A Handbook for States: Incorporating Renewable Energy into State Compliance Plans for EPA's Clean Power Plan

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FOREWORD

This document was prepared by the American Wind Energy Association (AWEA) and the Solar Energy Industries Association (SEIA) and is intended as a starting point for states that are considering renewable energy as a compliance tool for the U.S. Environmental Protection Agency's (EPA) proposed regulation of carbon emissions from existing power plants (Clean Power Plan) under section 111(d) of the Clean Air Act (CAA). This handbook will be updated after EPA releases the final rule in the summer of 2015.

As you know, state governments will play a critical role with EPA in reducing carbon emissions to meet the standards set forth in the rule. EPA has proposed that states can meet those standards using electric system-wide programs and policies that would allow wind and solar energy, and other resources, to serve as compliance tools for states.

The goal of this handbook is to help states understand how they can use renewable energy emission reduction strategies in their section 111(d) compliance plans as part of an overall balanced energy portfolio. The framework presented herein should reduce the barriers for state agencies to incorporate renewable energy policies and programs into state plans by clarifying and summarizing existing EPA guidance on the matter. With the information presented in this document, states should be in a better position to seek credit for renewable energy in their state plans.

In the pages that follow, this handbook provides detailed information on:

- What the Clean Power Plan says about using renewable energy as a compliance tool.
- Calculating carbon reductions from renewable energy; existing emissions reductions on a state-by-state basis; and deployment of renewable energy and the cost profile for doing so.
- The energy and emission reduction impacts of renewable energy policies and programs as well as the health and environmental benefits.
- A list of steps that states can use to draft their own compliance plans incorporating renewable energy.
- Guidance on addressing questions related to renewable energy at each step.
- A sample framework of a compliance plan using renewable energy to meet carbon emission targets.

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I. AT A GLANCE: RENEWABLES AS COMPLIANCE TOOLS TO REDUCE CARBON EMISSIONS

EPA's proposed Clean Power Plan allows states to meet the required carbon reductions using renewable energy as a compliance tool in their state plans. To date, state and local governments have increased their adoption of renewable energy policies and programs, which have provided appreciable emissions benefits. In the same vein, state and local air planners can achieve the carbon reduction goals set forth in the Clean Power Plan through the use of renewable energy. Alongside the carbon emission reductions that come from using renewable energy as a compliance tool, co-benefits include reducing emissions of sulfur dioxide (SO_2), nitrous oxide (NOx), mercury, and other air pollutants, while also reducing electric sector water use. These benefits can be achieved while spurring economic development.

As EPA continues to finalize the carbon emissions standards, emission reductions from renewable energy policies and programs are likely to become increasingly important for states to meet those standards because renewable energy is often the lowest cost, most rapidly deployable and scalable way of reducing pollution.

The proposed carbon regulations are the first attempt by the federal government to regulate carbon emissions from the existing electric power sector in each state. Thus, states have no experience in taking credit for carbon emissions reductions attributable to renewable energy to meet federal requirements. This document aims to help fill in some of those gaps.

II. CLEAN POWER PLAN

On June 18, 2014, EPA published in the *Federal Register* its long-anticipated proposal to regulate carbon dioxide emissions from existing power plants under Section 111(d) of the CAA: *Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions From Existing Stationary Sources: Electric Utility Generating Units*, 79 FR 34829.

EPA's proposed Clean Power Plan includes mandatory carbon reduction targets for each state: "Rate-Based Carbon Emission Performance Goals." EPA calculated such individual state goals by determining what constitutes the best system of emission reduction (BSER) and then modeling the emissions from the affected sources in each state, assuming that the states adopt a combination of four carbon reduction measures, or "Building Blocks":

1. Block 1: Heat rate (efficiency) improvements at individual electric generating units (EGU).
2. Bock 2: Increased utilization of natural gas combined cycle plants.
3. Block 3: Zero-emitting energy (renewable energy and nuclear energy).
4. Block 4: Demand-side energy efficiency.

The carbon emission targets will be legally binding on each state. States, in turn, would then implement how they plan to satisfy the goals through a state plan. States may choose whether to express the proposed performance levels in the form of carbon intensity emission rates or in a mass-based form.

A "rate-Based" performance goal refers to an emission performance goal expressed as carbon intensity, namely pounds of carbon per net megawatt hour (lbs/net MWh). Rate-based goals are in contrast to "mass-based" performance goals, which are typically used in cap-and-trade programs and are expressed as a quantity of carbon emissions, typically in metric tons of carbon equivalent (total tons of CO_2 per year).

EPA has proposed to extend the regulations beyond the fenceline of the affected EGUs, which is where EPA has traditionally confined its authority. EPA is proposing to give states broad discretion to develop state plans that best suit their circumstances and policy objectives.

Timing of Reductions

The Clean Power Plan assigns each state two different rate-based performance goals:

- Interim goals would apply as an average during a 2020-2029 phase-in period; and
- Final goals must be met by 2030 and maintained on a three-year rolling calendar year average thereafter.

Affected Sources

An affected EGU is "any fossil fuel-fired EGU that was in operation or had commenced construction as of January 8, 2014" and would otherwise meet the criteria for coverage as a fossil fuel-fired EGU in the New Source Performance Standard (NSPS) proposal. Those criteria include:

- Capacity of at least 250 million Btu per hour.
- Combustion of fossil fuel for more than 10 percent of its total annual heat output.
- Sale of greater than 219,000 MWh per year and one-third of its potential electrical output to a utility distribution system.

State Plans

The Clean Power Plan would require each state to submit an emission reduction plan to EPA for approval. Each plan must include "emission performance levels for its affected EGUs that are equivalent to the state-specific carbon goal in the emission guidelines, as well as the measures needed to achieve those levels and the overall goal."

States are not required to use measures from each building block. Instead, each state has the flexibility to select measures from the building block, or combination of building blocks, it prefers in order to achieve the state's emission reduction goal. States may also choose to include measures that were not part of the BSER determination so long as the state achieves reductions "at affected EGUs necessary to meet the goal EPA has defined as representing the BSER."

Plans must include a process for reporting on implementation, progress reporting, and corrective actions. Every two years, beginning on January 1, 2022, states will be required to compare their emissions performance with the goals outlined in the plan.

Criteria for Approval

EPA proposes evaluating state plans for approval based on the following criteria:

- Enforceable measures to reduce carbon emissions from EGUs.
- Projected emission reduction performance equivalent to EPA-established goals and on an equivalent timeline.
- Quantifiable and verifiable emission reductions.
- A process for biennial reporting on plan implementation and progress towards achieving emissions reductions.

State Plan Timing

EPA expects to finalize the rulemaking during the summer of 2015. States must submit their plans to EPA by June 30, 2016. States that cannot complete their plans by the deadline may participate in an optional two-phased plan submittal process, which consists of:

- A Letter of Intent to participate in the phased plan submittal process, due to EPA by April 1, 2016.
- An Initial Plan, submitted by June 30, 2016, that contains specific components, including:
  - The reasons why the state needs more time to complete a plan.
  - Commitments to "concrete steps" that will ensure that the state will submit a plan by June 30, 2017 (single state approach) or 2018 (multi-state approach).

• A final plan must be submitted either in 2017 (for an individual state plan) or 2018 (if working on a multi-state plan). Depending on the approach, EPA will review the plans and has proposed extending its review period from four months, as provided in the EPA framework regulations, to up to 12 months.

In developing its plan, a state will need to make a number of decisions that will require careful consideration in order to ensure that its plan both meets a state's policy objectives and is ultimately approved by EPA. The agency has raised a number of considerations for how it will apply the proposed general plan approvability criteria to different types of state plan approaches. This includes a number of considerations related to appropriate approaches, methods, and materials that are submitted for state plan components in an approvable plan, under different types of state plans. In particular, the Clean Power Plan identifies several key decision points and factors that states should consider when developing their plans:

1. Identification of affected entities (affected EGUs and other responsible parties).
2. Description of plan approach and geographic scope.
3. Identification of required emission performance level for affected EGUs.
4. Demonstration that plan is projected to achieve required emission performance level.
5. Identification of milestones.
6. Identification of corrective measures.
7. Identification of emission standards and any other measures.
8. Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable.
9. Identification of monitoring, reporting, and recordkeeping requirements.
10. Description of state reporting.
11. Certification of hearing on state plan.
12. Supporting material.

Further details are provided in ***Appendix 1.***

III. THE CLEAN POWER PLAN AND RENEWABLE ENERGY

Renewable energy is one of the four main building blocks outlined in the Clean Power Plan, and states are likely to rely upon the production of renewable energy as a type of control measure that reduces carbon emissions but also has a positive economic return for states as part of a balanced energy portfolio. EPA suggests levels of renewable energy generation that states would need to meet reduction targets. Building Block 3 of the BSER relies on reducing emissions through the substitution of power from more carbon-intensive affected EGUs with

power from low-and-zero-carbon generation. In particular, EPA includes the increased use of renewable energy and continued use of nuclear power in Building Block 3.

EPA proposes to credit existing renewable energy development by allowing renewable energy production to count towards meeting a state target, regardless of when the facility producing the energy was installed, as long as the energy produced is covered in the state plan and results in a carbon reduction after January 1, 2020. In practice, this means that emission reductions that occur in 2020 and later due to renewable energy production that occur pursuant to an existing RPS requirement, or otherwise, could be applied toward meeting the required level of emission performance in a state plan as long as the renewable energy production results in the reduction of carbon emissions.

To be clear, the renewable generation levels in the Clean Power Plan represent a total amount of renewable generation rather than the incremental amount above a particular baseline. As a result, the necessary renewable generation levels can be met from any renewable capacity, regardless of when the capacity was installed. In other words, EPA is proposing in the rule that a state may apply toward its required emission performance level the emission reductions that are achieved by existing renewable energy or associated programs, such as RPSs, during the compliance period (after 2020) even if the facility was installed, or the RPS was adopted, before the emission guidelines proposal (June 2014).

On October 28, 2014, EPA released a notice of data availability (NODA)[1] that addressed concerns voiced by stakeholders concerning a lack of flexibility in the plan's interim goals. EPA requested comment on establishing a crediting regime that would allow crediting of certain pre-2020 reductions and on allowing states to begin demonstrating emission performance earlier than 2020 to create a longer "glide path" for compliance. The creation of a crediting regime for early action has been pressed for by numerous industry commenters and would allow states who have taken initiative in reducing statewide carbon emissions to bank credits for implementing emissions reduction measures.

IV. REASONS TO TAKE ADVANTAGE OF RENEWABLE ENERGY UNDER SECTION 111(D)

Renewable energy can provide large emissions reductions in a cost-effective manner when part of a balanced energy portfolio and provide significant positive economic returns to a state. In

[1] Clean Power Plan Proposed Rule Notice of Data Availability, available at http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-notice-data-availability.

addition to this, inclusion of renewable energy policies and programs in 111(d) compliance plans offer many other benefits to states beyond reduced carbon emissions. Here are just some of the reasons states might want to take advantage of renewable energy policies as a compliance tool to meet their obligations under 111(d):

- **Renewable Energy Technologies are Effective Tools for Reducing Carbon Emissions**
    - Generating electricity from renewable energy has been well documented to reduce carbon emissions.
    - Renewable energy by its very nature does not emit carbon, or other air pollutants, when producing electricity.
    - Wind energy alone reduced carbon emissions by 127 million tons per year nationally in 2013, or more than 5% of electric sector emissions, with 11 states achieving reductions of greater than 10% and three other states just under 10%, according to calculations using an EPA tool.
    - Solar energy generation can be expected to avoid 13.8 million metric tons of CO_2 emissions in 2014, assuming one GWh of solar generation eliminating 690 metric tons of CO_2 emissions. Of this, distributed PV capacity (as of June 2014) will generate 10,450 GWh/year and displace 7.2 million metric tons of CO_2 per year.[2] Emission reductions resulting from solar deployment are certain to grow, as the industry grew 53% in 2013 compared to 2012.
    - For more information on this issue see ***Appendix 2.***

- **Renewable Energy Provides Co-Benefits to Aid in Compliance of Other Clean Air Act Requirements, as well as Other Environmental Benefits**
    - In addition to reducing carbon emissions, renewable energy reduces other harmful emissions such as NO_x and SO_2.
    - There is also less pollution of soil and water resources as a result of the development and use of renewables. Wind and solar energy are inexhaustible resources that generate no pollution or hazardous waste, require no mining, transportation, or refining of a feedstock or fuel.
    - Wind energy alone reduces SO_2 and NOx emissions by 347 million pounds and 214 million pounds per year respectively.
    - Solar energy reduces SO_2 emissions by 14.8 million pounds and NO_x emissions by 17.3 million pounds with the current levels of generation.
    - For more information on this issue see ***Appendix 3.***

[2] Solar data from U.S. Solar Market Insight Q2 2014. See also: http://www.epa.gov/cleanenergy/energy-resources/refs.html.

