WORLD RESOURCES INSTITUTE

FACT SHEET

APPENDIX A. DETAILED OVERVIEW OF METHODS: HOW STATES CAN MEET THEIR CLEAN POWER PLAN TARGETS

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In our fact sheet series, *How States Can Meet Their Clean Power Plan Targets*, we show how key states can use clean energy policies and other emission reduction opportunities to comply with the final Clean Power Plan (CPP). This appendix describes our methodology and assumptions in detail, and will be updated with state-specific information as each new fact sheet is completed.

OVERVIEW

For each state in the series, we develop projections of carbon dioxide (CO_2) emissions from existing power plants that reflect clean energy policies and other compliance options using an in-house, Excel-based model. We then compare resulting emission levels and emission rates to each state's power plant standards under the final CPP. Our analysis is intended to provide a technically feasible range of CO_2 emission and emission rate reductions for each state's existing fossil fleet; it is not an economic analysis.

We model the following compliance options in each state:

- Meeting the current requirements under the state's renewable standards and energy efficiency standards, where they exist.
- Fully utilizing existing natural gas combined-cycle (NGCC) capacity.
- Increasing the efficiency of the existing coal-fired power plant fleet.
- Adopting new or expanded renewable and/or energy efficiency standards (in some states).

Figure 1 | **Overview of Methodology to Estimate CO_2 Benefits of Existing Policies & Infrastructure Opportunities**

STEP 1
Business-as-usual Projections

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STEP 2.
Benefits from Implementing Existing Policies
(if not included in business-as-usual projections)

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STEP 2A.
CO_2 benefit from reduced generation
Energy efficiency standard

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STEP 2B.
CO_2 benefit from increased generation from renewable sources
Renewable standard

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STEP 3.
Benefits from Existing Power Plants

↓

STEP 3A.
CO_2 benefit from increasing use of existing natural gas capacity
Increased utilization of existing natural gas capacity, resulting in decreased use of coal capacity

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STEP 3B.
Decreased CO_2 emissions from remaining coal-fired generation
Increased efficiency at remaining coal plants

The model used to create these projections utilizes historical detailed state data from the U.S. Energy Information Administration.[1] We rely on electric generation projections from state environmental and energy agencies when available; otherwise, we rely on EIA's *Annual Energy Outlook 2015* (AEO2015). See Figure 1 for a summary of our methodology for existing clean energy policies and measures that use available infrastructure.

COMPARISON OF OUR PROJECTIONS WITH CPP TARGETS

The CPP provides targets for each state in mass-based terms of absolute emissions from affected power plants (short tons CO_2) as well as a fossil emission rate, which represents the carbon-intensity of electric generation at affected units (pounds CO_2 per megawatt-hour). In each fact sheet, we provide both rate- and mass-based results for existing plants to ease comparison with the CPP targets for the state's power plants. To the extent possible, our method for calculating and displaying our power sector emissions results is consistent with the U.S. Environmental Protection Agency's (EPA) approach under the final rule. The key exception relates to the treatment of simple-cycle natural gas generation[2] and other fossil generation, which together contribute less than 1 percent of fossil fuel-fired generation according to EPA data.[3] While these units are not covered under the rule, we were unable to exclude them due to the data sources we relied upon.

Consistent with EPA's approach, we calculated each state's emission rate for CPP compliance by dividing total emissions from existing fossil units by the sum of fossil generation plus incremental renewable generation and avoided generation from demand-side efficiency (post-2012) as follows:

$$\text{Clean Power Plan compliance emission rate (lbs./MWh)} = \frac{\text{(Coal emissions, lbs.} + \text{Existing natural gas emissions, lbs.} + \text{Other fossil emissions, lbs.)}}{\text{(Coal generation, MWh} + \text{Existing natural gas generation, MWh} + \text{Other fossil generation, MWh} + \text{Incremental efficiency, MWh} + \text{Incremental renewables, MWh)}}$$

This approach reflects the state's emission rate for Clean Power Plan compliance by starting with the CO_2 emissions and generation resulting from the state's existing fossil fleet in the numerator and denominator, respectively, and adding incremental efficiency and renewable generation to the denominator to reflect their potential use for compliance. Consistent with EPA's methodology, we defined 'existing' to include power plants on-line in 2012 and those that were under construction as of January 8, 2014. Our approach omits existing renewable and nuclear generation, which do not count toward compliance.

