WORLD RESOURCES INSTITUTE

Appendix

POWER SECTOR OPPORTUNITIES FOR REDUCING CARBON DIOXIDE EMISSIONS

Appendix A: Detailed Overview of Methods

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WRI developed projections of state-level carbon dioxide (CO_2) emissions reductions from the power sector based on existing policies and other reduction opportunities using available infrastructure, including:

- Meeting the current requirements under the state's renewable portfolio standard (RPS) and energy efficiency resource standard (EERS), where they exist
- Increasing combined heat and power (CHP) capacity at commercial and industrial facilities
- Fully utilizing existing natural gas combined cycle (NGCC) capacity
- Increasing the efficiency of the existing coal-fired power plant fleet.

The model used to create these projections builds on a variety of data from EIA's Annual Energy Review, Form EIA-860, and Form EIA-923, as well as data compiled for WRI's report entitled *Can the U.S. Get There from Here?*[1] Depending on availability, we rely on electric generation projections from state environmental and energy agencies or EIA's *Annual Energy Outlook 2012* (*AEO 2012*). We used *AEO 2012* instead of *AEO 2013* or *AEO 2014* because some of the underlying modeling builds on a previous WRI analysis that relied on projections from *AEO 2012*. This analysis is intended to provide a technically feasible range of CO_2 reductions; it is not an economic analysis. See Figure 1 for a summary of our methodology for existing policies and measures that use available infrastructure. The additional steps for expanded policies are shown in Step 4, below.

Figure 1 | **Methodology Summary**

STEP 1.
Reference Case Projections

STEP 2.
Benefits from Implementing Existing Policies (if not included in Reference Case)

Step 2a.
CO_2 benefit from reduced generation
Energy Efficiency Resource Standard

Step 2b.
CO_2 benefit from increasing the proportion of generation from renewable resources
Renewable Portfolio Standard

Adjusted Reference Case

STEP 3.
Benefits from Utilizing Existing Infrastructure

Step 3a.
CO_2 benefit from reduced generation
Increased Utilization of CHP at Industrial and Commercial Facilities

Step 3b.
CO_2 benefit from increasing the use of natural gas capacity and decreasing use of coal capacity
Increased Utilization of Existing Natural Gas Capacity

Step 3c.
Decreased emissions from remaining coal-fired generation
Increased Efficiency at Remaining Coal Plants

Step 1. Determine reference case electric generation and carbon dioxide (CO_2) emissions

For all states, we utilized EIA's *Annual Energy Review* for historical electricity generation[2] and CO_2 emissions[3] by fuel (coal, natural gas, other fossil, nuclear, and renewable) during the period from 2005 through 2011. Electric utilities, independent power producers, and commercial and industrial non-CHP units were included in this analysis. A forecast of generated electricity for each state through 2030 was determined by one of two methods as described below, depending on data availability (see Table 1).

Projections available from state environmental and energy agencies. Many state public utility commissions (PUCs) or other agencies provide forecasts of electricity generation for the state. Where available, we utilized these forecasts to help develop our own electricity generation projections. For each year, the percent change in the forecasted energy consumed by fuel, or electricity generated by fuel in the state's power sector, was applied to the state's generation in 2011 to create projections through 2030.Unless the source of the forecasted data made clear that it did *not* include planned retirements, new power plant builds, or fully meeting existing or soon to be adopted policies or programs (including new U.S. EPA rules), we conservatively assumed these were already captured in the reference case projections.

Projections from EIA's *AEO 2012*.When forecasts were unavailable from state agencies, we obtained regional projections of annual growth rates of electricity generation by fuel from *AEO 2012*.Because projections at the regional level may not accurately represent the trends expected to occur in each state, we used *AEO 2012* only when state-level projections were unavailable. EIA uses North American Electric Reliability Corporation (NERC) sub-regions for modeling the power sector, and some states overlap with multiple regions. When this occurs, we calculate the average annual growth rate of electricity generation by fuel weighted by the proportion of electric generation each region contributes to the state. These weighting factors are calculated using EPA's eGRID 2012 database, which lists each power plant in the United States by state and NERC sub-region.[4]

Where *AEO 2012* projections were used, we did not calculate an adjusted reference case since existing renewable portfolio standards and energy efficiency resource standards were captured in these projections, unless the proportion of in-state renewable generation did not meet the state's RPS requirement.[5] In these instances, we assume the RPS is met through in-state generation, and adjust the reference case projections accordingly.

To project CO_2 emissions, we calculated state-specific emissions rates for each fuel for 2011 and applied these rates to projected generation. Because we examined improved efficiency of existing coal units as a CO_2 reduction measure in this analysis, we did not assume any efficiency increases in our reference case projections.[6]

Step 2: Calculate benefits from implementing existing policies

We calculated the CO_2 benefits from existing state policies—including energy efficiency resource standards and renewable portfolio standards—for states that had such policies in place. We assumed that any goals or required targets set by existing policies would be achieved. If state-level projections did not include existing policies, we incorporated the emissions savings they generated into an "adjusted reference case" projection.

Step 2a.Determine reduced demand from existing energy efficiency resource standards

Reducing electricity demand through improved end-use efficiency results in less electricity generated, thereby reducing CO_2 emissions from fossil fuel-fired power plants. A variety of state policies and programs already drive efficiency improvements, including EERS, programs funded by system benefit charges, as well as least-cost procurement.[7] In some cases, CO_2 emissions savings from existing EERS may be captured in the reference case projections and therefore may not generate additional emissions reductions. For instance, *AEO 2012* did not explicitly model state energy efficiency programs, but we conservatively assume that programs in existence in 2011 and earlier are captured through regional electricity trends. When state forecasts were used, we conservatively assumed that existing EERS were captured in the reference case unless the source explicitly stated that electricity savings from existing programs were excluded.

If reference case projections did not include effects of the EERS, we implemented the annual percent savings required by each state's target from the *Database of State Incentives for Renewables & Efficiency* (DSIRE)[8] (see Table 2). For states without efficiency standards, we based future efficiency gains on input from in-state experts. We assumed states achieved these levels of energy savings by implementing any number of relevant measures, including an EERS, financial incentives, or other measures. Typically, energy efficiency targets do not apply to all electricity sales within a state. We accounted for this by adjusting electricity savings by the percent of electricity sales covered by the target as estimated by American Council for an Energy-Efficient Economy (ACEEE).[9] This provided an estimated reduction of in-state demand for electricity, which was translated to an estimate of reduced emissions from in-state generation. We assumed that this percent reduction in demand resulted in reduced in-state generation.[10] We assumed power plant operators maximized carbon-free generation, so that reduced demand did not affect nuclear generation, but proportionally reduced generation from the other resources (coal, natural gas, and other fossil fuels; renewable sources were reduced only in those states with an RPS expressed as a percentage of total sales).[11] Resulting emissions savings were calculated using the annual reference case emissions rates for each fuel type.[12]

Some states count CHP toward their energy efficiency standards and some states may allow other policies and programs to count under their energy efficiency goals. In our analysis, we conservatively assumed that the maximum amount of eligible CHP generation counted toward the EERS. This reduced the additional energy and CO_2 emissions savings achieved through increased utilization of CHP, while minimizing the potential for double-counting the savings.