- **Renewable Energy Contributes to a Reduction in Healthcare Expenditures**
    - The EPA has found that particulate exposure costs Americans between $110 billion and $270 billion each year and that the economic value of health impacts from such exposure in the United States is $361.7-886.5 billion annually, representing 2.5-6.0% of the national GDP.[3] Thus, deploying renewable energy (which produces no particulate matter in its production) has an immediate impact in reducing premature mortality, lost workdays, incidence of asthma attacks, and a reduction in overall healthcare costs.[4] When energy sources are adjusted to account for their externalities relative to producing particulate matter, renewable energy becomes even more cost-competitive.[5]
    - For more information, see ***Appendix 4.***

- **Renewable Energy Technologies are Cost-Effective and Bring Economic Benefits to a State**
    - The costs associated with renewable energy have been declining for years. According to data tracked by the U.S. Department of Energy, the cost for utilities to purchase wind energy has declined by more than half over the last 5 years, with both the Energy Information Administration and Lazard, a well-respected asset management firm, finding that wind energy is one of the lowest cost sources for new electric generation.
    - Power purchase agreements (PPAs) for wind in 2013 reached a nationwide average of $25/MWh, down from $70/MWh in 2009. With respect to solar, PPAs are now being signed in the $50-$60/MWh range for the next 20 to 25 years, offering price certainty to both utilities and ratepayers, and costs will continue to decline as economies of scale are achieved.
    - As these costs have dropped, more development has occurred, providing more job creation to states. With increased renewable development, jobs associated

[3] Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States (U.S. EPA Office of Air and Radiation 2011), per Solar Electricity: Economic Development and Impact (presentation by Lee J. Peterson, Esq. 2012); Machol, Rizk. 2013. Economic value of U.S. fossil fuel electricity health impacts. Environment International 52 75–80.

[4] Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States (U.S. EPA Office of Air and Radiation 2011), per Solar Electricity: Economic Development and Impact (presentation by Lee J. Peterson, Esq. 2012). Machol, Rizk. 2013. Economic value of U.S. fossil fuel electricity health impacts. Environment International 52 75–80.

[5] Solar Electricity: Economic Development and Impact (presentation by Lee J. Peterson, Esq. 2012).

with manufacturing, project development, construction, and operations will increase across the country. Furthermore, wind and solar energy reduce the cost of producing electricity by displacing more expensive forms of generation, producing economic savings for customers.

- For more information on this issue see ***Appendix 5.***

- **Renewable Energy is Widely Available to Serve as a Compliance Tool**
  - Renewable energy is already reducing carbon emissions across the nation today under existing state programs and policies, and can contribute to additional significant reductions as a compliance tool for meeting state emission targets under section 111(d). In the last five years, wind energy has represented 31% of all newly installed electric generating capacity, second only to natural gas. Solar energy was the fastest growing source of new energy in 2013, and is expected to have another record breaking year in 2014.
  - There are more than 65,000 megawatts of wind energy installed in 39 states and Puerto Rico. These wind turbines provide electrical output equivalent to 53 average coal plants or 14 average nuclear plants. Even in the handful of states without wind turbines today, projects are being developed and/or utilities are buying power from wind farms in other states. Wind provides 25% of the electric generation in two states, 12% or more in nine states, and 5% or more in 17 states.
  - The United States has some of the richest solar resources in the world. The U.S. solar industry grew by 53% from 2012 to 2013, accounting for nearly 30% of all new electric generating capacity added to the U.S. grid in 2013.[6] An additional 7.3 GW of solar capacity is expected to be added in 2014, bringing the cumulative U.S. total to over 20 GW—enough to power more than 4 million homes. The U.S. solar industry now supports nearly 175,000 employees at more than 6,100 companies spread across all 50 states.
  - For more information on this issue see ***Appendix 6.***

- **Renewable Energy is Fast to Build and Scalable**
  - Renewable energy offers a rapidly deployable solution for reducing emissions of carbon dioxide and other pollutants. Wind and solar developers already have a large backlog of potential projects in the development pipeline, and it is typically

[6] SEIA/GTM U.S. Solar Market Insight™ Year in Review 2013 Report. All U.S. Solar Market Insight Reports are available here: http://www.seia.org/research-resources/us-solar-market-insight.

possible to build a wind or solar project in a little over a year once site evaluation and permitting are complete.

- Since the end of 2005, the U.S. wind energy industry has doubled its installed capacity, on average, every 36 months. Over the last decade, the industry has gone from a low mark of installing 396 MW in 2004 to a high of more than 13,000 MW in 2012, with more than 12,000 MW currently under construction. U.S. wind energy's five-year average annual growth rate is 19.5 percent from 2009-2013.
- The solar industry has nearly doubled in growth every year since 2006.
- For more information on this issue see ***Appendix 7.***

- **Renewable Energy's Emissions Reductions are Easily Quantified and Verified**
  - Renewable energy's emissions reductions are readily quantifiable and verifiable, making renewable energy an attractive solution for states to comply with 111(d). All utility-scale wind and solar projects have revenue-grade metering equipment that measures the amount of wind and solar energy production. Such equipment and verification is necessary to ensure compliance with power purchase contract generation requirements, Renewable Energy Credit (REC) tracking, and claiming the federal production tax credit (PTC), which is based on electricity actually generated.
  - Rigorous accounting mechanisms for renewable energy credits are in wide use in 29 states and the District of Columbia for compliance with state renewable portfolio standard requirements in those states, and accounting mechanisms are in place nationwide for verifying renewable energy production to satisfy voluntary purchases of renewable energy credits. These well-established accounting mechanisms could be readily adopted for compliance with section 111(d) to ensure that renewable energy production is not "double-counted" and can be precisely and rigorously quantified.
  - Several tools, such as marginal emissions calculation and power system modeling, allow carbon emissions reductions to be calculated based on this measured wind or solar energy production. For instance, EPA's Avoided Emissions and Generation Tool (AVERT) is one free and easy-to-use option for calculating wind and solar energy's pollution reductions.
  - For more information on this issue see ***Appendix 8*** and further discussion below.

- **Renewable Energy Can be Reliably Integrated into the Grid**
  - Dozens of in-depth renewable integration studies confirm that significant amounts of wind and solar energy can be added to the power system without

harming reliability. And, real world operational experience confirms this. Grid operators are now reliably accommodating very large quantities of renewable energy in the U.S. and Europe, with wind energy alone providing double digit percentages of electric generation on an annual basis in nine states already and having provided, at times, 40% of electric generation in ERCOT (Texas), 34% in SPP (southern plains), 25% in MISO (the upper Midwest) and 18% in California.

- Wind energy has a small impact on total power system variability as changes in wind output occur gradually and are predictable, and most are canceled out by other changes in electricity supply and demand. Every day, grid operators constantly accommodate variability in electricity demand and supply by increasing and decreasing the output of flexible generators – power plants like hydroelectric dams or natural gas plants that can rapidly change their level of generation, and they accommodate wind using the same tools.
- Solar energy can be configured and operated to provide various reliability services and transmission benefits that will be essential to electric power system operations in conjunction with state implementation of §111(d) regulations.
- Utilities and policymakers are already addressing the changes to grid operations presented by increased renewable penetration. For example, in areas of an electric grid where the peak energy use is in the late afternoon, solar systems can be configured to coincide with peak demand later in the day. Solar can also be coupled with storage technologies to match their output to local power demand patterns, including evening peaks. This can be done economically if supported through appropriate policies, pricing options, and program offerings.[7]
- For more information on this issue see ***Appendix 9***.

- **Renewable Energy Diversifies the Energy Portfolio in a State and Increases Energy Security**
  - Increasing fuel diversity by adding fixed price energy resources – like renewable energy – to a state energy portfolio protects consumers from fluctuations in fuel costs. Just as a diverse financial portfolio protects investors from volatile economic markets or a fixed rate mortgage protects homeowners from sometimes volatile interest rates, a diverse electricity portfolio can protect ratepayers from the risks inherent in relying too heavily on a few resources to meet electricity demand. This is true even in the current low natural gas price environment. As Lawrence Berkeley National Lab found, wind energy acts as a

[7] See "Teaching the Duck to Fly: Integrating Renewable Energy," available here: http://www.raponline.org/featured-work/teach-the-duck-to-fly-integrating-renewable-energy

long-term hedge against the projected and likely rise in natural gas prices, with current wind PPA prices coming in below projected gas prices.[8]

V. INCORPORATING RENEWABLE ENERGY INTO STATE PLANS

Renewable energy is one of the best opportunities available to states to comply with section 111(d) regulations in a cost-effective and environmentally sound manner. Given the potential for renewable energy policies to be implemented in states that lack them or to be increased in states that currently have them, we focus on incorporating new renewable energy policies and an expansion of existing policies into state plans. This document explains nine steps that a state would take to use renewable energy policies as a compliance tool for section 111(d):

1. Bring together relevant state agencies.
2. Develop a preliminary estimate of potential carbon emissions reductions.
3. Potential Compliance Pathways.
4. Consider renewable energy programs/measures as compliance tools.
5. Credit renewable energy programs in compliance plans.
6. Consider multi-state/regional approaches.
7. Adjust EGU carbon emission rates based on the effects of renewable energy.
8. Choose policies and/or programs that satisfy pathway requirements.
9. Conduct reporting and recordkeeping for renewable energy programs and measures.
10. Account for interstate emission effects.

STEP 1. BRING TOGETHER RELEVANT STATE AGENCIES

States should inform and involve all relevant parties at the beginning of the process, which we recognize many states are already doing. This step serves to establish relationships between agencies, avoid confusion, identify relevant policies, and otherwise coordinate the effort. Some examples of groups that state or local environmental agencies may seek to include are:

- State air regulators
- State governor's office
- State energy office
- Public utility regulators
- Utilities and EGU owners and operators

[8] *See* Mark Bolinger, *Revisiting the Long-Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices*, Ernest Orlando Lawrence Berkeley National Laboratory, March 2013, available at http://emp.lbl.gov/sites/all/files/lbnl-6103e.pdf.

- Regional EPA representatives
- Regional transmission grid operators
- Other stakeholders, including zero-carbon generation owners and developers

To facilitate interagency dialogue, each stakeholder should become familiar with the following information early in the process:

- Data sources used for generation and demand forecasts in air quality modeling
- Roles and responsibilities of key state energy-related organizations
- State, tribal, and local renewable energy policies and programs in the jurisdiction
- Ways of estimating potential emission reductions
- Existing EPA renewable energy state plan guidance

Stakeholder agencies may want to consider the following preliminary questions before proceeding:

- What renewable energy policies and programs has the jurisdiction already adopted?
- What are the details of those policies and programs in terms of implementation dates, stringency, financial commitments, historical investments in renewable energy, and enforcement features?
- Is there any information on the carbon emission impacts (projected and/or historical) of those renewable energy policies?
- Which organization or agency monitors and evaluates the emission impacts of those renewable energy policies?
- Are program/policy impacts regularly and consistently reported to the state? How consistent and rigorous are these estimates?
- What compliance and enforcement does the state use for the renewable energy policies?
- Which entities retain credit for carbon emissions reductions from existing renewable energy projects?

STEP 2. CONSIDERATION OF RENEWABLE ENERGY PROGRAMS/MEASURES AS COMPLIANCE TOOLS

When considering potential renewable energy policies or programs to pursue for incorporation into a state plan, states may look to policies that have already been in place for some time, new policies, or policies that are emerging or being developed. States can use the state plan process to create new renewable energy efforts.

States and utilities use a variety of policy instruments to increase the production and use of renewable energy. The principal mechanisms include: RPSs, tax incentives (e.g., property tax exemptions, production-based tax incentives, etc.), financial assistance programs (e.g., grants,

loans, and other direct financial assistance based on generating capacity or investment level), customer generation such as net metering, and other policies (R&D support, manufacturing incentives; workforce training).

Experience to date indicates that RPSs have led to a large portion of the increase in renewable energy generating capacity and generation resulting from state policies, with a number of utilities choosing to purchase beyond their RPS requirements. Production-based tax incentives have also been used by states and utilities to help achieve RPS requirements, as well as to spur additional production and use of renewable energy. On the distributed generation level, net energy metering is a simple billing mechanism that has led to significant amounts of installed distributed solar systems. Further, these types of programs rely on measurable electric generation as the basis for recognizing customer generation, properly assigning compliance credit, or providing incentive payments. Other types of programs (e.g., certain grant and rebate programs) may not currently quantify electric generation output from funded renewable energy projects.