METHODOLOGY IN DETAIL

Step 1. Business-as-usual projections

For all states in the series, we utilized EIA's Annual Energy Review for historical electricity generation[4] and CO_2 emissions[5] by fuel (coal, natural gas, other fossil, nuclear, and renewable) during the period from 2005 through 2013. We included generation from electric utilities and independent power producers and excluded electricity generated from combined heat and power units at commercial and industrial facilities, which are not covered by the CPP. A forecast of generated electricity for each state through 2030 was determined by one of two methods as described below, depending on data availability. Table 1 summarizes the forecasts used for each state completed to date. To remain consistent with the CPP, we included the generation from existing fossil units as of 2012, adjusted to include units under construction as of January 8, 2014, consistent with the requirements under the CPP. Our "business-as-usual" (BAU) projections are based on the methodologies we describe below and do not represent EIA's Annual Energy Outlook Reference Case.

1. **Projections available from state environmental and energy agencies.** Some state public utility commissions (PUCs) or other agencies provide forecasts of electricity generation for the state based on state-specific projected demographics, fuel prices, and, in some cases, response to state and/or federal policies, which are likely to differ from the regional factors assumed in EIA's AEO2015. Where available, we utilized these forecasts to inform our own electricity generation projections. We first calculated average annual growth rates for electricity generation by fuel type from the state projections. We then forecasted generation by fuel type using these growth rates each year through 2030 beginning with the most recent year for which historical data were available. 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, we conservatively assumed these were already captured in the business-as-usual projections.
2. **Projections from EIA's AEO2015.** When forecasts were unavailable from state agencies, we obtained regional projections of annual growth rates of electricity generation by fuel from AEO2015. EIA uses North American Electric Reliability Corporation (NERC) subregions 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 subregion.[6] The AEO2015 projections are based generally on federal, state, and local laws and regulations in effect as of the end of October 2014. We conservatively assumed that any planned retirements, new power plant builds, or existing or soon to be adopted policies or programs that were announced or finalized before this time were included in our business-as-usual projections.

To project CO_2 emissions, we calculated state-specific emission rates based on EIA data for each fuel for 2013 and multiplied these rates by projected generation for that fuel in each year through 2030. In states that had fossil units under construction as of January 2014, EPA developed an adjusted 2012 baseline to count these units as "existing" under the rule (which are listed in Appendix 2 of EPA's technical support document[7]). For states in our series with relevant units (Virginia, Pennsylvania), we utilized the emission rates calculated by EPA (listed in EPA's Appendix 3[8]). 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 business-as-usual projections.[9]

Step 2: Estimating the CO_2 benefit of existing policies

We calculated the CO_2 benefits from existing state policies—including energy efficiency standards and renewable standards—for states that had such policies in place. We assumed that any voluntary goals or required targets set by existing policies would be achieved. If state-level projections did not include the full effect of existing policies (e.g., all efficiency expected as a result of an energy efficiency standard), we incorporated the additional emissions savings into our projections.

Step 2a. CO_2 benefit from reduced generation (energy efficiency 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 energy efficiency standards, combined renewable and efficiency standards, and least-cost procurement requirements.[10]

EFFICIENCY STANDARD ASSUMPTIONS

Most efficiency standards are expressed in terms of sales, or total demand for electricity in a state. Because our model projects in-state generation, we apply state efficiency targets to generation rather than sales (see Table 2 for assumptions for each state completed to date). In reality, it is unlikely that demand reductions will result in the same amount of reduced in-state generation because most states operate on a regional grid and demand reductions will impact regional generation. All else being equal, this method would be most accurate for states with the least difference between generation and sales. However, this method should provide a reasonable estimate of the effect of reduced demand on in-state generation, assuming that most states will be making shifts in demand and generation in response to the Clean Power Plan and that the balance of imports and exports for each state remains the same.

In addition, standards do not always 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 the American Council for an Energy-Efficient Economy (ACEEE).[11]

ACCOUNTING FOR EFFICIENCY EMBEDDED IN BUSINESS-AS-USUAL PROJECTIONS

In some cases, CO_2 emissions savings from existing standards may be captured in business-as-usual projections and therefore may not generate additional emissions reductions. AEO2015 does not explicitly model state energy efficiency programs, but some effects of programs in existence in 2014 and earlier are captured through regional demand trends. When basing our business-as-usual projections on AEO2015, we estimated the amount of efficiency that is likely embedded in the business-as-usual projections based on a methodology developed by EPA and Synapse to assist state implementation plan development for ozone and other criteria pollutants.[12,13] We then compared the embedded efficiency to that state's efficiency targets to determine to what extent achieving the state's target would result in additional demand reduction. We counted only the additional demand savings when determining the CO_2 reductions associated with achieving the target.

