REPORT:

EXPANDING THE SOLUTION SET:

HOW COMBINED HEAT AND POWER CAN SUPPORT COMPLIANCE WITH 111(d) STANDARDS FOR EXISTING POWER PLANTS

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Modeling Advisory Group members advised CCAP on whether the proposed assumptions were reasonable, whether the proposed scenarios were plausible and whether the study design was likely to achieve the stated objectives. CCAP followed this advice wherever practicable. All final decisions on assumptions and scenarios were made by CCAP. The Modeling Advisory Group members agreed that the policy scenario was plausible and useful for the analysis, but Advisory Group members do not endorse the chosen policy scenario and were not asked to do so.

Expanding the Solution Set: How Combined Heat and Power Can Support Compliance with 111(d) Standards for Existing Power Plants

Executive Summary

Once EPA issues its proposed guidance this spring for reducing carbon emissions from existing power plants, states will be looking for the most cost-effective compliance strategies and begin crafting their implementation plans. In most cases, this will entail using a *system-based* approach that considers a range of compliance options across the electricity system that reduce emissions from covered electric generation units that are subject to the regulation. This contrasts with a *source-based* approach that limits compliance options to measures that can be taken at the covered sources themselves.

In addition to certain efficiency improvements at the sites of power plants themselves and carbon capture and sequestration, most dispatch models[1] are set up to assess the economic potential for a range of clean energy sources to comply with these rules, including dispatch changes towards natural gas, nuclear power and renewable energy as well as new builds of such clean energy technologies. The Natural Resources Defense Council assessed how energy efficiency might contribute to compliance. However, until now, distributed combined heat and power (CHP)—a technology that displaces electricity sector emissions by producing both electricity and thermal energy with a single fuel source— has not been part of these assessments.

Combining two separate models, ICF International's Integrated Planning Model® (IPM) and CHPower model, this study looks at how combined heat and power can support state compliance with EPA's forthcoming guidance on regulating existing power plants under Section 111(d) of the Clean Air Act. Using conservative assumptions that were reviewed by a multi-stakeholder advisory group, we looked at how new CHP might come in under a business-as-usual "CHP Base Case," and under a "CHP 111(d) Policy Case." Our policy case built from the Natural Resources Defense Council's (NRDC) Moderate, Constrained Efficiency scenario from their recent modeling study,[2] which allowed for deployment of demand-side energy efficiency (up to 1 percent per year by 2020 and thereafter) at rates of 2.3-3.2 cents per kWh. Comparable to the treatment of energy efficiency, we assumed that net electric sector

[1] Dispatch models include a representation of existing and new power plants and simulate the lowest cost way of meeting electric demand, subject to constraints.
[2] NRDC. *Cleaner and Cheaper: Using the Clean Air Act to Sharply Reduce Carbon Pollution from Existing Power Plants*. March 2014. http://www.nrdc.org/air/pollution-standards/files/pollution-standards-IB-update.pdf.

emissions reductions from CHP investments would earn offset credits that could be sold to covered sources to support 111(d) compliance.

While energy efficiency comprised a significant share of the 111(d) compliance in CCAP's CHP 111(d) Policy Case, CHP also played a noteworthy role. In total[3], nearly 10 GW of CHP came in across the country by 2030. This reflects CHP that was both economical and "accepted" by the host site. CHP's impact was greater in later model run years as our assumptions acknowledged that CHP installations can take time to deploy even after a decision is made to implement a CHP project; as such, CHP played a smaller role in 2020 (roughly 5 GW in total). To put these numbers in context, 10 GW is roughly equivalent to 15 average sized coal-fired power plants. EIA's Annual Energy Outlook 2014 reference case scenario forecasts retirements of 47 GW of coal-fired power by 2020.[4]

Under the CHP Base Case, the models project that much of the CHP capacity would be deployed in regions with higher than average retail electric rates and that are already subject to state or regional carbon cap-and-trade programs—California and the Northeast. However, under the CHP 111(d) Policy Case, most of the incremental capacity is located in states with higher amounts of CHP technical potential and jurisdictions that are expected to see higher-than-average 111(d) compliance costs—regions that tend to have more coal-fired power generation and may also have more limited compliance solutions. In these states, CHP investments help lower overall compliance costs.

Our modeling assumptions were conservative on a number of accounts that tend to underestimate the amount of CHP available, deemed economical, and ultimately accepted by the end user:

- As many sites do not have supportive regulatory frameworks in place to sell power to the electric grid or do not receive market prices for doing so, we assume that CHP facilities do not export electricity at all. This effectively limits the size of CHP facilities to the total electricity consumed by the host site, and also limits the potential for CHP host sites to earn revenues from electricity sales that could bolster the economics of the CHP investment. If electricity exports were available, the CHP capacity for potential industrial CHP units could increase by 10 to 20 percent. [5]
- We assume that CHP facilities continue to pay their electric providers a fee equal to 15 percent of their historic electric charges to maintain back-up access to the electric grid. If states were to lower interconnection costs and backup rates, this cost would decline.
- We make the simplifying assumption that all new CHP facilities will be fueled by natural gas. While this is true 70 percent of the time, there are many instances where potential CHP sites have access to alternative fuels (e.g., landfill gas, paper mill byproducts or blast furnace gas) at a

[3] This includes roughly 6.4 GW of new CHP in the CHP Base Case and 3.5 GW of new CHP in the CHP 111(d) Policy Case.
[4] See AEO 2014, Table A9. http://www.eia.gov/forecasts/aeo/pdf/tbla9.pdf.
[5] Verbal communication with ICF International, April 28, 2014.

lower cost, improving the economics of the potential CHP investment and making it more likely that new CHP will get built.

- We use realistic assumptions based on survey data that acknowledge that industrial, commercial and institutional facilities often do not choose to invest in CHP, even when it is economical to do so. Acceptance rates could change over time with education or more proactive utility engagement. However, in our modeling, the acceptance rates stay constant.
- While about 15 percent of boilers are currently fueled by coal, because we expect that a number of these boilers will convert to natural gas in response to the Boiler MACT, the analysis does not look at the considerable near-term emissions reduction opportunity to switch from coal-fired boilers to natural gas-fired CHP.
- Under the CHP 111(d) Policy Case, we assume emissions credits for CHP are granted based on how their emissions compare with a state emissions rate standard as defined by NRDC's Moderate, Constrained Efficiency policy case. Alternative methods for assessing emissions reductions based on estimates of emissions reduced from electric generating units could offer more credit for CHP in coal-heavy states.
- We assume the investment tax credit for CHP expires in 2016.
- Finally, secondary benefits of CHP, including business resiliency and reductions in grid congestion, have real economic merit but the model does not attribute value to these co-benefits.

These assumptions all tend to understate the potential deployment of CHP under 111(d), suggesting that the results of this research may be seen as a lower estimate of possible new CHP capacity.

We conclude that allowing CHP as a means of compliance through fair treatment of thermal energy can be helpful to states projected to see higher-than-average compliance costs, notably in the Midwest, western portions of the PJM transmission organization territory, and some northern portions of the Southeast Electric Reliability Council (SERC) territory. CHP offers an additional low cost mitigation opportunity that can lower the cost of compliance with 111(d) standards that limit carbon emissions from existing power plants. For CHP, 111(d) can be a bigger driver for CHP deployment than more targeted policy approaches like an investment tax credit. Efforts to improve the rate at which otherwise economical CHP is accepted by the end user (e.g., through education or risk mitigation) and to establish policies and procedures for CHP to access the grid could further boost the potential of this win-win mitigation option.

Introduction

President Obama issued a Climate Action Plan[6] in June 2013 instructing the Environmental Protection Agency to "work expeditiously to complete carbon pollution standards for both new and existing power plants." Set to be released in June 2014, this guidance will, for the first time, lay out a framework for states to regulate carbon dioxide emissions from existing coal- and gas-fired power plants.