The Clean Power Plan provides states with significant flexibility with respect to the compliance tools they can choose to use when creating state implementation plans for Section 111(d) compliance. Here are a few examples of policies and programs that states may look to include in their state plans:

- **Renewable Portfolio Standard (RPS)**
    - Renewable portfolio standards (RPS) are state legislation and regulations aimed to increase production of energy from renewable resources, such as wind and solar, as an alternative to fossil fuel generation. An RPS requires load-serving entities to purchase a designated percentage of their electricity from renewable resources.
        - For more information on this issue see ***Appendix 13***.
- **Trading Programs**
    - Statewide and regional trading schemes create a market for carbon emissions by allowing covered entities to emit and then providing a system in which these entities can trade credits/allowances to reduce emissions in the most cost-effective way.
        - For more information on this issue see ***Appendix 14***.
- **Integrated Resource Plan (IRP)**
    - An IRP is a strategic plan mandated by a state's Public Utility Commission (PUC) that requires a utility to meet forecasted annual peak and energy demand (plus some established reserve margin) through supply- and demand-side resources over a specified future period of time. States frequently use legislation or

regulation to undertake planning efforts that are then reviewed by the state PUC.

    - For more information on this issue see ***Appendix 15*** and below.

- **Incentive Programs**
  - Incentive programs come in a variety of forms, including direct incentives, like rebates, grants and performance-based incentives, property tax incentives, sales tax incentives, and/or tax credits.
    - For more information on this issue see ***Appendix 16*** and below.
- **Utility Procurement**
  - Utilities can procure renewable energy by buying it through reverse auctions, value tariffs, and standard offer contracts, or by building it. Utility procurement gives the utility complete control over the renewable energy generation.
    - For more information on this issue see ***Appendix 18.***
- **Feed-in Tariffs**
  - Feed-in tariffs (FITs) are offered by some individual electric distribution utilities and some states for renewable energy systems that meet eligibility criteria. Under a FIT, the utility offers to purchase specific kinds of electricity (e.g., wind or solar) from sellers at posted prices or under a published pricing formula for a specified period of time.
    - For more information on this issue see ***Appendix 19***.
- **Customer Generation**
  - Community wind and solar and net-metering programs allow individual customers or groups of customers to generate or procure their own renewable energy, and in the case of net-metering, allow the customer to sell extra renewable energy back to the grid.
    - For more information on this issue see ***Appendix 20.***

STEP 3. RENEWABLE POLICIES AND/OR PROGRAMS CHOSEN MUST SATISFY PATHWAY REQUIREMENTS

This section describes the four requirements necessary for renewable energy policies or programs to be included in a state plan. A state must present evidence that the state has met or will meet these four requirements. EPA will evaluate the sufficiency of each plan based on four general criteria to determine whether a state's plan is "satisfactory" under CAA section 111(d)(2)(A).

Four general criteria:

1. A state plan must contain **enforceable** measures that reduce EGU carbon emissions from affected EGUs.

2. Measures in the plan must be projected to achieve emission performance equivalent to or better than the applicable state-specific carbon goal on a timeline equivalent to that in the emission guidelines.
3. EGU carbon emission performance under the state plan must be quantifiable and verifiable.
4. The state plan must include a process for state reporting of plan implementation (at the level of the affected entity), carbon emission performance outcomes, and, if necessary, implementation of corrective measures.

Enforceable. A state plan must include enforceable measures. To ensure that its plan is enforceable, a state will need to:

- Identify in its plan the entity or entities responsible for meeting compliance and other enforceable obligations under the plan.
- Include mechanisms for demonstrating compliance with plan requirements or demonstrating that other binding obligations are met.
- Provide a mechanism(s) for legal action if affected EGUs are not in compliance with plan requirements or if other entities fail to meet enforceable plan obligations.
- For more information on this issue see ***Appendix 25.***

Quantifiable. In order for a policy or program to be considered quantifiable, it must have a measureable effect on emissions, and the measurements must be reproducible. Drawing from past EPA guidance and the experiences of other states and regions, states can formulate a quantification approach that best suits the characteristics of their specific policy or program.

As discussed in the Clean Power Plan, all state plans will need to include a projection of the carbon emission performance by affected EGUs that will be achieved under a state plan (inclusive of plan measures that avoid carbon emissions from affected EGUs, such as renewable energy). Depending on whether the plan pursues a rate-based or a mass-based approach, this will include either a projection of the average carbon emission rate achieved by affected EGUs or total carbon emissions from affected EGUs.

The credibility of state plans under section 111(d) will depend in large part on ensuring credible and consistent emission performance projections in state plans. Therefore, the use of appropriate methods, tools, and assumptions for such projections is critical. EPA suggests that carbon emission projections might include the use of historical data and parameters for estimating the future impact of individual state programs and measures. Alternatively, a projection could be based on modeling, such as use of a capacity expansion and dispatch planning model, or a dispatch simulation model. This latter approach would be able to capture dynamic interactions within the electricity sector, based on system operation and market

forces, including interactions among state programs and measures and the dynamics of market-based measures.

In order to determine the value of incorporating renewable energy into a state plan, a state may first develop a preliminary estimate of potential carbon reductions from renewable energy policies and programs relative to a baseline.

- **Estimating the Carbon, Other Air, And Health Benefits of Renewable Energy**

Analysis to quantify the carbon and other air pollution, air quality, and human health benefits of renewable energy initiatives involves four basic steps, which are discussed further below and in the appendices:

- **Develop and project a baseline emissions inventory**
  - For more information on this issue see ***Appendix 10***.
- **Analytic approaches for projecting carbon emissions from affected EGUs**
  - For more information on the issue see ***Appendix 11***.
- **Quantifying the carbon and other air emission reductions from renewable energy measures**
  - For more information on this issue see below and ***Appendix 12***.
- **Calculating emissions reductions attributable to renewable energy from EPA's recently released Avoided Emissions and Generation Tool (AVERT)**
  - This tool is discussed in more detail below and in ***Appendix 24***.

Some states may not be interested in estimating all of the benefits described in this section, or they may not achieve benefits in each area, but these steps often occur sequentially. This is because estimating some of the benefits, such as improved air quality and reduced human health effects, requires information generated in previous steps—specifically the timing and type of generation displaced by renewable energy measures.

- **Information on Measure Quantification**

States should consider the following when formulating a quantification approach for the emission reductions attributable to renewable energy policies/programs:

- The energy data that is available.
- States may wish to bring in consultants or analysts in order to estimate carbon emissions reductions.
- States can ease the burden of quantification by collaborating with organizations that may already be estimating emission reductions or emissions more generally.

- Collaboration across state lines and jurisdictions. Interstate cooperation will change the scope of quantification efforts, but in turn it will provide increased resources for program evaluation.

States should plan to evaluate strategies over time and monitor the programs to ensure that emission reduction targets are met and the established rate of progress is kept. States will need to document program quantification schedules and practices and convey in their state plans that the programs will be reasonably monitored and emissions reductions will be adequately calculated. Some states may already have evaluation, measurement, and verification mechanisms in place through their utility commissions.

There are several methods for calculating the carbon emission reductions from renewable energy. The three main methods include using electric sector models, the emissions rates of the marginal generating units that are displaced by the addition of renewable energy, or average emission rates for all or a subset of emitting resources. Each of these methods involves first metering the amount of renewable energy generated (in MWh), and second determining which sources the renewable energy is displacing, the carbon emissions rate of those sources (can be calculated in lbs carbon emitted/MWh), and therefore the emissions savings attributable to renewable energy.

Resources for Measure Quantification

- The Avoided Emissions and Generation Tool (AVERT) was created by EPA to offer states a relatively simple mechanism to calculate the emissions reductions attributable to renewable energy. States can use AVERT to determine the effectiveness of state and regional efficiency efforts to reduce carbon from electric power plants, as well as NO_x and SO_2. AVERT can present county-level data of avoided emissions based on temporal energy savings and hourly generation profiles. With the concurrence of the relevant EPA regional office, AVERT results may be acceptable for state plan air quality modeling.
- In 2011, EPA released a resource for states entitled Assessing the Multiple Benefits of Clean Energy. Chapter 4 of this document provides good information on assessing the air quality benefits of clean energy initiatives. The document can be found at: http://www.epa.gov/statelocalclimate/documents/pdf/epa_assessing_benefits.pdf. More information on AVERT can be found at: http://epa.gov/avert/.
- For more information on ***Methods and Tools for Quantifying Avoided Carbon Emissions from Renewable Energy, see Appendix 26.***

Reporting and Recordkeeping: Reporting and recordkeeping for renewable energy requirements and programs will be an important component of certain types of state plans. If a state plan incorporates renewable energy requirements and programs under a rate-based approach or implements a mass-based portfolio approach with such measures, reporting and

recordkeeping requirements for an approvable plan would differ from those applicable to an affected EGU.

For example, these requirements may include compliance reporting by an electric distribution utility subject to an RPS. They may also include reporting by a vertically integrated utility implementing an approved integrated resource plan. In the latter instance, the utility may also be the owner and operator of affected EGUs, but additional reporting of quantified effects of renewable energy and demand-side energy efficiency measures under the utility plan would be necessary to demonstrate emissions performance under the state plan. In other instances, a state agency or entity or a private or public third-party entity may be implementing programs and measures that support the deployment of clean energy technologies that are incorporated in a state plan. In each of these instances, reporting of program compliance or program outcomes is a necessary part of an approvable plan to demonstrate performance under the plan.

For more information on this topic, see ***Appendix 27.***

STEP 4. POTENTIAL COMPLIANCE PATHWAYS

EPA is proposing a state plan approach that could accommodate a diverse set of state requirements, programs, and measures, through two basic approaches – direct emission limits and a portfolio approach. As discussed further below, under a direct emission limits approach, rate- or mass-based carbon emission limits would be directly enforceable against affected entities. Whereas under a portfolio approach, state plans would include multiple programs and measures that are designed to achieve either a rate-based or mass-based emissions performance goal for affected EGUs.

These two basic approaches provide four distinct state plan "pathways" under CAA section 111(d). These pathways include:

- Rate-based carbon emission limits applied to affected EGUs
- Mass-based carbon emission limits applied to affected EGUs
- A state-driven portfolio approach
- A utility-driven portfolio approach

A state plan could include a combination of measures that reduce carbon emissions at affected EGUs through the application of emission limits as well as measures that involve actions within the interconnected electricity system that reduce utilization at affected EGUs and thereby avoid EGU carbon emissions. Examples of these latter measures include, among others, renewable energy portfolio standards as well as certain components of utility

integrated resource plans. A state could either rely solely on carbon emission limits that are enforceable against affected EGUs or, alternatively, rely on a portfolio approach, which would include those limits as well as other enforceable measures. The table below provides practical examples of possible state plan approaches under each of these pathways, which are discussed in more detail below.

Rate-Based Plan (Simple)	Rate-Based Plan (More Complex)	Mass-Based Plan (Simple)	Mass-Based Plan (More Complex)
• **CO_2 rate limit applied directly to EGUs**	• **CO_2 rate limit applied directly to affected EGUs** ➢ Credit for EE/RE can be used toward compliance	• **CO_2 mass emissions limit applied directly to affected EGUs**	• **Portfolio of measures applied to meet a mass CO_2 goal** ➢ Translation from rate goal to mass goal (plan includes basis and supporting analysis)
• **Responsible party** is EGU owner/operator (subject to state regulations) • **Demonstration of compliance** based on monitoring and reporting of EGU stack CO_2 emissions and MWh output	• **Responsible party** is EGU owner/operator (subject to state regulations), along with: ➢ Electric distribution utility with regulatory obligations under state EERS and RPS • **Demonstration of compliance** based on: ➢ Monitoring and reporting of EGU stack CO_2 emissions and MWh output, and ➢ EM&V for EE/RE to determine "credits" that can be used to adjust CO_2 rate when demonstrating compliance	• **Responsible party** is EGU owner/operator (subject to state regulations) • **Demonstration of compliance** based on monitoring and reporting of EGU stack CO_2 emissions	•**Responsible parties include**: ➢ State (ultimate responsibility for achieving goal) ➢ Electric distribution utility with regulatory obligations under state EERS and RPS ➢ EGU owner/operator (for emission limit component) • **Demonstration of plan performance** based on monitoring and reporting of EGU stack CO_2 emissions

[9]

For more information explaining the pathways see ***Appendix 21: State Plan Pathways***.