EPA and Synapse's methodology calculates embedded savings by dividing the lifetime savings (MWh) of measures implemented in a given year by total electricity sales (MWh) for the residential, commercial, and industrial sectors to determine the lifetime savings per unit of demand.

Since the lifetime savings value reflects future demand reductions associated with efficiency measures (e.g., reduced demand due to installing more efficient lightbulbs that continue to deliver savings over the life of the new bulbs), Synapse and EPA then divide this percentage by the average efficiency measure lifetime to estimate the average percent savings embedded each year. These data are available in EIA Form-861.[14] We used this methodology to calculate embedded savings in each state for 2013, then applied the embedded percent savings to projected electricity generation (since our model projects generation, not sales) in each state over the average measure lifetime (Table 3), as follows:

$$\text{Annual embedded savings (TWh)} = \frac{\text{Projected generation (TWh)} \times \text{2013 cumulative savings (TWh years)}}{\text{(Average measure life (years)} \times \text{2013 sales (TWh)}}$$

Consistent with the approach we use to model the benefits of energy efficiency programs (see Efficiency Standard Assumptions section), this approach implicitly assumes that the impact of in-state efficiency measures on total sales is proportional to their impact on in-state generation. This may overestimate or underestimate the amount of embedded efficiency depending on whether the state is a net importer or net exporter, among other factors. States including efficiency programs in a "state measures" type implementation plan under the Clean Power Plan[15] will need to demonstrate how these programs will affect generation and emissions from affected units.[16]

When state forecasts were used (in the case of Virginia), we assumed that existing efficiency standards were captured in the business-as-usual projections unless the source explicitly stated that electricity savings from existing programs were excluded. This prevents us from double-counting the benefits of existing efficiency measures, but may underestimate the impact of these measures if they are not, in reality, fully captured in the business-as-usual projections. If states had voluntary efficiency programs, we assume associated savings were not captured in the business-as-usual projections unless the projections specified that a certain amount of efficiency is captured (e.g., both Dominion and Appalachian Power Company in Virginia project expected efficiency savings in their Integrated Resource Planning documents).

CALCULATING THE CO_2 BENEFIT OF REDUCED DEMAND

We calculated the CO_2 savings resulting from incremental efficiency gains (post-2012) by proportionally reducing generation from coal and other fossil sources, excluding natural gas. This mostly affects coal, which makes up the vast majority of non-natural gas fossil generation. The resulting CO_2 savings were then applied toward meeting the state's mass-based target. To quantify the benefit of incremental efficiency on the state's CPP compliance emission rate, we added the additional TWh of savings to the denominator of the state's emission rate while keeping the generation and emissions from the existing fossil fleet the same, consistent with EPA's method.

Reducing demand in the context of CPP implementation will result in CO_2 reductions through a number of mechanisms. The primary effect will be to reduce generation at the margin of the dispatch curve—that is, the unit with the highest operating cost that would have been turned on with the next unit of electric demand. However, the dispatch curve itself will shift in two important ways due to implementation of the CPP and the continuation of recent market trends. First, older coal units will likely drop out entirely, due to the CPP and to other environmental regulations, shifting fuel price economics, low electric demand growth, and the declining prices of renewables.[17] This will reduce overall coal generation. Second, the dispatch curve itself will shift to favor lower carbon sources due either to explicit carbon prices or other policies put in place as part of CPP implementation, such as renewable standards. Consistent with these shifts, and with our later assumption (Step 3a) that NGCC units will increase generation up to a 75 percent capacity factor, in this step and Step 2b (renewables), we reduce only coal generation rather than reducing all fossil generation including natural gas.

NOTE ON THE CLEAN ENERGY INCENTIVE PROGRAM

As part of the final Clean Power Plan, EPA is offering a Clean Energy Incentive Program to reward early investments in energy efficiency projects that benefit low-income communities. States can earn additional credits from EPA by implementing eligible projects in 2020 and 2021. Because of the technical difficulty of modeling a program like this, we did not incorporate this program into our analysis.

Step 2b: CO_2 benefit from increasing the proportion of generation from renewable sources (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.[18] In some cases, CO_2 emissions savings from renewable standards were captured in the business-as-usual projections and therefore did not result in additional emissions reductions. For instance, the AEO2015 reference case included all mandatory renewable portfolio standards that were implemented in 2014 or earlier. When state forecasts were used, we assumed that renewable portfolio standards were captured in the business-as-usual projections unless the source explicitly indicated that such programs were excluded.

