW to 7 MW to date), recovering those costs plus PGW's cost of capital over the first five years of CHP system operation through the facility's gas bills. The facility signs a service agreement that reflects the total PGW incentive, but the five-year through-the-bill cost recovery eliminates the site's need for upfront capital. After PGW cost recovery, the customer enjoys the benefits of ongoing energy savings during the remaining lifetime of the CHP equipment.

New Jersey (New Jersey Natural Gas) – New Jersey Natural Gas (NJNG) has a Fostering Environmental and Economic Development (FEED) program (Sheets 94-96) designed to provide financial assistance for energy-efficiency upgrades and economic development opportunities for commercial and industrial customers. FEED provides access to investment capital, incentives, and/or discounted rates to encourage the installation of energy-efficient equipment, including CHP projects, as well as business growth, expansion, and retention in the state. Up-front project funding is provided by NJNG with the principal and interest repaid by the customer over an agreed upon period of time. Long-term, fixed-price contracts for the purchase of natural gas are also available under FEED. This program provides no risk to ratepayers and no associated costs will be recovered through NJNG's rates.

Missouri – Utility involvement can include joint ownership of CHP assets, as is the case with Missouri Ethanol LLC in Laddonia, MO, a 45-million-gallon per year ethanol plant that began operation in September 2006. It is one of two ethanol plants in the state that employ gas turbine-based CHP through a utility-ethanol plant partnership. The CHP system is jointly owned by Missouri Ethanol and the Missouri Joint Municipal Electric Utility Commission (MJMEUC), a statewide joint action agency that supplies power and capacity services to 56 municipal Missouri utilities. The Missouri Ethanol project is patterned after an earlier CHP partnership between the City of Macon, MO, and the Northeast Missouri Grain LLC ethanol plant in Macon. In both Macon and Laddonia, the utilities own and are responsible for gas turbine operation. However, the ethanol plants own and are responsible for the heat-recovery equipment, including the HRSGs and downstream steam systems. Natural gas costs are shared between the utilities and ethanol plants in both cases. The Missouri Public Utility Alliance (MPUA) views the Laddonia project as a "win-win-win" effort, as it provides a cost-competitive power supply for MJMEUC, reduced steam costs for the ethanol plant, and additional baseload gas demand for the Missouri Municipal Gas Commission.

California – In December 2015, Southern California Gas Company (SoCalGas) instituted a new, optional Distributed Energy Resource Services (DERS) tariff that allows SoCalGas to plan, design, procure, construct, own, operate, and maintain distributed energy equipment on customer premises. Examples of customer end-use applications that can be served by the Distributed Energy Resources Services Tariff include Combine Heat and Power (CHP), Waste Heat to Power (WHP), fuel cells, and mechanical drive systems. Certain capacity and efficiency standards apply on a case-by-case basis. All project costs would be recovered from the tariff customer, with no subsidy from or business risk borne by other ratepayers. Although equipment is positioned on or adjacent to the customer's property, the equipment is owned and/or maintained by the utility. Tariff customers will pay a negotiated service fee that captures, at a minimum, the full system cost, including both capital and O&M over the contract term. Agreement to provide service is at SoCalGas' discretion and will depend on non-discriminatory factors such as safety, system capacity, SoCalGas resource availability, technical feasibility, and acceptability of commercial terms.

State Level Legislation and Regulation

Examples of State Legislation and Regulations		
State	**Title/Description**	**URL Address**
Alabama	AlabamaSAVES Revolving Loan Fund Program: The loans may be used to purchase and install equipment for renewable-energy systems and energy-efficient fixtures and retrofits installed on property owned and/or operated by eligible businesses. CHP is considered an eligible technology under this program, with loans ranging from $50,000 to $4-million.	http://bit.ly/1Oc2zpM
Arizona	Renewable Energy Standard: ACC approved the Renewable Energy Standard and Tariff (REST), which requires 25% of covered utilities' electricity to come from renewable sources by 2025. The standard specifically includes renewably fueled CHP as an eligible resource (i.e., systems fueled with biomass or biogas)	http://www.azcc.gov/divisions/utilities/electric/res.pdf?d=756
Arizona	Energy Efficiency Resource Standard: Utilities can count energy from CHP systems that do not qualify under the state's Renewable Energy Standards towards the standard.	http://images.edocket.azcc.gov/docketpdf/0000116125.pdf?d=52
Arizona	Southwest Gas Smarter Greener Better Distributed Generation program: Offers its customers rebates ranging from $400 to $500 per kilowatt of installed CHP capacity. Eligible CHP systems must achieve a total system efficiency of 60% to 70% or higher.	http://www.swgasliving.com/rebates/arizona/arizona-smarter-greener-better%C2%AE-distributed-generation-program-business
California	CaliforniaFIRST: The program allows property owners to finance the installation of energy and water improvements and pay the amount back on their property tax bill.	https://commercial.californiafirst.org/overview
California	Self-Generation Incentive Program: Provides incentives to renewably fueled and fossil-fueled CHP systems. The maximum incentive is $5 million with a minimum 40% customer investment. Eligible system size is capped at 3 MW and must meet a 60% minimum efficiency.	http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/index.htm

California	CPUC Feed-in-Tariff: FIT authorized for CHP systems up to 20 MW to execute a standard-offer contract to export energy to one of the state's largest three IOUs. The payment rate is fixed for the duration of the generator's contract, which ranges from 10 to 20 years, depending on the owners' discretion.	http://www.cpuc.ca.gov/PUC/energy/CHP/feed-in+tariff.htm
California	Discounted Natural Gas Rates: Natural gas utilities can provide natural gas to qualified cogeneration systems under the same distribution rates offered to large electric utilities.	ftp://ftp2.cpuc.ca.gov/LegacyCPUCDecisionsAndResolutions/Resolutions/G2738_19871016_AL1422G.pdf
California	Distributed Generation Certification Regulation: Amended its Distributed Generation Certification Regulation (Senate Bill 1298), which specifies the emissions regulations that particular generators are subject to. Applicable to distributed generation units.	http://www.arb.ca.gov/energy/dg/2006regulation.pdf
California	Standard Interconnection Agreement: Applies to CHP and other distributed generation systems up to 10 MW. It has been adopted as a model by all three major investor-owned utilities, and follows the established technical guidelines of the IEEE 1547 interconnection standard.	http://www.cpuc.ca.gov/PUC/energy/rule21.htm
California	Distributed Energy Resources Services Tariff: In December 2015, Southern California Gas Company (SoCalGas) instituted a new, optional Distributed Energy Resource Services (DERS) tariff that allows SoCalGas to plan, design, procure, construct, own, operate, and maintain distributed energy equipment on customer premises. Examples of customer end-use applications that can be served by the Distributed Energy Resources Services Tariff include CHP, WHP, fuel cells, and mechanical drive systems. Certain capacity and efficiency standards apply on a case-by-case basis.	https://www.socalgas.com/regulatory/documents/a-14-08-007/DER%20Webpage%20Script%20(080714)%20final.pdf
Connecticut	Low-Interest Loans: Support the installation of customer-side distributed resources (including CHP systems larger than 50 kW). The minimum loan size is $1,000,000 for a program total of $150-million.	http://www.cga.ct.gov/2011/pub/chap283.htm#Sec16-243j.htm
Connecticut	Microgrid Grant & Loan Program: Supports distributed energy generation at critical facilities.	http://www.ct.gov/deep/cwp/view.asp?a=4120&Q=508780

Connecticut	C-PACE: Allows commercial, industrial or multi-family property owners to access 100% upfront, long term financing for energy efficiency and clean energy improvements on their properties through a special assessment on the property tax bill, which is repaid over a period of years (up to 20 years).	http://www.cpace.com/
Connecticut	Streamlined Permitting: Streamlines the permitting process for eligible systems that produce both electric and thermal energy. The rule explicitly mentions CHP and any systems that are more than 55% efficient, have a nameplate capacity less than 15 MW, a power-to-heat ratio between 0.15 and 4.0, and that produce fuel for non-emergency use are eligible.	http://www.ct.gov/deep/lib/deep/air/regulations/mainregs/sec42.pdf
Connecticut	Standby Rate Ruling: Developing a pilot program to promote CHP by limiting the demand charge electric companies impose on qualifying systems (between 0.5 and 5 MW).	http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=10&Seq=1
Connecticut	Property Tax Exemption: Municipalities are authorized, but not required, to offer a property tax exemption lasting up to 15 years for qualifying CHP systems.	http://www.cga.ct.gov/2011/pub/chap203.htm#Sec12-81.htm
Connecticut	Integrated Resource Plan: In 2014, the Connecticut Department of Energy and Environmental Protection (DEEP) released a draft Integrated Resource Plan proposing to offer incentives of up to $450/ kWh for up to 160 MW of new CHP capacity in the state. The incentives will decline over time, as the state's deployment goals are met.	http://www.ct.gov/deep/lib/deep/energy/irp/2014_irp_draft.pdf
Connecticut	Power Purchase Agreement: Connecticut Natural Gas and Southern Connecticut Gas have designed and tested a zero-capital program, which was designed to help spur third-party CHP owners with customers interested in on-site CHP. The program would encourage five or ten year power purchase agreements (PPAs) between customers and the third-party developers and owners.	https://www.cngcorp.com/wps/wcm/connect/42bbd20048ea0c62b80ef980657d4c17/06-LGS+%28Large+General+Service%29.pdf?MOD=AJPERES&CACHEID=42bbd20048ea0c62b80ef980657d4c17
Delaware	Output Based Emissions Regulations: Qualifying systems must be at least 55% efficient and at least 20% of the fuel's total recovered energy must be thermal and 13% electric (corresponding to an allowed power-to-heat ratio between 4.0 and 0.15).	http://www.dnrec.state.de.us/air/aqm_page/docs/pdf/Final Regulation 1144.pdf

Georgia	Georgia Power Standby Rate: Customers can contract for either firm or interruptible standby capacity to replace onsite generation when the system is not in service. Customers must provide notification to the utility within 24 hours of taking firm backup power. Maintenance power is available as firm service during the off-peak months and as interruptible service during peak months. Customers may also purchase supplemental power (i.e., to augment what is produced onsite) at the same rates as other customers. While there are no ratchets, demand charges are subject to a "standby demand adjustment factor," which adjusts the billed standby demand once a customer uses backup service for more than 876 hours during the most recent 12-month period. This provides an incentive for a customer to use standby service as efficiently as possible.	http://www.georgiapower.com/pricing/files/rates-and-schedules/12.30_BU-8.pdf
Hawaii	Green Infrastructure Bonds: To help developers of clean-energy installations (including CHP) on commercial or residential properties secure low-cost financing.	http://www.capitol.hawaii.gov/session2013/bills/SB1087_CD1_.htm
Illinois	Cash Incentives for CHP: Up to $2 million, for individual CHP projects in Illinois public sector facilities.	http://www.illinois.gov/dceo/whyillinois/KeyIndustries/Energy/Pages/CHPprogram.aspx
Illinois	Standard Interconnection Agreement: Established standards for net-metering and interconnection for renewable energy systems since 2008. Although S.B. 680 only requires the promulgation of interconnection standards for "eligible renewable generating equipment," the ICC developed four tiers of interconnection standards for all distributed generation up to 10 MW.	http://www.ilga.gov/legislation/publicacts/fulltext.asp?Name=095-0420&GA=095
Maryland	Standard Interconnection Agreement: Maryland PSC adopted interconnection standards that include CHP up to 10 MW and applies to both fossil-fueled and renewably fueled systems.	http://www.dsd.state.md.us/comar/SubtitleSearch.aspx?search=20.50.09
Maryland	BGE Smart Energy Savers Program: This program provides incentives to industrial and commercial customers who install efficient (>65% high-heating value) CHP systems.	http://www.bgesmartenergy.com/business/CHP

Maryland	Net-Metering Rule: Expanded several times since enactment in 1997. Applies to all utilities. Residents, businesses, schools or government entities with systems that generate electricity using micro-CHP (less than 30 kW in capacity) are eligible for net metering. Net excess generation (NEG) is generally carried over as a kWh credit at the retail rate, for 12 months.	http://www.dsd.state.md.us/comar/SubtitleSearch.aspx?search=20.50.10
Massachusetts	Energy Efficiency First Fuel Requirement: Electric and gas utilities to prioritize cost-effective energy efficiency and demand reduction resources. Demand side resources include energy efficiency, load management, demand response and generation that is located behind a customer's meter including a CHP system with an annual efficiency of 60% or greater, with the goal of 80% annual efficiency for CHP systems by 2020.	https://malegislature.gov/Laws/GeneralLaws/PartI/TitleII/Chapter25/Section21
Massachusetts	Alternative Energy Portfolio Standard: The APS requires that 5% of a supplier's (both regulated distribution utilities and competitive suppliers) retail sales must come from alternative energy sources by December 31, 2020. An alternative energy source is defined as one that generates electricity using CHP (regardless of fuel type), gasification with capture and permanent sequestration of carbon dioxide, flywheel energy storage, paper-derived fuel sources, or energy-efficient steam technology.	http://www.mass.gov/eea/docs/doer/rps/rps-225-cmr16-mar-12-2009.pdf
Massachusetts	Mass Save: This program was created implement the Green Communities Act of 2008, which recognizes CHP as an energy-efficiency measure eligible for utility incentives. The incentives are tiered (ranging from $750 to $1,200), with large incentives (covering up to 50% of installed costs) given to the most efficient systems.	http://www.masssave.com/business/eligible-equipment/combined-heat-and-power
Michigan	Property Assessed Clean Energy (PACE) financing: For commercial and industrial property owners for energy efficiency and/or renewable energy projects, including CHP, that range in size from $10,000 to $350,000.	http://a2energy.org/commercial-savings
Michigan	Standard Interconnection Agreement: Delineates five separate tiers of interconnection, and covers systems of all sizes with the largest interconnection tier for systems 2 MW systems and above. Both fossil-fueled and renewably fueled CHP systems are eligible for standardized interconnection.	http://efile.mpsc.state.mi.us/efile/docs/15787/0046.pdf