1) Direct Emission Limits Compliance Program[10]

Under this program, EGU owners and operators are held solely responsible for compliance with the EPA's emissions standards. This system would allow for a federally-enforceable obligation on the specific EGUs to be sufficient to achieve the required level of emission performance for the state, either by meeting the aggregate emission rate or by meeting the aggregate mass-based emission budget. This compliance plan would leave the individual owner or operator of

[9] EPA, State Plan TSD at 6.

[10] This section borrows from the Georgetown Climate Center's *Clean Power Plan Implementation: Overview of Potential Compliance Pathways* (Jan. 2015), available at http://www.georgetownclimate.org/an-overview-of-potential-clean-power-plan-compliance-pathways.

the EGU as the party responsible for compliance and could open them up to citizen-suits and EPA enforcement in the event of noncompliance.

a. Rate Based Trading System

Under this option, owners and operators of affected EGUs must meet emissions rate requirements or acquire credits from an emissions trading program. Owners or operators of EGUs would be required to modify the unit's efficiency to meet the rate based emissions standard or seek emissions credits by EGUs with emissions rates lower than the standard dictates. These credits would take the form of avoided MWh of generation or avoided tons of carbon by affected or non-affected sources, which would then be sold for compliance purposes in a similar manner to RECs. Credits would be gained by non-affected sources through generation at a rate below the standard or demand-side energy efficiency measures by utilities or regional operators.

In a rate based system, zero-emitting generation may not necessarily result in improvements in the emission rates of EGUs as the rate applies strictly to the unit and lessened emissions from a specific plant due to timed outages of higher polluting fossil facilities does not lower that EGU's emission rate per MWh. A rate-based system requires a mechanism to credit zero-emitting resources and demand-side energy efficiency. EPA proposes that these resources could be credited as either avoided generation in megawatt hours or as avoided emissions in tons or pounds of carbon. A state or other entity could certify credits from providers of zero-emitting generation or demand-side efficiency resources; these credits could be purchased by EGUs that exceed the emission rate standard and applied to adjust the EGU's rate.

b. Mass Based Trading System

Under this approach, an EGU owner or operator would be solely liable for emissions reductions through either reduction to emissions levels or holding the required amount of allowances or credits equal to the annual credit emissions from the unit. States may choose to freely distribute credits to low emission EGUs or sell them at auction to raise state revenue (or a combination thereof), which could then be invested into energy efficiency or clean energy programs or refunded to electricity customers, among other options.

c. Carbon Fee Approach

Though EPA's Clean Power Plan does not specifically prescribe a carbon fee approach, parties have suggested that states may implement such a fee on EGUs for every ton emitted by the plant. This would act as a price signal that would drive necessary reductions to meet emissions limits established the states and EPA. States could use these fees in a variety of ways, not

dissimilar to how a state may expend funds acquired through sales of emission credits or allowances. In states with organized markets, the generator could include the fee in its bid into the ISO/RTO market, based on the EGU's CO2 emissions. For states without organized markets, vertically integrated utilities could incorporate the fee into decisions to determine the least cost dispatch available to serve load. While EGU's would ultimately be responsible for paying the fee as part of a state's emission reduction plan, the state would ultimately have to demonstrate to the EPA that the state is meeting the required emission performance level, and the plan could be required to include backstop commitments that would guarantee that the level is met.

A carbon fee approach inherently accounts for zero-emitting resources and energy efficiency since it results in higher cost of operation for fossil EGUs and favors clean generation. This would effectively coincide with EGU requirements under a rate or mass based system and act as a financial cue for economic dispatch to result in lowered emissions.

2) EGU-Plus Compliance Programs

This compliance program would rely on both enforceable obligations on EGUs and, in part, other measures that together would achieve the required level of emission performance in either a rate or mass based system. Unlike an EGU Compliance Program, limits on affected EGUs would not be sufficient on their own to guarantee that the state would achieve the targets set by EPA.

a. State Driven Portfolio Approach

Under this approach, owners and operators of affected EGUs must comply with the portion of the standard that establishes EGU obligations while the state and responsible parties must show that programs in place are meeting the assigned portion of the standard. This could be implemented in either a rate or mass based format. This would involve both enforceable obligations on affected EGUs and a portfolio of other enforceable measures, such as an RPS and/or Energy Efficiency Resource Standard.

A state driven portfolio approach would leave a number of entities with enforceable obligations including:

- Owners and operators of EGUs subject to direct emission limits.
- Electric distribution utilities responsible for meeting energy efficiency or zero-emitting resource requirements.
- Public or private third-party entities responsible for meeting energy efficiency or zero-emitting resource requirements.

- State agencies or authorities that administer programs to deploy energy efficiency and zero-emitting resources.

Examples might include a state-wide cap and trade program or direct emission limits on affected EGUs that are insufficient to meet EPA standards, and thus the state would rely upon enforceable obligations on additional entities.

b. Utility Driven Portfolio Approach

A utility driven portfolio approach could be implemented in states with vertically integrated, state-regulated utilities whereby utilities would develop and implement portfolio measures designed to meet the state's rate or mass based emission performance level. These utility plans may include shifting generation from coal to NGCC or renewable generation, credit trading programs, and/or reducing load through demand-side energy efficiency. Such plans would be developed and approved through an integrated resource planning process overseen by a state's public utility commission. Under this approach, the entirety of the portfolio obligations would be enforceable against the utility, as both the owner and operator of the EGU and the entity responsible for implementing other plan measures. In states with more than one vertically integrated utility or with affected units not owned or operated by a vertically integrated utility, the state might divide the emission reduction obligations among utilities or might apply the utility-driven portfolio approach to a large, vertically integrated utility and use another approach for other affected units.

This approach may also be useful in states with municipally-owned utilities or cooperatives; however, this presents enforceability issues as such entities are not regulated by state PUCs. Rather than PUC oversight, states could identify the appropriate authority to oversee the development and enforcement of the plan's components.

c. State Commitment Approach

Under this state commitment approach, the state plan would include a federally enforceable commitment by the state to implement state-enforceable measures, such as an RPS or EERS, that would achieve a portion of the required rate- or mass-based emission performance level. Under this approach, only the requirements for affected EGUs and the commitment by the state to achieve the necessary emission reductions would be federally enforceable; state requirements for entities other than affected EGUs would not be components of the state plan and would not be federally enforceable. If the state program fails to achieve the expected emission reductions, the state could be subject to citizen suits and EPA enforcement actions. A number of stakeholders have suggested that a state commitment compliance plan would be

required to include a source-level federally-enforceable backstop to ensure that required reductions would be achieved. Stakeholders have also suggested that such plans could include interim contingency measures to be automatically implemented if the state programs are not achieving the emission reductions necessary to meet the state's commitment.

STEP 6. CREDITING RENEWABLE ENERGY PROGRAMS INTO COMPLIANCE PLANS

States can claim credit for emissions reductions from renewable energy at the measure, program, policy, or portfolio level. However, particular attention should be paid to how various policies and programs overlap or interact to avoid misrepresenting or double counting achieved emissions reductions.

Treatment of Interstate Emission Effects

Programs and measures in a state plan, such as renewable energy measures, may affect the emission performance of the interconnected electricity system beyond a state border. Fortunately, there are a number of well-established practices to ensure that the state or entity making the financial commitment to develop renewable energy receives full credit for the emissions reductions that are achieved. Many state measures allow for actions in neighboring states to meet the in-state requirement if the renewable energy credits are purchased by an in-state load-serving entity, while other measures explicitly address carbon emissions in neighboring states. For example, many state renewable portfolio standards allow for generation by qualifying renewable energy sources in other states to count toward meeting the state portfolio requirement if the renewable energy credits are purchased by an in-state load-serving entity. Some states also apply carbon emission requirements related to the generation of power purchased by regulated utilities, including power imported from out of state.

EPA proposes in the Clean Power Plan to allow for interstate effects on carbon emissions from affected EGUs to be attributed in different ways in the context of an approvable state plan. This section discusses in more detail the options and alternatives for treatment of interstate carbon emission effects presented in the Clean Power Plan. These options and alternatives could be applied to both projections of plan performance and demonstration of achieved emission performance under a plan. These options and alternatives may not be mutually exclusive – in some instances states could apply different approaches, without introducing the potential for double counting of emission effects.

In general, the options and alternatives address different possible state plan scenarios, and consider the range of interstate approaches that states are currently using to implement electricity sector policies, such as multi-state emission budget trading programs and regional renewable energy certificate markets for state RPSs. The options and alternatives reflect

possible accounting approaches for interstate emission effects under CAA section 111(d) that could potentially align with these current state programs and measures that states may want to include in a state plan. For more information on this topic see ***Appendix 28***.

Summary of Possible Approaches for Treatment of Interstate Emission Effects

- EPA is proposing a set of approaches for addressing interstate emission effects that result from the implementation of state plans that incorporate renewable energy programs. The preamble also solicits comment on additional alternatives.
- Consistent with existing state RPS policies, a state could take into account all of the carbon emission reductions from renewable energy programs and measures implemented by the state, whether they occur in the state and/or in other states.
- States participating in multi-state plans would have the flexibility to distribute the carbon emission reductions among states in the multi-state area.
- States could jointly demonstrate carbon emission performance by affected EGUs through a multi-state plan in a contiguous electric grid region, in which case attribution among states of emission reductions from renewable energy measures would not be necessary.

For more information on this topic see ***Appendix 29***.

STEP 6. ADJUSTING EGU CARBON EMISSION RATES BASED ON THE EFFECTS OF RENEWABLE ENERGY

EPA is proposing that renewable energy requirements, programs, and measures may be incorporated into a rate-based plan approach. Measures that avoid carbon emissions from affected EGUs, such as renewable energy generation, could be used to adjust the carbon emission rate of an affected EGU when demonstrating compliance. Alternatively, a state could use the effect of such measures as a basis for administratively adjusting the average carbon emission rate of affected EGUs when demonstrating achievement of the required emission rate performance level in a state plan.

Under this approach, affected EGUs could comply with a rate-based carbon emission limit through actions at the EGU, as well as through the use of credits for actions that occur elsewhere in the interconnected electricity system that avoid carbon emissions from affected EGUs. If a state is implementing a portfolio approach, then the state could adjust the average

carbon emission rate of affected EGUs through a similar process when demonstrating achievement of the required emission rate performance level in the state plan.

See ***Appendix 24, Calculating the Carbon Emission Reductions from Renewable Energy,*** which explores the mechanics and implications of the different possible approaches for adjusting carbon emission rates. Aspects of this discussion may apply to both retrospective demonstration of carbon emission performance achieved by affected EGUs under an approved state plan and projections of carbon emission performance by affected EGUs included in a submitted state plan.

STEP 7. CONSIDERING MULTI-STATE/REGIONAL APPROACHES

Neither GHG emissions nor energy markets follow state political boundaries; therefore, state-centric strategies are not necessarily the most cost-effective or sensible based on market realities. Collaborative strategies among groups of states or regions, on the other hand, might enable greater flexibility and lower compliance costs.

While EPA's proposed rule does not require interstate approaches, it does permit them. Any regional approach would be voluntary and largely state-driven, presenting both an opportunity and a challenge to states in considering an expanded realm of compliance options. EPA has indicated that there will be a longer drafting window for jointly filed multi-state compliance plans (one year).

Potential Types of Multi-State/Regional Coordination

States and utilities have expressed interest in a wide array of coordination techniques including:

- Joint analysis to inform individual state plans and further understanding of interactions with other state's plans.
- Utilizing a common quantification and measurement protocol to ensure consistency within a region.
- When state programs would require covered facilities to meet an average emission rate, states may want to consider allowing emissions from sources within the state be average with emissions from unites owned by the same company in other states.
- Creating a renewable generation and energy efficiency mechanism that would allow firms to trade credits across state lines to demonstrate compliance.
- Developing a joint compliance program with a multi-state emission budget or central administrative entity.

Potential benefits of interstate collaboration

Multi-state collaboration has distinct market advantages and allows states to better address compliance demands. Some potential boons to states coordinating in multi-state compliance efforts include:

- Economic efficiency from using the diversity of a region's emission reduction resources
- Multi-state shared regulatory experience.
- Regional economies of scale.
- Predictability and risk-sharing across an entire region.
- Netting emission reductions across an area.
- Making interstate trading easier through standardized trading schemes.
- Increased understanding of program interaction.
- Submitting a single plan.
- Extended timeframe to file a state plan.
- Administrative and accounting efficiency.

Unique considerations to designing a regional compliance mechanism

Drafting a multi-state or regional compliance mechanism requires considering a number of factors, such as:

- Determining sensible groupings of states.
- Establishing a basic governing framework.
- Evaluating methods for reducing emissions.
- Addressing multi-state equity issues as they pertain to differences in compliance burden and opportunities.
- Tasking an entity or entities (either existing or newly-formed for this unique case) with responsibility for administration and monitoring.
- Possible improvements on existing planning processes or reduction approaches (i.e., Northwest Power and Conservation Council, Western Regional Air Partnership, et al.).
- Accomplishing the above under the deadlines prescribed by EPA.
- Determining interstate issues, such as emissions budgets and crediting.