When renewable standards were not fully captured in the business-as-usual projections, we assumed each state met its annual incremental renewable goals. Since most renewable targets are based on total electricity demand, we estimate the effects of the renewable targets after projected generation has been adjusted to capture the effects of efficiency targets, as follows:

1. (From Step 2a) Adjusted generation (TWh) = Business-as-usual generation (TWh) – Additional efficiency savings due to efficiency target (TWh)
2. Renewable generation required by renewable standards (TWh) = Adjusted generation (TWh) × Percent renewable target

For the purposes of this analysis, we assumed that new renewables development occurs in-state to help comply with new standards. For this reason, we assumed that all new renewable electricity generated for compliance with the state's RPS after 2013 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 existing contracts for out-of-state renewable energy remain in place through 2030, but all new renewable energy capacity is built in-state. We assumed that the incremental renewable generation displaced coal and other fossil generation (excluding natural gas) in proportion to the annual energy mix for electricity generation, as we did in the case of energy efficiency (see Step 2a). Resulting emission savings were calculated using the business-as-usual emission rates for each fuel type and were applied toward meeting the state's mass-based target. To quantify the benefit of new renewable energy toward meeting the state's emission rate, we added the TWh of additional renewable energy to the denominator of the state's emission rate while keeping the generation and emissions from the existing fossil fleet the same, consistent with EPA's methods.

As previously mentioned, we do not attempt to model the effect of the Clean Energy Incentive Program.

Step 3: Estimating the CO_2 benefit of existing power plants

After applying the effects of existing clean energy policies, we then calculated the effects of additional measures that states could use to comply with the CPP using existing infrastructure.

Step 3a: CO_2 benefit from increasing use of natural gas capacity and decreasing use of coal capacity

To calculate underutilized (i.e., slack) natural gas capacity, we first determined total existing natural gas combined-cycle (NGCC) capacity and generation (2013) from the existing units in the state covered under the Clean Power Plan. Because EIA's summary tables from the Annual Energy Review did not break down natural gas generation or capacity by technology type (e.g., NGCC), we utilized two databases to calculate these values—EIA's "existing units" database from Form EIA-860,[19] and the "generation and fuel data" database from Form EIA-923.[20,21]

We estimated potential generation by assuming each existing NGCC unit would be run at 75 percent capacity for an entire year, consistent with the assumption EPA used in developing state-specific standards ("maximum utilization" column in Table 5).[22] 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 2022. We assumed that slack natural gas capacity would begin to be utilized starting in 2018, increasing to maximum utilization in 2022 (unless the state is expected to achieve similar levels of generation under our business-as-usual projections).[23] There may be current infrastructure limitations that need to be addressed to increase natural gas utilization (e.g., transmission constraints, pipeline capacity limitations). We assumed this lead time to account for any infrastructure improvements that might be needed to enable maximum utilization of slack capacity. We assumed maximum utilization continued—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 2022 through 2030. 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.[24] Because the Clean Power Plan only covers existing fossil units, we did not include any new NGCC units that began construction after January 8, 2014, which is EPA's cutoff for new versus existing units.

We assumed that the incremental natural gas generation displaced coal generation. The CO_2 emission benefit was calculated as the difference between emission levels after fully capturing the CO_2 benefit from existing clean energy policies and the emission levels resulting from the fleet's new fuel mix. To quantify the benefit of fully utilizing the existing natural gas fleet toward meeting the state's emission rate, we adjusted the CO_2 emissions in the numerator and the TWh of fossil generation in the denominator to reflect the new fossil mix while holding the TWh of incremental efficiency savings and renewable generation constant in the denominator. While our analysis is focused solely on power-sector CO_2 emissions, the overall climate benefit of switching from coal to natural gas depends on methane leakage associated with the production of natural gas. Increased use of natural gas reduces power-sector CO_2 emissions, but increases methane emissions from natural gas systems. Going forward, industry should work with EPA to reduce methane leakage rates from natural gas systems.[25]

Step 3b: Decreased emissions from remaining coal-fired generation

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.[26,27] 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.[28] For purposes of this analysis, we used the potential average fleet-wide improvement rates that EPA used to set the state targets under the final rule.