Minnesota	Net-Metering Rule: Enacted in 1983 and expanded in 2013, applies to all utility types. All "qualifying facilities" up to 100 kW in capacity are eligible. There is no limit on statewide capacity, though IOUs may request a cumulative generation limit once generation has reached 4% of annual retail electricity sales.	https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B84622862-F00D-499A-B116-30F78862AD40%7D&documentTitle=20127-77081-01%22
Minnesota	University of Minnesota CHP Bonds: $10 million, of $64.1 million, is being dedicated to a CHP project, designed to replace current coal furnaces.	http://discover.umn.edu/news/politics-governance/session-successes-position-university-minnesota-advance-research-and
Missouri	Missouri Ethanol LLC and MJMEUC CHP Partnership: Missouri Ethanol LLC in Laddonia, MO, a 45-million-gallon per year ethanol plant that began operation in September 2006. It is one of two ethanol plants in the state that employ gas turbine-based CHP through a utility-ethanol plant partnership. The CHP system is jointly owned by Missouri Ethanol and the Missouri Joint Municipal Electric Utility Commission (MJMEUC), a statewide joint action agency that supplies power and capacity services to 56 municipal Missouri utilities.	http://www.districtenergy.org/pdfs/DEMagArticles/2Q07/WebLink2q07.pdf
New Hampshire	Output Based Emissions Regulations: Cap SO2, NOx, CO_2 and mercury emissions on older power plants. These regulations use output-based methods to measure emissions and impact several power plants that were in existence prior to the legislation. CHP is not directly mentioned in the regulations, and specific allocations describing how thermal output would be credited are not listed in detail.	http://www.gencourt.state.nh.us/rsa/html/nhtoc/NHTOC-X-125-O.htm
New Hampshire	Standard Interconnection Agreement: Established standardized interconnection rules for net-metered systems up to 1 MW in January 2001. Systems that connect to the grid using inverters that meet IEEE 1547 and UL 1741 safety standards do not require an external disconnect device.	http://www.puc.state.nh.us/Regulatory/Rules/Puc300.PDF
New Hampshire	Net-Metering Rule: Amended existing rule in 2012 to include CHP systems up to 1 MW. CHP may account for a maximum of 4 MW of the state's 50 MW aggregate net-metering limit.	http://www.puc.state.nh.us/Regulatory/Rules/PUC900.pdf

New Jersey	Streamlined Permitting: Offers a general permit for CHP combustion turbines and reciprocating engines. Units with total design efficiency greater than or equal to 65% are eligible.	http://www.state.nj.us/dep/aqpp/downloads/general/GP-021.pdf.
New Jersey	Energy Resilience Bank: Invest in long-term recovery strategies focused on critical facilities and enhancing energy resilience.	http://www.njeda.com/web/pdf/ERBProgramGuide.pdf
New Jersey	Sales & Use Tax Exemption: Applies to the purchase of natural gas and utility service for on-site cogeneration facilities.	http://www.districtenergy.org/assets/pdfs/2010CampConf/New-Jersey-Cogeneration-Bill-12.3.09.pdf
New Jersey	New Jersey Cogeneration Bill of 2009: Allows CHP systems to “wheel power” to their district energy thermal customers, regardless of whether they are separated by an easement, a street, another building, or a utility-owned right-of-way	http://www.districtenergy.org/assets/pdfs/2010CampConf/New-Jersey-Cogeneration-Bill-12.3.09.pdf
New Jersey	Fostering Environmental and Economic Development: Designed to provide financial assistance for energy-efficiency upgrades and economic development opportunities for commercial and industrial customers. FEED provides access to investment capital, incentives, and/or discounted rates to encourage the installation of energy-efficient equipment, including CHP projects, as well as business growth, expansion, and retention in the state.	http://www.njng.com/regulatory/pdf/Tariff03012015.pdf
New York	Discounted Natural Gas Rates: Customers using natural gas for distributed generation including CHP have been able to qualify for discounted natural gas delivery rates.	http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B3CD9E19C-22C1-4749-9E1F-E78260350465%7D
New York	Flex Tech Program: Provides New York State industrial, commercial, institutional, government, and nonprofits with technical assistance to help them make “informed energy decisions.”	http://www.nyserda.ny.gov/All-Programs/Programs/FlexTech-Program
New York	ConEdison Standby Tariff: Tariff is entirely demand based and they do not employ a ratchet. Standby rates do not apply to customers whose on-site generation capacity is less than 15% of their maximum demand.	http://www.coned.com/dg/service_categories/standby.asp

New York	Standby Rate Ruling: Established guidelines for utilities requiring that investor-owned utilities make their standby rates reflective of actual costs.	http://www.utilityregulation.com/content/orders/01NYdoc10690.pdf
New York	CHP Accelerator Program: This program is sponsored by NYSERDA and provides incentives for the installation of pre-qualified, pre-engineered CHP systems by pre-approved CHP system installers.	http://www.nyserda.ny.gov/Funding-Opportunities/Current-Funding-Opportunities/PON-2568-CHP-Acceleration-Program.aspx
New York	Community Risk and Resiliency Act: The NYS 2100 Commission recommended evaluation CHP and distributed generation projects to improve grid resiliency. The act also requires the New York Department of Environmental Conservation and the New York Department of State to provide guidance to help communities implement the act, including the use of resiliency measures.	http://assembly.state.ny.us/leg/?default_fld=&bn=A06558&term=2013&Summary=Y&Actions=Y&Memo=Y&Text=Y
New Mexico	Energy Efficiency and Renewable Energy Bonding Act: Authorizes up to $20 million in bonds, backed by the state's Gross Receipts Tax, to be issued to finance energy efficiency and renewable energy improvements in state government and school buildings.	http://www.emnrd.state.nm.us/ECMD/CleanEnergyTaxIncentives/CREB.html
New Mexico	CHP Tax Credit: Offers a 6% tax credit for qualifying clean-energy projects, including "recycled energy".	http://www.tax.newmexico.gov/Tax-Professionals/tax-credits-overview.aspx
North Carolina	CHP Tax Credit: Equal to 35% of the cost of eligible renewable energy property (including CHP fueled by non-renewable fuels) placed into service.	http://www.dor.state.nc.us/downloads/nc478g_instructions.pdf
Ohio	Ohio Air Quality Improvement Tax Incentives Act: Provides a 100% exemption from the tangible personal property tax (on property purchased as part of an air quality project), real property tax (on real property comprising an air quality project), a portion of the corporate franchise tax (under the net worth base calculation), and sales and use tax (on the personal property purchased specifically for the air quality project only) for outstanding bonds issued by OAQDA.	http://www.ohioairquality.org/clean_air/default.asp

Ohio	CHP Tax Exemption: May provide a 100% sales and use tax exemption for certain tangible personal property for industrial and commercial property owners.	http://development.ohio.gov/bs/bs_contaxexempt.htm
Oregon	Standby Rate Ruling: Portland General Electric's (PGE) standby tariff is attractive because it does not employ a ratchet, but instead applies an as-used, on-peak demand charge to CHP systems. Under this approach, an assumed outage only affects the demand charge in the month that the outage occurs and does not reduce the electric savings from the CHP system in other months.	https://www.portlandgeneral.com/our_company/corporate_info/regulatory_documents/pdfs/schedules/Sched_200.pdf
Oregon	Financial Incentives for Carbon Reductions: NW Natural offers financial incentives ($30/ metric ton of CO_2-equivalent) to encourage CHP deployment to lower carbon emissions. Eligible systems must be at least 10% more efficient than a combined cycle gas turbine. Reaching this goal will support the deployment of 80 to 120 MW of CHP by 2020.	https://www.nwnatural.com/uploadedFiles/UM%201744%20-%20NWN's%20Application%20for%20Carbon%20Emissions%20Reduction%20Program.pdf
Pennsylvania	Discounted Natural Gas Rates: Philadelphia Gas Works (PGW) offers discounted gas rates for commercial and industrial customers who use natural gas in any combination of cooling, heating, and power production.	http://www.pgworks.com/business/fueling-the-future/combined-heat-power
Pennsylvania	Philadelphia Gas Works CHP Up-Front Capital Financing: Understanding that the up-front costs of CHP can be a hurdle to market development, Philadelphia Gas Works (PGW), the municipal gas utility in Philadelphia, works with commercial and industrial customers on a case-by-case basis to provide an incentive in an amount up to the up-front capital cost for small and mid-size CHP systems (70 kW to 7 MW to date), recovering those costs plus PGW's cost of capital over the first five years of CHP system operation through the facility's gas bills. The facility signs a service agreement that reflects the total PGW incentive, but the five-year through-the-bill cost recovery eliminates the site's need for upfront capital. After PGW cost recovery, the customer enjoys the benefits of ongoing energy savings during the remaining lifetime of the CHP equipment.	http://www.pgworks.com/business/customer-care/large-business

Texas	Streamlined Permitting: Developed a streamlined air permitting process for NOx and CO emissions from CHP systems (following passage of authorizing legislation in 2011). The streamlined process expedites permitting for natural gas-fired CHP systems that are less than 15 MW and where thermal output is more than 20% of the total energy output.	http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/segu_final.pdf
Texas	Output Based Emissions Regulations: Adopted a standard permit to facilitate CHP deployment for systems under 10 MW. The permit relies on an output-based standard to measure NOx emissions. In 2011, Texas adopted a more robust streamlined permitting process, which likewise relies on an output-based standard.	http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/segu_final.pdf
Texas	Energy Security Technologies for Critical Government Facilities: Requires all government entities to identify critical government-owned buildings and facilities and to obtain a feasibility study to consider the technical opportunities and economic value of implementing CHP.	http://www.statutes.legis.state.tx.us/Docs/GV/htm/GV.2311.htm
Texas	House Bill 2049: Signed in June 2013, clarifies language in the Texas Utility Code to allow CHP facilities to sell electricity and heat to any customer located near the CHP facility.	http://www.legis.state.tx.us/tlodocs/83R/billtext/pdf/HB02049I.pdf
Washington	Standard Interconnection Agreement: For distributed generation systems, including CHP (regardless of fuel type), up to 20 MW in size. The standards apply to the state's investor-owned electric utilities, but not to municipal utilities or electric cooperatives.	http://apps.leg.wa.gov/WAC/default.aspx?cite=480-108
Washington	Renewable Energy Standard: Utilities must generate 15% of their electric load from new renewables by 2020 and to undertake all cost-effective energy conservation, including CHP. High-efficiency CHP, owned and used by a retail electric customer to meet its own needs may be counted toward conservation targets.	http://www.secstate.wa.gov/elections/initiatives/text/i937.pdf

Appendix B

Enforceability of CHP Programs under the Clean Power Plan

Introduction

The Clean Air Act (CAA) embraces a model of cooperative federalism, with a shared set of responsibilities between federal and state governments. For over 40 years, states have implemented EPA-approved plans to achieve air quality standards and other objectives set forth by Congress in the 1970, 1977 and 1990 Clean Air Act Amendments. In what is now a familiar pattern, the U.S. EPA sets an overall goal and states develop plans to achieve the goal, following criteria set out in the statute or EPA guidelines. This same pattern will apply to state compliance plans to control CO_2 emissions from power plants under the Clean Power Plan (CPP)[59] and section §111(d) of the CAA.[60] But there are differences between the requirements for §111(d) compliance plans, relative to those applicable to state implementation plans developed under section §110 of the CAA. Section §111(d) plans are subject to fewer limitations.

General Criteria for State Plan Approval

- Enforceable
- Performance
  - Projected and actual achievement of emission goal established by EPA
- Measurable
  – Quantifiable & Verifiable
- Accountability
  – A process to report on plan implementation, emissions, outcomes, and corrective measures

The CPP establishes general criteria by which EPA will approve or disapprove state compliance plans, along with a number of components that each plan must contain.[61] The components can vary somewhat, depending on what approach the state takes. Most of the criteria and plan elements are self-explanatory and relatively uncontroversial. But one of the criteria (“enforceability”) has generated some confusion and heightened attention – partly because it exists at the boundaries between state and federal authority and between private and governmental responsibilities under the CAA. In this Appendix, we address “Enforceability” and related criteria, as described in the final CPP.

Enforceability comes up in the final rule in several contexts. To approve a state plan, EPA must find that the provisions of the plan are enforceable by some entity or entities. There are two aspects to this. First the state must have authority to enforce its plan. State authority can be demonstrated in a variety of ways, including interagency agreements, contracts, or state regulatory requirements.

Second, and more controversial, is the requirement that some parts of the plan need to be federally enforceable, that is by EPA, or – in some limited cases – by citizen suits. The final rule

[59] EPA published final rules to control CO_2 emissions from fossil fired power plants at 80 *Fed. Reg.* 64661 (October 23, 2015). EPA proposed rules were published at 79 *Fed. Reg.* 34830 (June 18, 2014).

[60] 42 USC §7411(d).

[61] *See,* e.g., 80 *Fed. Reg.* at 64943, § 60.5740; 40 CFR 60.23.

resolved much of the concern about federal enforceability by stating that state measures, including CHP incentive programs that are directed by the state legislature or utility commission, do not need to be included in the federally enforceable component of a state compliance plan.[62] Similarly, the final rule clearly endorses mechanisms by which emission rate credits (ERCs) or emission allowances may be earned by CHP systems. So long as those mechanisms meet the design criteria in the rule, there is no federal enforceability issue associated with the trade of ERCs or allowances from CHP operators to power plant owners.