Step 2b: Calculate the benefits from meeting existing renewable energy standards

Renewable portfolio standards (RPS) or alternative energy standards specify a percentage of electricity generation (or sales) that must be met by renewable or other alternative energy sources.[13] In some cases, CO_2 emissions savings from renewable standards were captured in the reference case projections and therefore did not result in additional emissions reductions. For instance, *AEO 2012* included all mandatory renewable portfolio standards that were implemented in 2011 or earlier in its reference case projections. When state forecasts were used, we conservatively assumed that renewable portfolio standards were captured in the reference case unless the source explicitly indicated that such programs were excluded.

When renewable portfolio standards were not included in the reference case projections, we assumed each state met its annual incremental RPS goals, as documented in the DSIRE database published in March 2013 (see Table 3).[14] For states without RPS goals, we based future growth of renewable generation on input from in-state experts. We assumed states achieved these levels of renewable generation by implementing any number of relevant measures, including an RPS, financial incentives, or other measures. Since most renewable targets are tied to demand, we estimated renewable generation by multiplying the percent annual goal by the projected electric generation after it was adjusted for the effects of energy efficiency programs. For the purposes of this analysis, we assumed that new renewables development occurs in-state to help comply with new CO_2 standards. For this reason, we assumed that all new renewable electricity generated for compliance with the state's RPS after 2011 occurs in-state, and utilities do not purchase out-of-state renewable energy certificates or make alternative compliance payments for compliance purposes. Under this assumption, any contracts for out-of-state renewable energy remain in place through 2030, but all new renewable energy capacity is built in-state. For those states that have only used in-state generation for RPS compliance to date, we assume that all future generation for RPS compliance will also be met through in-state generation. We assumed that the incremental renewable generation displaced fossil fuel use in proportion to the annual energy mix for electricity generation.[15] Resulting emissions savings were calculated using the reference case emissions rates for each fuel type.

Step 3: Calculate benefits from utilizing available infrastructure

In addition to meeting renewable or efficiency standards that are already on the books, states can take additional measures using existing infrastructure to help meet a potential emissions standard for the power sector.

Step 3a: Determine reduced demand (and increased on-site emissions) from policies that promote CHP systems

State measures that can facilitate CHP deployment include standard interconnection rules, reduced stand-by rates, net metering policies, technical assistance, and financial incentives. We assumed that states implementing these types of programs would add new CHP capacity as a result. If states did not have explicit CHP capacity targets or projected capacity increases as a result of existing programs, we assumed that existing practices (such as those previously described) would allow states to achieve 25 percent of their technical potential for new CHP as estimated by ICF International (see Table 4).[16,17] We assumed that CHP capacity would increase at a constant rate between 2011 and 2030. The CHP benefits presented in this section and on the summary figures of each fact sheet only reflect additional benefits beyond those counted toward state EERS, where applicable.

We estimated the electricity savings and the net increase in onsite fuel combustion associated with new CHP capacity using documented assumptions from ICF International's *Effect of a 30 Percent Tax Credit on the Economic Potential for Combined Heat and Power*.[18] We assumed that CHP units that produce cooling, heating, and power used half their thermal output to displace purchased electricity (by replacing electric chillers with thermally driven absorption chillers) and half to displace onsite fuel consumption. We also assumed that all new CHP units used 100 percent natural gas.[19] We assumed that this percent reduction in demand resulted in reduced in-state generation.[20] We assumed power plant operators maximized carbon-free generation so that reduced demand did not affect nuclear generation, but proportionally reduced generation from the other resources (coal, natural gas, and other fossil fuels; renewable sources were reduced only in those states with an RPS expressed as a percentage of total sales). Resulting emissions savings were calculated using the annual reference case emissions rates for each fuel type. We assumed that the CO_2 emissions associated with increased on-site fuel consumption from CHP would be deducted from the credit provided to CHP units under power sector regulations. Thus, we incorporated these additional CO_2 emissions into our projections.

Step 3b: Calculate underutilized natural gas capacity

To calculate underutilized (i.e., slack) natural gas capacity, we first determined the existing NGCC capacity and the current (2011) generation from these units. Because EIA's summary tables from the *Annual Energy Review* did not break down natural gas generation or capacity by technology type (e.g., natural gas combined cycle, or NGCC), we utilized two databases to calculate these values—EIA's *existing units* database from Form EIA-860,[21] and the generation and fuel data database from Form EIA-923.[22,23]

We estimated potential generation by assuming each existing NGCC unit was run at 75 percent capacity for an entire year (see Table 5).[24] We then compared potential generation to projected generation to determine the electricity that could be generated from the state's slack natural gas capacity in 2020. We assumed that slack natural gas capacity would begin to be utilized starting in 2015, increasing to maximum utilization in 2020.[25, 26] We applied this approach to all subsequent years—regardless of changes in electricity demand or coal plant efficiency—so that the maximum amount of electricity would be generated from existing NGCC units from 2020 through 2030. To provide a conservative estimate, we utilized the listed summer capacity for all NGCC units, which is sometimes lower than nameplate capacity due to electricity used for station service or auxiliaries during the period of peak summer demand.[27] If states reported planned or under construction NGCC units in the EIA-860 database, which contains proposed units through 2017, we assumed these units would come online and run the maximum potential capacity calculated previously, increasing the state's potential generation from NGCC units. This assumption is sensitive to relative fuel prices.

The CO_2 emissions benefit was calculated as the difference between reference case (or adjusted reference case, if applicable) emissions levels and the emissions levels resulting from the fleet's new fuel mix. We did not account for the increases in methane associated with the increased production of natural gas due to a higher demand for the fuel. Going forward, industry should work with EPA to reduce methane leakage rates from natural gas systems.[28]

Step 3c: Calculate the benefit from increasing the efficiency of the existing coal-fired power plant fleet

According to the National Energy Technology Laboratory and researchers at Lehigh University, it is likely that the existing coal fleet could achieve a 5 percent increase in efficiency on average.[29] Existing coal plants can increase efficiency through refurbishment and improved operation and maintenance practices, though the actual efficiency potential depends on plant age and other physical limitations.[30, 31] Another option to reduce the emissions intensity of a coal plant is co-firing with natural gas using the igniters that are already built into many existing pulverized coal boilers.[32] For purposes of this analysis, we conservatively assumed that the coal-fired power plant fleet remaining after step 3b decreases its heat rate by

2.5 percent, half of these potential levels.[33] This in turn would reduce CO_2 emissions by 2.5 percent at existing coal plants. The 2.5 percent improvement rate is assumed to be a fleet-wide average, as some units may be able to achieve greater or fewer reductions.