EPA determined the potential improvement rates using historical data for the 884 coal units that reported hourly heat input and gross electricity generation to the agency in 2012. The average gross heat rate of these units has fluctuated over time due to a number of factors, including retirement of less-efficient units, fluctuations in weather conditions, deterioration of plant equipment, and changes in dispatch patterns. EPA grouped the units by regional interconnection and calculated potential improvement rates by comparing the units' 2012 heat rates to the best historical heat rates they achieved between 2002 and 2012 using three different analytical approaches. The agency used the most conservative estimate for each interconnection in setting the targets: 2.1 percent for western, 2.3 percent for Texas, and 4.3 percent for eastern. EPA notes that these levels of heat rate improvements can be achieved by continuing to utilize the types of good maintenance and operating practices that would be necessary to maintain the higher heat rates that the coal fleet had previously achieved—they do not account for improvements that could be achieved through additional equipment upgrades.[29] We assumed that the coal fleet within each state in our analysis achieved the potential improvement rate for its corresponding interconnection region beginning in 2022 (Table 6). The percent improvement rate is assumed to be a fleet-wide average, as improvement levels could be lower or higher at individual units.

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).[30] 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.[31]

Estimating the CO_2 benefits of expanded policies

In some cases, we examined how much further states could reduce emissions by expanding or adopting new clean energy policies (Table 7). We developed the assumptions for expanded renewable generation and energy efficiency policies in consultation with in-state experts and typically based the assumptions on proposed legislation in the state, analyses of the potential for additional clean energy development in the state or region, or some combination of both. We calculated the benefits of expanded policies by running a separate model scenario with the new assumptions, starting with our business-as-usual projections (the same one from each state's initial scenario) and layering the expanded policies and improved use of existing power plants in the same order and using the same methodology as the existing policy approach that is detailed in Figure 2.

SUMMARY OF KEY UNCERTAINTIES AND LIMITATIONS

- This is not an economic analysis. We did not estimate the costs and benefits from taking the measures we included in our analysis.
- This analysis focuses solely on power sector CO_2 emissions. We do not model methane emissions associated with natural gas production, processing, and transmission.
- 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 (or increase) the maximum capacity factor an individual NGCC unit can achieve.
- We assumed utilities would not purchase out-of-state renewable energy certificates or make alternative compliance payments for compliance with renewable standards; instead, we assumed each state complied with in-state renewable generation only.
- We assumed that efficiency standards would reduce in-state generation proportionally to total electricity sales.

- We assumed that incremental energy efficiency and renewable generation used for CPP compliance displaces coal and other fossil generation proportionally, excluding natural gas.
- The emission trajectories we show in our analyses illustrate the impact on states' power sectors of fully implementing the measures we describe, including meeting their renewable standards using in-state generation and meeting their efficiency standards using in-state programs. They are not intended to predict any state's actual emissions or emission rate under Clean Power Plan compliance. It would not be possible using our model to predict actual emissions for a given state under the plan because states can trade allowances (mass-based) or emission rate credits (rate-based) to meet their targets. Therefore, emission levels in a given state could actually be higher than EPA's targets if the state holds credits from other states that went beyond EPA's targets. Likewise, states that go beyond what is required under the Clean Power Plan—for example, using the measures we illustrate in our analysis—could then sell surplus credits to other states.

Figure 2 | **Overview of Methodology to Estimate CO_2 Benefits of Expanded Policies & Infrastructure Opportunities**

STEP 1.
Business-as-usual Projections

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STEP 2.
Benefits from Implementing Expanded Policies
(if not included in business-as-usual projections)

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STEP 2A.
CO_2 benefit from reduced generation
Energy efficiency standard

↓

STEP 2B.
CO_2 benefit from increased generation from renewable sources
Renewable standard

↓

STEP 3.
Benefits from Existing Power Plants

↓

STEP 3A.
CO_2 benefit from increasing use of existing natural gas capacity
Increased utilization of existing natural gas capacity, resulting in decreased use of coal capacity

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STEP 3B.
Decreased emissions from remaining coal-fired generation
Increased efficiency at remaining coal plants

Table 1 | **Business-as-Usual Sources**

STATE	SOURCE	NOTES
Virginia	U.S. Energy Information Administration, *Annual Energy Outlook 2015;* 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 83 percent and 2 percent of Virginia's generation in 2013, 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 2013. Relied on regional projections of annual electricity generation growth rates by fuel from AEO2015 for the remaining electricity generated in Virginia.
Pennsylvania	U.S. Energy Information Administration, *Annual Energy Outlook 2015*	Overlaps with Reliability First Corporation East and West regions.
Michigan	U.S. Energy Information Administration, *Annual Energy Outlook 2015*	Overlaps with Reliability First Corporation Michigan, Reliability First Corporation West, Midwest Reliability Council East, and Midwest Reliability Council West regions.
Missouri	U.S. Energy Information Administration, *Annual Energy Outlook 2015*	Overlaps with Midwest Reliability Council West, Southwest Power Pool North and South, and SERC Reliability Corporation Central, Delta, and Gateway regions.