This Appendix explores various options by which a CHP module in a state's CPP compliance plan can satisfy the enforceability requirement. In general, we conclude that EPA is very *unlikely* to disapprove a CHP component of a state plan due to concerns about enforceability.[63] This is because of the wide degree of flexibility afforded to states in formulating compliance plans under §111(d) and the final CPP rule, and because EPA and the Obama Administration clearly favor energy efficiency and low-emission resources like CHP as compliance options, and have set ambitious goals for CHP development.[64] Moreover, as a practical matter, the agency will have its hands full responding to states that refuse to file compliance plans or whose plans are clearly deficient. By contrast, EPA is likely to afford deference to states that make a good-faith effort to effectively include CHP in their plans. Keys to EPA approval of §111(d) plans are to: 1) make reasonable assumptions about the performance of the CHP elements of the plan; 2) identify who is responsible for any state incentive programs designed to generate emission reductions or credits from CHP; 3) rely on established EM&V protocols; and 4) include correction or, in some cases, backstop mechanisms that will be implemented if projected CHP strategies underperform.

Statutory Requirements

A plan under §111(d) must, "provide for the implementation and enforcement of the standards of performance" established by EPA,[65] – meaning each state's goal for reducing CO_2 emissions from its fleet of affected EGUs. As states approach the task of compliance planning under §111(d), we reiterate that the concept of enforceability is different for state compliance plans under §111(d) than it is for state implementation plans to meet ambient air quality standards for criteria pollutants (under §110 of the Clean Air Act). This conclusion is based on the language of the CAA which states that the EPA Administrator shall establish a procedure "similar" to that used by states to submit implementation plans to achieve ambient air quality standards under §110.[66] "Similar" by definition is not "identical," and EPA clearly has discretion to use a different

[62] 80 *Fed. Reg.* at 64832, footnote 782 ("…'State measures' refer to measures that are adopted, implemented, and enforced as a matter of state law. Such measures are enforceable only per state law, and are not included in and codified as part of the federally enforceable state plan.").
[63] CHP components in this context are measures or programs designed to promote the deployment of non-affected CHP projects to reduce demand and associated emissions, from affected EGUs. Note that a limited number of existing CHP projects are classified as affected EGUs and subject to the requirements of the Clean Power Plan.
[64] *See* Executive Order, Accelerating Investment in Industrial Energy Efficiency, August 30, 2012, https://www.whitehouse.gov/the-press-office/2012/08/30/executive-order-accelerating-investment-industrial-energy-efficiency.
[65] 42 USC §7411(d)(1)(B).
[66] 42 USC §7411(d)(1).

definition for §111(d) plan enforceability than has historically been applied to state implementation plans (SIPs) under §110.[67] For this reason, EPA guidance documents and regulations issued pursuant to §110 SIP development are not necessarily applicable to the question of whether a §111(d) compliance plan is adequately enforceable.

Language on Enforceability in the Final Rule

Under the final CPP, states must establish emission standards along with implementation and enforcement measures that will achieve a level of emission performance equal to or better than state-specific CO_2 emission performance goals established in the final rule.

The CPP provides states with a series of options for establishing emission standards that will accommodate a diverse range of state approaches. Each state will have significant flexibility to determine the best way to achieve its CO_2 goals.[68] Under the final rule, states may choose to submit plans that hold the affected EGUs fully and solely responsible for achieving the emission performance level, or to rely in part on measures undertaken by the state itself (or other entities) to achieve some of the required emissions reductions. More specifically, states may adopt one of two approaches to compliance: a source-based ''emission standards'' approach, and a ''state measures'' approach. Under either approach CHP owners can help achieve compliance by selling credits or allowances to power plant owners.

Under a mass-based plan, states have the additional option to adopt a set of policies and programs, which "rely upon state-enforceable measures on entities other than affected EGUs." The "state measures" can be combined with federally enforceable, emission standards imposed on affected EGUs to meet the state emission target. States that choose the "state measures approach" must use a mass-based CO_2 emission goal as the metric for demonstrating plan performance.[69] Under a state measures approach, states would be required to include federally enforceable "backstop" measures[70] applicable to each affected EGU in the event that state

[67] *See also* 80 *Fed. Reg.* at 64853 (distinguishing 110 authority from section 111(d)). For additional discussion of the differences between §110 SIP and §111(d) implementation plans, *see*, Regulatory Assistance Project, Feb. 2015, "It's Not a SIP: Opportunities and Implications for State §111(d) Compliance Planning" (http://www.raponline.org/document/download/id/7491). This policy brief provides a side-by-side comparison of Sections §110 and §111(d) of the Clean Air Act and highlights the significant differences in requirements for state compliance plans under each section. The authors distinguish between EPA's constrained role in reviewing and approving state plans for ambient air quality standards and the wide flexibility afforded by §111(d). The authors describe opportunities for states to use new approaches to air quality planning due to the unusual flexibility allowed under Section §111(d). States are not confined to the prescriptive federal requirements generally associated with state implementation plans (SIPs). Instead, states can craft their Clean Power Plan compliance to take advantage of complementary state policies, and can tailor their plans to achieve compliance more cost-effectively, meet other state public policy goals, and boost state employment and economic gains — as long as the plan meets EPA's established greenhouse gas emissions reduction targets. The authors suggest several steps states can take to maximize reward and minimize risk when taking innovative approaches to air-quality planning under Section §111(d).
[68] 79 *Fed. Reg.* at 34900.
[69] 80 *Fed. Reg.* at 64668.
[70] 80 *Fed. Reg.* at page 64668 ("With a state measures approach, the plan must also include a contingent backstop of federally enforceable emission standards for affected EGUs that fully meet the emission

measures fail to achieve the state plan's emission-reduction trajectory.[71] Hence, states will be able to utilize a variety of measures to demonstrate how they will achieve their emissions targets and meet the "enforceability" criteria for state plan approval – without making each individual measure or credit/allowance transaction subject to federal enforcement.[72]

State plans must include a timeline describing all programmatic plan milestone steps the state will take between initial plan submission and 2022 to ensure that the plan is effective as of 2022.[73]

In general, the final rule states that all measures relied on to achieve the emission performance level be included in the state plan. Each state measures plan must identify:

- Each affected EGU and federally enforceable emission standards for all affected EGUs,
- The backstop of (federally enforceable) emission standards,
- Monitoring, recordkeeping and reporting requirements, and
- Each state measure and demonstration that each state measure will result in reductions that are quantifiable, non-duplicative, permanent, verifiable, and enforceable.

But ''state measures'' are only enforceable pursuant to state law, and "are not included in and codified as part of the federally enforceable state plan."[74] A state measure meets the enforceability criteria if:

- It is a technically accurate limitation or requirement and the time period for the limitation or requirement is specified,
- Compliance requirements are clearly defined,

guidelines and that would be triggered if the plan failed to achieve the required emission reductions on schedule. A state would have the option of basing its backstop emission standards on the model rule, which focuses on the use of emissions trading as the core mechanism…"). EPA proposed the "model rule" on October 23, 2015, published at 80 *Fed. Reg.* 64966.

[71] A discussion of approaches to state plans occurs in the final rule at 80 *Fed. Reg.* at 64675.

[72] States are more likely to succeed at incentivizing private entities to invest in cost-effective CHP projects if they can structure the relevant parts of their compliance plans to eliminate any perceived risk of federal enforcement or citizen suits against a CHP owner or industrial participant in a state or utility IEE program.

[73] *See* 80 *Fed. Reg.* at 64668 (providing "States must submit a report to the EPA in 2021 that demonstrates that the state has met the programmatic plan milestone steps that the state indicated it would take during the period from the submittal of the final plan through the end of 2020, and that the state is on track to implement the approved state plan as of January 1, 2022. The plan must also include a process for reporting on plan implementation, progress toward achieving CO_2 emission reductions, and implementation of corrective actions, in the event that the state fails to achieve required emission levels in a timely fashion. Beginning January 1, 2025, and then January 1, 2028, January 1, 2030, and then every two calendar years thereafter, the state will be required to compare emission levels achieved by affected EGUs in the state with the emission levels projected in the state plan and report the results of that comparison to the EPA by July 1 of those calendar years.").

[74] 80 *Fed. Reg.* at 64832, footnote 782.

- The affected entities responsible for compliance and liable for violations can be identified,
- Each compliance activity or measure is enforceable as a practical matter, and
- The state maintains the ability to enforce violations and secure appropriate corrective actions.[75]

Under guidelines that predate the §111(d) proposal, EPA has explained that: "a requirement that is enforceable as a practical matter is one that is quantifiable, verifiable, straightforward, and calculated over as short a term as reasonable." Those terms are carried over into and expanded in the final rule, which states that both emission standards and state measures must "result in reductions that are quantifiable, non-duplicative, permanent, verifiable, and enforceable."[76]

None of these requirements is a challenge for CHP systems. First, EPA's final rule clearly contemplated that CHP and Waste Heat to Power ("WHP") may be used as a compliance option in state plans. The rule provides:

> Electric generation from non-affected CHP units may be used to adjust the CO_2 emission rate of an affected EGU, as CHP units are low-emitting electric generating resources that can replace generation from affected EGUs.[77]
>
> Industrial facilities that install new equipment to capture waste heat from an existing combustion process and then use the waste heat to generate electricity—a form of combined heat and power (CHP) production—can produce generation that replaces generation from affected EGUs and thereby reduces CO_2 emissions. A section 111(d) plan may rely on ERCs issued on the basis of generation of this nature…[78]

Second, emission reductions from CHP systems are quantifiable[79] and verifiable[80] because they typically incorporate sophisticated monitoring equipment and utilize well-established evaluation, measurement and verification standards. States that adopt a CHP "measure" will need to develop a reasonable forecast of the energy savings or emission reductions they expect to achieve through CHP, based on the potential for CHP development in the state and the anticipated impact of state or utility programs to promote CHP development.

CHP emission reductions are "permanent"[81] because CHP systems are long-lived capital

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[75] 80 *Fed. Reg.* at 64948, 40 C.F.R. § 60.5780. 40 CFR §60.5800.
[76] 80 *Fed. Reg.* at 64708.
[77] 80 *Fed. Reg.* at 64902.
[78] 80 *Fed. Reg.* at 64757. 80 *Fed. Reg.* at 64896 and 64902 (providing that to be used for compliance CHP systems must be installed after 2012, but only their generation or savings produced in 2022 and after can be used to adjust a CO_2 emission rate under a mass-based compliance regime); *see also* 80 *Fed. Reg.* 64950.
[79] 80 *Fed. Reg.* at 64850, 64852. (An emission standard or a state measure is quantifiable "if it can be reliably measured, using technically sound methods, in a manner that can be replicated.").
[80] 80 *Fed. Reg.* at 64850, 64852 (An emission standard or a state measure is verifiable "if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state and the Administrator to independently evaluate, measure, and verify compliance with it.").
[81] 80 *Fed. Reg.* at 64850, 64852 (An emission standard or a state measure is permanent "if the emission standard must be met for each applicable compliance period.").

investments that are financed and designed to operate for decades.

CHP emission reductions are “non-duplicative”[82] so long as the state has an ERC or allowance tracking mechanism to ensure that any credits generated by a CHP system are not used twice.

Overall, a CHP element of state plan meets the enforceability criteria[83] because ERCs generated by, or allowances directly allocated to (or earned by) CHP systems are subject to a web of contractual requirements that ensure any failure to operate would not give rise to an ERC or an allowance in the first place. Moreover, many CHP systems are financed in part through state or utility incentive programs that have performance requirements in the documents giving rise to those incentives that are enforceable by the agencies or the utilities involved.

Who Has Enforceable Obligations under the State Plan?

It is important to understand who does *not* have federally enforceable obligations under a §111(d) compliance plan. The final rule insulates CHP owners providing ERCs or allowances from any exposure to federal enforcement or federal citizen suit enforcement. This includes any company who sells emission reduction credits or allowances to power plant owners for compliance purposes. This is true even if state programs financially supported the CHP projects that generate the credits. This conclusion is based on a shift in the final rule that eliminated elements of the proposed rule that had suggested that performance of state energy-efficiency or clean-energy programs could be enforced federally.[84] Some feared that if the state program could be enforced by federal agencies or citizen suits, then the participants in those programs might also become involved in the enforcement action. It was always unlikely that the “enforceability” criteria for approval of state plans would actually have this effect, but now there is no risk what-so-ever. The final rule makes clear that the only entities subject to federal enforcement and federal citizen suits are the owners of affected electric power plants. Hence industrial facilities that participate in a state or utility CHP program that generate credits for CPP compliance would not be subject to federal enforcement. As voluntary suppliers of emission credits, their only obligations would be to satisfy the terms of emission credit sales contracts, agreements, or efficiency programs under which they receive financial incentives.[85] Aside from

[82] 80 *Fed. Reg.* at 64850, 64852 (“A state measure is non-duplicative with respect to an affected entity if it is not already incorporated as a state measure or an emission standard in another state plan.”).

[83] In developing its CAA section 111(d) plan, to ensure that the plan submittal is enforceable and in conformance with the CAA, a state should follow the EPA’s prior guidance on enforceability.” 80 *Fed. Reg.*at 64850. Prior EPA guidance on enforceability includes:

1. September 23, 1987, memorandum and accompanying implementing guidance, ‘‘Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency,’’
2. August 5, 2004, ‘‘Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures,’’ and (3) July 2012 ‘‘Roadmap for Incorporating Energy Efficiency/ Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix F.’’

[84]*See* discussion at 79 *Fed. Reg.* at 34901 (questioning “whether the fact that requiring all measures relied on to achieve the emission performance level to be included in the state plan renders those measures federally enforceable”).

[85] This is an important point since industrial, commercial and institutional customers who could become hosts for a CHP facility would be unlikely to invest in such systems if they perceived that this would

these contracts and the terms of any conventional air pollutant permit, the CHP owners will only be subject to enforcement actions under state air quality laws if states later adopt CO_2 controls for industrial sources.