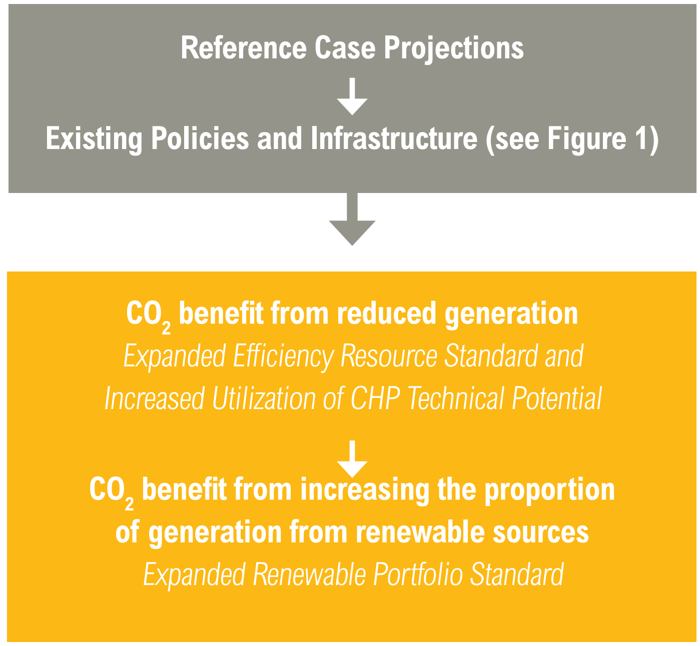
Some studies have examined the phenomenon that improving the efficiency of coal plants would decrease the marginal cost of generation, which would increase their competitiveness and lead to increased operation at those plants (and decreased generation at gas plants).[34] However, for purposes of this analysis we assumed that each state would maximize its fleet of power plants fueled by energy sources other than coal in order to reduce emissions, and so this rebound effect would not materialize.[35]

Step 4: Calculate GHG benefits from expanded policies

In addition to what states can achieve under existing laws and utilizing available resources, we illustrate the CO_2 benefits that states could achieve if they expanded current EERS and RPS targets and measures to promote CHP (see Table 6).

To estimate the CO_2 benefits that states could achieve if they build off existing energy efficiency programs and expand their current EERS targets, we assumed that states achieve their targets more quickly than their existing ramp-up schedules. If annual state savings targets were less than 2 percent, we assumed that the standards would be increased to 2 percent per year, consistent with the assumption made by Synapse Energy Economics and the Natural Resources Defense Council in their analyses.[36] For states without efficiency standards, we based future efficiency gains on input from in-state experts. We assumed states achieved these levels of energy savings by implementing any number of relevant measures, including an EERS, financial incentives, or other measures. We assumed that states would continue to achieve the maximum annual rate of electricity savings from their existing target date through 2030.We assumed that expanded measures to promote CHP systems would allow states to increase capacity to 50 percent of their technical potential in 2030. Where applicable, we conservatively assumed that the maximum amount of eligible CHP would be applied toward expanded state efficiency standards.

Figure 2 | **Estimating the CO_2 Benefit of Expanded Policies and Infrastructure**



To estimate the CO_2 benefits that states could achieve with an expanded RPS, we assumed that states would continue to increase their renewable generation after their target was reached. The rate of increase was determined by the average annual rate of increase over the period covered by the RPS. If annual targets require renewable growth of less than 1 percent per year, we assumed that the standards would be increased to 1 percent per year, the most common average growth rate required by mature state programs. For states without RPS goals, we based future growth of renewable generation on input from in-state experts. We assumed states achieved these levels of renewable generation by implementing any number of relevant measures, including an RPS, financial incentives, or other measures. We used the same methods to calculate the CO_2 benefits from each measure as described in the existing policies section. To ensure that slack natural gas capacity remains utilized, we assumed that demand reductions from expanded measures only displaced coal and other fossil generation. To calculate resulting CO_2 emissions, we applied the emissions rate for each fuel type based on the new fossil fuel mix after accounting for existing policies and utilization of slack natural gas capacity.

COMPARISON WITH EPA'S PROPOSED TARGETS

For the two state fact sheets published after EPA released its proposed Clean Power Plan (Missouri and Virginia), we show the results in terms of an emission rate (pounds CO_2 per megawatt-hour) instead of absolute emissions (million metric tons CO_2). This allows for easier comparison with EPA's proposed emission rate targets for each state.[37]

We convert from absolute emissions to an emission rate by dividing power sector CO_2 emissions by total generation, with two modifications for consistency with EPA's Clean Power Plan: 1) we omit generation from hydropower since EPA does not count existing hydropower in its calculation of state targets, and 2) we only include 6 percent of nuclear generation since this is the amount that EPA counts in its calculation of state targets.[38]

KEY UNCERTAINTIES AND LIMITATIONS

- This is not an economic analysis. Due to modeling limitations, we were not able to estimate the costs and benefits from taking the measures we included in our analysis.
- This analysis focuses solely on CO_2 emissions. We do not account for methane emissions associated with natural gas production, processing, and transmission.
- The EPA has not yet proposed a national emissions standard for existing power plants. We use the NRDC proposal—the only detailed plan of potential rules with requirements for each individual state that existed at the time we conducted this analysis—for illustration purposes only and not as an endorsement of any particular rules. State measures may be counted differently under the actual rules developed by EPA, thus actual compliance levels could potentially be greater or less than what was modeled in our analysis.
- Where possible, we relied on state-specific electricity projections. Where these were not available, we utilized regional projections from the EIA Annual Energy Outlook, which might not accurately capture expected state-specific trends. Additionally, because we relied on these other data sources for projected electric generation, any limitations inherent in those projections also hold true for our analysis.
- We assume the entire NGCC fleet in each state can achieve a capacity factor of 75 percent. Unit-specific factors may decrease the maximum capacity factor an individual NGCC unit can achieve.
- If states are implementing policies that promote increased CHP utilization, but do not have a specific target for new CHP capacity, we assume CHP capacity increases to 25 percent of the state's technical potential for new CHP (as estimated by ICF International). Existing policies may actually achieve fewer or greater new CHP installations.
- We assumed utilities would not purchase out-of-state renewable energy certificates or make alternative compliance payments for compliance with RPS requirements; instead, we assumed each state complied with in-state renewable generation only.