Table 2 | **Energy Efficiency Assumptions**

STATE	ENERGY EFFICIENCY STANDARDS
Virginia	Virginia has a voluntary goal to reduce electricity consumption by 10 percent below 2006 levels by 2022. We assumed the state would ramp up efficiency efforts starting in 2018 to achieve this goal in 2022.
Pennsylvania	Pennsylvania has set separate phases of efficiency standards. Utilities were initially required to 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 of this program 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 the 2009/2010 baseline. Phase III of this program, adopted in June 2015, sets specific energy efficiency targets for each utility that range from 2.6 percent to 5.0 percent cumulative savings from 2016 through 2020 compared to the 2009/2010 baseline.
Michigan	Michigan's efficiency standard requires annual electricity savings of 0.3 percent of sales in 2009, increasing to 1 percent in 2012 and each year thereafter. We apply the percent savings to projected generation to estimate savings from the standard each year.
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, 1.7 percent in 2019, and 1.9 percent in 2020 (and subsequent years) for cumulative savings of nearly 10 percent of electricity sales by 2020. We apply the percent savings to projected generation to estimate savings from the goal each year.

Table 3 | **Electricity Savings, Sales, and Efficiency Measure Lifetimes, 2013**

	A. CUMULATIVE ELECTRICITY SAVINGS, EXCLUDING TRANSPORT (MWH-YEAR)	B. ELECTRICITY SALES, EXCLUDING TRANSPORT (MWH)	C. LIFETIME SAVINGS PER UNIT ELECTRICITY DEMAND (A/B)	D. AVERAGE MEASURE LIFE (YEAR)	PERCENT EFFICIENCY EMBEDDED (C/D)
Virginia	For our analysis of Virginia, we relied largely on generation and energy efficiency projections from the state's two largest utilities, Dominion Power and Appalachian Power Company.				
Pennsylvania	22,211,166	145,437,975	0.15	12	1.2 percent
Michigan	7,501,796	103,032,663	0.07	11	0.69 percent
Missouri	4,107,187	83,381,680	0.05	10	0.48 percent

Table 4 | **Renewable Assumptions**

STATE	RENEWABLE TARGET (PERCENT OF SALES)	MODELING NOTES
Virginia	Voluntary program for IOUs: goal of 15 percent by 2025 (based on 2007 sales)	Voluntary program not included in BAU projections, beyond any additional renewable generation assumed by Dominion or Appalachian Power in their integrated resource plans.
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.
Michigan	10 percent by 2015	Renewable target included in BAU projections; adjusted to ensure target met through in-state generation
Missouri	Investor-owned utilities: 15 percent by 2021	Renewable target included in BAU projections; adjusted to ensure target met through in-state generation

Table 5 | **Natural Gas Assumptions**

STATE	2013 NGCC CURRENT CAPACITY FACTOR	2013 SLACK NGCC GENERATION	"MAXIMUM" NGCC GENERATION BY 2022 (EXISTING + SLACK INCLUDING UNDER CONSTRUCTION UNITS COVERED BY THE CPP)
Virginia	60 percent	5 TWh	43 TWh
Pennsylvania	65 percent	7 TWh	68 TWh
Michigan	23 percent	19 TWh	27 TWh
Missouri	24 percent	9 TWh	12 TWh

Table 6 | **Heat Rate Improvement Assumptions**

STATE	REGION	ASSUMED IMPROVEMENT RATE
Virginia	Eastern	4.3 percent
Pennsylvania	Eastern	4.3 percent
Michigan	Eastern	4.3 percent
Missouri	Eastern	4.3 percent