Once EPA finalizes its guidance to states and determines required emission reductions, the decision-making will move to the state level. Consistent with EPA's guidance, state government agencies will be charged with applying standards to the covered sources in their states and devising systems for meeting those standards. As under Section 110 of the Clean Air Act where states have included fees, permits, auctions and cap-and-trade programs in their State Implementation Plans, under Section 111(d) states are given considerable flexibility in how they accomplish this task. The President has also directed the Agency to provide for flexibility in how states require sources to comply with the standards.

Numerous states and stakeholders have asked EPA to allow for compliance via a "system-based approach" that would permit states to recognize the full set of mitigation options that can reduce emissions from covered sources and EPA officials have strongly suggested they will allow states to adopt flexible compliance strategies. Rather than be limited to heat rate improvements, co-firing and carbon capture and sequestration, a system-based approach would allow for consideration of dispatch changes that involve shifts away from older and inefficient coal-fired power generation, and towards underutilized natural gas combined cycle generation, and also incremental generation (or energy savings) from a range of clean energy sources that are not directly covered by the regulation.

Recent power sector dispatch modeling has evaluated how, under a system-based approach, a range of clean energy technologies (natural gas, nuclear and renewable energy) can support compliance with 111(d) policy simply by operating more and displacing older and less efficient generation. Moreover, the Natural Resources Defense Council (NRDC) has evaluated how demand-side energy efficiency might support compliance with 111(d). However, distributed energy resources such as combined heat and power (CHP) can also play an important role, supporting achievement of 111(d) standards for existing fossil fuel-fired power plants at a lower cost while at the same time achieving greater efficiencies and cost savings within the industrial, commercial and institutional sectors.

Combined heat and power conserves fuel by producing two energy streams—thermal energy and electricity—using the same fuel stock. Where such energy streams are currently produced separately—electricity from an electric generating unit and thermal energy from a boiler—CHP offers an opportunity to significantly lower emissions while also lowering energy costs for the steam host. At the same time, in valuing the emissions reductions achieved through displacement of higher emitting electric generation, the 111(d) rule could offer a new incentive for industrial, commercial and institutional facilities to adopt

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

combined heat and power. Improving the energy efficiency of the industrial sector with technologies like CHP can make U.S. industry more competitive in the global marketplace.

CCAP commissioned ICF International to undertake new modeling with the Integrated Planning Model (IPM®), linked for the first time with their CHPower Model, to estimate how new CHP units at industrial, commercial and institutional facilities can support compliance with existing source standards for the power sector. This same approach can be used to evaluate the role of combined heat and power in meeting the objectives of other air quality policies affecting the electricity sector.

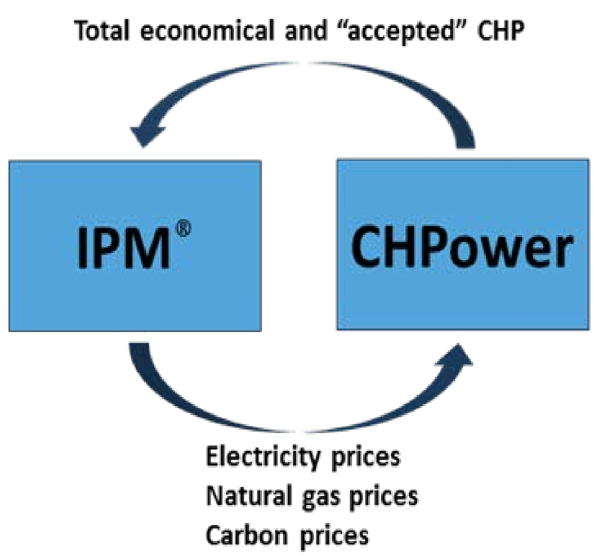
Methodology

For the first time, this analysis makes it possible for CHP to be considered as a new build option within a power sector dispatch study. This investigation made use of two models: the Integrated Planning Model (IPM®) and the CHPower Model.

The Integrated Planning Model is a power sector dispatch model that solves for the least cost way of meeting generation and capacity requirements subject to constraints. The Environmental Protection Agency and other public and private entities use the IPM® to evaluate the effects of environmental policies on the power system. The IPM® captures every generating unit in the country, distributed across fifteen regions. The model can retire plants that are not covering their operating costs. In addition, the model has parameters for new plants that can be built to meet demand, depending on the economics. The IPM® solves for the lowest cost way of meeting the policy constraints while maintaining power system reliability.

The CHPower Model forecasts the industrial, commercial and institutional facilities most likely to install or expand combined heat and power systems over time. The model includes a dataset of both existing and potential new CHP units across the United States. The model calculates the payback on new CHP investments based on assumed technology characteristics and costs, energy prices, rates of market acceptance (acknowledging that end users may opt not to make investments that are economical), and rates of market penetration.

Figure 1. Feedback Between IPM® and CHPower Models



CCAP's 111(d) and CHP study added model CHP plants to each of the IPM® power regions.[7] The IPM® was first run without any CHP. Key parameters from the IPM® results (electricity prices,[8] natural gas prices and, where applicable, carbon prices) were fed into ICF's separate CHPower model to determine how much incremental CHP might become economical in each of IPM®'s model regions. This amount of CHP was added to the appropriate model CHP plants, and the IPM® was rerun to determine whether there would be any significant change in the key IPM® parameters. These iterations continued until there was no significant change.

[7] IPM® includes more than 110 model regions, aggregated into fifteen for reporting.

[8] Note that the CHPower Model modified the electric rate results from the IPM® model (which provides wholesale rates) to make them indicative of average retail rates. The average retail rate for each state was further modified to account for peak and off-peak rates. Larger customers were assumed to pay lower rates than smaller customers.

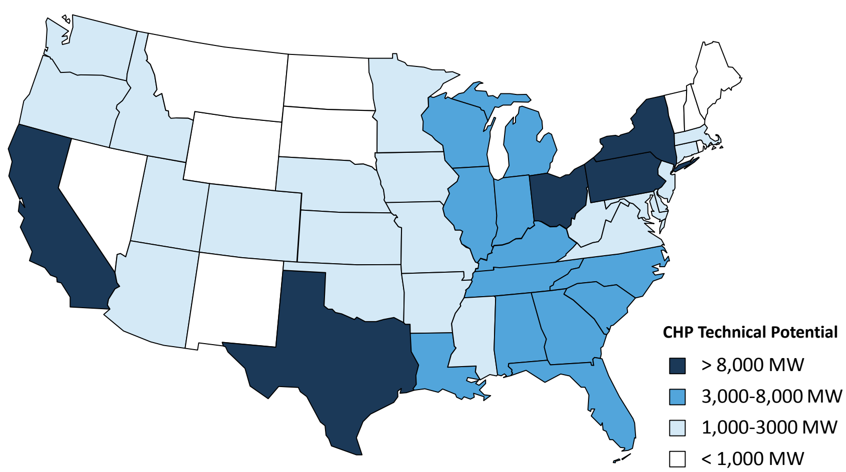
Assumptions

In addition to the full set of power sector assumptions used in the IPM®, this study required a number of assumptions about combined heat and power technology. Our explanation here focuses on the assumptions needed to characterize the availability, cost and penetration of combined heat and power. We also reference the sources used to populate the IPM®.

CHP Technical Potential and Characteristics

This technical potential was based on data from existing industrial, commercial and institutional facilities that currently do not have CHP or have room to expand their CHP to meet new thermal loads ("potential CHP sites"). The specific potential CHP sites are identified using a number of data sources, with the main criterion being sites that have applications that use both electric and thermal load. ICF International identified about 38 such good applications (sectors or subsectors), for a total of 125.6 GW of technical potential nationally. This technical potential is increased over time based on market growth rate projections from EIA for the industry and business sectors.[9] The specific location of each of the potential CHP facilities is identified at the zip code, county and state level (Alaska and Hawaii were not modeled). The distribution of this technical potential is shown in Figure 2.

Figure 2. CHP Technical Potential by State



Source: ICF International Internal Estimates

[9] For the industrial sector, CHP is assumed to grow at the rate of EIA-AEO output for the index of industrial shipments. For commercial sectors, growth is based on commercial floor space. ICF considers negative changes to be zero growth in CHP potential, and very high growth areas would be limited to 5 percent per year.