Table 1 | **Reference Case Assumptions**

STATE	SOURCE	NOTES
Ohio	Public Utilities Commission of Ohio. 2012. *Ohio Long-Term Forecast of Energy Requirements 2011–2030.* Accessible at: <http://www.puco.ohio.gov/emplibrary/files/util/UtilitiesDeptReports/OhioLTFEnergyReq2011-2030.pdf>.	Provided fuel-specific energy requirements for electricity generation in Ohio. For modeling purposes, we calculated the annual percent change in energy consumption by fuel. These values were applied to Ohio's 2011 electric generation to forecast generation by fuel type from 2012 through 2030. Existing RPS and EERS requirements are not included in reference case forecasts.
North Carolina	U.S. Energy Information Administration, *Annual Energy Outlook 2012*	Overlaps with SERC Reliability Corporation Virginia-Carolina and Central regions.
Michigan	*U.S. Energy Information Administration, Annual Energy Outlook 2012*	Overlaps with Reliability First Corporation Michigan, Reliability First Corporation West, Midwest Reliability Council East, and Midwest Reliability Council West regions.
Pennsylvania	U.S. Energy Information Administration, *Annual Energy Outlook 2012*	Overlaps with Reliability First Corporation East and West regions.
Illinois	U.S. Energy Information Administration, *Annual Energy Outlook 2012*	Overlaps with Midwest Reliability Council West, Reliability First Corporation West, and SERC Midwest regions.
Colorado	U.S. Energy Information Administration, *Annual Energy Outlook 2012*	Overlaps with Western Electricity Coordinating Council Rockies, Southwest, and Northwest Power Pool Area regions.
Wisconsin	U.S. Energy Information Administration, *Annual Energy Outlook 2012*	Overlaps with Midwest Reliability Council West, Midwest Reliability Council East, and Reliability First Corporation regions.
Minnesota	U.S. Energy Information Administration, *Annual Energy Outlook 2012*	Overlaps with Midwest Reliability Council West.
Tennessee	U.S. Energy Information Administration, *Annual Energy Outlook 2012*	Overlaps with Reliability First Corporation West and SERC Reliability Corporation Central.
Arkansas	U.S. Energy Information Administration, *Annual Energy Outlook 2012*	Overlaps with Southwest Power Pool Area, SERC Reliability Corporation Delta, and SERC Reliability Corporation Central regions.
Missouri	U.S. Energy Information Administration, *Annual Energy Outlook 2012*	Overlaps with Midwest Reliability Council West, Southwest Power Pool North and South, and SERC Reliability Corporation Central, Delta, and Gateway regions.
Virginia	U.S. Energy Information Administration, *Annual Energy Outlook 2012;* projections from Dominion Power and Appalachian Power	Relied on Dominion Power and Appalachian Power projections of electricity generation by fuel type found in their annual integrated resource planning reports (accounting for 80 percent and 2 percent of Virginia's generation in 2012, respectively). Both utilities serve customers in neighboring states, so we apportioned each utility's generation projections to Virginia based on the proportion of electricity generated in each of their service states by fuel type as reported in EIA's Form 923 in 2012. Relied on regional projections of annual electricity generation growth rates by fuel from *AEO 2012* for the remaining electricity generated in Virginia.

Table 2 | **State Energy Efficiency Resource Standards**

STATE	EERS
Ohio	22 percent cumulative electricity savings between 2009–25; annual savings schedule of 0.3 percent per year in 2009, ramping up to 1 percent per year from 2013–18 and 2 percent per year from 2019–25.
North Carolina	Investor-owned utilities may meet up to 25 percent of renewable energy requirements through energy efficiency measures (including CHP) through 2020, and up to 40 percent starting in 2021. Because NC does not have a specific EE target, in order to estimate the electricity savings and CO_2 benefit of the efficiency gains captured in the *AEO 2012* reference case we assume that the annual efficiency gains contained in the *AEO 2012* reference case are analogous to the annual electric savings targets (0.5 percent) estimated by ACEEE's *2012 State Energy Efficiency Scorecard*.
Michigan	Annual electricity savings of 0.3 percent of sales in 2009, ramping up to 1 percent in 2012 and each year thereafter.
Pennsylvania	Phase I requires that electric distribution companies with at least 100,000 customers must reduce electricity sales by a cumulative 1 percent by May 2011 and a cumulative 3 percent by May 2013 compared to a 2009/2010 baseline. Phase II sets specific energy efficiency targets for each utility that range from 1.6 percent to 2.9 percent cumulative savings from 2013 through 2016 compared to a 2009/2010 baseline. Because PA has a cumulative rather than annual target, in order to estimate the electricity savings and CO2 benefit of the efficiency gains captured in the *AEO 2012* reference case we assume that the annual efficiency gains contained in the *AEO 2012* reference case are analogous to the annual electric savings targets (0.9 percent) estimated by ACEEE's *2012 State Energy Efficiency Scorecard*.
Illinois	Annual electricity savings starting at 0.2 percent of sales in 2008, ramping up to 1 percent in 2012 and 2 percent in 2015 and each year thereafter.
Colorado	Investor-owned utilities required to achieve electricity savings of at least 5 percent of 2006 electricity sales by 2018. In 2011, the Public Utilities Commission raised the target for Xcel Energy to annual targets of 1.14 percent in 2012 ramping up to 1.68 percent in 2020. We assume that the annual efficiency gains contained in the *AEO 2012* reference case are analogous to the annual electric savings targets (1.4 percent) estimated by ACEEE's *2012 State Energy Efficiency Scorecard*.
Wisconsin	Utilities must spend 1.2 percent of their annual gross operating revenues on energy efficiency programs. In order to estimate the electricity savings and CO_2 benefit of the efficiency gains captured in the *AEO 2012* reference case, we assume that the annual efficiency gains contained in the *AEO 2012* reference case are analogous to the annual electric savings targets (0.75 percent per year from 2011-2015) as estimated by ACEEE.
Minnesota	Annual electricity savings of 1.5 percent in 2010 and each year thereafter.
Tennessee	No existing efficiency standard; 1 percent annual savings starting in 2015 through a new efficiency standard, financial incentives, or other measures.[39]
Arkansas	Investor-owned utilities must achieve savings of 0.25 percent of 2010 electricity sales ramping up to 0.75 percent in 2013. The 2014 target has been set at 0.9 percent of 2013 electricity sales. Targets for the next three year period are currently under discussion.

STATE	EERS
Missouri	Missouri's Energy Efficiency Investment Act established voluntary energy efficiency savings goals of 0.3 percent of sales in 2012, ramping up to 0.9 percent in 2015 and 1.7 percent in 2019, for cumulative savings of nearly 10 percent of electricity sales by 2020. We treat this as an existing clean energy policy assuming associated savings are not captured in the reference case.
Virginia	Virginia has a voluntary goal to reduce electricity consumption by 10 percent below 2006 levels by 2022. In our scenario for Virginia that examines opportunities from existing infrastructure only, we assumed no additional efficiency gains from this program beyond any efficiency assumed by Dominion or Appalachian Power in their integrated resource plans. The state's Board on Energy Efficiency is developing a strategic plan to accelerate the goal by two years.