Implications

The final rule contains wide flexibility for power plant owners and states. The "state measures" approach allows states to count emission reductions from CHP programs toward compliance with state targets, without subjecting those programs to federal enforcement. This form of compliance plan is likely to be attractive to many states. It is the emission targets (including any backstop emission limits) that are federally enforceable under this kind of §111(d) compliance plan – not the particulars of any CHP program referenced in the plan.

From the perspective of power plant owners, the final rule allows CHP systems to generate ERCs that can be purchased to show compliance under a rate-based emission limit. Under a mass-based regime, power plant owners will be able to purchase allowances generated by CHP systems, so long as the state has created a set aside or direct allocation mechanism by which CHP systems can earn allowances. This opportunity for bilateral credit/allowance sales will likely be attractive to CHP investors who can deal directly with power plant owners, independent of state or utility-based DSM or energy-efficiency programs.

So long as the state has adequate controls to ensure the integrity of the allowance allocation and emission trading system or the process by which ERCs are issued, then any CHP element of a state plan will be judged as enforceable, quantifiable, non-duplicative permanent and verifiable.

In the following example we describe a likely scenario for how the enforceability requirement will play out for CHP systems under the final rule's state measures and mass-based approach:

A state compliance plan may project that a set of CHP incentives (managed by a state agency or under a utility DSM program) will achieve a certain amount of energy savings or CO_2 tonnage reductions. The state strategy is enforceable because it is based on a series of contractual agreements and EM&V protocols signed by entities that receive incentives or other financial support to invest in CHP. Under a state measures approach, if a measure's emission reduction estimate is underperforming, neither that state, nor participants in that specific program are subject to federal enforcement. Rather, it is the overall performance of a state plan that is federally enforceable, and if one strategy falls short it may be made up by over-performance from other plan elements, or by corrective measures (e.g., to improve the CHP/IEE strategy, or other elements of the compliance plan) taken in later years of the applicable three-year

subject them to federal or state enforcement under air-quality laws for the resulting emission-reduction performance of those systems. CHP systems may need to secure permits to meet conventional air-quality controls, but those permits would not include conditions relative to CO_2 control impacts of their facilities unless they are an affected unit under EPA's §111(d) rules. Only very large CHP systems that sell large significant amounts of power into wholesale power markets are affected units under the Clean Power Plan. *See* 80 *Fed. Reg.* at 64716 (discussing applicability requirements for CHP).

compliance period. In some cases, a backstop mechanism can also be invoked to ensure the emission reductions forecast in the state measure are achieved.

Another scenario for how the enforceability requirement may play out under a mass-based plan is as follows:

A state sets aside allowances from the overall pool, and either directly allocates them to CHP operators based on documented CHP operations from the previous year, or allows CHP operators to earn the allowances based on real-time operations. The allowances awarded to the CHP owner are then sold under contract to a power plant operator, who then retires them as part of its compliance demonstration at the end of a compliance period. So long as the state has adequate controls to ensure the integrity of its allowance allocation and allowance tracking, then the system is completely enforceable and failure to perform will be highly visible and correctable.

In the following example we describe a likely scenario for how the enforceability requirement will play out for CHP systems under a rate-based approach:

A state compliance plan might encourage power plant owners to create a standard offer to purchase emission rate credits from industrial, commercial and institutional customers who invest in CHP systems. Under this approach, the state plan would allow EGUs to submit a compliance plan that includes an option to purchase ERCs, which in combination with other elements of the unit's compliance plan will achieve the target assigned to that unit. The state would also set up a process by which ERCs are issued to qualified CHP operators based on the EM&V protocols consistent with EPA requirements. This element of the state plan is enforceable since it is based on a series of contracts with suppliers of emission rate credits – under which payments will typically be performance based. If the amount of credits secured under this strategy are less than projected, the power plant owner will simply adjust its compliance plan to rely more heavily on other strategies within the three-year averaging window to demonstrate compliance with the applicable limit (e.g. by purchasing more emission credits from other forms of energy efficiency or shifting more of its generation to power plants with lower emission rates).

Finally, federal enforceability is not an issue in rate-based plans because transactions for sale of ERCs would not be a part of the state plan. While the process of issuing ERCs would be subject to EPA approval and oversight, the sale of ERCs between a CHP owner and a power plant owner is not, and would be enforceable only as a matter of contract law between those parties. Federal enforceability is not an issue under mass-based plans since the final EPA rule removes "state measures' from the federally enforceable part of the state compliance plan, and because transactions involving the sale of allowances between CHP and power plant owners is not subject to federal agency oversight, so long as the underlying process for allocating and awarding allowances is sound.

Concluding Thoughts on Enforceability with Respect to CHP

The enforceability requirements for state plans under the final rule present no obstacles to the use of CHP as a compliance measure for state CO_2 targets. States can promote CHP investments to meet the requirements of the CPP in a variety of ways. The final rule does not impose any federally enforceable obligations against CHP owners or state program administrators. As such, we believe that states and EGU owners can begin to develop compliance plans that incorporate CHP with confidence.

Appendix C

Calculating CO_2 Savings from CHP Under the Clean Power Plan

Introduction

The Clean Power Plan recognizes the CO_2 emissions benefits of CHP. The final rule highlights CHP's thermal efficiency,[86] notes that CHP and WHP are eligible for emission rate credits (ERCs),[87] and exempts most existing industrial CHP systems from the requirements of the CPP.[88] The final rule also allows affected EGUs to use partial or full conversion to CHP as an approach to reduce their emissions rate, allowing an owner/operator applying CHP technology to an affected EGU to account for the increased efficiency by counting the useful thermal output as additional MWh of generation, thereby lowering the unit's computed emission rate and assisting with achievement of an emission rate-based standard of performance. The rule also acknowledges that "CHP units are low-emitting electric generating resources that can replace generation from affected EGUs."[89] EPA had already recognized the value of CHP as a proven cost-effective technology to reduce greenhouse gas emissions by providing technical assistance to large energy users through the Combined Heat and Power Partnership, exempting most industrial CHP units from regulation under the 111(b) rule, and by annually issuing awards to various CHP ENERGY STAR® projects in recognition of their emissions reductions.

CO_2 Reduction Benefits of CHP

The CO_2 savings benefits of a CHP system are found in the aggregate reduction in overall fuel consumption. A CHP system replaces both a separate on-site thermal system (furnace or boiler) and purchased power (typically electricity from a central station power plant) with a single, integrated system concurrently producing both thermal energy and power. To calculate the fuel use or CO_2 emissions reduction from a CHP system, both outputs of the CHP system must be considered. The CHP system's thermal output displaces the fuel normally consumed in, and emissions from, an on-site boiler, and the power output displaces the fuel consumed in, and emissions from, grid-connected power plants. To quantify the net fuel or CO_2 emissions savings of a CHP system, the fuel use or emissions released from the CHP system must be subtracted from the fuel use or emissions that would normally occur without the system (i.e., the fuel use and emissions from conventional separate heat and power). CHP systems not only reduce the amount of total fuel required to provide electricity and thermal energy services to a user, but also shift where that fuel is used. Installing a CHP system on-site will generally result in a modest increase in the amount of fuel that is used at the site, because additional fuel is required to operate the CHP system producing both thermal energy and electricity compared to the on-site boiler that would have otherwise been used to serve the local thermal loads.

In any approach used to determine the "net" emissions reduction benefits of CHP, the first step is to calculate the incremental emissions that CHP generates at the host site. Table C-1 presents

[86] 80 *Fed. Reg.* at 64902 ("CHP units are typically very thermally efficient").
[87] *Id.,* at 64902 ("Electric generation from non-affected CHP units may be used to adjust the CO_2 emission rate of an affected EGU").
[88] 80 *Fed. Reg.* at 64953, §60.5850.
[89] *Id.,* at 64902.

the energy performance and incremental CO_2 site emissions for typical CHP systems. For natural gas CHP, the CHP systems range from a 200 kW microturbine that could be used to provide power and hot water to a commercial application, to a 20 MW gas turbine providing power and steam to a manufacturing facility. For biomass boiler/steam turbine CHP, the systems include a boiler firing wood waste and a boiler firing pulping or "black" liquor.[90] A 10 kW reciprocating engine CHP system fueled by propane that could be used by a light commercial application is also included. The energy and emissions calculations in the table are based on CHP system performance characteristics from the 2015 edition of the DOE/EPA CHP Technology Catalog[91] for electrical efficiency, power to heat ratio and total CHP efficiency for each system. Values for annual useful thermal output, CHP fuel use, and total CHP CO_2 emissions are calculated from these performance characteristics based on each system operating 7,500 hours per year. The tables also include a comparison to demand-side efficiency measures that result in 1 MW of site electricity savings (7,500 MWh of savings on an annual basis).

Table C-1 includes estimates of displaced thermal fuel and CO_2 emissions for each CHP system based on typical boilers that would have been replaced by the installation of the CHP system. In the case of natural gas and propane CHP, the typical displaced boilers are assumed to be conventional 80 percent efficient natural gas/propane boilers that would have provided the same useful thermal output as the CHP system (i.e., generating steam on site). For biomass CHP, the displaced boiler is assumed to be a similarly fueled biomass boiler providing the same amount of steam energy to the process and at the same boiler efficiency as the CHP boiler – 65 percent for wood waste and 70 percent for pulping liquor. Incremental CO_2 emissions are then calculated for each CHP system by subtracting the displaced thermal CO_2 emissions from the total CHP CO_2 emissions.

Incremental emissions are a function of the overall CHP efficiency and the power to heat ratio of the CHP system. For natural gas CHP, incremental emissions can range from 45 percent of the total CO_2 emissions from the CHP system (1,000 kW reciprocating ("recip") engine CHP system with 78.9 percent total efficiency - 1,929 tons incremental vs 4,334 tons total CO_2 emissions for 7,500 MWh of CHP generation) to 53 percent (20 MW gas turbine system - 48,077 tons incremental vs 89,969 tons total CO_2 emissions for 150,000 MWh of generation). The incremental emissions for the 10 kW propane engine system are 34 percent of the total CHP system emissions. While discussions continue on the appropriate methods to characterize biogenic CO_2[92]

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[90] Biomass boiler/steam turbine CHP systems are common within the U.S. forest products industry. Low pressure (~5 bar) and medium pressure (~12 bar) steam is extracted from the turbine and is used in the pulp and paper manufacturing process, and generated electricity is used onsite or sold. Because of the large onsite steam requirements, forest product CHP systems are optimized for steam production and generally produce limited amounts of electricity in relation to steam generation. The most common fuels used within forest product CHP systems are pulping liquors, a by-product of the chemical pulp manufacturing process, and wood waste, though some fossil fuels such as natural gas and coal are used as well. Within the U.S. industrial sector, the pulp and paper and wood products industry comprised nearly 60 percent of the biomass material used in combustion for energy generation. http://www.eia.gov/totalenergy/data/monthly/pdf/sec10_5.pdf.

[91] DOE/EPA, March 2015, "CHP Technology Catalog."

[92] Biogenic CO_2 emissions are defined as CO_2 emissions related to the natural carbon cycle, as well as those resulting from the production, harvest, combustion, digestion, fermentation, decomposition, and processing of biologically based materials. CO_2 emitted from burning sustainable biomass will not increase total atmospheric CO_2. CO_2 is captured from the atmosphere by plants and trees during their growth, when

emissions resulting from biomass combustion, abundant research has made it clear that for the types of biomass being used in CHP systems in the forest products industry (i.e., black liquor, bark, and other woody residues from manufacturing), it is reasonable to use a biogenic CO_2 emissions factor of zero.[93,94,95,96] Therefore, while biomass boiler/steam turbine CHP will consume additional biomass fuel compared to the steam-only biomass boiler that it replaces, there are no new CO_2 emissions released to the environment associated with either the CHP biomass boiler or the displaced steam-only biomass boiler.[97] The final rule includes language clarifying that biomass fuels can be used in non-affected CHP systems.[98]

Finally, Table C-1 presents the effective or incremental CO_2 emissions rate in pounds per MWh for each CHP system. This value is calculated by dividing the incremental CO_2 emissions (in pounds) by the net electricity generation for each system.[99] For natural gas CHP, incremental CO_2 emission rates range from 514 lbs CO_2/MWh for the 1,000 kW recip engine CHP system to 676 lbs CO_2/MWh for the 200 kW microturbine system.[100] The incremental emission rate for the 10 kW propane engine system falls within the natural gas range at 572 lbs/MWh. The incremental emission rates for the biomass CHP systems and for end-use energy efficiency are all zero lbs CO_2/MWh.

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it is released again during combustion it is reentering the carbon cycle, not being newly created. If plant materials are then regrown over a given period of time, the regrowth of new biomass takes up as much CO_2 as was released from the original biomass through combustion. Debate continues on the precise categorization of biomass resources that would be considered sustainable in regards to the carbon cycle.

[93] U.S. EPA, November 2014, Revised Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources, Appendix D: Feedstock Categorization and Definitions, http://www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html

[94] Gaudreault, C., Malmberg, B., Upton, B., Miner, R. 2012, "Life cycle greenhouse gases and non-renewable energy benefits of kraft liquor recovery." *Biomass and Bioenergy*. 46: 683-692.

[95] Gaudreault, C., Miner, R. 2015, "Temporal aspects in evaluating the greenhouse gas mitigation benefits of using residues from forest products manufacturing facilities for energy production. " 19 *Journal of Industrial Ecology* 6: 994-1007. http://onlinelibrary.wiley.com/doi/10.1111/jiec.12225/abstract.

[96] Lamers, P., 2013, "Sustainable International Bioenergy Trade. Evaluating the impact of sustainability criteria and policy on past and future bioenergy supply and trade." PhD Dissertation Utrecht University.

[97] Small amounts of methane and nitrous oxide, also greenhouse gases, are produced during the combustion of these materials.