The costs of the potential CHP vary based on four different size classes and assumed technology types, and align with assumptions used by the EPA CHP Partnership (shown in Table 1, below). As the analysis focuses on the most economical solutions, we included just the lowest cost CHP facility type for each size class—reciprocating engines for smaller size bins, and gas turbines for larger ones. Prices are assumed to escalate based on inflation; and capital costs, including permitting costs, are adjusted for each state based on assumptions from the Army Corp of Engineers Civil Works Cost Index System.

Table 1. Assumed Cost of CHP Units by Size Class

Market Size Bin	**50-1,000 kW**	**1-5 MW**	**5-20 MW**	**>20 MW**
Technology	**500 kW RE**	**3000 kW RE**	**10 MW GT**	**40 MW GT**
Capacity, kW	512.5	3000	12500	40000
Capital Cost $/kW	$2,217	$1,604	$1,802	$1,144
After Treatment Cost, $/kW	$552	$313	$174	$104
Total Capital Cost, $/kW	$2,769	$1,917	$1,976	$1,248
Heat Rate, Btu/kWh	11,293	8,454	12,482	9,488
Thermal Output, Btu/kWh	5,546	3,208	5,262	3,118
Electric Efficiency, %	30.2%	40.4%	27.3%	36.0%
CHP Efficiency	79.3%	78.3%	69.5%	68.8%
O&M Costs, $/kWh	$0.0215	$0.0150	$0.0120	$0.0092
Economic Life, years	15	15	20	20
Avoided Boiler Efficiency	80%	80%	80%	80%
Avoided AC Efficiency, kW/ton	1.00	0.68	0.68	0.68
Cooling Hours	2,000	2,000	2,000	2,000
Absorption Cooling Efficiency, Btu/ton	17,143	17,143	10,000	10,000
Tons of cooling	166	561	6,578	12,473
kW AC/kW Generated	0.32	0.13	0.36	0.21
Capital Cost, $/ton	$1,845	$1,410	$950	$950
Capital Cost Adder, $/kWe	$597	$264	$500	$296

Source: EPA CHP Partnership Catalog of CHP Technologies

We note that these costs are higher than those assumed by the Energy Information Administration.[10] In addition, the assumed costs and technical characteristics are based on recent estimates from CHP equipment suppliers and developers that were collected by ICF International to update the CHP technology characterizations for the EPA CHP Partnership. These cost estimates differ somewhat (both up and down) from the costs reviewed by the Modeling Advisory Group.[11]

In terms of fuels, all new CHP was assumed to run on natural gas. While some facilities may have access to lower cost fuels like biomass, bio gas, blast furnace gas, or other waste products, these opportunity fuels are not reflected in the model. Moreover, we assume that the counterfactual boiler being replaced is fueled by natural gas. This captures the likelihood that remaining coal-fired boilers may be switching to natural gas to comply with the Boiler MACT. Therefore, our study does not consider the more significant emissions reductions that can come from replacing coal-fired boilers with natural gas-fired CHP.

The analysis assumes that CHP facilities are sized based on thermal load, and that building larger units to facilitate electricity exports is not an option. In some cases, the assumed CHP capacity is reduced to match the amount of electricity consumed at the host facility. This conservative assumption potentially underestimates the total CHP potential, but considers that many sites do not have the infrastructure and/or supportive utility and regulatory frameworks in place to sell power to the electric grid, or do not receive market prices for selling power back to the grid. ICF International estimates that if electricity exports were included, the CHP capacity for potential industrial CHP units could increase by 10 to 20 percent.[12]

CHP Acceptance Rates

To represent the fact that many otherwise economical distributed generation projects do not move forward, we used CHP Project Acceptance curves (shown in Figure 3) that were differentiated based on whether the facility is industrial or commercial/institutional. The rationale is that institutional projects can accept projects that take longer to pay back. This means that for any given payback period (say, if a CHP investment will pay back in two years), an institutional CHP facility will have a higher acceptance rate (the investment will more likely move forward) than an industrial CHP facility. These curves were

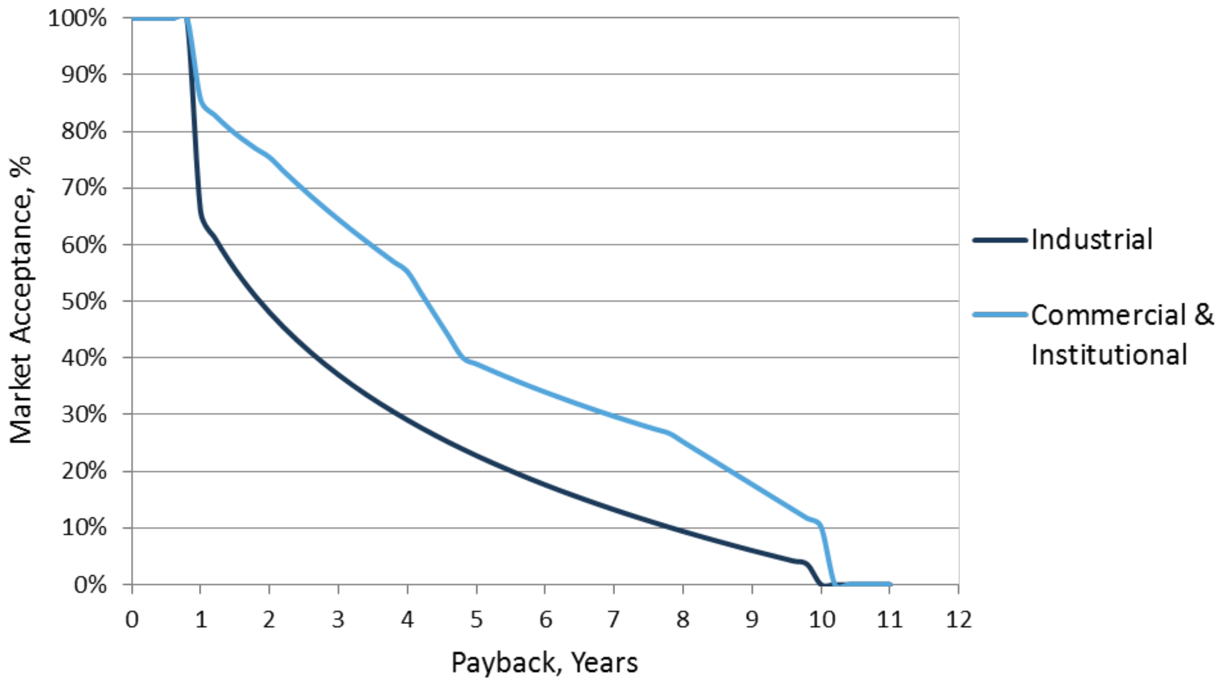
[10] Sentech. *Commercial and Industrial CHP Technology Cost and Performance Data Analysis for EIA*. June 2010. http://www.meede.org/wp-content/uploads/Commercial-and-Industrial-CHP-Technology-Cost-and-Performance-Data-Analysis-for-EIA_June-2010.pdf.

[11] For example, the capital costs used in the study for the three smallest size classes are higher than the costs that were reviewed by the Modeling Advisory Group, while the capital costs for the largest size class is lower. The operation and maintenance costs used in the study are higher than the costs reviewed by the Modeling Advisory Group except for the 1-5 MW size class.

[12] Verbal communication with ICF International, April 28, 2014.

based on survey data[13] on what payback levels are needed for distributed generation investments to move forward.

Figure 3. Acceptance Curves



CHP Development Curves

Through use of market penetration curves, we also assume that economical and accepted CHP does not get built instantaneously. The cumulative market penetration of CHP over time is based on a typical S-shaped Bass diffusion curve—a standard approach used to capture the uptake of products in the marketplace—with allowance for growth aligned with projected growth of the underlying sectors. In general, we assume it typically takes more than a decade to achieve 100 percent of the CHP. This assumption considers that a CHP facility takes some time to plan and deploy even once a site has decided to build it.