Table 3 | **State Renewable Portfolio Standards**

STATE	RENEWABLE TARGET (% OF SALES)	MODELING NOTES
Ohio	12.5 percent by 2024	RPS not included in BAU projections.
North Carolina	12.5 percent by 2021	RPS included in BAU projections; adjusted to ensure RPS met through in-state generation. We assume the efficiency savings in the *AEO 2012* reference case are equivalent to 0.5 percent annual electric savings as estimated in ACEEE's *2012 State Energy Efficiency Scorecard*. This results in 4 percent of the REPS renewable requirement being met through efficiency (see table in Step 2a for additional information).
Michigan	10 percent by 2015	RPS included in BAU projections; adjusted to ensure RPS met through in-state generation
Pennsylvania	8 percent by 2021 (Tier I) 10 percent by 2021 (Tier II)	RPS included in BAU projections; adjusted to ensure AEPS met through in-state generation. For conservative purposes, modeled Tier I requirement only since some fossil-based energy sources qualify as a Tier II resource.
Illinois	Investor-owned utilities: *25 percent by 2025*	RPS included in BAU projections. Adjusted to ensure all new renewable electricity generated after 2011 for compliance with the RPS occurs in-state.
Colorado	Investor-owned utilities: *30 percent by 2020*; Electric cooperatives with less than 100,000 custom ers and municipal utilities with greater than 40,000 customers: *10 percent by 2020*; Electric cooperatives with 100,000 customers or more: *25 percent by 2020*	RPS included in BAU projections; adjusted to ensure RPS met through in-state generation.
Wisconsin	10 percent by 2015	RPS included in BAU projections. Adjusted to ensure all new renewable electricity generated after 2011 for compliance with the RPS occurred in-state.
Minnesota	Xcel Energy: *30 percent by 2020* All other utilities: *25 percent by 2025* Utilities must also supply an additional 1.5 percent of their sales from solar energy by 2020	RPS included in BAU projections. Adjusted to ensure all new renewable electricity generated after 2011 for compliance with the RPS occurred in-state
Tennessee	No existing target	Assumed renewable generation grew by 3.4 percent from 2012 to 2030. This is consistent with the historical rate (2002-2011) and results in 15 and 21 percent renewable generation in 2020 and 2030, respectively.
Arkansas	No existing target	Assumed renewable generation reaches 15 percent of electricity sales in 2020 and 25 percent in 2030 (up from 6 percent in 2012)

STATE	RENEWABLE TARGET (% OF SALES)	MODELING NOTES
Missouri	Investor-owned utilities: 15 percent by 2021	RPS included in BAU projections. Adjusted to ensure all new renewable electricity generated after 2011 for compliance with the RPS occurred in-state.
Virginia	Voluntary program for IOUs: goal of 15 percent by 2025 (based on 2007 sales, excluding the average annual percentages of nuclear generation from 2004-2006)	Voluntary program not included in BAU projections, beyond any additional renewable generation assumed by Dominion or Appalachian Power in their integrated resource plans.

Table 4 | **Combined Heat and Power Assumptions**

STATE	CHP PROGRAMS AND POLICIES	SOURCE FOR CHP TECHNICAL POTENTIAL	EXISTING CHP CAPACITY	CHP CAPACITY IN 2030
Ohio	Ohio has partnered with U.S. DOE to provide guidance, technical assistance, and sharing of best practices among industrial facilities to promote CHP. The state also began offering CHP as an eligible resource to count toward its energy efficiency resource standard in 2012.	ICF International; estimate prepared in 2012 for Ohio Coalition for Combined Heat and Power	521MW	2,971 MW; 50 percent of electricity savings go toward meeting the state's EERS.
North Carolina	In 2010, North Carolina extended its renewable energy tax credit so that businesses can receive up to $2.5 million for the installation of a CHP system through 2015. North Carolina also allows energy produced from a CHP system that uses nonrenewable energy sources to be counted as an energy efficiency measure under its Renewable Energy and Energy Efficiency Standard.	ICF International, accessible at <http://www.meede.org/wp-content/uploads/IECA-RAC-NC-8-4-Hedman-V2.pdf>	1,530 MW	2,769 GW; Because there is no maximum set on how much CHP can be used as an energy efficiency measure under the state's Renewable Energy and Energy Efficiency Standard, 100 percent of electricity savings go toward meeting the state's Renewable Energy and Energy Efficiency Standard. This is assumed to be captured in the *AEO2012* reference case.
Michigan	The state allows electricity savings from CHP to count toward its energy efficiency resource standard.	ICF International, Effect of a 30 Percent Tax Credit on the Economic Potential for Combined Heat and Power, 2010	3,000 MW	4,187 MW; 13 percent of electricity savings go toward meeting the state's EERS
Pennsylvania	The state allows CHP to count towards the Tier II resource requirement.	Pennsylvania Combined Heat and Power Market Assessment, U.S. DOE Mid-Atlantic Clean Energy Application Center, Prepared for The State of Pennsylvania. April 2011. http://www.maceac.psu.edu/states/MACEAC%20CHP%20Market%20Analysis%20Pennsylvania.pdf	3,303 MW	5,103 MW; No electricity savings go towards meeting the state's EERS. Because we do not model Tier II resources, no electricity savings go towards meeting the state's AEPS.
Illinois	Renewable-fueled CHP is an eligible resource under the RPS. The state allows electricity savings from CHP to count as an energy efficiency measure under its RPS on a case-by-case basis.	ICF International, *Effect of a 30 Percent Tax Credit on the Economic Potential for Combined Heat and Power, 2010*	1,300 MW	3,000 MW; 100 percent of electricity savings count as an energy efficiency measure under the state's EERS
Colorado	CHP is eligible for standardized interconnection. Renewable-fueled CHP is an eligible resource for the distributed generation carve-out for investor-owned utilities of 3 percent of sales by 2020 under the states' RPS.	ICF International estimates prepared for ACEEE in 2012, accessible at http://www.aceee.org/sites/default/files/publications/researchreports/ie123.pdf	677 MW	1,120 MW; not an eligible resource under the state's EERS

STATE	CHP PROGRAMS AND POLICIES	SOURCE FOR CHP TECHNICAL POTENTIAL	EXISTING CHP CAPACITY	CHP CAPACITY IN 2030
Wisconsin	Wisconsin has favorable interconnection standards and CHP systems are eligible for net metering.	ICF International, *Effect of a 30 Percent Tax Credit on the Economic Potential for Combined Heat and Power*, 2010	1,600 MW	2,500 MW; Wisconsin's energy efficiency standard does not prohibit CHP, but CHP has not been included in utilities' plans to meet the standard through 2015, so we do not count any of the CHP benefits toward the energy efficiency standard.
Minnesota	Renewable-fueled CHP is an eligible resource under the RPS. The state allows electricity savings from CHP to count as an energy efficiency measure under its EERS on a case-by-case basis.	ICF International, *Effect of a 30 Percent Tax Credit on the Economic Potential for Combined Heat and Power*, 2010	918 MW	1,546 MW; 100 percent of electricity savings count as an energy efficiency measure under the state's EERS
Tennessee	Tennessee has interconnection standards and offers a loan program for CHP technologies.	ICF International, *Effect of a 30 Percent Tax Credit on the Economic Potential for Combined Heat and Power*, 2010	512 MW	1,234 MW; Because Tennessee has no existing EERS, we do not count any of the CHP benefits toward other efficiency gains achieved.
Arkansas	Arkansas currently does not provide incentives or favorable net metering/ interconnection standards for CHP.	ICF International, *Effect of a 30 Percent Tax Credit on the Economic Potential for Combined Heat and Power*, 2010	493 MW	833 MW; not an eligible resource under the state's EERS.
Missouri	Limited policies to encourage CHP. Interconnection guidelines require utilities to accommodate renewable-fuel distributed generation systems of 100 kW or less.	ICF International, *Effect of a 30 Percent Tax Credit on the Economic Potential for Combined Heat and Power*, 2010	236 MW	651 MW; Because Missouri has no mandatory EERS, we do not count any of the CHP benefits toward other efficiency gains achieved. .
Virginia	Virginia has a grant program for clean energy manufacturers.	ICF International, *Effect of a 30 Percent Tax Credit on the Economic Potential for Combined Heat and Power*, 2010	1,732 MW	2,554 MW; Because Virginia has no mandatory EERS, we do not count any of the CHP benefits toward other efficiency gains achieved..