Table 7 | **Expanded Policy Assumptions**

STATE: VIRGINIA		
EXISTING EFFICIENCY STANDARD	**EXPANDED EFFICIENCY STANDARD**	**BASIS FOR EXPANDED POLICY ASSUMPTION**
No expanded policies were considered for Virginia.		
STATE: PENNSYLVANIA		
EXISTING EFFICIENCY STANDARD	**EXPANDED EFFICIENCY STANDARD**	**BASIS FOR EXPANDED POLICY ASSUMPTION**
Phase III of this program, sets specific energy efficiency targets for each utility that range from 2.6 percent to 5.0 percent cumulative savings from 2016 through 2020 compared to the 2009/2010 baseline	19 TWh of PUC-identified “maximum achievable” cost-effective efficiency potential is achieved by 2030.	Pennsylvania’s PUC recently found that the state can achieve nearly 27 TWh of economic potential by 2025; 19 TWh of this potential is considered to be achievable after taking into account real—world barriers to encouraging end users to adopt efficiency measures among other costs and barriers. The PUC found that this level of savings would result in $2.8 billion in net benefits, with benefits outweighing costs nearly 2 to 1.
EXISTING RENEWABLE TARGET	**EXPANDED RENEWABLE TARGET**	
8 percent by 2021 (Tier I resources)	16 percent by 2030	Pennsylvania’s utilities will need to grow the state’s renewable generation sources by about 9 percent per year between 2014 and 2021 in order to meet the current Tier I goal. Continuing to grow renewable generation by this same rate between 2021 and 2030 will result in 18 percent in-state renewable generation by 2030.
STATE: MICHIGAN		
EXISTING EFFICIENCY STANDARD	**EXPANDED EFFICIENCY STANDARD**	**BASIS FOR EXPANDED POLICY ASSUMPTION**
Annual electricity savings of 0.3 percent in 2009, ramping up to 1 percent in 2012 and each year thereafter	Annual savings of 0.3 percent per year in 2009, ramping up to 1 percent per year from 2012–18 and 2 percent per year from 2019–30	Proposed state legislation introduced in April 2015 known as the “Powering Michigan’s Future” bill package (House bills 4055, 4518 and 4519 and Senate bills 295, 296 and 297)
EXISTING RENEWABLE TARGET	**EXPANDED RENEWABLE TARGET**	
10 percent by 2015	20 percent by 2022	Proposed state legislation introduced in April 2015 known as the “Powering Michigan’s Future” bill package (House bills 4055, 4518 and 4519 and Senate bills 295, 296 and 297).
STATE: MISSOURI		
EXISTING RENEWABLE TARGET	**EXPANDED RENEWABLE TARGET**	
Investor-owned utilities: 15 percent by 2021	All utilities: 15 percent by 2021, 20 percent by 2030	Consultation with state experts

ENDNOTES

1. Specifically, we utilize EIA's Net Generation by State by Type of Producer by Energy Source and U.S. Electric Power Industry Estimated Emissions by State databases, which can be found at: <http://www.eia.gov/electricity/data/state/>. Both of these databases are based on information EIA collects from power plants and includes detailed data on electricity generation and fuel consumption.

2. Simple-cycle units operate on a single power cycle and do not recover waste heat from the combustion turbine engine, whereas combined-cycle units recover the waste heat to generate additional electricity.

3. "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units." 40 CFR Part 60. Accessible at: <http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf>.

4. 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/>.

5. 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/>.

6. U.S. Environmental Protection Agency (EPA). "eGRID2012 Version 1.0." Accessible at: <http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html>.

7. U.S. Environmental Protection Agency. Data File: Goal Computation Appendix 1-5 (XLSX). "Appendix 2 - Under Construction." Accessible at: <http://www2.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents>.

8. U.S. Environmental Protection Agency. Data File: Goal Computation Appendix 1-5 (XLSX). "Appendix 3 - State-level Data." Accessible at: <http://www2.epa.gov/cleanpowerplan/clean-power-plan-final-rule-technical-documents>.

9. See Step 3b for a discussion on the historical CO_2 emissions improvement rate for the existing coal-fired power plant fleet in the United States.

10. American Council for an Energy-Efficient Economy (ACEEE). 2014. "The 2014 State Energy Efficiency Scorecard." Report Number U1408.

11. American Council for an Energy-Efficient Economy (ACEEE). 2014. "The 2014 State Energy Efficiency Scorecard." Report Number U1408.

12. For more details, see: U.S. Environmental Protection Agency. 2014. "Background and Draft Methodology for Estimating Energy Impacts of EE/RE Policies." Accessible at: <http://epa.gov/statelocalclimate/documents/pdf/EPA%20background%20and%20methodology%20EE_RE_02122014.pdf>. Synapse. 2012. "State Energy Efficiency in the AEO Electricity Forecasts." Accessible at: <http://www.synapse-energy.com/project/state-energy-efficiency-embedded-annual-energy-outlook-forecasts>.

13. This methodology is also consistent with the examples EPA provided to support Clean Power Plan compliance in its technical support document entitled "Incorporating RE and Demand-Side EE Impacts into State Plan Demonstrations." Accessible at: <http://epa.gov/airquality/cpp/tsd-cpp-incorporating-re-ee.pdf>.

14. Form EIA-861 contains detailed data on electric power sales, revenue, and energy efficiency. Accessible at: <http://www.eia.gov/electricity/data/eia861/>.