Assigning Emissions and Costs to CHP

Depending on the nature and objectives of the regulation, various methods have been proposed to assign emissions to combined heat and power. For the purpose of this analysis where the main objective is to understand the share of CHP emissions that should be assigned to electricity production, we

[13] Primen's 2003 Distributed Energy Market Survey; summary available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001010294. Even though this survey is from 2003, anecdotal evidence from ICF's ongoing consulting in this field suggests that these data are reflective of current circumstances.

apportion emissions to the boiler and to electric production using the heat rate chargeable to electricity. This is the portion of the energy input to the system that is used for electricity production as opposed to thermal production. The effective heat rate chargeable to electricity—4,645 and 5,590 BTU/kWh for small and large CHP units, respectively—is the heat rate that remains after subtracting out the avoided boiler fuel. In essence, these values reflect the net amount of natural gas that is needed by the CHP system to produce electricity after the avoided boiler fuel is subtracted. These heat rates are used for estimating the emissions from CHP units chargeable to electricity and also the share of costs associated with electricity.

In this analysis, the CHP emissions rate assigned to electricity is compared with each state's emissions rate standard (described below in the section titled "Scenarios"). The reduction in emissions credited to the CHP unit is the difference between the state standard and the CHP unit's emissions rate chargeable to electricity. This approach results in fairly consistent crediting to CHP units across the country, with CHP units in coal-heavy states receiving somewhat higher credit values than CHP units in states with more natural gas-fired power generation. We note there is an alternative approach where credit would be granted based on an estimate of the emissions reduced on the power grid. Such an approach would lead to larger differences between coal-heavy states and those dominated by cleaner electric generation.

Federal and State CHP Policies

Consistent with assumptions in the IPM® model, we assume implementation of final policies and regulations. For CHP, we assume the 10 percent Federal Investment Tax Credit expires at the end of its current authorization (2016). In addition, as noted earlier, given that the Boiler MACT will already have been implemented, our analysis only looks at the opportunity to convert natural gas-fired boilers to combined heat and power. We do not consider the significant near-term emissions reduction opportunity to convert coal-fired boilers to natural gas-fired CHP. In addition, while not yet final, we note that the 111(b) New Source Performance Standards will not apply to the new CHP units in our analysis due to our assumption that the new units would not export electricity.[14] Finally, due to uncertainty surrounding the potential requirements for New Source Review related to major source modifications when there is no underlying New Source Performance Standard, we do not factor in costs to comply with case-by-case New Source Review determinations for greenhouse gases.

At the state level, there is significant variation in how state and utility policies foster or impede CHP through standby rates and grid interconnection standards, and therefore significant variation in the costs to maintain access to the grid in case the CHP facility has an outage. Such rules are becoming more favorable to CHP in some areas, and some states have adopted specific incentives or mandates for CHP. Where such policies reduce barriers to CHP deployment or even encourage CHP, costs may be lower or

[14] Per EPA's proposal, the 111(b) NSPS would only apply to large CHP units that sell more than 25 MW and at least a one-third of their electricity to the electric grid.

acceptance rates could be higher. However, estimating the actual cost implications of each state and utility policy was beyond the scope of this study.

To represent the costs that distributed energy facilities must pay to maintain access to the electric grid, we assume that only 85 percent of the historic electric costs are avoided. In other words, businesses that generate thermal energy and electricity on-site via a new CHP unit must also continue to pay their power providers a rate equivalent to 15 percent of their historic electric costs. We do not assume any additional state incentives or mandates. Clearly, states looking to take advantage of the CHP opportunity to lower 111(d) compliance costs might also implement changes to interconnection and backup rate rules that would lower the cost to access the grid.

IPM® Assumptions

Most of the IPM® assumptions are the same as those in NRDC's Reference Case presented in the March 2014 issue brief, *Cleaner and Cheaper: Using the Clean Air Act to Sharply Reduce Carbon Pollution from Existing Power Plants, Delivering Health, Environmental and Economic Benefits*.[15] The Reference Case assumptions are benchmarked to the Energy Information Administration's Annual Energy Outlook 2013, including natural gas prices. One exception was CCAP's assumption regarding the cost of carbon capture and sequestration (CCS): we reduced the credit for enhanced oil recovery making this technology somewhat more expensive. However, this change ultimately had very little effect on the outcome. The main change we made to the NRDC Reference Case assumptions, in both the base case and the policy case, was to add combined heat and power as a compliance option. As described previously, we included combined heat and power as one of the technologies that could come in as a "new build" by iterating with the CHPower Model. Under the policy case, CHP units would earn credits for the net electric sector emissions reduced.

[15] NRDC. *Cleaner and Cheaper: Using the Clean Air Act to Sharply Reduce Carbon Pollution from Existing Power Plants*. March 2014. http://www.nrdc.org/air/pollution-standards/files/pollution-standards-IB-update.pdf.

Scenarios

We ran two scenarios—a "CHP Base Case" and a "CHP 111(d) Policy Case" to understand the impacts of a 111(d) scenario that includes combined heat and power. In seeking a high degree of comparability with NRDC's base case and 111(d) scenarios, an additional goal was to understand how adding in combined heat and power as a new build option might change the choice of compliance solutions as compared to a scenario that did not allow CHP to be used as a means of compliance.

Our CHP Base Case built from the Reference Case developed by the Natural Resources Defense Council. Details on the NRDC assumptions and results can be found in the Technical Appendices on NRDC's website.[16] The key change was the addition of CHP as a compliance option, as described above under the methodology and assumptions sections. This would allow us to understand how much CHP might be economical and accepted business-as-usual, before imposition of a carbon constraint. Note that this treatment of CHP is different from how we treat energy efficiency.

NRDC's Reference Case is based on the Energy Information Administration's reference case projection, which models future electricity demand under a business-as-usual scenario that includes some, but not all, state energy efficiency policies, potentially underestimating energy efficiency investments in the reference case.[17] At the same time, as is the case with CHP, the literature on the subject of energy efficiency establishes there are numerous barriers to deployment of otherwise cost-effective efficiency investments, and it is reasonable to believe that such barriers would continue to hamper efficiency investments in the base case. A carbon standard could help overcome such barriers and promote new efficiency investments. To ensure comparability with NRDC's Reference Case, we allowed energy efficiency as an option only in the policy scenario.

Our CHP 111(d) Policy Case was built from NRDC's Moderate, Constrained Efficiency policy case. Key features of this scenario include how the standards are set and the assumptions on the availability and costs of demand-side energy efficiency. In NRDC's proposed regulatory structure, standards are set at the state level by applying benchmark emission rates based on the historic amounts of generation from coal- and gas-fired power plants over a baseline period (2008-2010). The initial benchmark emissions rates were 1,500 lb/MWh and 1,000 lb/MWh for coal- and gas-fired power plants, respectively. As an example, a state with a 50-50 mix of coal and natural gas in the baseline period would receive a statewide target of 1,250 lb/MWh. For coal-fired power plants, these benchmark rates were lowered to 1,200 lb/MWh starting in 2025.

[16] NRDC. 'Cleaner and Cheaper: Using the Clean Air Act to Sharply Reduce Carbon Pollution from Existing Power Plants.' http://www.nrdc.org/air/pollution-standards/.
[17] EPA's website describes efforts to estimate emissions reductions resulting from state programs that were not captured in EIA's Annual Energy Outlook. See http://epa.gov/statelocalclimate/state/statepolicies.html for details.

A second key feature of NRDC's Moderate, Constrained Efficiency policy scenario is the assumption that energy efficiency deployment grows to one percent per year in every state by 2020. (This is in contrast to their Full Efficiency scenarios that assume energy efficiency deployment grows to two percent per year in every state by 2020.) Based on reviewing several states' experiences in driving energy efficiency and also advice received from our Modeling Advisory Group, we were comfortable that states would be able to reach the one percent per year efficiency improvement level. We also felt comfortable that NRDC's assumed range of on-system costs for demand-side energy efficiency programs (2.3 to 3.2 cents per kilowatt-hour) would be reasonable and could be sustained at the one–percent-per-year level of efficiency.