Table 5 | **Slack Natural Gas Capacity Assumptions**

STATE	2011 NGCC CURRENT CAPACITY FACTOR	2011 SLACK NGCC GENERATION	SLACK NGCC GENERATION, INCLUDING PROPOSED UNITS THROUGH 2017	"MAXIMUM" NGCC GENERATION BY 2020 (EXISTING + SLACK INCLUDING PROPOSED UNITS)
Ohio	47 percent	6.6 TWh	15 TWh	26 TWh
North Carolina	38 percent	8.5 TWh	23 TWh	31 TWh
Michigan	24 percent	9.7 TWh	9.7 TWh	14 TWh
Pennsylvania	53 percent	14 TWh	14 TWh	49 TWh
Illinois	12 percent	15 TWh	15 TWh	18 TWh
Colorado	43 percent	6.0 TWh	12 TWh	20 TWh
Wisconsin	25 percent	10 TWh	10 TWh	15 TWh
Minnesota	15 percent	9.7 TWh	16 TWh	18 TWh
STATE	**2012 NGCC CURRENT CAPACITY FACTOR**	**2012 SLACK NGCC GENERATION**	**SLACK NGCC GENERATION, INCLUDING PROPOSED UNITS THROUGH 2017**	**"MAXIMUM" NGCC GENERATION BY 2020 (EXISTING + SLACK INCLUDING PROPOSED UNITS)**
Tennessee*	53 percent	0.8 TWh	9 TWh	12 TWh
Arkansas*	36 percent	15 TWh	15 TWh	29 TWh
Missouri*	31 percent	7 TWh	7 TWh	12 TWh
Virginia*	69 percent	2 TWh	31 TWh	53 TWh

** Data from 2012 were used when they became available. States with 2012 data are marked with an asterisk (*).*

Table 6 | **Expanded Policies Assumptions**

STATE	EXISTING EERS	EXPANDED EERS
Ohio	Twenty-two percent cumulative electricity savings between 2009–25; annual savings schedule of 0.3 percent per year in 2009, ramping up to 1 percent per year from 2013–18 and 2 percent per year from 2019–25.	Annual savings schedule of 0.3 percent per year in 2009, ramping up to 1 percent per year from 2013–14 and 2 percent per year from 2015–30.
	CHP CAPACITY IN 2030, EXISTING POLICIES	**CHP CAPACITY IN 2030, EXPANDED POLICIES**
	3.0 GW; 70 percent of the electricity savings go toward meeting the state's existing EERS.	5.4 GW; 55 percent of the electricity savings go toward the expanded EERS.
	EXISTING RPS	**EXPANDED RPS**
	12.5 percent by 2024.	18.5 percent by 2030.
STATE	**EXISTING EERS**	**EXPANDED EERS**
North Carolina	Approximately 0.5 percent annual electric savings from 2012-21, as estimated by ACEEE's *2012 State Energy Efficiency Scorecard*.	Approximately 0.5 percent annual electric savings through 2014, ramping up to 2 percent per year from 2015–30.
	CHP CAPACITY IN 2030, EXISTING POLICIES	**CHP CAPACITY IN 2030, EXPANDED POLICIES**
	2.8 GW; 100 percent of electricity savings go toward meeting the state's Renewable Energy and Energy Efficiency Standard.	4.0 GW; 100 percent of electricity savings go toward meeting the state's Renewable Energy and Energy Efficiency Standard.
	EXISTING RPS	**EXPANDED RPS**
	12.5 percent by 2021.	21 percent by 2030.
STATE	**EXISTING EERS**	**EXPANDED EERS**
Michigan	Annual electricity savings of 0.3 percent in 2009, ramping up to 1 percent in 2012 and each year thereafter.	Annual savings schedule of 0.3 percent per year in 2009, ramping up to 1 percent per year from 2012–14 and 2 percent per year from 2015–30.
	CHP CAPACITY IN 2030, EXISTING POLICIES	**CHP CAPACITY IN 2030, EXPANDED POLICIES**
	4.2 GW; 13 percent of electricity savings go toward meeting the state's existing EERS.	5.4 GW; 11 percent of electricity savings go toward meeting the state's expanded EERS.
	EXISTING RPS	**EXPANDED RPS**
	10 percent by 2015.	25 percent by 2030.

STATE	EXISTING EERS	EXPANDED EERS
Pennsylvania	Approximately 0.9 percent annual electric savings from 2012-16, as estimated by ACEEE's *2012 State Energy Efficiency Scorecard.*	Approximately 0.9 percent annual electric savings through 2014, ramping up to 2 percent per year from 2015–30.
	CHP CAPACITY IN 2030, EXISTING POLICIES	**CHP CAPACITY IN 2030, EXPANDED POLICIES**
	5.1 GW; No electricity savings go toward meeting the state's existing EERS or Tier I AEPS since CHP is a Tier II resource.	6.9 GW; No electricity savings go toward meeting the state's existing EERS or Tier I AEPS since CHP is a Tier II resource.
	EXISTING RPS	**EXPANDED RPS**
	8 percent by 2021 (Tier I resources).	17 percent by 2030 (Tier I resources).

STATE	EXISTING EERS	EXPANDED EERS
Illinois	Annual electricity savings of 0.2 percent in 2008, ramping up to 1 percent in 2012 and 2 percent in 2015 and thereafter.	Illinois' EERS is already at the upper limit of what we consider in the expanded scenario in this series. We do not consider an additional expansion.
	CHP CAPACITY IN 2030, EXISTING POLICIES	**CHP CAPACITY IN 2030, EXPANDED POLICIES**
	3 GW; 100 percent of electricity savings go toward meeting the state's existing EERS.	5 GW; 100 percent of electricity savings go toward meeting the state's EERS.
	EXISTING RPS	**EXPANDED RPS**
	25 percent by 2025.	30 percent by 2030.

STATE	EXISTING EERS	EXPANDED EERS
Colorado	Investor-owned utilities required to achieve electricity savings of at least 5 percent of 2006 electricity sales by 2018. In 2011, the Public Utilities Commission raised the target for Xcel Energy to annual targets of 1.14 percent in 2012 ramping up to 1.68 percent in 2020.	Approximately 1.4 percent annual electric savings through 2014, ramping up to 2 percent per year from 2015–30.
	CHP CAPACITY IN 2030, EXISTING POLICIES	**CHP CAPACITY IN 2030, EXPANDED POLICIES**
	1.1 GW; not eligible for state's EERS.	1.6 GW; not eligible for state's EERS.
	EXISTING RPS	**EXPANDED RPS**
	Investor-owned utilities: *30 percent by 2020*; Electric cooperatives with less than 100,000 customers and municipal utilities with greater than 40,000 customers: *10 percent by 2020*; Electric cooperatives with 100,000 customers or more: *25 percent by 2020.*	Investor-owned utilities: *40 percent by 2030*; Electric cooperatives with less than 100,000 customers and municipal utilities with greater than 40,000 customers: *20 percent by 2030*; Electric cooperatives with 100,000 customers or more: *35 percent by 2030.*

STATE	EXISTING EERS	EXPANDED EERS
Wisconsin	Annual electricity savings of 0.75 percent per year from 2011-2015.	Annual electricity savings of 0.75 percent per year through 2014, ramping up to 2 percent per year from 2015–30.
	CHP CAPACITY IN 2030, EXISTING POLICIES	**CHP CAPACITY IN 2030, EXPANDED POLICIES**
	2.5 GW; no savings applied toward existing EERS.	3.5 GW; no savings applied toward expanded EERS.
	EXISTING RPS	**EXPANDED RPS**
	10 percent by 2015.	25 percent by 2030.