15. Under a state measures plan type, states can use a portfolio of state-enforced measures that can apply both to affected units and other entities (e.g., demand-side efficiency; renewable portfolio standard; cap-and-trade programs). See Box 2 of the state fact sheets for more information on state plan types and other compliance considerations.

16. For more details on incorporating efficiency and renewables into state plans, see: <http://epa.gov/airquality/cpp/tsd-cpp-incorporating-re-ee.pdf>.

17. More than 18 gigawatts of coal plants retired between 2011 and 2013 and studies estimate that 50–117 gigawatts of coal generation could be "ripe for retirement" in the coming years due to the factors described in the text. This accounts for 16–38 percent of existing coal generation capacity (though likely a smaller percentage of total generation because the units most likely to retire tend to be smaller, less efficient, and have lower capacity factors). For further discussion, see: Union of Concerned Scientists. 2013. "Ripe for Retirement: An Economic Analysis of the U.S. Coal Fleet — 2013 Update." Accessible at: <http://www.ucsusa.org/clean_energy/smart-energy-solutions/decrease-coal/economic-analysis-us-coal-plants.html#.VfmIzxFVhBc>. N. Bianco, K. Meek, R. Gasper, M. Obeiter, S. Forbes, and N. Aden. 2014. "Seeing is Believing: Creating a New Climate Economy in the United States." Working Paper. Washington, DC: World Resources Institute. Accessible at: <http://www.wri.org/publication/new-climate-economy>.

18. In states where "alternative" energy sources include fossil fuels, we 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.

19. U.S. Energy Information Administration (EIA). "Form EIA-860 detailed data." Accessible at: <http://www.eia.gov/electricity/data/eia860/>.

20. U.S. Energy Information Administration (EIA). "Form EIA-923 detailed data." Accessible at: <http://www.eia.gov/electricity/data/eia923/>.

21. 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 2013, including generation by prime mover and fuel type.

22. NGCC plants are designed to be operated at a capacity of 85 percent. However, actual potential capacity factors vary among units. We conservatively assumed a maximum capacity factor of 75 percent.

23. 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.

24. U.S. Energy Information Administration (EIA) definitions of net summer capacity and generator nameplate capacity. Accessible at: <http://www.eia.gov/tools/glossary/index.cfm?id=net%20summer%20capacity> and <http://www.eia.gov/tools/glossary/index.cfm>.

25. For additional information, see: <http://www.wri.org/publication/clearing-the-air>, <http://www.wri.org/publication/reducing-methane-emissions-natural-gas-development-strategies-state-level-policymakers>, and <http://www.wri.org/publication/delivering-us-climate-commitment-10-point-plan-toward-low-carbon-future>.

26. 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>.

27. “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>.

28. Personal communication with Tomas Carbonell, Environmental Defense Fund, July 12 2013.

29. U.S. Environmental Protection Agency. 2015. “Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.” Docket ID No. EPA-HQ-OAR-2013-0602. “Greenhouse Gas Mitigation Measures.” Accessible at: <http://epa.gov/airquality/cpp/tsd-cpp-ghg-mitigation-measures.pdf>.

30. 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. 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.

31. 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.

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ABOUT WRI

World Resources Institute is a global research organization that turns big ideas into action at the nexus of environment, economic opportunity and human well-being.

Our Challenge
Natural resources are at the foundation of economic opportunity and human well-being. But today, we are depleting Earth's resources at rates that are not sustainable, endangering economies and people's lives. People depend on clean water, fertile land, healthy forests, and a stable climate. Livable cities and clean energy are essential for a sustainable planet. We must address these urgent, global challenges this decade.

Our Vision
We envision an equitable and prosperous planet driven by the wise management of natural resources. We aspire to create a world where the actions of government, business, and communities combine to eliminate poverty and sustain the natural environment for all people.

Our Approach
COUNT IT
We start with data. We conduct independent research and draw on the latest technology to develop new insights and recommendations. Our rigorous analysis identifies risks, unveils opportunities, and informs smart strategies. We focus our efforts on influential and emerging economies where the future of sustainability will be determined.

CHANGE IT
We use our research to influence government policies, business strategies, and civil society action. We test projects with communities, companies, and government agencies to build a strong evidence base. Then, we work with partners to deliver change on the ground that alleviates poverty and strengthens society. We hold ourselves accountable to ensure our outcomes will be bold and enduring.

SCALE IT
We don't think small. Once tested, we work with partners to adopt and expand our efforts regionally and globally. We engage with decision-makers to carry out our ideas and elevate our impact. We measure success through government and business actions that improve people's lives and sustain a healthy environment.