As noted previously in our discussion of the IPM® assumptions, the main change we made to the NRDC's Moderate, Constrained Efficiency policy case was to add CHP as a compliance option (the primary purpose of our study). New CHP units earn offset credits based on the net reduced emissions from the electric sector. These offsets can be sold to covered sources to support compliance with the 111(d) standard, and create new value that accrues to the CHP unit.

Results

We find that combined heat and power offers an economical approach to help meet power demand in both the CHP Base Case and the CHP 111(d) Policy Case. However, there is considerable variation by region, and the amount of projected deployment is small compared to the sizeable technical potential.

CHP Base Case Results

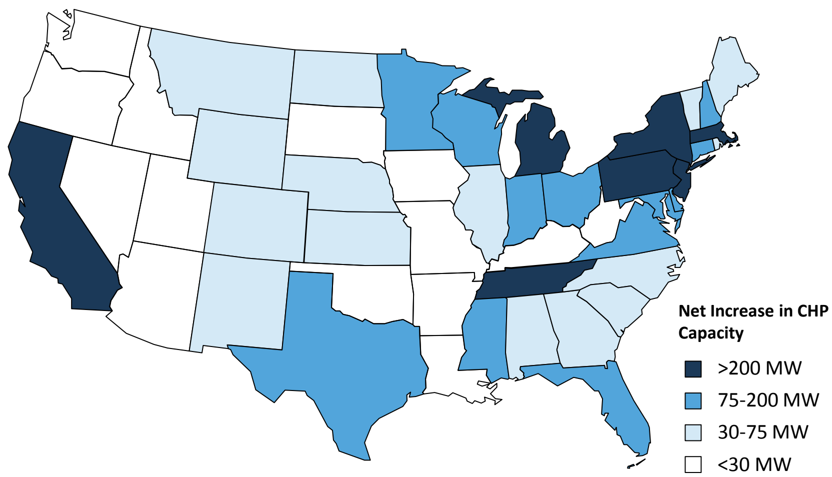
Under the CHP Base Case, we find that 6.4 GW of CHP would be built under business-as-usual conditions by 2030. As explained in the assumptions, the amount of economical CHP would be higher than this, but through use of "acceptance rates" we recognize that only a portion of otherwise economical CHP is typically developed. More than half (59 percent) of the new capacity is in the largest (>20 MW) size bin, though there is growth in CHP from all four size bins.

Table 2. Base Case CHP Capacity by Size Bin

Forecast Year	50-1,000 kW	1-5 MW	5-20 MW	>20 MW	Total
2016	58	140	82	431	712
2018	127	316	176	1,022	1,641
2020	222	550	306	1,784	2,862
2025	461	1,083	609	3,240	5,393
2030	574	1,297	752	3,796	6,419

Much of the projected new CHP capacity comes in regions with higher-than-average retail electric rates and that are already subject to state or regional carbon cap-and-trade programs—California and parts of the Northeast. However, there is also new capacity in Pennsylvania and in parts of the Midwest and South. Possible explanations include high levels of technical potential for CHP in these states, low projected natural gas prices and environmental pressures on coal power plants, which lead to increases in electric rates. Together, these effects improve the economics for natural gas-fired CHP relative to electric generation.

Figure 4. Base Case Increase in CHP Capacity, 2030



CHP 111(d) Policy Case Results

Our policy case results demonstrate that CHP deploys on an economic basis in response to a carbon price. The total amount that comes in is comparable to other low carbon electricity sources such as carbon capture and sequestration. Moreover, the 111(d) incentive for CHP achieves better results from the standpoint of CHP deployment than policy measures targeted specifically to boost CHP investments.

Changes in Projected CHP Capacity

On top of the CHP that comes in under the CHP Base Case, under the CHP 111(d) Policy Case, we project an additional 3.5 GW of CHP would be built by 2030, for a total of close to 10 GW of economic and accepted CHP. Due to assumptions on the rate of CHP deployment, most of the new CHP capacity enters the market by 2025. The majority (73 percent) is in the largest (>20 MW) size class. See Figures 5 and 6 for details.

While 10 GW may seem small when compared to the President's aspirational goal of achieving 40 GW of CHP by the end of 2020, the modeled 111(d) design drives more CHP than policy solutions such as a 30 percent investment tax credit.[18] In combination with state-level policies, 111(d) can be an important driver towards achieving the President's goal.

[18] For example, see: USCHPA & WADE. *Effect of a 30 Percent Investment Tax Credit on the Economic Market Potential for Combined Heat and Power*. October 2010.

Figure 5. Cumulative CHP Market Penetration (MW)

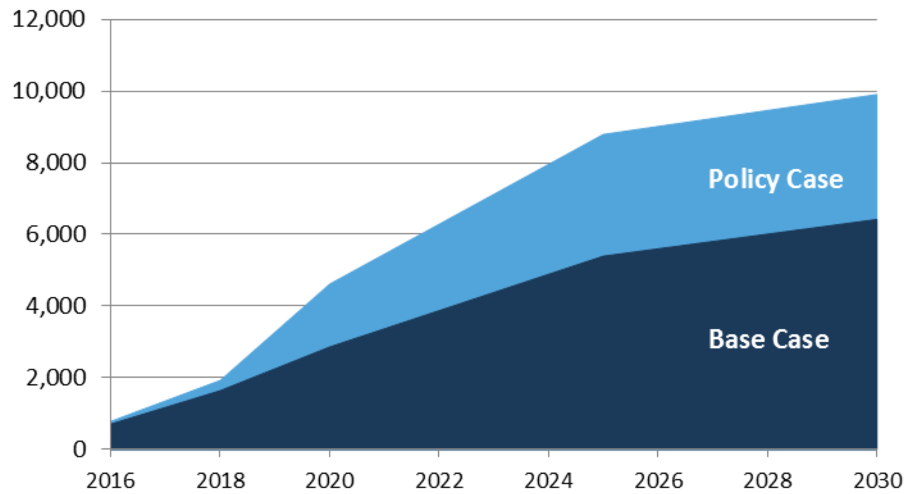
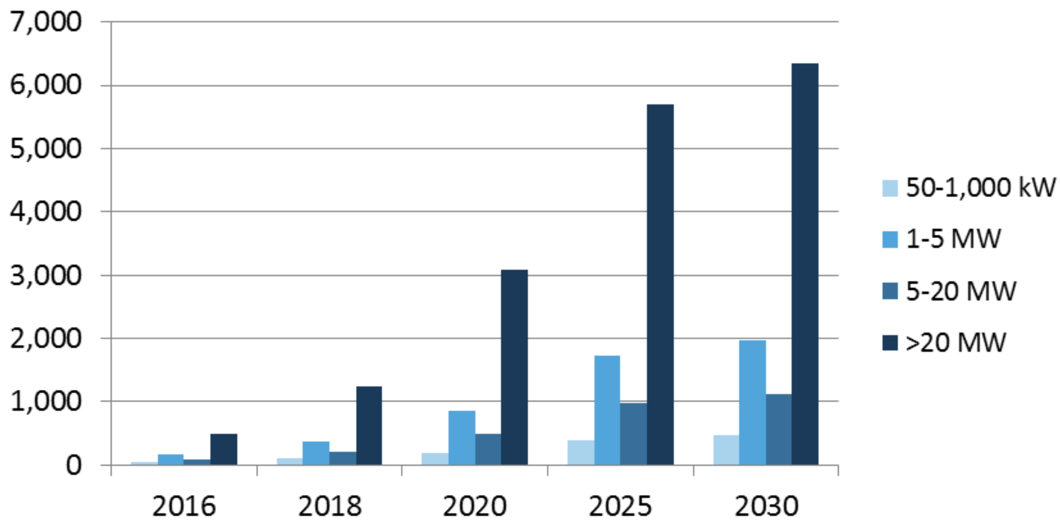


Figure 6. Cumulative Total CHP Market Penetration by Size and Year (MW)



Most of this incremental capacity in the CHP 111(d) Policy Case is located in states with higher amounts of CHP technical potential (as shown previously in Figure 2) and that are expected to see higher-than-average 111(d) compliance costs—regions that tend to have more coal-fired power generation and may also have more limited compliance solutions. The net increase in CHP capacity by state is shown in Figure 7 and also detailed in the Appendix.