[98] The final rule notes that not all biomass feedstocks can be treated equally with respect to CO_2 emissions reductions. States are required to detail the kinds of biomass feedstocks being proposed as a method of compliance, with specific attention being given to exactly what would happen to the biomass in absence of compliance with the Clean Power Plan. The final rule makes several comments on which kinds of biomass are most likely to be considered beneficial for CO_2 reduction. The plan, "generally acknowledges the CO_2 and climate policy benefits of waste-derived biogenic feedstocks and certain forest--and agriculture—derived industrial byproduct feedstocks." The final rule also emphasizes "state plans must specify how biogenic CO_2 emissions will be monitored and reported, and identify specific EM&V, tracking and auditing approaches for qualified biomass feedstocks."

[99] This approach for calculating the effective CO_2 emissions rate for CHP is based on the "avoided emissions approach" as described later in this Appendix.

[100] As a comparison, the CO_2 emissions rate for average fossil grid generation (eGRID 2015 – 2012 data) is 1,640 lbs/MWh on a national basis, and the CO_2 emissions rate for advanced natural gas combined cycle generation with 50% electrical efficiency is 798 lbs/MWh.

Table C-1. Typical CHP System Performance

System[101]	10 kW Recip Engine CHP	200 kW Micro-turbine CHP	1,000 kW Recip Engine CHP	7,000 kW Gas Turbine CHP	20,000 kW Gas Turbine CHP	15,000 kW Back Pressure Steam Turbine CHP	15,000 kW Back Pressure Steam Turbine CHP	End Use Efficiency
CHP and Displaced Boiler Fuel	Propane	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Wood Waste	Pulping Liquor	N/A
Fuel CO_2 Emissions Rate,[102] lbs/MMBtu	138.6	116.9	116.9	116.9	116.9	0.0[103]	0.0[103]	N/A
CHP Electric Efficiency, %	27.8%	29.5%	34.5%	28.9%	33.3%	5.9%	6.4%	N/A
Power to Heat Ratio	0.52	0.74	0.78	0.70	0.89	0.10	0.10	N/A
Total CHP Efficiency	80.9%	69.5%	78.9%	70.4%	70.5%	64.6%	69.6%	N/A
CHP Electric Generation, MWh_e	75	1,500	7,500	52,500	150,000	112,500	112,500	7,500*
CHP Thermal Output, MMBtu	489	6,940	32,916	257,228	573,370	3,799,706	3,799,706	0
CHP System Fuel Use, MMBtu	921	17,349	74,152	619,827	1,539,248	6,460,845	5,999,356	0
CHP System CO_2 Emissions,[104] tons	64	1,014	4,334	36,229	89,969	0	0	0
Displaced On-site Boiler Efficiency	80%	80%	80%	80%	80%	65%	70%	N/A
Displaced On-site Boiler Fuel,[105] MMBtu	611	8,675	41,145	321,535	716,712	5,845,701	5,428,151	0
Displaced Boiler CO_2 Emissions,[106] tons	42	507	2,405	18,794	41,892	0	0	0
Incremental CO_2 Emissions,[107] tons	21	507	1,929	17,435	48,077	0	0	0
Incremental CO_2 Rate, lbs/MWh	572	676	514	664	641	0	0	0

*Electric savings based on 1 MW of end use efficiency savings for 7,500 hours per year

[101] Natural gas and pulping liquor CHP system performance based on DOE/EPA CHP Technology Catalog, March 2015; Propane CHP performance based on 10 kW system supported by Propane Education and Research Council.
[102] U.S. EPA, "Emission Factors for Greenhouse Gas Inventories," https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf.
[103] Pulping liquor and wood waste are assumed to have a biogenic CO_2 emission factor of 0 lbs/MMBtu.
[104] CHP System CO_2 emissions = CHP fuel use (MMBtu) * Fuel-specific CO_2 emissions rate (lbs/MMBtu).
[105] Displaced boiler fuel = CHP thermal output / Displaced boiler efficiency.
[106] Displaced boiler CO_2 emissions = Boiler fuel use (MMBtu) * Fuel specific CO_2 emissions (lbs/MMBtu).
[107] Incremental CO_2 emissions = CHP system emissions – Displaced on-site boiler emissions.

CHP generates reductions in CO_2 emissions from the power sector when the incremental emissions rate of the CHP system as calculated in Table C-1 in terms of lbs CO_2/MWh is less than the emissions rate of the electricity that CHP displaces on the grid (including transmission and distribution losses). Table C-2 presents the potential CO_2 savings for the seven CHP systems and traditional demand-side energy efficiency measures compared to three sources of central station generation:

1. Average fossil generation based on eGRID 2015[108] (2012 national data),
2. Existing natural gas combined cycle generation (NGCC) with a net electric efficiency of 43 percent, and
3. Advanced natural gas combined cycle generation (AGCC) with a net electric efficiency of 50 percent.

Table C-2 does not propose using any of these specific central station generation sources as the baseline for calculating CHP CO_2 reductions under the Clean Power Plan (this issue is discussed in a later section in this Appendix), but is meant to demonstrate that well designed and operated CHP systems provide significant CO_2 emission-reduction benefits compared to a range of fossil-fueled central station power, including advanced natural gas combined cycle generation.

In calculating the potential emissions benefits of CHP (and of traditional end-use efficiency measures), it is important to consider that one MWh of electricity demand reduction at the point of use generally would replace more than one MWh of central station grid generation because of transmission and distribution (T&D) losses in delivering power from the power plant to the end-user. The calculations of potential energy and CO_2 emissions savings in Table C-2 are based on national average T&D losses of 8.33 percent (eGRID 2015[109]) – as an example, 100 MWh of net CHP generation or end-use efficiency savings is equivalent to 109.1 MWh of displaced central station generated electricity. The CO_2 savings in Table C-2 are calculated by subtracting the incremental CO_2 emissions of the CHP systems in Table 1 from the CO_2 emissions of the equivalent displaced grid power (grid emissions in pounds equals displaced central station power generation times the grid emissions rate in lbs/MWh).[110]

Compared to average fossil grid generation (Case 1), the CO_2 savings from natural gas CHP generation ranges from 1,113 lbs/MWh for the 200 kW microturbine CHP system to 1,275 lbs/MWh for the 1,000 kW recip engine system, or 62 percent to 71 percent of the 1,789 lbs of CO_2 emissions from the equivalent central station power displaced by 1 MWh of CHP generation. The savings range from 344 lbs/MWh to 505 lbs/MWh when CHP is compared to existing natural gas combined cycle generation (Case 2) - or 34 to 50 percent of the 1,020 lbs pf CO_2 emissions from an equivalent amount of displaced NGCC power; and from 194 lbs/MWh to 356 lbs/MWh when natural gas CHP is assumed to be displacing advanced natural gas combined cycle generation (Case 3) - or 22 to 41 percent of the 870 lbs of CO_2 emissions from an equivalent amount of displaced AGCC power. Since both biomass CHP systems and traditional end-use

[108] eGRID 2015 (2012 data) as used in the EPA CHP Emissions Calculator, https://www.epa.gov/chp/chp-emissions-calculator.
[109] *Id.*
[110] CO_2 savings can also by calculated by multiplying the net generated CHP power (10,000 MWh) times the difference of the displaced grid emissions rate corrected for T&D losses (corrected grid emissions rate corrected = grid emissions rate/(1-%T&D losses) and the effective emissions rate of the CHP system.

efficiency measures have effective emissions rates of zero lbs/MWh, all result in CO_2 savings equal to the full emissions levels from the equivalent amount of power generation for each fossil fuel option.

Table C-2 illustrates the potential energy and CO_2 emissions savings that CHP represents compared to fossil-fueled grid generation. An accurate estimate of the energy and emissions savings of a specific CHP project (essentially identifying the heat rate and emission rate of the grid power displaced by CHP) could be made with the use of an electricity capacity dispatch model to determine how the dispatch mix for a given region and generation resources are impacted by the reduction in the system demand curve resulting from the addition of CHP resources. In one study of this type done by the Center for Clean Air Policy,[111] the results indicated that baseload on-site generation (which is the operating mode of most CHP systems) displaces a mix of central station fossil generators depending on the location and operating characteristics of the CHP project; it does not displace only one technology such as natural gas combined cycle.

However, dispatch models are complicated and costly to run. There are various approaches that can be used to estimate the representative heat rates and CO_2 emissions of displaced central station power without resorting to the use of expensive dispatch models. Although not as accurate as a detailed dispatch analysis, EPA's Combined Heat and Partnership program suggests that the eGRID average fossil fuel heat rate and emission rate is a reasonable estimate for the calculation of displaced grid fuel and emissions for a baseload CHP system (i.e., greater than 6,500 annual operating hours).[112] Similarly, for non-baseload CHP systems with relatively low annual capacity factors (i.e., less than 6,500 annual operating hours) and with a relatively high generation contribution during periods of high system demand, EPA suggests the most appropriate estimate of displaced generation is represented by the eGRID non-baseload heat rate and emissions rate. EPA also recommends the use of heat and emissions rates for the eGRID subregion where the CHP system is located as the preferred level of estimating displaced grid savings.[113] For an additional level of precision, EPA has developed the *AVoided Emissions and geneRation Tool* (AVERT) to estimate the emission benefits of energy efficiency and renewable energy policies and programs, which could be used to estimate displaced generation heat rates and emissions from CHP and end-use efficiency.[114] The emission and heat rates of grid power assumed to be displaced by CHP generation become key parameters in calculating ERCs for non-affected CHP under the Clean Power Plan.

[111] Catherine Morris, 2001, Center for Clean Air Policy, "Clean Power, Clean Air and Brownfield Redevelopment."

[112] "Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems", U.S. EPA Combined Heat and Power Partnership, February 2015.

[113] Rothschild, S. and Diem, A., "Guidance on the Use of eGRID Output Emissions Rates," http://www.epa.gov/ttn/chief/conference/ei18/session5/rothschild.pdf.

[114] *AVoided Emissions and geneRation Tool* (AVERT), https://www3.epa.gov/avert/.

Table C-2. Potential Energy Savings and CO_2 Emissions Reductions for Typical CHP Systems Compared to Fossil-Fueled Grid Power

System	10 kW Recip Engine CHP	200 kW Microturbine CHP	1,000 kW Recip Engine CHP	7,000 kW Gas Turbine CHP	20,000 kW Gas Turbine CHP	15,000 kW Back Pressure Steam Turbine CHP	15,000 kW Back Pressure Steam Turbine CHP	End Use Efficiency
CHP System Fuel	Propane	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Wood Waste	Pulp Liquor	N/A
CHP Generation, MWh	75	1,500	7,500	52,500	150,000	112,500	112,500	7,500
Incremental CHP Fuel Use, MMBtu	310	8,675	33,007	298,292	822,536	615,144	571,205	0
Incremental CHP CO_2 Emissions, Tons	21	507	1,929	17,435	48,077	0	0	0
T&D losses, %	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%	8.33%
Displaced Central Station Power, MWh	82	1,636	8,182	57,271	163,630	122,723	122,723	8,132
1) Displacing Average Fossil Generation (eGRID 2015 - 2012 Data – Heat Rate = 9,447 Btu/kWh, CO_2 Rate = 1,640 lbs/hr)								
Displaced Fossil Heat Rate*, Btu/kWh	10,305	10,305	10,305	10,305	10,305	10,305	10,305	10,305
Displaced Fossil CO_2 Rate*, lbs/MWh	1,789	1,789	1,789	1,789	1,789	1,789	1,789	1,789
Displaced Grid Fuel, MMBtu	773	15,458	77,291	541,036	1,545,817	1,159,362	1,159,362	77,291
Displaced Grid CO_2 Emissions, tons	67	1,342	6,709	46,962	134,177	100,633	100,633	6,709
Energy Savings, MMBtu	**463**	**6,784**	**44,284**	**242,744**	**723,281**	**544,218**	**588,157**	**77,291**
Energy Savings, MMBtu/MWh	**6.2**	**4.5**	**5.9**	**4.6**	**4.8**	**4.8**	**5.2**	**10.3**
CO_2 Savings, Tons	**46**	**835**	**4,780**	**29,527**	**86,100**	**100,633**	**100,633**	**6,709**
CO_2 Savings, lbs/MWh	**1,217**	**1,113**	**1,275**	**1,125**	**1,148**	**1,789**	**1,789**	**1,789**
CO_2 Savings, % of Grid Emissions	**68%**	**62%**	**71%**	**63%**	**64%**	**100%**	**100%**	**100%**

*eGRID Average Fossil Heat Rate and Emission Rate adjusted for T&D losses

Table C-2 (continued). Potential Energy Savings and CO_2 Emissions Reductions for Typical CHP Systems Compared to Fossil-Fueled Grid Power