STATE	EXISTING EERS	EXPANDED EERS
Minnesota	Annual electricity savings of 1.5 percent per year from 2011-2015.	Annual electricity savings of 1.5 percent per year through 2014, ramping up to 2 percent per year from 2015–30.
	CHP CAPACITY IN 2030, EXISTING POLICIES	**CHP CAPACITY IN 2030, EXPANDED POLICIES**
	1.5 GW; 100 percent of electricity savings go toward meeting the state's existing EERS.	2.2 GW; 100 percent of electricity savings go toward meeting the state's existing EERS.
	EXISTING RPS	**EXPANDED RPS**
	27 percent by 2025	32 percent by 2030

STATE	EXISTING EERS	EXPANDED EERS
Tennessee	No existing efficiency standard.	1 percent annual savings starting in 2015 through a new efficiency standard, financial incentives, or other measures.
	CHP CAPACITY IN 2030, EXISTING POLICIES	**CHP CAPACITY IN 2030, EXPANDED POLICIES**
	1,234 MW	Assumed no additional CHP capacity installed
	EXISTING RPS	**EXPANDED RPS**
	No existing target	Assumed renewable generation grew by 2.9 percent from 2014 to 2030. This is consistent with the historical rate (2004-2013) and results in 16 and 22 percent renewable generation in 2020 and 2030, respectively.

STATE	EXISTING EERS	EXPANDED EERS
Arkansas	Investor-owned utilities must meet annual electricity savings of 0.25 percent of 2010 sales in 2011, rising to 0.75 percent of 2010 sales from 2013 through 2014, and 0.9 percent of 2013 sales in 2015.	All electric utilities achieve annual electricity savings of 0.9 percent from 2016-30.
	CHP CAPACITY IN 2030, EXISTING POLICIES	**CHP CAPACITY IN 2030, EXPANDED POLICIES**
	833 MW	Assumed no additional CHP capacity installed
	EXISTING RPS	**EXPANDED RPS**
	No existing target	15 percent by 2020 and 25 percent by 2030

STATE	EXISTING EERS	EXPANDED EERS
Missouri	Voluntary energy efficiency savings goals for investor-owned utilities of 0.3 percent of sales in 2012, ramping up to 0.9 percent in 2015 and 1.7 percent in 2019, for cumulative savings of nearly 10 percent of electricity sales by 2020. We model this as an existing policy assuming the savings are not captured in the baseline.	All electric utilities achieve annual electricity savings of 2 percent from 2015-30.
	CHP CAPACITY IN 2030, EXISTING POLICIES	**CHP CAPACITY IN 2030, EXPANDED POLICIES**
	651 MW	Assumed no additional CHP capacity installed
	EXISTING RPS	**EXPANDED RPS**
	Investor-owned utilities: 15 percent by 2021	All utilities: 15 percent by 2021, 20 percent by 2030

STATE	EXISTING EERS	EXPANDED EERS
Virginia	Voluntary goal to reduce electricity consumption by 10 percent below 2006 levels by 2022. In our scenario for Virginia that examines opportunities from existing infrastructure only, we assumed no additional efficiency gains from this goal beyond any efficiency assumed by Dominion or Appalachian Power in their integrated resource plans.	1.3 percent of annual sales from 2015-2030.
	CHP CAPACITY IN 2030, EXISTING POLICIES	**CHP CAPACITY IN 2030, EXPANDED POLICIES**
	2,500 MW	Assumed no additional CHP capacity installed
	EXISTING RPS	**EXPANDED RPS**
	Voluntary program for IOUs: goal of 15 percent by 2025 (based on 2007 sales, excluding the average annual percentages of nuclear generation from 2004-2006). In our scenario for Virginia that examines opportunities from existing infrastructure only, we assumed no additional renewable generation from this goal beyond any renewables assumed by Dominion or Appalachian Power in their integrated resource plans.	Assume IOUs generate 15 percent of all generation in 2025 from renewable resources.