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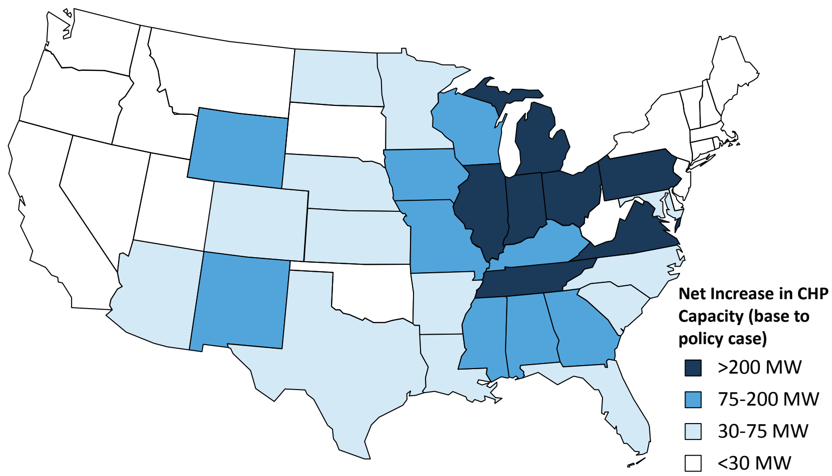
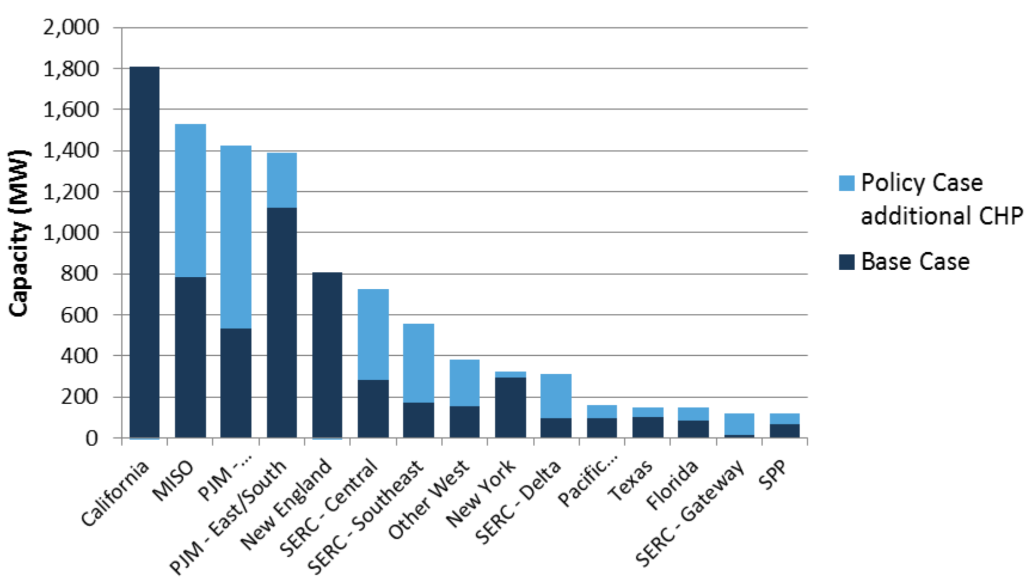
http://www.localpower.org/WADE_USCHPA_ITC_Report.pdf. This report shows a 60% increase from 2010 to 2017. Our results show 61% nationally from 2013 to 2020.

Figure 7. Net Increase in CHP Capacity, 2030



The very different regional impacts forecasted under the CHP Base Case as compared to the CHP 111(d) Policy Case are illustrated in Figure 8. It quickly becomes clear that coal-heavy regions in the Midwest and South, in particular, are projected to see a strong incentive to employ combined heat and power as a means of compliance.

Figure 8. CHP Capacity by Region, Base and Policy Cases, 2030

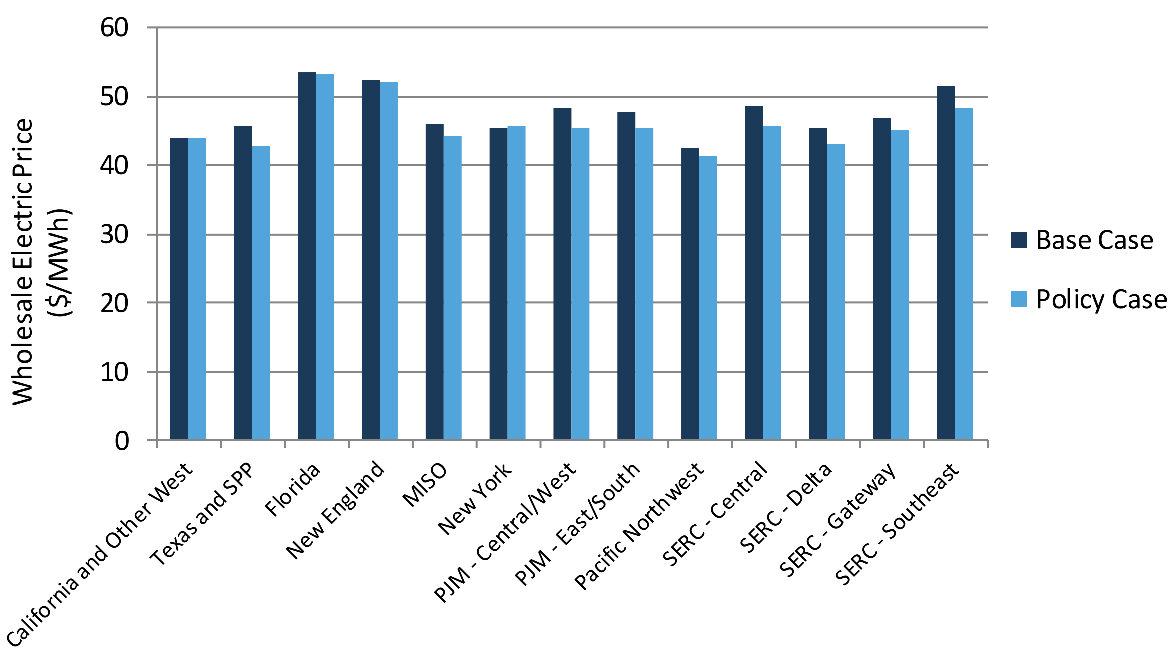


CHP deployment under the CHP 111(d) Policy Case appears to be closely linked to increases in carbon price. The national average price is about $19-22 per ton in the 2020-2030 timeframe, but the price is somewhat above this (roughly $21-32 per ton) in areas that are projected to see the most CHP deployment.

Further, under the CHP 111(d) Policy Case, the other potential CHP driver—spark spread—moves slightly in the opposite direction. Spark spread reflects the difference between the natural gas price and the electric price, and is a key indicator of the profitability of natural gas-fired electric generation, including natural gas-fired combined heat and power. When natural gas prices are low and electric prices are high, this creates more of an economic incentive for facilities to consider natural gas-fired CHP in order to avoid the higher electric prices. In contrast, when natural gas prices go up and electricity prices go down, the economic incentive for natural gas-fired CHP is reduced.

Under the CHP 111(d) Policy Case, electricity prices come down slightly in many areas of the country, and in other regions, the prices stay roughly constant (see Figure 9). At first glance this may seem counter-intuitive, as many expect electricity prices to rise as a result of carbon regulations. However, because the assumed standard is set as an emissions rate for each state, natural gas-fired power units emit below the standard and derive a new source of revenue by selling their over-compliance to coal-fired power generators. This results in lower operating costs for natural gas-fired power plants and helps lower electricity prices for all generators to the extent that natural gas-fired power plants are the "marginal unit"—the last power plant needed to meet electric demand at any given point in time and that sets the price on the electric grid.