System	10 kW Recip Engine CHP	200 kW Microturbine CHP	1,000 kW Recip Engine CHP	7,000 kW Gas Turbine CHP	20,000 kW Gas Turbine CHP	15,000 kW Back Pressure Steam Turbine CHP	15,000 kW Back Pressure Steam Turbine CHP	End Use Efficiency
2) Displacing Current Natural Gas Combined Cycle (NGCC) Generation (43% efficiency – Heat Rate = 8,000 Btu/kWh, CO_2 Rate = 935 lbs/hr)								
Displaced NGCC Heat Rate*, Btu/kWh	8,727	8,727	8,727	8,727	8,727	8,727	8,727	8,727
Displaced NGCC CO_2, Rate*, lbs/MWh	1,020	1,020	1,020	1,020	1,020	1,020	1,020	1,020
Displaced NGCC Fuel, MMBtu	655	13,090	65,452	458,165	1,309,043	981,782	981,782	65,452
Displaced NGCC CO_2, tons	38	765	3,825	26,774	76,497	57,373	57,373	3,825
Energy Savings, MMBtu	**345**	**4,416**	**32,445**	**159,873**	**486,508**	**366,638**	**410,577**	**65,452**
Energy Savings, MMBtu/MWh	**4.6**	**2.9**	**4.3**	**3.0**	**3.2**	**3.3**	**3.6**	**8.7**
CO_2 Savings, Tons	**17**	**258**	**1,896**	**9,339**	**28,420**	**57,373**	**57,373**	**3,825**
CO_2 Savings, lbs/MWh	**448**	**344**	**505**	**356**	**379**	**1,020**	**1,020**	**1,020**
CO_2 Savings, % of Grid Emissions	**44%**	**34%**	**50%**	**35%**	**37%**	**100%**	**100%**	**100%**
3) Displacing Advanced Natural Gas Combined Cycle (AGCC) Generation (50% efficiency - Heat Rate = 6,824 Btu/kWh, CO_2 Rate = 798 lbs/hr)								
Displaced AGCC Heat Rate*, Btu/kWh	7,444	7,444	7,444	7,444	7,444	7,444	7,444	7,444
Displaced AGCC CO_2, Rate*, lbs/MWh	870	870	870	870	870	870	870	870
Displaced AGCC Fuel, MMBtu	558	11,166	55,831	390,815	1,116,614	837,460	837,460	55,831
Displaced AGCC CO_2, tons	33	653	3,263	22,843	65,266	48,950	48,950	3,263
Energy Savings, MMBtu	**249**	**2,492**	**22,824**	**92,523**	**294,078**	**222,316**	**266,255**	**55,831**
Energy Savings, Btu/MWh	**3.3**	**1.7**	**3.0**	**1.8**	**2.0**	**2.0**	**2.4**	**7.4**
CO_2 Savings, Tons	**11**	**146**	**1,334**	**5,408**	**17,189**	**48,950**	**48,950**	**3263.3**
CO_2 Savings, lbs/MWh	**298**	**194**	**356**	**206**	**229**	**870**	**870**	**870**
CO_2 Savings, % of Grid Emissions	**34%**	**22%**	**41%**	**24%**	**26%**	**100%**	**100%**	**100%**

*NGCC and AGCC Heat Rates and Emission Rates adjusted for T&D losses

Calculating CO_2 Reduction Credits from CHP under the CPP

Recognizing the CO_2 emissions benefits of CHP, the final rule specifically states that electric generation from non-affected CHP units may be used to adjust the CO_2 emission rate of an affected EGU (i.e., serve as a compliance option) under a rate-based plan, as CHP units are low-emitting electric generating resources that can replace higher emitting generation from affected EGUs. The rule goes on to state that where a state plan provides for the use of electrical generation from eligible non-affected CHP units to adjust the reported CO_2 emission rate of an affected EGU, the state plan must provide a required calculation method for determining the MWh that may be used to adjust the CO_2 emission rate of the affected EGU. The rule further requires that the proposed accounting method must adequately address the fact that a non-affected CHP unit is a fossil fuel-fired emission source, as well as the fact that the incremental CO_2 emissions related to electrical generation from a non-affected CHP unit are typically very low.[115] EPA will review whether a state's proposed accounting method for electric generation from eligible non-affected CHP units is approvable per the requirements of the final emission guidelines, as part of its overall plan review of the rate-based emission standards and implementing and enforcing measures in the state plan. EPA notes that the proposed model rule for a rate-based emission-trading program includes a proposed accounting method for non-affected CHP units. The accounting method provided in a final model rule could be a presumptively approvable accounting approach.

As shown in Tables C-1 and C-2, the level of CO_2 savings delivered by CHP depends on the overall efficiency and ratio of power to thermal output of the CHP system, as well as the emissions characteristics of the electricity from affected EGUs that the CHP electric output displaces. CHP clearly provides significant emissions savings compared to average fossil generation, which is often used as a first-cut estimate of displaced grid power. Beyond this, well-designed and properly operated CHP also provides CO_2 emissions savings compared to high efficiency natural gas combined cycle generation, which is often considered the marginal new generation resource in many regions. The role CHP can play in each state and the value of the savings that CHP can deliver depend on the emissions rates of affected EGUs in the state and EPA's target emission standard for the state.

In the final rule, EPA prescribes how to "net-out" the incremental emissions from CHP in determining the ERCs for non-affected CHP used as a compliance measure. The approach takes into account the fact that, as described above, a non-affected CHP unit is a fossil fuel-fired emission source, <u>and</u> the fact that the incremental CO_2 emissions related to electrical generation from non-affected CHP units are typically very low. In accordance with these considerations, EPA prescribes that the non-affected CHP unit's electrical MWh output that can be used to adjust the reported CO_2 emission rate of an affected EGU should be prorated based on the CO_2 emission rate of the electrical output associated with the CHP unit (a CHP unit's "incremental CO_2 emission rate") compared to a <u>reference CO_2 emission rate</u>. This "incremental CO_2 emission rate" related to the electric generation from the CHP unit would be relative to the applicable CO_2 emission rate for affected EGUs in the state and the proration of the credited electricity from the CHP unit would be limited to a value between 0 and 1."[116] Note that biomass-based CHP systems using fuels with biogenic CO_2 emission factors of zero lbs/MWh have no

[115] 80 *Fed. Reg.* at 64902.
[116] 80 *Fed. Reg.* at 64902 (emphasis added).

incremental emissions and therefore would be treated as zero carbon generation resources. Such systems would not need to prorate the MWh output of the CHP unit, and each MWh generated by these systems would equal one ERC similar to other renewable energy generation resources or to demand side efficiency.

For those CHP systems using fossil fuels such as natural gas and propane that do generate incremental emissions and therefore must prorate the output to account for these emissions, the final rule does not define the terms "reference CO_2 emission rate," nor "applicable CO_2 emission rate for affected EGUs." However, EPA provided detailed requirements for the issuance of ERCs for CHP in the proposed rate-based model trading rule, and described how the electrical generation from a non-affected CHP unit could be used to adjust the CO_2 emission rate of an affected EGU. As specified in the emissions guidelines of the CPP, a CHP unit's electrical output would be prorated based on the CO_2 emission rate of the electrical output associated with the CHP unit (a CHP unit's ''incremental CO_2 emission rate'') compared to a reference CO_2 emission rate. This ''incremental CO_2 emission rate'' related to the electric generation from the CHP unit would be relative to the applicable CO_2 rate-based emission standard for affected EGUs in the state and would be limited to values between 0 and 1, and prorated as follows:[117]

Prorated MWh = (1 – (Incremental CHP electrical emission rate / Applicable affected EGU emission rate standard)) * CHP MWh output

EPA prescribes that the incremental CO_2 emission rate is the net emission rate when the CHP unit's CO_2 emissions related to its thermal output are deducted from the CHP unit's total CO_2 emissions. This approach is based on the avoided emissions approach used in Tables C-1 and C-2, and is generally accepted as appropriately accounting for the modest increase in on-site emissions associated with a CHP system. Under this approach, the incremental emissions is calculated by subtracting from the measured emissions of the CHP system the emissions that would have been produced on-site to provide the same thermal output without the CHP system (i.e., emissions that would have occurred from a "counterfactual boiler" – the boiler that is now not needed due to the installation of CHP). These incremental emissions are then divided by the net electric output of the CHP system to calculate the incremental emissions rate:

$$\text{Incremental Emission Rate} = \frac{\text{(Annual CHP } CO_2 \text{ Emissions – Annual Displaced Boiler } CO_2 \text{ Emissions)}}{\text{(Annual CHP Electricity Output)}}$$

The incremental emission rate is then inserted into the previous formula to determine the prorated output (MWh) for a CHP system. That, in turn, determines the number of ERCs to be awarded to a CHP installation.

Example Calculation

Below is an example calculation demonstrating the avoided emissions approach for calculating the effective emissions rate and estimating overall CO_2 savings follows for a hypothetical 7 MW natural gas fuelled combustion turbine CHP system situated in Illinois. This calculation is consistent with the approaches used in Tables C-1 and C-2:

[117] 80 *Fed. Reg.* at 64990.

Example Calculation for CHP Emission Rate Credit

CHP Net Electric Capacity:	7 MW
CHP Net Electric Efficiency:	28.9%
CHP Useful Thermal Capacity:	34.30 MMBtu/hr
CHP Annual Capacity Factor:	80% (7,008 full load hours)
Annual CHP Electricity Output:	49,056 MWh
Annual CHP Useful Thermal Output:	240,410 MMBtu
Annual CHP Fuel Input (natural gas):	579,166 MMBtu
Annual CHP CO_2 Emissions:	33,852 tons
Annual Displaced Boiler Fuel (natural gas): (Based on an assumed 80% boiler efficiency)	300,513 MMBtu
Annual Displaced Boiler CO_2 Emissions:	17,565 tons
Affected EGU Emissions Rate:	1,895 lbs CO_2/MWh (2012 Average Fossil Generation Emissions Rate for Illinois)
T&D Losses:[118]	6%
Displaced EGU Emissions Rate with T&D Loss:	= (1,895) / (1-6%) = 2,016 lbs CO_2 / MWh

Step One: Calculate an effective or incremental emissions rate for the CHP system

= *(Annual CHP CO_2 Emissions – Annual Displaced Boiler CO_2 Emissions)*
(Annual CHP Electricity Output)

= (33,852 tons – 17,565 tons) / 49,056 MWh

= 664 lbs/MWh

Step Two: Calculate prorated MWh Credit for CHP

= Prorated MWh = (1 – (Incremental CHP electrical emission rate / Applicable affected EGU emission rate standard))

= (1 - (664 lbs/MWh / 2,016 lbs/MWh))

= 67%

(Every MWh of electricity generated by the CHP system is equivalent to 0.67 MWh of displaced grid electricity in terms of CO_2 credits)

[118] 80 *Fed. Reg.* at 65007. The proposed federal plan specifies how avoided T&D losses will be quantified and applied to energy efficiency and CHP savings determined at the customer facility or premises. The EPA is proposing that demand-side efficiency programs – other than T&D efficiency measures such as CVR and volt/VAR optimization – may adjust reported savings by using a T&D adder. If such an adder is applied, the presumptively approvable approach is to use the smaller of 6 percent or the calculated statewide annual average T&D loss rate (expressed as a percentage) calculated using the most recent data published by the U.S. EIA State Electricity Profile.

Calculate total ERCs from CHP

= (*Net CHP Electricity Generation*) * *(Prorated CHP MWh Credit)*

= 49,056 MWh * 67%

= 32,867 ERCs

What Is the Applicable EGU Emissions Rate for Prorating CHP Output when Determining ERCs?

As shown in the example above, the key factor in determining the ERCs for CHP beyond the incremental emissions rate of the CHP system itself is the applicable affected EGU emission rate used in the denominator of the proration formula. The final rule does not define the terms "reference CO_2 emission rate" or "applicable CO_2 emission rate for affected EGUs." However, the proposed model rate-based rule outlines a detailed proposed approach for determining CHP ERCs under a rate-based plan and defines the term "reference CO_2 emission rate" in a footnote as the "the applicable CO_2 emission rate standard is in Table 6 of this preamble."[119] Table 6 from the proposed federal plan is presented below:

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

Technology	2022-2024 Compliance Rate	2025-2027 Compliance Rate	2028-2029 Compliance Rate	Final Rate
SGU or IGCC	1,671	1,500	1,380	1,305
Stationary combustion turbine	877	817	784	771

The model rule does not specify whether the "applicable CO_2 emission rate" is intended to refer to the interim glide path performance rates or the final targets for SGU or stationary combustion turbines. EPA staff, however, has clarified that the "reference CO_2 emission rate" for natural gas and propane CHP is intended to be the performance rates for stationary combustion turbines in Table 6 above (i.e., 877 lbs/ MWh in 2022). This proposed level of proration of the MWh output of CHP places natural gas and propane CHP at a significant disadvantage compared to energy efficiency and other low emissions solutions. Although it is understood that the ERCs are not meant to represent CO_2 savings, but instead zero carbon MWhs, it seems counterintuitive that the proration of natural gas and propane CHP should be based on the target rates of affected EGUs that would be least likely to have their output reduced by increased efficiency or CHP development. In reality, generation from a natural gas CHP system is more likely to reduce the amount of central coal-fired generation. If measured relative to that generation resource, the prorated ERCs of a CHP system would be substantially higher as shown in Table C-3 below comparing the prorated MWh percentages of four typical CHP systems based on the 2022 targets for stationary combustion turbines and steam generating units (1,671 lbs/MWh):

[119] *Id.,* at n. 64.

Table C-3. Percent of MWh Output from Natural Gas/Propane CHP Credited Using EPA's Proposed Approach

	200 kW Microtubine CHP	1 MW Recip Engine CHP	7 MW Gas Turbine CHP	20 MW Gas Turbine CHP
Net Electric Efficiency	29.5%	34.5%	28.9%	33.3%
Total CHP Efficiency	69.5%	78.9%	70.4%	70.5%
Incremental CO_2 Emissions, lbs/MWh	676	514	664	641
Output Proration based on 2022 Stationary Turbine Rate (877 lbs/MWh)	23%	41%	24%	27%
Output Proration based on 2022 Steam Gen/IGCC Rate (1,671 lbs/MWh)	60%	69%	60%	62%

Many in the CHP industry have commented that it would be more appropriate for EPA to define the reference rate using actual affected EGU emissions data from the previous calendar year. The data on actual EGU emission rates will be readily available during the compliance periods under the CPP, since states must submit emissions data to EPA as part of their Clean Power Plan compliance. Under this approach, EPA would update the reference rate each year, sorting emissions (lb of CO_2) and output (MWh) from all affected EGUs into the appropriate eGRID subregion or state. [120]

During the CPP compliance periods, owners of affected EGUs may adjust the dispatch orders of their generation assets to achieve targets, varying the consumption of coal and natural gas. It is reasonable to assume that CHP would offset emissions from a *mix* of fossil resources. Using a reference rate based on the average affected EGU emission rates for the state or regional electricity grid is a reasonable way to estimate the emissions benefits of CHP. CHP would most likely offset fossil-based generation; it would not offset baseload nuclear or hydro, nor would it offset wind or solar resources.