For more information explaining regional approaches see ***Appendix 23: Multi-State/Regional Approaches.***

VI. ELEMENTS OF INCORPORATING RENEWABLE ENERGY INTO A STATE PLAN

Here are the template elements that a state must address to incorporate renewable energy into a state plan:

Source Type Affected

- Quantity of carbon emissions targeted by policy/program
- Source(s) of targeted carbon emissions
- Jurisdiction of the policy/program

Policies

- Process state went through to develop policy/program
- Carbon reduction goals of the policy/program
- Utility involvement
- Other public/private entities involved
- Anticipated effects on emissions

Implementation

- Federal, state, and local agencies involved in implementation
- State and local legislation and/or agency rules relevant to implementation
- Utility involvement in implementation
- Necessary interagency cooperation
- Steps that have already been taken to meet goals
- Implementation process going forward

Monitoring and Enforcement

- Agencies responsible for monitoring and enforcement
- Process of agency reporting
- Consequences of compliance/non-compliance

Projected Reductions and Carbon Emissions Benefit Calculations

- Approach for measuring carbon emission savings
- Calculation of emissions reductions from renewable energy programs/policies
- Emissions reduction credits being claimed

GUIDANCE FOR FILLING IN A STATE PLAN USING RENEWABLE ENERGY AS A COMPLIANCE TOOL

In the following sections we provide: (1) guidance on filling in the template elements; and (2) two model state plans based on a hypothetical state scenario.

Source Type Affected

This section should describe the agencies, industries, sectors, etc. on to which the policy/program is applicable. Describe the source of the targeted emissions, the range of

application of the measures chosen, and the entities that are obligated to help reduce emissions. The source type will most likely be electric or natural gas utilities.

Questions to consider for this section:

- Who will be immediately affected by this policy or program?
- What is the scope of the utilities whose emissions this measure intends to reduce?

Policy/Program

Include a brief description of the renewable energy program being used to claim emission reduction credits, including an overview of the structure of the measure, its purpose, and how emissions benefits will be achieved.

Questions to consider for this section:

- What is the intended purpose of this policy/program?
- What commitments have state or local governments made under the policy/program?
- What type of emissions reductions will this measure produce?

Strengthened or New Policies Strategy

Delineate the renewable energy provisions more specifically to convey the nuts and bolts of the measure and information about its development. Include reduction targets and their timelines. For example, a typical renewable energy target may be stated as a 1.5% statewide reduction in overall carbon emissions annually, or a cumulative reduction of 20% by 2025. Explain the means by which pollutants will be reduced.

Questions to consider for this section:

- What is the background of the development of the renewable energy program?
- What does this policy/program specifically mandate/require?
- What are the goals/benchmarks of this renewable energy program?
- How will this measure satisfy EPA requirements for the state plan?

Implementation

The purpose of this section is to explain the process necessary for proper program administration. List the federal, state, and local government agencies involved in the operation of the renewable energy program and its associated programs. Describe the level of responsibility for the program implementation assigned to each group (e.g., utilities, agencies, private actors). Detail applicable legislation/agency rules that authorize the measure. Include steps toward the implementation that have already occurred.

Questions to consider for this section:

- Which government agencies must be involved to implement this policy/program?

- What relationship structure must exist among agencies/utilities to implement this measure?
- What are the responsibilities of the parties involved?
- What steps toward program implementation have already occurred?

Monitoring and Enforcement

This section provides specifics on the procedures and evidence that federal, state, and local agencies will require to verify that progress toward attainment is properly monitored and maintained. The state must ensure that program standards are enforced and explicit deadlines are set for utility reporting on program progress. Explain the procedure for regularly evaluating utility programs and the process for confirming that reduction targets are met.

Questions to consider for this section:

- What agencies will be charged with the task of monitoring program/policy progress?
- Through which channels will reporting on progress take place?
- What agency relationships are necessary to ensure accurate and efficient monitoring and enforcement?
- How will the relevant government agencies verify that the targets set by the renewable policies are met?

Projected Reductions and Emissions Benefit Calculations

This section describes the carbon emission benefits anticipated from the measure's implementation and the calculations used to arrive at them. First, calculate the amount of carbon emission reductions achieved through the renewable energy programs. In some cases, a simple calculation will suffice; in other cases, the complexity of calculations may require an appendix. The form and content of this section largely depends on the specifics of the renewable energy program.

Questions to consider for this section:

- What method of emissions reduction calculation will be most cost effective for this measure?
- Which state agencies, utilities, or other grid operators have access to the data needed to perform an estimate?
- What does the EPA require for performing these calculations?
- Is any reduction credit being claimed?

SAMPLE STATE PLAN 1: RPS PATHWAY

For the purpose of demonstration, we have developed the following hypothetical scenario using an RPS as a reference example for the compliance tool. As discussed, many states have RPS programs in place, enforceable against EGU owners and other entities. These existing programs may provide a helpful starting place for states as they consider what to include in their 111(d) plans.

In this hypothetical scenario, the state, which we have called the "State of Cimarron," does not currently meet the required carbon reduction targets set forth by EPA and so is looking to expand a current RPS as its compliance tool, which must be submitted to the regional EPA office by June 30, 2016; it does not anticipate needing to request an additional year for submitting its plan or to join a multi-state plan.

When designing a plan to reduce power sector carbon intensity, most states will look to two state entities to implement and enforce the plans: the public utility commission (PUC) and the state environmental protection agency. Many states also have state energy departments, which could play important roles in plan implementation. Typically, these entities are created by the legislature, so their authority is defined by statute. In some states, the state Constitution establishes the PUC, providing the PUC with a source of authority independent from the legislature.

In many states, environmental regulators have direct authority over power plant emissions. EPA has delegated to environmental regulators in these states the authority to issue and enforce CAA Title V (major source) permits. States could use this authority to write carbon emission rates and annual emission tonnage limits into those permits. PUCs, meanwhile, have indirect authority over power sector pollution. Some PUCs review utility decisions to install pollution controls or use particular fuels to generate power, and can set and enforce renewable energy mandates. Ideally, environmental agencies and PUCs will work together, with input from utilities and other stakeholders, to craft a 111(d) plan. In most cases, environmental regulators will submit state plans under Section 111(d). We make this assumption for the hypothetical scenario below.

MODEL 1: CIMARRON STATE IMPLEMENTATION PLAN (RPS Model)

1.0 INTRODUCTION

The purpose and goal of this state compliance plan is to provide for the implementation, maintenance, and enforcement, in the State of Cimarron (Cimarron), of carbon dioxide emissions limits for existing power plants placed upon the state by EPA under the authority of § 111(d) of the CAA. The EPA has proposed to allow states to submit plans that hold various entities accountable for achieving the state's performance standard. A state's choice may depend on the structure of its electric sector.

In Cimarron, utilities are vertically integrated and generate nearly all of the states' coal-fired power (co-generators are responsible for approximately three percent). Utilities in Cimarron are well-positioned to implement a wide range of measures; therefore, Cimarron has considered that holding EGUs responsible for meeting the entire performance standard could be the simplest approach.[11] The Cimarron PUC may enforce its RPS against distribution utilities, competitive suppliers, and other entities with obligations under this state plan.

Cimarron, like more than twenty-five other states, has established a process for long-term utility planning—long-term Integrated Resource Plans (IRP)—which could provide a familiar forum and highly salient information for the crafting of a 111(d) state plan. Cimarron's IRP process makes it well-suited to inform the formulation of a 111(d) plan. Every two years, utilities within the state must submit fifteen-year plans that are intended to minimize the total societal cost of meeting the demand for electric energy services. The rule also requires plans to reduce environmental impacts and meet renewable energy requirements under the state RPS. However, the IRP process does not, by itself, create enforceable requirements, but the rules allow utilities to request enforceable approvals of specific measures within the IRP. These measures, then, could be enforceable under the State of Cimarron law and could be written into a 111(d) state plan.

In addition to taking the lead on developing a state plan, the State of Cimarron's broad authority under the state's Constitution allows it to submit the plan to EPA for consideration prior to the June 30, 2016 deadline.[12] The Cimarron PUC has expansive authority that would

[11] In non-vertically integrated states, generation and distribution are mostly separate, and distribution is further split between distribution utilities and competitive suppliers who serve more than half of each retail market. In such states, merchant generators are subject to state environmental regulation, while distribution utilities and competitive suppliers are regulated by its PUC. To implement a utility-only plan in those states, regulators would need some additional authority. For instance, regulators might not have authority to require utilities to hold carbon emission allowances or to create credits representing renewable energy.

[12] Planning processes in other states might be more limited by statute and fall short of this IRP process.

allow entities to generate renewable credits under its Constitutional powers. If the PUC finds that state inaction would lead to the imposition of a Federal plan that would raise rates, the PUC may argue the Commission's constitutional duty to maintain just and reasonable rates implicitly authorizes it to submit a 111(d) plan to EPA.

In 2008, Cimarron passed the *Reenergize Cimarron Act* (the Act). The state now wishes to increase the standard in that act for use in its upcoming state compliance plan. The Act established the RPS based on its authority under the State of Cimarron Constitution, so the RPS is not constrained by any specific statute. The Act adopted an RPS that requires utilities to procure, at minimum, fifteen percent of retail sales from renewable generators by 2025.[13] To increase the mandate, Cimarron would have to follow ordinary rulemaking procedures. In its state plan, Cimarron proposes to require all utilities in the state to procure 40 percent of retail sales from renewable energy by 2030.

2.0 GENERAL METHODOLOGY AND PLAN CONTENT

In developing the § 111(d) state plan, Cimarron has monitored stationary sources and established an air quality database for carbon emissions for which standards exist. Cimarron then took the following steps

2.1 IDENTIFICATION OF AFFECTED ENTITIES

The state's five largest electric generating power plants are currently the targeted sources of carbon pollution subject to this state plan, though the state will receive credit for emissions reductions that occur out of state.

2.2 DESCRIPTION OF PLAN APPROACH AND GEOGRAPHIC SCOPE

Cimarron will be implementing its plan through the strengthening of the state's RPS as a means to reduce their carbon emissions from 1467 lbs/MWh to an interim 2020-2029 average rate of 911 lbs/MWh and a final 2030 rate of 873 lbs/MWh. This measure applies to electric generating power plants operating within Cimarron.

Under its existing RPS, Cimarron has already placed varying renewable integration requirements on the state's utilities. In addition, the existing RPS requires Cimarron's covered entities to submit plans to the Cimarron PUC on July 1, 2015, to outline compliance through 2017, and then in 2017 and in 2021 to outline compliance through 2021 and 2025, respectively. These plans will detail what amount of energy the entities

[13] If the law required the sales to come from, e.g., "alternative" sources, the legislature would need to act to limit the expansion of the program to zero-emission generation so non-renewables were not included.

will procure through building new renewable energy generation and what amount through renewable energy credits. The RPS directs the Cimarron PUC to establish a program that certifies and tracks renewable energy credits.

2.3 IDENTIFICATION OF STATE EMISSION PERFORMANCE LEVELS

One of the required components of a state plan is a projection that the plan will achieve the required level of carbon emission performance by affected EGUs that is specified in the plan. All state compliance plans will need to include a projection of the carbon emission performance by affected EGUs that will be achieved under a state plan (inclusive of plan measures that avoid carbon emissions from affected EGUs, such as renewable energy). Depending on the type of plan approach, this will include either a projection of the average carbon emission rate achieved by affected EGUs or total carbon emissions from affected EGUs.

Electricity sector modeling includes the use of dispatch simulation models and capacity expansion and dispatch planning models that simulate the operation of individual EGUs (or aggregations of EGUs) in the electric system over time based on a detailed characterization of those EGUs, engineering and market operating constraints, other market factors (e.g., fuel prices, transmission constraints), emission constraints, and the requirement to meet a certain level of energy and peak demand.

The Clean Power Plan establishes carbon emission performance levels for Cimarron and requires that they conform to the plan. If EPA's rate-based standard were converted to a mass-based standard, EPA has estimated that Cimarron must reduce carbon dioxide emissions from existing and new power plants by around 8.2 million metric tons in 2030, or around 9 million short tons.

2.4 IDENTIFICATION OF MILESTONES

Under the existing RPS, the compliance schedule for Cimarron's utilities varies depending upon the size, scope, and nature of the entity's operation.