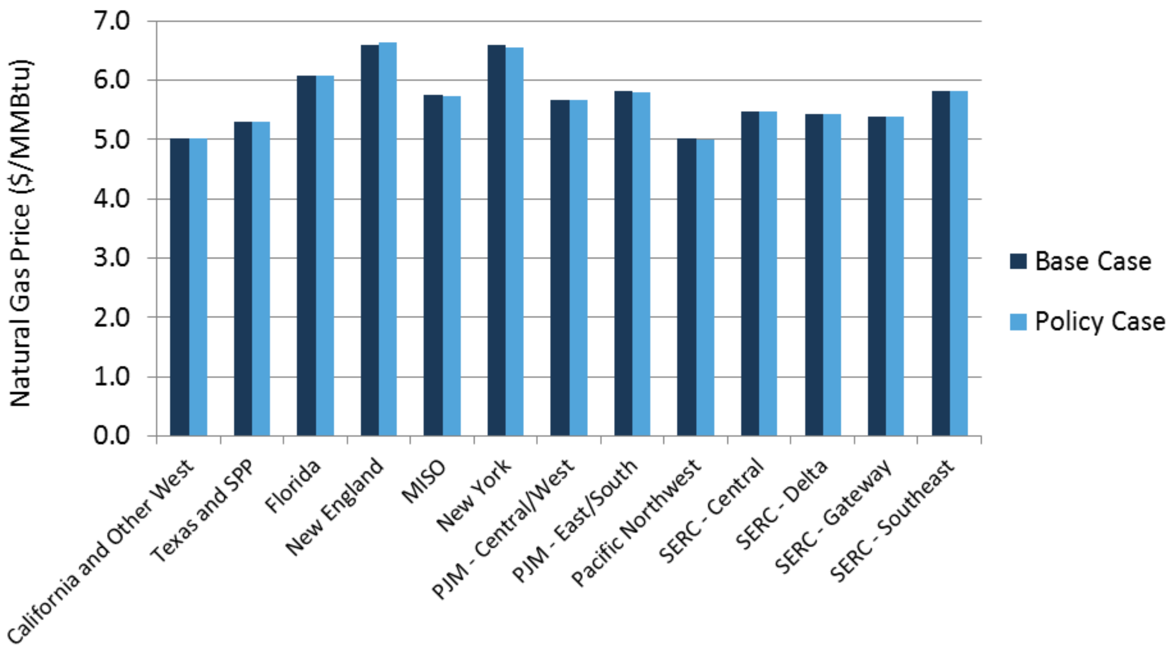
Figure 9. Regional Electric Prices for Base Case and Policy Case, 2030



At the same time, as shown in Figure 10, below, there is little change in natural gas prices. This means that, if anything, the change in spark spread under the CHP 111(d) Policy Case slightly discourages CHP as compared to the CHP Base Case. And in fact, in areas where projected carbon prices under 111(d) regulations are zero or very low, this smaller spark spread results in slightly less projected CHP in the CHP 111(d) Policy Case as compared to the CHP Base Case.

We note that the electric, natural gas and carbon price changes seen in this study relate to our use of an emission rate standard that is applied at the state level. As noted previously, our policy scenario uses the same benchmark emission rates as in NRDC's Moderate, Constrained Efficiency scenario. Other system-based designs, including designs that rely on an absolute emission limit, could lead to different energy and carbon price outcomes that could offer a stronger incentive for new CHP investments. See, for example, *Alternative Approaches for Regulating Greenhouse Gas Emissions from Existing Power Plants under the Clean Air Act: Practical Pathways to Meaningful Reductions*.[19]

Figure 10. Regional Natural Gas Prices for Base Case and Policy Case, 2030



Changes in 111(d) Compliance Strategy

Comparing our results with the recently published NRDC Moderate, Constrained Efficiency policy scenario helps illuminate the role CHP availability might play in meeting compliance. Compliance

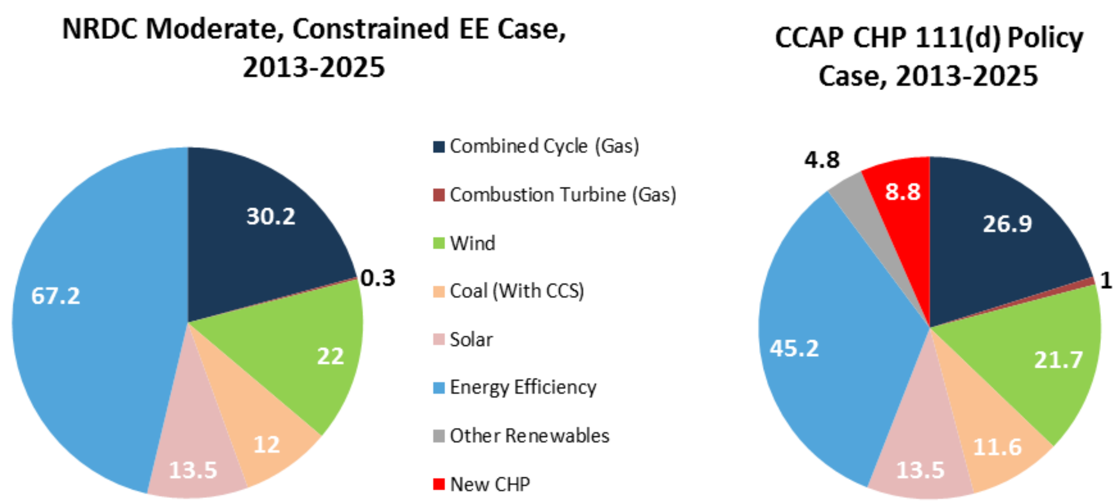
[19] Phillips, Bruce. *Alternative Approaches for Regulating Greenhouse Gas Emissions from Existing Power Plants under the Clean Air Act: Practical Pathways to Meaningful Reductions*. February 27, 2014. http://catf.us/resources/publications/files/NorthBridge_111d_Options.pdf.

strategy is illustrated in capacity retirements, the types of new capacity built, carbon capture retrofits, and changes in overall generation.

Through 2025[20], allowing CHP to come in as a new build and support 111(d) compliance (as well as our assumption about higher carbon capture technology costs) contributed to more unplanned coal retirements (roughly 2 GW), as well as changes in the new unplanned capacity that was built to comply with 111(d) standards while maintaining power operations. In addition, CCAP's policy scenario saw a very small (0.4 GW or 3 percent) reduction in unplanned CCS retrofits.

In terms of new unplanned capacity, relative to NRDC's Moderate, Constrained Efficiency policy scenario, CCAP's CHP 111(d) Policy Case resulted in more CHP and renewable energy capacity, but commensurately less new energy efficiency and natural gas combined cycle technology (see Figure 11).

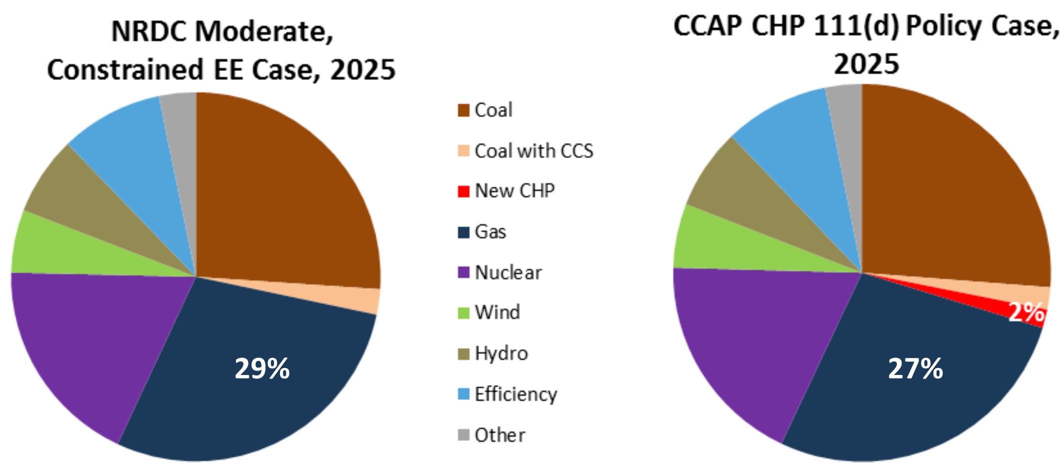
Figure 11. Cumulative unplanned builds (includes base case and policy case unplanned builds[21]) 2013-2025 (GW)



And comparing the generation characteristics of both scenarios in 2025 (Figure 12), it appears that the CHP scenario displaces mainly natural gas generation (by 61 TWh) as well as a smaller amount of coal-fired power generation with carbon capture and sequestration (by 14 TWh). It allows uncontrolled coal-fired power generation to operate slightly more (by 6 TWh).