In addition, using the eGRID subregions for the average emission rates would also provide a better estimation of emissions impacts than using state averages because there are significant exports and imports of electricity across state borders. The eGRID subregions were defined to approximate regional power pools, for which exports and imports are minimal.[121]

[120] It should be relatively easy for EPA to sort the EGU CO_2 emissions and output into the eGRID subregions in order to calculate these average emission rates.
[121] "Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems," EPA CHP Partnership, February 2015, p. 25.

Appendix D

EM&V Requirements for CHP under the Clean Power Plan

Introduction

The Clean Power Plan (CPP) supports the use of CHP as a proven, cost effective, and widely available emission reduction measure for the power sector. States, private organizations and firms, and other entities around the country have already made substantial investments in CHP programs and projects, resulting in lower electricity costs, reduced carbon emissions, and cleaner air. The EPA expects such investments to continue and, as detailed in Appendix C, has established provisions in the emission guidelines in the CPP and in the proposed federal Implementation Plan (FIP) for crediting the resulting savings from CHP in state plans that demonstrate compliance in terms of an emission rate. Section VIII.K of the CPP sets out additional considerations and requirements for state plans focused on rate-based emission standards. This includes the basic accounting method for adjusting the reported CO2 emission rate of an affected EGU, as well as requirements for the use of measures to adjust a CO2 emission rate. These requirements include eligibility, accounting, and quantification and verification requirements (EM&V) for the use of CO2 emission reduction measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs in rate-based state plans.

The state plan must also demonstrate that the MWhs for which ERCs are issued are properly quantified and verified through plan requirements for EM&V and verification that meet the requirements in the emission guidelines as discussed in section VIII.K.3. Rate-based emission standards must also include monitoring, reporting, and recordkeeping requirements for CO_2 emissions and useful energy output for affected EGUs; and related compliance demonstration requirements and mechanisms. These requirements are discussed in more detail in sections VIII.F and VIII.K of the CPP.

As a general matter, EPA tried to adhere to four principles for EM&V as articulated in the FIP and draft EM&V Guidance for demand-side energy efficiency:

- EM&V should ensure that savings from energy efficiency are quantifiable and verifiable;
- Requirements should balance the accuracy and reliability of results with the associated costs of EM&V;
- The requirements should avoid excessive interference with existing practices that are already robust, transparent and effective; and
- EPA recognizes that EM&V is routinely evolving to reflect changes in markets, technologies and data availability.

Section VIII.K.2 of the CPP prescribes that state plans include a requirement that EM&V plans and M&V reports be submitted to the state for rate-based emission trading programs. States must require that at the initiation of an eligible measure, project providers must develop and submit to the state an EM&V plan that documents how requirements for quantification and verification will be carried out over the period that MWh generation or savings are produced. States must also require that after a project or program is implemented, the provider must submit periodic M&V reports to confirm and describe how each of the requirements was applied.

These reports must also specify the actual MWh savings or generation results, as quantified by applying EM&V methods on a retrospective (ex-post) basis. States may not allow MWh values that are quantified using ex-ante (pre- implementation) estimates of savings.

EM&V Requirements for Non-Affected CHP

In section IV.C.8 of the FIP, EPA identifies and discusses specific requirements for Evaluation, Measurement, and Verification (EM&V[122]) Plans, Monitoring and Verification Reports, and Verification Reports for eligible measures under the proposed rate-based model trading rule. This section of the FIP addresses approaches used to quantify and verify MWh from renewable energy, demand-side energy efficiency, and other eligible measures (including CHP and WHP) used to generate ERCs or otherwise adjust an emission rate, and describes certain established industry best-practice methods, procedures, and approaches that would be presumptively approvable if included in state plans. States wishing to adopt the model rule would need to submit these methods, procedures, and approaches as specified, or submit alternative EM&V approaches that are functionally equivalent to the industry best-practices described as presumptively approvable.[123]

The rate-based model rule in the FIP proposed specific EM&V requirements for non-affected CHP. In addition to the CHP-specific EM&V requirements outlined in the associated provisions in the model rule and discussed below, non-affected CHP must also follow the requirements for renewable energy discussed in the section IV.D.8.b of the FIP, including (1) metering requirements, (2) special treatment for units of less than 10 kW, and (3) accounting for T&D losses:

1. Metering Requirements – The primary metric for renewable energy (RE) under the model rule is electricity generation in units of MWh. The proposed rule requires that measured output must be derived either from: (1) A revenue quality meter that meets the applicable ANSI C–12 standard or equivalent, which is the typical requirement for settlements with RTO and other control-area operators; or (2) for customer-sited generators that are interconnected behind the customer meter, measurement at the AC output of an inverter, adjusted to reflect the energy delivered into either the transmission or distribution grid at the generator bus bar.
2. Treatment for units less than 10 kW – a RE generating facility of 10 kW capacity or less may estimate the facility’s output if the state where it is located explicitly allows estimates to be used and provides rules for when it will be allowed. In the latter case, calculations of system output must be based on the unit’s capacity, estimated capacity factors, and an assessment of the local conditions that affect generation levels. All such input parameters and assumptions must be clearly described and documented. For units

[122] EM&V is defined here as the set of procedures, methods, and analytic approaches used to quantify the MWh output from RE, demand-side EE, and other eligible measures to ensure that the resulting savings and generation are quantifiable and verifiable.

[123] EPA acknowledges that EM&V is routinely evolving to reflect changes in markets, technologies and data availability, and expects to update its EM&V guidance over time. They expect that alternative quantification approaches will emerge that can be approved for use, provided that such approaches are functionally equivalent to the provisions for EM&V outlined in the proposed model rule.

that are managed by regional transmission operators or other control area operators, metered generation data should be electronically collected by the control area's energy management system, verified through an energy accounting or settlements process, and reported by the control area operator to the registry of Renewable Energy Credits at least monthly.

3. T&D Losses – RE units that directly serve on-site end-user electricity loads are allowed to quantify avoided transmission and distribution system losses as is commonly practiced with demand-side energy efficiency.

The EPA requested comment on the metering, measurement, and verification, and other requirements proposed for RE resources, including the appropriateness of the requirement to use a revenue quality meter for monitoring generation for resources with a nameplate capacity of 10 kW or more. They also requested comment on the definition of a revenue quality meter, the appropriateness of other types of meters for monitoring generation, and whether 10 kW is the appropriate threshold under which an eligible resource can be issued ERCs for generation based on data other than metered generation – and if not, what would be the appropriate threshold.

The specific EM&V requirements for CHP proposed in section IV.D.8.d of the FIP noted that in order to determine the incremental CO_2 emission rate, a CHP unit would need to monitor CO_2 emissions and energy output. The specified monitoring requirements are considered to be standard methods currently in use, and the specific requirements would depend on the size of the CHP units and the fuel used in the unit:

- Non-affected CHP facilities with electric generating capacity greater than 25 MW must follow the same monitoring and reporting protocols for CO_2 emissions and energy output as are required for affected EGU CHP units. These requirements are discussed in section IV.D.13 of the FIP.

  Essentially, the EM&V plan for these units must meet the requirements that apply to an affected EGU under 40 CFR 62.16540. These requirements state that the facility must prepare a monitoring plan in accordance with the specific requirements of the CPP, and the facility must install, certify, operate, maintain and calibrate a CO_2 continuous monitoring system (CEMS) to directly measure and record CO_2 concentrations in the exhaust gas, and an exhaust gas flow rate monitoring system. As an alternative to direct measurement of CO_2 concentration, the facility may use date from a certified oxygen monitor to calculate hourly average CO_2 concentrations. The section includes specific requirements for CEMS certification and specific guidelines on calculating the appropriate CO_2 reporting parameters from the various approaches to monitoring CO_2 concentrations.

- For non-affected CHP facilities with electric generating capacity less than or equal to 25 MW, which use only natural gas and/or distillate fuel oil, the low mass emission unit CO_2 emission monitoring and reporting methodology outlined in 40 CFR part 75 is acceptable under the proposed guidelines. Under the low mass emission unit methodology, hourly CO_2 mass emissions are estimated based on the fuel-based CO_2 emissions factor (lbs/MMBtu) and the metered hourly fuel input to the CHP system.

The EPA specifically requested comment on whether CHP units should be subject to the same EM&V requirements as RE resources, and on any additional EM&V requirements to which CHP units should be subject. EPA requested comment on specifying in the final model rule that if a CHP unit has an electric generating capacity greater than 25 MW, its EM&V plan must meet the requirements that apply to an affected EGU under 40 CFR 62.16540. EPA also requested comment on specifying in the final model rule that if a CHP unit has an electric generating capacity less than or equal to 25 MW, the EM&V plan must meet the low mass emission unit CO_2 emission monitoring and reporting methodology in 40 CFR part 75. EPA requested comment on any alternatives to these proposed measurement methodologies.

EM&V Requirements for State Plans

To ensure that compliance measures such as energy efficiency and CHP are quantifiable and verifiable, the EPA's final emission guidelines require that all providers demonstrate that they will apply best-practice EM&V approaches as discussed in Section VIII.K.3 of the CPP. One way to make this demonstration is to use the presumptively approvable EM&V approaches specified in Section IV.D.8 of the proposed model trading rule. States may also submit other means of meeting the EM&V requirements so long as the state satisfactorily demonstrates in the state plan submittal that such alternative means of addressing requirements are as stringent as the presumptively approvable approach.

Any CHP pathway will require accurate measurement of the performance and efficiency of installed CHP systems. Most operators of CHP systems routinely measure these values as part of their standard approach to monitoring and evaluating project performance. States that have implemented CHP incentive programs including New York, Massachusetts, New Jersey and Maryland have developed detailed EM&V protocols that include standards for specific CHP system parameters including meter types, meter placement, data collection frequency and performance calculations. These protocols can be referenced and adapted as part of a state's CPP compliance plan.

As part of its plan, a state could create a registry and certification process to make it easier to record and trade credits or allowances generated or earned by CHP operation. This will help reduce the cost and uncertainty associated with data collection. EM&V can be a complex process; however, if the state simplifies the process and inspires confidence that the credits and compliance revenue will flow back to CHP projects, more facilities might choose to invest in CHP. Under such a certification mechanism, a state agency or third-party verification agent might carry out the EM&V for the CHP host. A registry, like those currently used to track Renewable Energy Credits (RECs) for compliance with Renewable Portfolio Standards (and for voluntary renewable energy markets), could be used to certify and track emission rate credits in ways that prevent double-counting of emission reductions or energy produced.

The specific EM&V guidance in the CPP and proposed in the model rate-based rule does not apply to states submitting mass (or tonnage) based plans. In these cases, compliance is determined solely by CO_2 emissions measurements at the affected source. The EM&V guidance in the CPP and FIP, however, can be used as models for states to track savings from measures such as energy efficiency and CHP internal to their mass-based compliance plans.

Appendix E
Key Resources

General Information	
Title/Description	**URL Address**
US DOE Report, March 2016, Technical Potential for CHP in the United States. Data on the technical potential in industrial facilities and commercial buildings for CHP, waste heat to power CHP (WHP CHP), and district energy CHP in the U.S. Data are provided nationally and at the state level by CHP system size range and facility type.	http://energy.gov/sites/prod/files/2016/03/f30/CHP Technical Potential Study 3-18-2016 Final.pdf
CHP/DHC Country Scorecard: United States. IEA's 2008 U.S. scorecard discusses the status of CHP and district heating and cooling (DHC) in the United States, along with existing barriers and drivers for CHP development.	http://www.iea.org/chp/countryscorecards/
Combined Heat and Power: Effective Energy Solutions for a Sustainable Future. This 2008 report from the Oak Ridge National Laboratory projects economic and environmental benefits from a scenario in which CHP provides 20 % of U.S. electricity generation.	http://info.ornl.gov/sites/publications/files/Pub13655.pdf
Utility Incentives for Combined Heat and Power. This 2008 EPA report surveys existing utility CHP incentives and provides a case study of several successful CHP projects that received support through these	http://www.epa.gov/chp/documents/utility_incentives.pdf
National CHP Roadmap: Doubling Combined Heat and Power Capacity in the United States by 2010. This 2010 USCHPA paper emerged following a multi-year stakeholder planning process. The report identifies key stakeholders and lays out policy priorities to achieve ambitious deployment goals.	http://energy.gov/eere/amo/downloads/national-chp-roadmap-doubling-combined-heat-and-power-capacity-united-states-2010
Combined Heat and Power: A Clean Energy Solution. This 2012 DOE and EPA paper provides a foundation for national discussions on effective ways to reach the President's 40 GW CHP target, and includes an overview of the key issues currently impacting CHP deployment and the factors that need to be considered by stakeholders participating in the dialogue.	http://www.epa.gov/chp/documents/clean_energy_solution.pdf
Executive Order 13624 (2012). Accelerating Investment in Industrial Energy Efficiency. Establishes Administration goal of 40 GW of new CHP and estimates economic and environmental benefits of achieving this goal.	http://www.whitehouse.gov/the-press-office/2012/08/30/executive-order-accelerating-investment-industrial-energy-efficiency

Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans. This 2012 EPA guide provides four pathways for state agencies to include energy efficiency/ renewable energy in state air-quality plans. It does not explicitly address CHP, though the guidance is applicable to CHP policies.	http://epa.gov/airquality/eere/pdfs/EEREmanual.pdf
The Opportunity for Combined Heat and Power in the United States. This 2013 document from the American Gas Association and ICF International provides a market assessment of CHP potential in the United States, with a focus on impacts to the natural gas industry.	https://www.aga.org/opportunity-chp-us
Guide to Using Combined Heat and Power for Enhancing Reliability and Resiliency in Buildings. In the wake of Hurricane Sandy, this 2013 DOE and EPA report discusses opportunities for CHP to contribute to reliability and resiliency, options for CHP financing, and how to determine if CHP is an appropriate fit for various applications.	http://epa.gov/chp/documents/chp_for_reliability_guidance.pdf
Combined Heat and Power: A Resource Guide for State Energy Officials. This 2013 resource guide from the National Association of State Energy Officials provides State Energy Officials with a technology and market overview of CHP and ways in which they can support CHP through state energy and energy assurance planning, energy policies and utility regulations, and funding/financing opportunities for CHP. Includes examples of successful policies to overcome environmental, regulatory, and financial barriers to deployment.	http://www.naseo.org/data/sites/1/documents/publications/CHP-for-State-Energy-Officials.pdf
Guide to the Successful Implementation of State Combined Heat and Power Policies. This 2013 report from the SEE Action Network provides state utility regulators and other state policy-makers with actionable information to assist them in implementing key state policies that impact CHP. Includes best practices for interconnection, standby rates and portfolio standards.	https://www4.eere.energy.gov/seeaction/publication/guide-successful-implementation-state-combined-heat-and-power-policies
How Electric Utilities Can Find Value in CHP. This 2013 ACEEE white paper explains the major benefits CHP confers to electric utilities and offers specific examples of how electric utilities today are enjoying the benefits of CHP.	http://aceee.org/white-paper/electric-utilities-and-chp
Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities. This 2013 DOE report profiles critical infrastructure that remained operational during recent extreme weather events.	http://energy.gov/sites/prod/files/2013/11/f4/chp_critical_facilities.pdf
Combined Heat and Power Systems: Improving the Energy Efficiency of Our Manufacturing Plants, Buildings, and Other Facilities. This 2013 issue paper by NRDC provides a series of detailed case studies elaborating system attributes and benefits.	http://www.nrdc.org/energy/files/combined-heat-power-IP.pdf

Gas-Fired Combined Heat and Power Going Forward: What Can State Utility Commissions Do? This 2014 document from the National Regulatory Research Institute examines barriers in state regulations that obstruct the development of CHP.	http://energy.ky.gov/Programs/Documents/NRRI Report-What Can Commissions Do.pdf
Industrial Energy Efficiency: Designing Effective State Programs for the Industrial Sector. This 2014 report from the SEE Action Network provides state regulators, utilities, and other program administrators with an overview of U.S. industrial energy efficiency programs and assesses some of the key features of programs that have generated increased energy savings. The report includes project profiles of selected successful utility programs.	https://www4.eere.energy.gov/seeaction/publication/industrial-energy-efficiency-designing-effective-state-programs-industrial-sector
From Threat to Asset: How Combined Heat and Power (CHP) Can Benefit Utilities. This 2014 ICF report provides updated deployment data, considers CHP's benefits, the scale of the opportunity, and potential benefits for utilities (e.g., utility ownership or management of projects, rate basing of projects, reduction in grid congestion).	http://www.icfi.com/insights/white-papers/2014/how-chp-can-benefit-utilities
Five Actions Governors Can Take to Help Industry Save Energy. This 2014 paper is the result of the National Governor's Association policy academy on CHP in 5 states. It provides an overview of successful CHP policies and recommendations.	http://www.nga.org/files/live/sites/NGA/files/pdf/2014/1412FiveActionsGovernorsCanTake.pdf
Combined Heat and Power: Frequently Asked Questions. This EPA CHPP fact sheet addresses several frequently asked questions about how CHP works, as well as the costs and benefits associated with CHP.	http://epa.gov/chp/documents/faq.pdf
Combined Heat and Power Installation Database. This interactive database allows users to identify CHP installation by state, with basic information about all U.S. installations.	https://doe.icfwebservices.com/chpdb/
Implementing EPA's Clean Power Plan: A Menu of Options. This 2015 report by the National Association of Clean Air Agencies includes two chapters on CHP. The report serves as a tool to apprise state regulators of tools to achieve the Clean Power Plan emission targets. It highlights CHP benefits, provides examples of successful state policies, and discusses approaches for measuring emission benefits.	http://www.4cleanair.org/NACAA_Menu_of_Options
EPA Action Guide Policy Considerations for Combined Heat and Power. Highlights state policy opportunities to further CHP deployment. These include financing, regulatory, and utility policies.	http://epa.gov/statelocalclimate/documents/pdf/guide_action_chapter6.pdf
DOE Barriers to Industrial Energy Efficiency and Appendix. This study examines barriers that impede the adoption of energy-efficient technologies and practices in the industrial sector, and identifies successful examples and opportunities to overcome these barriers.	http://energy.gov/eere/amo/downloads/barriers-industrial-energy-efficiency-study-appendix-june-2015

Federal Technical Support	
Title/Description	**URL Address**
DOE Technical Assistance Partnerships (TAPs). DOE's CHP TAPs promote and assist in transforming the market for CHP, WHP, and district energy with CHP throughout the United States.	http://www.energy.gov/eere/amo/chp-technical-assistance-partnerships-chp-taps
EPA CHPP. The CHP Partnership is a voluntary program seeking to reduce the environmental impact of power generation by promoting the use of CHP. The Partnership works closely with energy users, the CHP industry, state and local governments, and other clean energy stakeholders to facilitate the development of new projects and to promote their environmental and economic benefits.	http://www.epa.gov/chp/

Information about States	
Title/Description	**URL Address**
Challenges Facing Combined Heat and Power Today: A State-by-State Assessment. This 2011 ACEEE discusses barriers to CHP along with suggestions for how CHP stakeholders can further the development of the CHP market in the United States and individual states.	http://www.aceee.org/research-report/ie111
ACEEE's State and Local Policy Database. This is an online database that includes comprehensive information on energy efficiency policies currently implemented at the state and local level. The database tracks CHP policies.	http://database.aceee.org/
Portfolio Standards and the Promotion of Combined Heat and Power. This report provides an overview of existing state portfolio standards and their treatment of CHP.	https://www.epa.gov/sites/production/files/2015-07/documents/portfolio_standards_and_the_promotion_of_combined_heat_and_power.pdf

Availability of Incentives	
Title/Description	**URL Address**
Federal Finance Facilities Available for Energy Efficiency Upgrades and Clean Energy Deployment: A Guide for State, Local & Tribal Leaders and their Partners. This 2013 multi-agency compendium provides information about a wide array of federal funding opportunities that can be used to support CHP deployment (among other things). Includes resources from HUD, USDA, DOE and SBA.	http://energy.gov/sites/prod/files/2013/08/f2/Federal%20Finance%20Facilities%20Available%20for%20Energy%20Efficiency%20Upgrades%20and%20Clean%20Energy%20Deployment.pdf
Database of State Incentives for Renewables and Efficiency (DSIRE). This website contains extensive information on federal, state, and local programs, policies, and incentives for energy efficiency and renewable energy, including CHP. The database can be searched by program type, including green power programs.	http://www.dsireusa.org
EPA CHP Partnership Policy Portal dCHPP (CHP Policies and incentives database). This is an online database that allows users to search for CHP policies and incentives by state or at the federal level.	http://www.epa.gov/chp/policies/database.html
CHP Financial Tools (PUCO). This webcast provides information about financing options available to organizations interested in CHP development. Topic areas included private financing, utility programs, government incentives, power purchase agreements and CHP project estimation.	http://1.usa.gov/1PjxemS

Project Development Process	
Title/Description	**URL Address**
Catalog of CHP Technologies. (2014) Provides information on available technologies and capital costs.	http://www.epa.gov/chp/documents/catalog_chptech_full.pdf
Guide to Federal Financing for Energy Efficiency and Clean Energy Deployment. (2014). Provides an overview of federal grants, loans and other financial assistance for an array of energy-efficiency investments, including CHP.	http://energy.gov/sites/prod/files/2014/10/f18/Federal%20Financing%20Guide%2009%2026%2014.pdf

CHP Project Development Handbook. This guide walks project developers through the entire deployment process, from feasibility analysis to A63procurement and operations and maintenance.	http://www.epa.gov/chp/documents/chp_handbook.pdf
CHP Emissions Calculator. The CHP Emissions Calculator compares fuel-specific emissions from a CHP system to those of a separate heat and power system.	http://www.epa.gov/chp/basic/calculator.html
HUD CHP Screening Tool. This interactive tool allows users to quickly calculate a theoretical payback for a system if they enter only utility rates, location, square footage and number of occupants.	http://portal.hud.gov/hudportal/HUD?src=/program_offices/comm_planning/library/energy/software
GTI Report on Emissions Factors for Building Energy Consumption. This 2013 report on full fuel-cycle energy use includes a discussion of average and marginal factors for electric generation when evaluating the effects of incremental energy efficiency improvements, like CHP.	https://www.aga.org/full-fuel-cycle-energy-and-emission-factors-building-energy-consumption-20node3-update-jan-20node4

Guidance on Specific Policy Approaches	
Title/Description	**URL Address**
Output-Based Environmental Regulations: An Effective Policy to Support Clean Energy Supply. This factsheet provides an overview of the benefits of OBR and a survey of states that have adopted them.	http://www.epa.gov/chp/policies/output_fs.html
Output-Based Regulations: A Handbook for Air Regulators. This handbook explains the benefits of OBR, how to develop OBR, and the experience of several states in implementing OBR. This handbook is intended as a resource for air regulators in evaluating opportunities to adopt OBR and writing regulations.	http://www.epa.gov/chp/documents/obr_handbook.pdf
Approaches to Streamline Air Permitting for Combined Heat and Power: Permits by Rule and General Permits. This 2014 EPA fact sheet provides an overview and background on existing state policies that have been adopted to streamline permitting for CHP projects.	http://www.epa.gov/chp/documents/PBRFactsheet-10162014.pdf
Standby Rates for Customer Sited Resources: Issues, Considerations and the Elements of Model Tariffs. This 2009 EPA guide provides an overview of standby tariffs and identifies best practices for rate design.	http://www.epa.gov/chp/documents/standby_rates.pdf
Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States. This 2014 report by the Regulatory Assistance Project identifies best practices for standby rate design and assesses the existing approaches in 5 states.	www.raponline.org/document/download/id/7020

§111(d) Analysis	
Title/Description	**URL Address**
Expanding the Solution Set: How CHP Can Support §111(d) Compliance with Existing Power Plant Standards. This document finds that §111(d) can support the deployment of 10 GW of new CHP installations, with concentrations in the industrial Midwest and Southeast. The report provides state-specific projections. The analysis is very conservative (e.g., it assumes only a 50% acceptance rate for projects with less than a 2-year payback period).	http://ccap.org/assets/CCAP-Expanding-the-Solution-Set-How-Combined-Heat-and-Power-Can-Support-Compliance-with-111d-Standards-for-Existing-Power-Plants-May-2014.pdf
Change Is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution. This 2013 report by ACEEE considers a suite of four energy-efficiency policies (portfolio standards, building codes, appliance standards and CHP) and finds that an emissions standard for existing power plants set at 26% below 2012 levels can be achieved at no net cost to the economy. In particular, it finds that the rule can support nearly 20 GW of new CHP. Analysis is conservative, as it assumes no new economic incentives.	http://aceee.org/research-report/e1401
Navigating the Clean Power Plan: A Template for Including Combined Heat and Power in State Compliance Plans. This 2015 tool, put together by ACEEE, is intended to help states document and claim emissions reductions resulting from the adoption of CHP. It includes background guidance and precedents, particular elements states should address in order to claim emissions reduction credit for CHP, recommendations on how to address these elements, and model language based on a hypothetical compliance plan scenario.	http://aceee.org/sites/default/files/chp-cpp-template.pdf
Distributed Generation: Cleaner, Cheaper, Stronger – Industrial Efficiency in the Changing Utility Landscape. This 2015 report by the Pew Charitable Trusts examines how the utility sector is responding to new policies, technologies, and market opportunities and models the potential impact of favorable tax policy and the Clean Power Plan on CHP and WHP deployment. It finds that the CPP could result in nearly 20 GW of new CHP and WHP during the compliance period.	http://www.pewtrusts.org/~/media/assets/2015/10/cleanercheaperstrongerfinalweb.pdf

CHP By Sector	
Title/Description	**URL Address**
CHP in the Hotel and Casino Market Sectors. This 2005 report and related 2007 market update provide an overview of this market segment and assess energy use and other attributes that make the sector a particularly good candidate for CHP.	http://epa.gov/chp/documents/hotel_casino_analysis.pdf
The Role of Distributed Generation and Combined Heat and Power (CHP) Systems in Data Centers. This 2007 EPA report considers the energy use and other attributes that make data centers particularly good candidates for CHP.	http://epa.gov/chp/documents/datactr_whitepaper.pdf
Opportunities for Combined Heat and Power at Wastewater Treatment Facilities: Market Analysis and Lessons from the Field. This 2011 EPA report presents the opportunities for combined heat and power (CHP) applications in the municipal wastewater treatment sector, and it documents the experiences of wastewater treatment facility (WWTF) operators who have employed CHP.	http://epa.gov/chp/documents/wwtf_opportunities.pdf
Combined Heat and Power: A Guide to Developing and Implementing Greenhouse Gas Reduction Programs. This 2014 EPA report explores the potential use of CHP at government facilities and includes a number of case studies about the same.	http://epa.gov/statelocalclimate/documents/pdf/CHPguide508.pdf
Combined Heat and Power: Project Profiles Database. This DOE database includes a drop-down menu to allow users to search for CHP case studies by fuel type, location, prime mover, market sector, and NAICS code.	http://www1.eere.energy.gov/manufacturing/distributedenergy/chp_database/