Hanover Power Standard: The RPS standard for Hanover Power requires that the following percentages of retail electricity sales be generated or procured using eligible renewable sources by December 31 of the given year: 15% by 2010; 18% by 2012; 25% by 2016; 30% + 1.5% solar by 2020.

Standard for Non-Hanover Public Utilities: The RPS standard for other Cimarron public utilities requires that the following percentages of retail electricity sales be generated or

procured using eligible renewable sources by December 31 of the given year: 12% by 2012; 17% by 2016; 20% + 1.5% solar by 2020; 25% + 1.5% solar by 2025.

Standard for Non-Public Utilities: The standard for other Cimarron utilities requires that the following percentages of retail electricity sales be generated or procured using eligible renewable sources by December 31 of the given year: 12% by 2012; 17% by 2016; 20% by 2020; 25% by 2025.

For the purposes of demonstrating reasonable progress toward complying with EPA's carbon pollution standard, Cimarron will be claiming reductions of carbon emissions attributable to the total (both under the existing RPS and the incremental RPS increase) amount of renewable energy driven by the state's RPS policy.

2.5 PROJECTED REDUCTIONS AND EMISSIONS BENEFIT CALCULATIONS

To calculate emissions reductions attributable to Cimarron's RPS, the total gigawatt-hours of renewable energy sourced electricity consumption must first be calculated. Cimarron has elected to use EPA's AVERT model to analyze the emissions reductions attributable to the RPS,[14] which comes out to the following: 27,195,000 MWh of renewable energy in 2030 (state retail sales times 40%) multiplied by 1834 lbs of CO2/MWh of renewable energy; the incremental emissions savings calculated in EPA's AVERT tool for 2013 wind energy in the Upper Midwest region = 25 million short tons of emissions reductions.

2.6 ANTICIPATED EFFECTS OF THE POLICY/PROGRAM

By increasing the reliance on renewable energy sources for electric energy consumption, Cimarron will decrease the amount of fossil fuels burned in the state and will achieve more limited reductions in adjoining states from which Cimarron purchases electricity and/or RECs. Carbon dioxide, as well as sulfur dioxide and nitrogen oxide, emissions will decline with the reduction in fossil-fuel consumption. A number of studies by independent grid operators, utilities, state entities, including the government of Cimarron, and government laboratories have shown that reliability will not be negatively affected by the levels of renewable integration proposed in this state plan.[15]

[14] AVERT may be used to derive marginal emission reductions from historical generation and emissions data, which can be used to derive a marginal avoided CO2 emission rate. However, AVERT does not quantify average emissions rates. AVERT approximates historical dispatch behavior using a statistical algorithm. It does not represent transmission constraints, or significant changes in grid structures or future economic conditions.
[15] See the studies listed at http://variablegen.org/resources/.

2.7 IMPLEMENTATION OF STATE PLAN

Cimarron's state plan relies upon collaborative effort among federal, state, and local agencies, as well as private industry, through authority granted by both state and federal law.

2.8 PARTIES INVOLVED IN PLAN IMPLEMENTATION

The Cimarron PUC is the primary entity charged with program oversight and implementation, working in collaboration with the state DEQ and the EPA for establishment of covered entities. The PUC will also report to the Cimarron General Assembly annually on program progress. Covered entities, such as regulated utilities, will consult with the PUC on procurement strategies and implementation of state policy. Additionally, entities must submit plans to the PUC for meeting the renewable energy procurement goals set forth by the state plan.

2.9 CURRENT IMPLEMENTATION EFFORTS

For the interim compliance period (2020-2029), all entities will be required to have plans approved by the PUC and will commence implementation in 2020 to achieve the increased RPS numbers.

2.10 STRATEGIES FOR CARBON EMISSIONS REDUCTION ATTAINMENT

Through a combination of utility approved plans reducing covered stationary source emissions, generation switching, integration of broader renewable energy resources, and state led energy efficiency and demand response programs, Cimarron hopes to reduce carbon emissions below the EPA's required emissions limits by the programmatic deadline of 2030.

2.11 FUTURE POLICY IMPLEMENTATION PROCESS

As the implementation processes progress, the PUC will work with covered entities to meet the interim objective and final goal of 20% renewable energy procurement by 2030. This may include modification of utilities IRPs, assessment of REC market performance, or adjustment of RPS goals.

2.12 ENFORCEMENT, QUANTIFICATION, MONITORING, AND VERIFICATION OF RENEWABLE ENERGY PROGRAMS AND MEASURES

The Cimarron PUC is the primary agency charged with the monitoring of compliance program progress and overseeing enforcement of the state plan.[16]

2.13 PROCESS OF AGENCY REPORTING

Utilities are required to file annual compliance reports with the PUC detailing their retail sales, REC retirements, and REC trading activities. Each covered entity will direct its own program evaluation and verification through an independent contractor and report its findings to the PUC annually. If the PUC finds a utility is non-compliant, the commission may order the utility to construct facilities, purchase eligible renewable electricity, purchase RECs, or engage in other activities to achieve compliance. If a utility fails to comply, the PUC may impose a financial penalty on the utility in an amount not to exceed the estimated cost of achieving compliance. The penalty may not exceed the lesser of the cost of constructing facilities or purchasing credits, and proceeds must be deposited into a special account reserved for energy and conservation improvements.

Entities will be required to file formal reports on procurement progress, including compliance of renewable energy credits with PUC regulations, annually filed in January of the following year. The PUC will communicate to the Cimarron General Assembly on or before March 1 of each year the status of renewable energy deployment in the state, the effects of the standard on electricity prices, the cost effectiveness of the standard, and the effect on employment of the standard.

2.14 IDENTIFICATION OF MONITORING, REPORTING, AND RECORDKEEPING REQUIREMENTS

To verify compliance, RPSs have been complemented by tracking systems for renewable energy generation and use. These tracking systems account for the growing amount of renewable energy that is produced for obligated retail sellers as well as large and small retail energy consumers that purchase renewable energy on a voluntary basis. Tracking renewable energy varies depending on the form by which a utility acquires such energy—be it through building generation, bilateral contracts, or RECs.

Building Renewable Generating Facilities: Utilities with RPS obligations may build, own, and operate their own renewable energy generating facilities. For large renewable

[16] In states that are not vertically integrated, merchant generators in the State of Cimarron would be subject to state environmental regulation, while distribution utilities and competitive suppliers would regulated by PUCs. Under a portfolio or State commitment approach to the States' 111(d) plans, the PUCs would enforce the RPS compliance program against distribution utilities, competitive suppliers, and other entities with obligations under the plan.

energy facilities, production is measured through a revenue-grade utility meter as it enters the grid at the point of interconnection; this meter is subject to the same verification standards as for any other generator participating in the wholesale market. Although not all distributed PV systems are metered and monitored, many are. For example, every system that is contracted under third-party ownership is metered and monitored, typically remotely (electronically) and often in near real time, such that time of day production can be recorded. Moreover, in states where distributed PV is used to meet state RPS requirements, metering and reporting is generally required for tracking of Solar RECs, regardless of the ownership of the system. The type of metering may be similar to that for third-party owned systems or may be less granular, for example, using an analog meter to manually record monthly production. For the portion of the distributed PV market that is not metered, estimates of performance can be made by using any number of publicly and commercially available models, including the NREL PVWatts, Sandia National Labs flat plate, PVSyst, SolarAnywhere,® FleetView®, and/or Homer model.

***Bilateral Contract Model*:** Distribution utilities with RPS obligations contract with renewable energy generators for supply. These contracts typically specify a delivery amount in MWh over a specified contract period. These supply contracts may be short- or long-term, may specify generation from certain renewable energy EGUs, and may be solicited through an RFP or entered into through negotiation. Quantification of renewable energy generation (in MWhs) is also accomplished through the use of a revenue-grade meter that measures the flow of electricity from the generator into the transmission grid. A contract may also stipulate an adjustment to the metered MWh generation data to account for transmission losses that occur between the point of injection of electricity to the transmission grid and the point of receipt at a utility transmission or distribution system. RECs should be acquired with the receipt of electricity with bilateral contracts so that the purchaser may satisfy its RPS obligations through the contract.

State RPS compliance processes provide for PUC review of supply contracts, including inspection of meters and verification of electricity delivery from the generator to the utility distribution network through a specified contract path (e.g., through evidence of transmission rights held or scheduled). The purchasing utility also reports their purchase and delivery of RPS-compliant renewable energy pursuant to the contract to the state agency responsible for RPS enforcement, typically the state PUC or state energy office. Verification is accomplished by audit of electricity supply contracts along with REC tracking system reports of RECs held by the utility and submitted for retirement by the tracking system administrator. Bilateral contracts require certification by the seller that

attributes related to the sold electricity have not been and will not be otherwise sold, retired, claimed, represented as part of energy sold elsewhere, or used to satisfy obligations in another jurisdiction.

***REC Model*:** Renewable energy generators register their EGU with the renewable energy tracking system established by the state. The registration process collects data about the generator's attributes: type of resource (e.g., wind), plant-level emissions, geographic location, nameplate capacity (MW), commercial operation date, ownership, and the eligibility for RPS compliance or voluntary market certification. After the generator is registered, revenue-meter data is transmitted to the tracking system. Meter accuracy is verified for renewable energy generators in the same manner as for any other generator participating in wholesale electricity markets. Each MWh of renewable energy generation reported to the tracking system by a registered generator results in the issuance of a REC, with its own unique serial number and information about the generator, location, resource type, and the month in which the MWh was generated, and the month or quarter in which the certificate was issued. The system tracks each REC through these transactions and ultimately "retires" the REC when the final purchaser designates it for retirement. Retirement could result from the REC being used to satisfy a state RPS, or as a result of a voluntary buyer retiring the REC to demonstrate that they had purchased and used renewable energy to meet their electricity demand.

2.15 MECHANISMS FOR DEMONSTRATING COMPLIANCE

In demonstrating compliance, plant owners can average their emissions across individual boilers at the same facility and within the same subcategory, providing a limited degree of compliance flexibility.

Annual reports are due six months after calendar year end and must include all information in 40 CFR 60.5815 (Part 75 reporting program). EGUs may report emissions directly to EPA. Cimarron must report all information necessary to demonstrate plan performance and implementation, including programmatic milestones and implementation of corrective actions if relevant.

2.16 CERTIFICATION OF HEARING ON STATE PLAN

Cimarron's state plan must provide certification that the state held a hearing on the plan, a list of witnesses (with their organizational affiliation, if any) appearing at the hearing, and a brief written summary of each presentation or written submission, pursuant to the requirements of the EPA framework regulations at 40 CFR 60.23-60.2.

MODEL 2: COMMONWEALTH OF FILLMORE STATE PLAN (CREDITING MODEL)[17]

I. INTRODUCTION

The Commonwealth of Fillmore (Fillmore) plans to use a tradable credit system to implement EPA's proposed existing-source performance standards. The program would award carbon reduction credits, or CRCs, based on the CO2 emission rate and output of generators over time, and require credits to be periodically retired to demonstrate compliance with EPA's standard. Under this program, for each MWh of electricity produced (or saved with renewable energy), one credit is awarded for each pound of emissions less than that permitted by EPA's proposal. To the extent that a source emits at a rate greater than the EPA standard, a credit deficit is established. The program accommodates trading, either intrastate or interstate, to enable excess reductions from one facility to be used for compliance at a deficient facility. (Some of the preliminary steps described above in the Model Rule 1 approach above are not discussed here as they would be redundant.)

a. PLAN APPROACH

The Commonwealth of Fillmore is implementing this measure to reduce the production of fossil-fuel generated electric power and increase the production of non-emitting sources. The decrease in production from fossil-fuel plants will have a corresponding impact on the burning of fossil fuels at electric generating facilities, thereby reducing carbon emissions from these sources. EGUs will be provided credits or establish a credit deficiency based upon their annual emission rates each year.

The Fillmore Dept. of Environmental Quality will determine, each year, the emissions for each of the EGUs that EPA has identified as affected facilities in the state. EPA prescribes acceptable procedures for measuring emissions in its proposed rule. Additionally, owners or operators of affected EGUs would measure and report the megawatt-hours produced by their facility during that same annual period.

b. ESTABLISHING CARBON REDUCTION CREDITS FOR FOSSIL ELECTRICITY GENERATING UNITS

[17] This model rule is based on one set forth by the Western Resource Advocates, available at http://www.westernresourceadvocates.org/energy/pdf/CRC%20Program%20-%20WRA%20working%20paper%208%2025%2014.pdf.