[20] Note that these comparisons use the 2025 model year to be comparable with NRDC's published output.
[21] We show both the base case and policy case so that CHP and energy efficiency are presented in a comparable way.

Figure 12. Generation Mix, 2025



Costs

Including CHP as a new build option helps lower compliance costs as compared to a compliance strategy that does not specifically allow CHP to be used as a means of compliance. We look at costs in two ways: *total system costs*, and 111(d) *compliance costs*. In calculating total system costs, we assigned costs to the CHP facilities in the same way we assigned emissions—based on the portion of the energy input to the system that is used for electricity production as opposed to thermal production. In calculating compliance costs, we factor in only the CHP compliance costs that covered sources would need to pay to purchase CHP credits. In both cost estimates, to be comparable with NRDC's approach, we include the end user energy efficiency investment costs.

As compared to the NRDC Reference Case, the total system costs for the CHP 111(d) Policy Case comes to $8,113 million, which is slightly less than the NRDC Moderate, Constrained Efficiency policy case, which did not specifically consider CHP as a compliance option. Factoring in only the CHP compliance costs that covered sources would need to pay to purchase CHP credits, covered sources would reduce their compliance costs by more than a third as compared to the NRDC Moderate, Constrained Efficiency policy case.

Emissions Reductions

The CHP 111(d) Policy Case achieves the emission rate standards consistent with NRDC's Moderate, Constrained Efficiency scenario and results in significant emissions reductions—a 29.4 percent reduction from NRDC's Reference Case in 2025. These results show slightly higher emissions than NRDC's own scenario because they factor in the portion of the CHP facility emissions attributable to electricity.

Conclusions

Our study found that combined heat and power can offer a cost-effective solution towards achieving 111(d) compliance. At the same time, a system-based 111(d) policy design puts these efficiency investments 'over the top,' shortening payback periods to the point that companies will choose to undertake projects at a number of industrial, commercial and institutional facilities. Allowing incremental combined heat and power to participate in 111(d) compliance alongside other clean energy sources will help ensure the full amounts of CHP deployment forecasted under the CHP Base Case and CHP 111(d) Policy Case are realized. Further, we note that while this study focused on one design of a system-based standard. Depending on the impact on carbon prices and spark spread, and also the choice of crediting methodology, other designs could have an even greater impact in spurring CHP.

The CHP opportunity is particularly important in states with significant technical potential and that also are expected to have higher-than-average compliance costs due to heavy reliance on coal-fired power generation and/or more limited availability of other compliance options. We find the greatest opportunity in the Midwest, western portions of the PJM transmission organization territory, and some northern portions of the Southeast Electric Reliability Council (SERC) territory. In these states and regions, CHP can meaningfully contribute to 111(d) compliance while bringing a range of secondary benefits, potentially including manufacturing competitiveness, job creation, resilience to electrical disruptions, and reduced electrical grid congestion.

To take advantage of this opportunity to simultaneously drive greater industrial, commercial and institutional efficiency as well as power sector 111(d) compliance, states will need to adopt a system-based approach that explicitly allows combined heat and power to be used for compliance on a similar basis to other clean energy sources. In addition, states wanting to foster this technology will need to consider how to fairly apportion emissions between the thermal and electricity energy outputs. Depending on the chosen design of the system-based approach, methods may also be needed to fairly quantify emissions and emissions reductions.

A final conclusion is that 111(d) policy alone will not drive achievement of the President's goal of encouraging 40 GW of CHP by 2020, but can play an important role in achieving that target. Additional solutions are needed to improve the attractiveness at the state level by lowering interconnection, standby and other costs for CHP units to access the grid. Moreover, education and risk mitigation measures could be helpful in improving the likelihood that economical CHP will be developed. Greater interest by electric utilities in CHP investments could be helpful in fully developing economical CHP, and the self-interest afforded by support towards 111(d) compliance could offer utilities a new reason to evaluate such options.

Appendix: State-by-State CHP Deployment Results, MW in 2030

State	Base Case					Policy Case (Cumulative)					Δ, Base to Policy Case (all sizes)
	50-1,000 kW	1-5 MW	5-20 MW	>20 MW	Total Market (all sizes)	50-1,000 kW	1-5 MW	5-20 MW	>20 MW	Total Market (all sizes)	
Alabama	0	0	0	46	46	0	7	0	119	126	80
Arizona	0	1	0	26	27	0	13	7	80	100	72
Arkansas	0	0	0	15	15	0	5	0	49	54	39
California	354	540	336	574	1,803	266	564	348	583	1,761	-42
Colorado	0	6	2	24	32	0	23	11	39	73	41
Connecticut	5	37	27	80	149	6	39	28	82	154	5
Delaware	0	7	11	132	150	0	7	11	133	151	1
Florida	0	17	2	66	85	0	44	10	99	154	68
Georgia	0	0	0	45	45	0	23	0	192	214	169
Idaho	0	1	0	17	18	0	0	0	14	14	-4
Illinois	0	0	0	47	47	0	34	8	309	351	304
Indiana	0	3	0	75	78	3	64	38	201	305	227
Iowa	0	0	0	16	16	0	16	3	99	118	102
Kansas	0	5	2	26	32	0	24	20	47	91	60
Kentucky	0	0	0	10	10	0	13	7	80	100	90
Louisiana	0	0	0	0	0	0	0	0	43	43	43
Maine	7	22	12	22	63	5	23	12	22	62	-1
Maryland	0	39	20	136	195	4	51	25	150	229	35
Massachusetts	81	121	54	153	409	56	122	54	153	385	-24
Michigan	0	68	44	239	352	25	145	90	310	570	218
Minnesota	0	12	2	147	162	0	21	9	185	215	54
Mississippi	0	0	0	81	81	0	12	8	166	185	104
Missouri	0	0	0	27	27	0	17	3	95	115	89
Montana	0	1	1	29	32	0	3	3	41	47	15
Nebraska	0	14	4	38	57	2	28	9	49	89	32
Nevada	0	0	0	19	19	0	0	0	21	21	2
New Hampshire	33	26	13	30	101	27	25	13	30	95	-6
New Jersey	79	167	133	195	573	60	170	134	196	560	-14
New Mexico	0	0	0	44	44	0	5	1	125	130	86
New York	0	99	41	132	272	0	112	47	138	297	26
North Carolina	0	0	0	38	38	0	6	0	93	100	62
North Dakota	0	2	1	66	69	0	6	5	97	107	39
Ohio	0	0	0	79	79	0	64	39	384	486	407
Oklahoma	0	0	0	5	5	0	0	0	10	10	4
Oregon	0	0	0	25	25	0	0	0	20	20	-5
Pennsylvania	0	51	28	391	470	0	104	63	505	671	201

Rhode Island	13	23	17	0	53	10	23	17	0	50	-2
South Carolina	0	0	0	33	33	0	3	0	96	99	66
South Dakota	0	3	0	0	3	0	10	4	0	13	10
Tennessee	0	0	0	235	235	2	47	26	468	543	308
Texas	0	0	0	116	116	0	0	0	170	170	54
Utah	0	0	0	2	2	0	1	0	9	11	9
Vermont	3	9	1	20	32	3	9	1	20	33	1
Virginia	0	0	0	128	128	0	22	15	310	347	219
Washington	0	0	0	0	0	0	0	0	0	0	0
West Virginia	0	0	0	2	2	0	11	9	9	30	28
Wisconsin	0	25	0	110	134	0	56	37	157	250	116
Wyoming	0	0	0	54	54	0	3	1	147	151	97
U.S. Total	574	1,297	752	3,796	6,419	468	1,974	1,117	6,343	9,902	3,483

Note: Alaska and Hawaii were not included in the model.

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