ENDNOTES

1. Report available at: <http://www.wri.org/publication/can-us-get-there-from-here>.
2. U.S. Energy Information Administration (EIA). *Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923).* Accessible at: <http://www.eia.gov/electricity/data/state/>.
3. U.S. Energy Information Administration (EIA). *U.S. Electric Power Industry Estimated Emissions by State (EIA-767, EIA-906, EIA-920, and EIA-923).* Accessible at: <http://www.eia.gov/electricity/data/state/>.
4. U.S. Environmental Protection Agency (EPA). eGRID2012 Version 1.0. Accessible at: <http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html>.
5. EIA's model allows states to purchase renewable energy credits from outside the state or NERC sub-region for compliance purposes, so renewable portfolio standards do not always increase in-state renewable generation to the amount required by state standards.
6. See Step 3c for a discussion on the historical CO_2 emissions improvement rate for the existing coal-fired power plant fleet in the United States.
7. American Council for an Energy-Efficient Economy (ACEEE). 2012. *The 2012 State Energy Efficiency Scorecard.* Report Number E12C.
8. The database can be found at www.dsireusa.org. If a state has a cumulative savings target and does not specify an annual savings schedule, we assume the target is reached by achieving a constant rate of annual savings between the implementation date and the target year.
9. American Council for an Energy-Efficient Economy (ACEEE). 2012. *The 2012 State Energy Efficiency Scorecard*. Report Number E12C.
10. Because most states operate on a regional grid and demand reductions will impact regional generation, it is unlikely that demand reductions will result in the same amount of reduced in-state generation. Because all states would be operating under the new EPA standards, other states in the region would likely be making similar shifts in demand and generation, so assuming no shifts in the balance of imports and exports provides a good estimate of the effect of demand reduction on in-state emissions. In addition, EPA standards will likely credit in-state demand reductions for the benefits that accrue, even if the benefits occur outside state borders.
11. In reality, reduced demand will displace generation from units that are at the margin of the dispatch curve, which may have an emission rate that is higher or lower than the fleet average. It is also likely that the emissions impacts of reduced demand will vary on a temporal basis.
12. The fleet-wide CO_2 emissions rate represents the quantity of CO_2 emitted for every unit of electricity generated.
13. In states where "alternative" energy sources include fossil fuels, we conservatively assume that the maximum amount of fossil fuel generation will be applied toward the standard and the remainder, if any, will be met by renewable sources.
14. The database can be found at: <www.dsireusa.org>.
15. Renewable generation displaces fossil fuel generation only; nuclear generation is not affected.
16. ICF International (2010) provides state-level technical potential estimates in *Effect of a 30 Percent Tax Credit on the Economic Potential for Combined Heat and Power*. We used more recent ICF estimates if they were available.
17. This level of technical potential aligns with a moderate policy scenario assessed by ICF International (2010) in *California: Combined Heat and Power: Policy Analysis and 2011–2030 Market Assessment.*
18. ICF International. 2010. *Effect of a 30 Percent Tax Credit on the Economic Potential for Combined Heat and Power.*
19. According to the ICF International CHP database (http://www.eea-inc.com/chpdata/), the majority of CHP capacity added in the past ten years has been natural-gas fired.
20. Because most states operate on a regional grid and demand reductions will impact regional generation, it is unlikely that demand reductions will result in the same amount of reduced in-state generation. Because all states would be operating under the new EPA standards, other states in the region would likely be making similar shifts in demand and generation, so assuming no shifts in the balance of imports and exports provides a good estimate of the effect of demand reduction on in-state emissions. In addition, EPA standards will likely credit in-state demand reductions for the benefits that accrue, even if the benefits occur outside state borders.
21. U.S. Energy Information Administration (EIA). *Form EIA-860 detailed data.* Accessible at: <http://www.eia.gov/electricity/data/eia860/>.
22. U.S. Energy Informtion Administration (EIA). *Form EIA-923 detailed data.* Accessible at: <http://www.eia.gov/electricity/data/eia923/>.
23. The EIA-860 database includes generator-level information about existing and planned generators at electric power plants with 1 megawatt or greater of combined nameplate capacity, including the fuel type and capacity for each plant but not generation. EIA-923 contains plant-level data for all plants operating in 2011, including generation by prime mover and fuel type.
24. NGCC plants are designed to be operated at a capacity of 85 percent. However, actual potential capacity factors vary among units. We assume a maximum capacity factor of 75 percent to remain conservative. See: Massachusetts Institute of Technology (MIT). 2011. "Electric Power Generation." *The Future of Natural Gas.* Accessible at: <http://mitei.mit.edu/system/files/NaturalGas_Chapter4_Electricity.pdf>; National Energy Technology Laboratory.Natural Gas Combined-Cycle Plant. Accessible at: <http://www.netl.doe.gov/KMD/cds/disk50/NGCC%20Plant%20Case_FClass_051607.pdf>.
25. We assumed that all slack natural gas would be used to displace coal generation. If slack natural gas capacity was greater than coal generation, we assumed that natural gas generation only increased to the amount necessary to displace all coal generation.
26. There may be current infrastructure limitations that prevent utilization of slack capacity (e.g., transmission constraints, pipeline capacity limitations). We assumed a lead time to account for infrastructure improvements that might be needed to enable maximum utilization of slack capacity.
27. U.S. Energy Information Administration (EIA). *Net summer capacity.* Accessible at: <http://www.eia.gov/tools/glossary/index.cfm?id=net%20summer%20capacity>.
28. For additional information, see: <http://www.wri.org/publication/clearing-the-air>.

29. Phil DiPetro and Katrina Krulla. 2010. "Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions." National Energy Technology Laboratory, Office of Systems, Analyses and Planning. DOE/NETL-2010/1411. Accessible at: <http://www.netl.doe.gov/energy-analyses/pubs/ImpCFPPGHGRdctns_0410.pdf>; Chris Nichols, Gregson Vaux, Connie Zaremsky, James Murphy, and MassoodcRamezan. 2008. "Reducing CO_2 Emissions by Improving the Efficiency of the Existing Coal-fired Power Plant Fleet." National Energy Technology Laboratory, Office of Systems, Analyses and Planning, and Research and Development Solutions, LLC, DOE/NETL-2008/1329. Accessible at: <http://www.netl.doe.gov/energy-analyses/pubs/CFPP%20Efficiency-FINAL.pdf>; Bilirgen et al. 2010. "Analyses Show Benefits of Improving Unit Heat Rate as Part of a Carbon Mitigation Strategy." *Lehigh Energy Update* 28 (1). Accessible at: <http://www.lehigh.edu/~inenr/leu/leu_65.pdf>.
30. Phil DiPetro and Katrina Krulla. 2010. *Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions.* National Energy Technology Laboratory, Office of Systems, Analyses and Planning. DOE/NETL-2010/1411. Accessible at: <http://www.netl.doe.gov/energy-analyses/pubs/ImpCFPPGHGRdctns_0410.pdf>.
31. "Regulating Greenhouse Gas Emissions Under the Clean Air Act." 73 *Register* §147(2008). Accessible at: <http://www.gpo.gov/fdsys/pkg/FR-2008-07-30/pdf/E8-16432.pdf>.
32. Personal communication with Tomas Carbonell, Environmental Defense Fund, July 12 2013.
33. For comparative purposes, the emissions rate for the U.S. coal fleet has improved by about 0.7 percent since 2000. Calculated using: U.S. Energy Information Administration (EIA). *Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923).* Accessible at: <http://www.eia.gov/electricity/data/state/>; and U.S. Energy Administration Administration (EIA). U.S. Electric Power Industry Estimated Emissions by State (EIA-767, EIA-906, EIA-920, and EIA-923). Accessible at: <http://www.eia.gov/electricity/data/state/>.
34. It was found that coal generation would increase by 0.83 percent as a result of the efficiency gains. For more information, refer to: Joshua Linn, Dallas Burtraw, and Erin Mastrangelo. 2012. "Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act." RFF Discussion Paper 11-43; and Dallas Burtraw and Matt Woerman. 2012. "The Consequences of Subcategorization in a GHG Tradable Performance Standard Policy." Presentation at the annual meeting of the Association of Environmental and Resource Economists, Asheville TN, June 4, 2012.
35. As this is meant to be an illustrative analysis of what is technically feasible, not what is economically likely under a specific set of policy choices, we have not applied the rebound effect in this context; it would run counter to the assumption that states will maximize gas generation to help meet a potential emissions standard for the power sector.
36. Daniel A. Lashof, Starla Yeh, David Doniger, Sheryl Carter, and Laurie Johnson. 2012. *Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters.* Natural Resources Defense Council. Accessible at: <http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf>.
37. On November 6, 2014, EPA released guidance on translating a rate-based goal to a mass-based equivalent. Because EPA recognizes that there are numerous ways to complete this translation, and because EPA would need to approve any methodology the state uses, we did not include a mass-based conversion in our analysis; See: <http://www2.epa.gov/carbon-pollution-standards/fact-sheet-clean-power-plan-technical-support-document>.
38. For more details on EPA's methodology, see the Clean Power Plan proposed rule technical documents, accessible at: < http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents>.
39. While Tennessee does not have a binding energy efficiency standard, its largest utility, Tennessee Valley Authority, has established a short-term goal to reduce peak demand by 1,400 megawatts (MW) by 2012. See: < http://www.energyright.com/pdf/highlights_2012.pdf>.