To determine the number of credits each EGU receives, regulators would compare the emission rate of the EGU in a compliance year to the required standard for that same year. Each generator would receive one carbon reduction credit for each pound of carbon per megawatt-hour that its emission rate was less than the standard in that year, multiplied by the output in that year. So, if the standard was 1200 lbs/MWh in a particular year, and a generator produced 1000 MWh with an emission rate of 1000 lbs/MWh, that generator would receive 200,000 credits for that year.

$$(1200 lbs/MWh - 1000 lbs/MWh) * 1000\ MWh * 1(CRC/lbs) = 200{,}000\ CRCs$$

Mathematically, the number of CRCs provided to a facility each year can be shown as:

$$CRCs = (RSTATE - R) * E * C$$

RSTATE is the state's CO2 emission rate (lbs/MWh) standard for that year
R is the CO2 emission rate (lbs/MWh) of the facility in that year
E is the output, i.e. net5 energy (MWh), produced by the generator during the year
C is the conversion factor of 1 CRC per pound

Facilities that emit carbon at a rate greater than the standard for that year would have a credit deficiency (negative credits), using the same formula as above. This is important because EGUs with credit deficits will have a compliance obligation to the extent of that negative balance, which they would meet by acquiring or earning CRCs. At the end of a compliance period, an EGU will be in compliance with the standard if it does not have a credit deficit. Provided that none of the state's EGUs have a credit shortfall, the state will be able to demonstrate compliance with EPA's performance standard.

c. PROVIDE CREDITS TO ZERO-EMISSION RESOURCES

EPA has identified zero-emission renewable energy production as emission reduction systems that states can use to reduce the emission rates of their generation portfolios. Because these measures produce or avoid megawatt-hours and have zero emissions, EPA proposes that the energy associated with these measures to reduce the average emission rate for all generators in a state. To receive credit for zero-emission energy, a state would determine the energy production from such sources. Those financially responsible for the development of these resources, e.g. the utility or REC holder, would be entitled to receive CRCs.

The program would allow any renewable resource, regardless of where it produced or saved energy, to receive CRCs in a state so long as safeguards are in place to prevent duplicative CRC awards. Allowing out-of-state providers to receive CRCs is consistent with the "system" of emission reduction EPA has identified. If state law defines RECs to include all environmental

attributes, CRCs would be awarded to a REC holder only if that person or entity commits to retire the RECs in the same state where the CRCs are used for compliance, or to hold the RECs until they expire.

The awarding of credits for renewable energy is straightforward, and uses the same formula as for EGU's above except that the resource emission rate is zero. For every megawatt-hour produced or saved in a year, these measures receive credits equal to the state's emission rate standard for that year. EPA has prescribed specific metering requirements to measure renewable energy production. The CRC program would also allow aggregated renewable distributed generation, such as rooftop solar, to receive credits for its metered production. Using the scenario above, if a renewable resource produced 1000 MWh, 1,200,000 CRCs would be awarded.

$$(1200 lbs/MWh - 0 lbs/MWh) * 1000\ MWh * 1(CRC/lbs) = 1{,}200{,}000\ CRCs$$

d. RETIREMENT OF CARBON REDUCTION CREDITS

Retirement of credits is periodically required to ensure compliance with the standard. This obligation is placed upon each affected EGU. The number of credits to retire equals the credit deficit, if any, that an EGU accumulated during the compliance period. So, if a generator had a credit deficit of 100,000 for two years, at the end of that compliance period the EGU would need to retire 200,000 credits. Any person, entity or generator that was awarded credits at any time would have those credits available to provide or sell to deficient EGUs. Put another way, an EGU whose emissions exceed the state standard emission rate in a year would offset its excess emissions through the retirement of CRCs. Those CRCs represent emission reductions beyond the standard at another EGU, or created by an emission reduction measure. Under this program, until retired for compliance, credits can be banked, sold or traded, and do not expire.

e. ANTICIPATED EFFECTS OF THE PROGRAM

Rate impacts of this plan are minimized by matching the periodic compliance obligation to the lumpiness of typical utility resource development and retirement. This lumpiness can create short-term credit shortfalls that would be difficult or costly to address. To mitigate this concern, while the regulation calls for an annual accumulation of CRC retirement obligations, the compliance periods are spaced two years apart – to conform to EPA's proposal that emission rate reduction progress be assessed at least biannually. Because credits do not expire unless retired for compliance, and can be banked, sold or exchanged, this two-year window should provide ample flexibility for generator compliance. And, given that carbon is a global pollutant that stays in the atmosphere for 100 years or more, the extended compliance periods should have little impact on the overall benefits of the program.

In addition, to assure that market failures or other dislocations do not create short-term credit scarcities and extraordinary prices, an affected EGU that is unable to comply with the standard in a particular compliance period would be permitted to make up its deficiency within twelve (12) months by retiring 125% of the CRC shortfall. This provision protects against price spikes if the market temporarily fails. Requiring non-compliant EGUs to later retire 125% of their deficit should provide a strong incentive for timely compliance. However, the increase in consumer electricity prices is minimal with the average rate payer seeing a 6.3% increase in prices over today's rates in 2030, or 0.4% per year.

f. STRATEGIES FOR CARBON EMISSIONS REDUCTION ATTAINMENT

Through a combination of utility credit trading, reduced firing of covered stationary sources, and integration of broader renewable energy resources, Fillmore hopes to reduce carbon emissions below the EPA's required emissions limits by the programmatic deadline of 2030.

Interstate trading markets for CRCs may be established with an exchange rate developed for differences between state plan stringencies. Using CRC exchange rates preserves single state emission rate standards, but allows reduction measures to be developed and/or awarded anywhere without a locational penalty or reward. This can lower costs by allowing the most economic reductions in a region to be developed first.

APPENDIX 1. REQUIRED STATE PLAN COMPONENTS

The Clean Power Plan requires that state plans must include 12 components:

1. Identification of affected entities (affected EGUs and other responsible parties)

   - A state may identify affected EGUs as the only entities subject to requirements in its state plan
   - A state plan may include other non-EGU affected entities that have enforceable obligations under the plan

2. Description of plan approach and geographic scope

   - A state may participate in a multi-state plan or develop a state-specific plan
   - A multi-state approach may provide participating states with greater flexibility and options

3. Identification of required emission performance level for affected EGUs

   - Emission performance level must be equal to or better than state carbon emission performance goal for affected EGUs
   - A state may convert its goal from a rate basis to a mass basis, if appropriate

4. Demonstration that the plan is projected to achieve required emission performance level

   - State plan must demonstrate that the suite of enforceable measures in the plan are projected to achieve the required emission performance level for affected EGUs specified in the plan (on a rate or mass basis, as applicable)
   - During the initial 2020-2029 plan performance period, demonstration on an average basis (rate goal) or cumulative basis (mass goal)
   - Plan must demonstrate it will achieve the required final emission performance level in 2030
   - This demonstration includes a detailed description of the analytic process, tools, and assumptions used to project future carbon emission performance
   - Considerations related to projecting the emission performance of affected EGUs under a state plan are discussed in the "Projecting EGU Carbon Emission Performance in State Plans" Technical Support Documentation (TSD)

5. Identification of milestones

- Periodic programmatic milestones are required to demonstrate program implementation (for plans that are not "self-correcting")
- "Self-correcting" plans inherently assure full achievement of the state plan's required level of emission performance through requirements that are enforceable against affected EGUs
- Milestones must have specific achievement dates appropriate to the programs and measures in the plan
- State plan demonstration must also indicate the plan's trajectory of emission performance improvement
- State must compare the collective emission performance achieved by affected entities in the state during the previous two-year period with performance projected in the state plan, beginning in 2022 and for each year during the interim performance period

6. Identification of corrective measures

- A plan without self-correcting mechanisms must specify corrective measures that will be implemented if the state plan fails to achieve its projected emission performance trajectory by more than 10 percent of the plan's projection and a process and a schedule for implementing such measures

7. Identification of emission standards and any other measures

- State plan must identify the applicable emission standards for affected entities (e.g., individual affected EGUs, groups of affected EGUs, all the state's affected EGUs in aggregate, affected entities that are not EGUs)
- State plan must identify any implementing and enforcing measures for the emission standards, including the schedule for compliance for each affected entity
- Averaging times for emission standards for an affected entity:
    - Rate-based emission performance level – cannot exceed 12 months
    - Mass-based emission performance level – cannot exceed 3 years

8. Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable

- State plan must describe how each emission standard has these characteristics, recognizing the non-traditional nature of some potentially affected entities
- An emission standard is quantifiable if it can be reliably measured using technically sound methods in a replicable manner

9. Identification of monitoring, reporting, and recordkeeping requirements

- Plan must include monitoring and reporting requirements for carbon emissions and energy output (if applicable) from affected EGUs
- Plan must include monitoring and reporting requirements for other affected entities if included in the plan

10. Description of state reporting

- Annual reports, due six (6) months after calendar year end
- Must include all information in 40 CFR 60.5815 (Part 75 reporting program)
- EGUs may report emissions directly to EPA, if a state wants to incorporate the Part 75 reporting program; this option may save state resources
- State must report all information necessary to demonstrate plan performance and implementation, including programmatic milestones and implementation of corrective actions (if relevant)

11. Certification of hearing on state plan

- State plan must provide certification that it held a hearing on the state plan, a list of witnesses (with their organizational affiliation, if any) appearing at the hearing, and a brief written summary of each presentation or written submission, pursuant to the requirements of the EPA framework regulations at 40 CFR 60.23-60.29

12. Supporting material

- State must provide supporting material and technical documentation for applicable plan components

- Must demonstrate that it has the legal authority for each implementation and enforcement component in its plan, as part of a federally enforceable emission standard, by providing material related to the state's legal authority used to implement and enforce each component of the plan, such as statutes, regulations, public utility commission orders, and any other applicable legal instruments

- Must provide analytical materials used in translating a rate-based goal to a mass-based goal if a mass-based goal is used, analytical materials used in projecting emission performance that will be achieved through the plan, relevant implementation materials, and any additional technical requirements and guidance the state proposes to use to implement elements of the plan.

APPENDIX 2: RENEWABLE ENERGY TECHNOLOGIES ARE EFFECTIVE TOOLS FOR REDUCING CARBON EMISSIONS

WIND ENERGY IS GREATLY REDUCING EMISSIONS OF CARBON DIOXIDE AND OTHER POLLUTANTS IN NEARLY EVERY STATE

AWEA used a new EPA modeling tool to quantify the state-by-state pollution reductions wind energy is currently providing, and the results are shown in the tables below. The 167.7 million megawatt-hours (MWh) of wind energy produced in the U.S. in 2013 reduced carbon emissions by 125.7 million short tons, the equivalent of reducing power sector emissions by 5.3 percent or taking 20 million cars off the road. These emissions savings were broadly distributed across nearly every state, accounting for the fact that wind energy is widely deployed and that many utilities in states without wind plants are purchasing wind energy from facilities in other states. Emissions savings are reported in the states that the model indicates fossil-fired power plants are reducing their emissions due to wind generation, which in inter-state power markets are not always the states in which the wind plants are located.[18] Results are listed alphabetically by state name in the first table, and ranked by amount of carbon emission reductions in the second table.

Table 1: State-by-state analysis of wind energy's 2013 emissions reductions using EPA's AVERT tool, **listed alphabetically by state name**

State	carbon reductions	SO_2 reductions (pounds)	NO_X reductions (pounds)

[18] EPA recently released a new tool, AVERT, that allows for the calculation of emissions reductions associated with wind energy and other non-emitting solutions. EPA's AVERT tool uses empirical power system data to identify the power plants that are most likely to have their fuel use and emissions reduced by the addition of wind energy or another zero-carbon solution, and then reports in highly granular detail the impact of that solution on each power plant's emissions. AVERT is available for download at http://epa.gov/statelocalclimate/resources/avert/index.html. AWEA put DOE EIA 2013 state-by-state wind generation data, available at http://www.eia.gov/electricity/monthly/current_year/february2014.pdf, into the AVERT tool. For this analysis, which was intended to calculate where wind power is reducing emissions in physical reality, emissions reductions were counted in the wind-producing region for power purchase contracts that are not known to call for physical delivery of the wind generation, such as those involving renewable energy credit purchases. However, as a policy matter, AWEA is advocating that EPA allocate credit for emissions reductions to the entity purchasing the wind generation and associated environmental attributes, which would result in a different state-by-state distribution. This analysis modeled emissions savings in the receiving region only for power purchase contracts that are known to call for the physical delivery of wind generation from one AVERT region to another, such as those from wind plants in the Northwest to utilities in California and from Upper and Lower Midwest wind plants to utilities in the Southeast. Because the AVERT tool's regions are not perfectly coterminous with actual grid operating areas, particularly in the Southeast and to a lesser extent the Western U.S., to better reflect reality calculated emissions savings in the Southeast were allocated to states with utilities that have wind development or wind purchases with physical delivery of the generation. AVERT does not model Hawaii and Alaska, so those were calculated separately using EIA fuel mix and emissions data.

	(short tons)		
Alabama	864,575	3,886,975	1,214,725
Alaska	114,986	202,375	1,079,335
Arkansas	1,135,500	3,073,400	2,147,200
Arizona	437,700	217,100	548,300
California	8,117,000	65,900	6,501,500
Colorado	6,610,400	11,034,000	13,889,700
Connecticut	319,900	190,100	356,900
Delaware	162,700	216,700	145,400
Georgia	926,675	3,430,775	1,234,525
Hawaii	436,795	2,096,789	2,489,937
Iowa	6,394,300	27,219,100	14,488,800
Idaho	302,700	2,800	78,300
Illinois	9,791,700	25,886,200	9,480,500
Indiana	2,765,500	18,073,100	5,809,800
Kansas	4,249,000	6,513,500	7,935,900
Kentucky	580,200	3,327,900	1,119,000
Louisiana	697,625	578,300	2,017,575
Massachusetts	632,000	1,656,600	561,800
Maryland	842,300	3,102,000	1,511,500
Maine	108,400	186,100	60,100
Michigan	1,198,800	5,520,300	2,289,100
Minnesota	4,961,800	6,948,100	8,466,300

Missouri	6,054,800	21,833,600	8,005,700
Mississippi	626,875	3,217,375	1,041,925
Montana	661,500	2,325,800	1,753,800
North Dakota	2,733,700	6,493,200	8,072,600
Nebraska	3,253,200	13,594,200	6,515,200
New Hampshire	242,300	571,900	373,500
New Jersey	532,500	224,600	599,900
New Mexico	130,000	81,700	373,400
Nevada	651,700	1,049,300	1,339,400
New York	1,493,900	2,493,800	2,404,900
Ohio	2,482,300	16,442,500	4,044,900
Oklahoma	5,886,300	17,767,700	15,503,000
Oregon	1,586,400	3,213,900	1,712,400
Pennsylvania	2,741,200	14,453,700	6,927,400
Rhode Island	149,000	6,100	57,600
South Dakota	663,800	4,864,200	3,913,500
Tennessee	1,506,100	2,927,500	1,796,200
Texas	25,178,100	67,727,700	29,078,900
Utah	2,817,900	2,785,400	10,675,700
Virginia	259,900	983,600	557,600
Vermont	12,400	200	8,200
Washington	3,726,700	1,854,900	9,988,600

Wisconsin	5,032,700	18,504,700	6,222,900
West Virginia	1,303,000	3,034,000	1,331,500
Wyoming	4,556,000	6,379,100	8,647,000
Total	**125,677,881**	**337,698,064**	**213,051,972**

Table 2: State-by-state analysis of wind energy's 2013 emissions reductions using EPA's AVERT tool, ***ranked by carbon emissions reductions***

State	**carbon reductions (tons)**	**SO_2 reductions (pounds)**	**NO_X reductions (pounds)**
Texas	25,178,100	67,727,700	29,078,900
Illinois	9,791,700	25,886,200	9,480,500
California	8,117,000	65,900	6,501,500
Colorado	6,610,400	11,034,000	13,889,700
Iowa	6,394,300	27,219,100	14,488,800
Missouri	6,054,800	21,833,600	8,005,700
Oklahoma	5,886,300	17,767,700	15,503,000
Wisconsin	5,032,700	18,504,700	6,222,900
Minnesota	4,961,800	6,948,100	8,466,300
Wyoming	4,556,000	6,379,100	8,647,000
Kansas	4,249,000	6,513,500	7,935,900
Washington	3,726,700	1,854,900	9,988,600
Nebraska	3,253,200	13,594,200	6,515,200
Utah	2,817,900	2,785,400	10,675,700
Indiana	2,765,500	18,073,100	5,809,800

Pennsylvania	2,741,200	14,453,700	6,927,400
North Dakota	2,733,700	6,493,200	8,072,600
Ohio	2,482,300	16,442,500	4,044,900
Oregon	1,586,400	3,213,900	1,712,400
Tennessee	1,506,100	2,927,500	1,796,200
New York	1,493,900	2,493,800	2,404,900
West Virginia	1,303,000	3,034,000	1,331,500
Michigan	1,198,800	5,520,300	2,289,100
Arkansas	1,135,500	3,073,400	2,147,200
Georgia	926,675	3,430,775	1,234,525
Alabama	864,575	3,886,975	1,214,725
Maryland	842,300	3,102,000	1,511,500
Louisiana	697,625	578,300	2,017,575
South Dakota	663,800	4,864,200	3,913,500
Montana	661,500	2,325,800	1,753,800
Nevada	651,700	1,049,300	1,339,400
Massachusetts	632,000	1,656,600	561,800
Mississippi	626,875	3,217,375	1,041,925
Kentucky	580,200	3,327,900	1,119,000
New Jersey	532,500	224,600	599,900
Arizona	437,700	217,100	548,300
Hawaii	436,795	2,096,789	2,489,937
Connecticut	319,900	190,100	356,900

Idaho	302,700	2,800	78,300
Virginia	259,900	983,600	557,600
New Hampshire	242,300	571,900	373,500
Delaware	162,700	216,700	145,400
Rhode Island	149,000	6,100	57,600
New Mexico	130,000	81,700	373,400
Alaska	114,986	202,375	1,079,335
Maine	108,400	186,100	60,100
Vermont	12,400	200	8,200
Total	**125,677,881**	**337,698,064**	**213,051,972**

According to the results from the AVERT tool, 1 MWh of wind energy avoids .75 tons, or 1,500 pounds, of carbon dioxide emissions on average. A typical 2 MW wind turbine avoids around 4,000-4,500 tons of carbon emissions annually, equivalent to the annual carbon emissions of more than 700 cars. When the 12,000 MW of wind plants currently under construction are operational, the wind fleet will reduce emissions another 24 million tons annually, in total reducing power sector emissions by the equivalent of 6.4 percent.

Importantly, the AVERT analysis prepared by AWEA also demonstrates that wind energy plays an important role in reducing emissions of SO_2 and NO_x as well, thus facilitating compliance with EPA regulations limiting those pollutants. Wind energy currently reduces SO_2 emissions by more than 337 million pounds per year and NO_x by 213 million pounds per year.

Wind energy reduces emissions because electricity produced by a wind project results in an equivalent decrease in electricity production at another power plant. Due to its low operating costs (and zero fuel cost), using economic dispatch, grid operators use wind energy to ramp down the output of the online power plants with the highest operating costs, which are typically the least efficient fossil fuel-fired power plants due to their high fuel costs. Wind energy is also occasionally used to reduce the output of hydroelectric dams, which allows the dam to store water that is used later to displace fossil generation.

As discussed in AWEA's most recent annual market report, independent power system operators have also conducted studies that identify the impact of wind generation on system-wide carbon emissions, and have concluded that wind energy displaces 0.48 to 0.81 short tons of carbon dioxide per MWh of wind generated,[19] which is consistent with the results from the AVERT analysis above. Wind's emissions savings vary somewhat by region due to variations in the fossil fuel generation mix, primarily driven by variations in the share of time that coal versus gas provide marginal generation.

The AWEA report also calculated that in 2013 wind energy saved 36.5 billion gallons of water that would have been consumed at conventional power plants, the equivalent of roughly 116 gallons per person in the U.S. or 276 billion bottles of water, providing critical relief in drought-stricken areas in the Midwest and Western U.S.[20]

SOLAR ENERGY IS REDUCING CARBON EMISSIONS IN EVERY STATE TODAY

Solar energy is not a hypothetical way to reduce carbon emissions; solar energy generation significantly reduces carbon emissions today. Solar energy systems in the U.S. are expected to generate more than 20,000 gigawatt hours (GWh) in 2014.[21] With one GWh of solar generation eliminating 690 metric tons of CO_2 emissions, solar generation can be expected to avoid 13.8 million metric tons of CO_2 emissions in 2014.[22]

Emission reductions resulting from solar deployment are certain to grow. In 2013 alone, the solar industry grew 53 percent over 2012, installing 5.2 GW of solar generating capacity. On average, a new solar project was installed in the U.S. every 4 minutes in 2013.[23] Solar energy accounted for 29 percent of new electric generation capacity installed in 2013.[24] An approximate 6.8 GW of new solar capacity is projected to come online in 2014.[25]

As mentioned previously, the EPA's Avoided Emissions and Generation Tool (AVERT) can be used to calculate the carbon emissions reductions from solar energy using historic dispatch

[19] AWEA U.S. Wind Industry Annual Market Report for the Year Ending 2013, available at http://www.awea.org/AMR2013
[20] Id.
[21] SEIA analysis based on data from SEIA/GTM Research U.S. Solar Market Insight: 2013 Year in Review
[22] For more information, see http://www.epa.gov/cleanenergy/energy-resources/refs.html
[23] U.S. Solar Market Insight 2013 Year in Review Report. Available at: www.seia.org/smi.
[24] U.S. Solar Market Insight 2013 Year in Review Report. Available at: www.seia.org/smi.
[25] SEIA analysis based on data from SEIA/GTM Research U.S. Solar Market Insight: 2013 Year in Review and EIA Electric Power Monthly, December 2013, Table ES3.

data.[26] The chart below shows the current CO_2, NO_x and SO_2 avoided in each AVERT region at current solar energy deployment levels.[27]

AVERT REGION	STATES WITHIN AVERT REGION	CUMULATIVE CAPACITY (MW)	CO_2 EMISSIONS REDUCED (TONS)	SO_2 EMISSIONS REDUCED (POUNDS)	NO_X EMISSIONS REDUCED (POUNDS)
California	CA, UT	5171.70	4,433,300	705,700	6,340,000
Great Lakes/ Mid-Atlantic	DE, IL, IN, KY, MD, MI, NJ, OH, PA, VA, WI, WV	1241.90	1,325,700	6,069,800	2,406,700
Lower Midwest	AR, KS, LA, MO, NM, OK, TX	141.48	180,800	418,300	394,800
Northeast	CT, MA, ME, NH, NJ, NY, RI, VT	1408.35	1,113,600	1,972,900	1,574,000
Northwest	ID, MT, NV, OR, UT, WA, WY	312.70	329,800	389,800	785,200
Rocky Mountains	CO, SD, WY	331.50	464,000	647,900	899,300
Southeast	AL, AR, FL, GA, KY, LA, MO, MS, NC, OK, SC, TN, TX, VA, WV	927.03	959,800	2,975,400	1,486,000
Southwest	AZ, CA, NM, NV, TX	1850.40	2,070,300	977,800	2,987,300
Texas	TX, OK	201.20	203,600	408,800	236,800
Upper Midwest	IA, IL, MI, MN, MO, MT, ND, NE, SD, WI	72.43	94,500	286,000	170,800

[26] The AVERT tool statistically determines the marginal electric generating units (EGUs) on an hourly basis. The AVERT tool is free to use with a simple user interface designed to meet the needs of state air quality planners and other interested stakeholders, and can easily be used to evaluate county-level emissions displaced at EGUs by EE/RE policies and programs, and to analyze the emission benefits of different renewable energy programs in multiple states within an AVERT region. The tool can also be used to quantify the nitrogen oxides (NO_x), sulfur dioxide (SO_2), and carbon dioxide (CO_2) emissions benefits of state and multi-state renewable policies and programs. Read more here: http://epa.gov/statelocalclimate/resources/avert/index.html

[27] Solar deployment data taken from SEIA/GTM Research U.S. Solar Market Insight: 2013 Year in Review and SEIA solar industry 2012 data. Report available here: http://www.seia.org/research-resources/us-solar-market-insight. Hawaii and Alaska have been excluded; the total MW of cumulative capacity in each state have been split equally between the utility PV and rooftop PV specifications in the model; states in multiple AVERT regions have had their cumulative capacity divided equally among the multiple AVERT regions the state is present in, with the exception of Texas. All Texas cumulative solar capacity was run in the Texas AVERT region.

An increase in the amount of electricity produced from solar decreases the amount of electricity produced by fossil fuel power plants. Solar can potentially replace polluting sources on a 1:1 basis, depending on the combination of solar and other technologies deployed on the complex grid. For example, CSP with thermal energy storage can provide the equivalent of baseload, intermediate, or peaking conventional fossil-fuel generation; in other areas, PV combined with wind, storage and/or demand-side resources could provide a complete substitute for fossil-fired generation. As a general matter, when solar is placed on the grid it displaces electricity production from a source that emits carbon pollution, often at a high rate, such as a simple-cycle natural gas generator.

Numerous studies have shown the extent to which renewable energy can effectively reduce emissions. The Western Wind and Solar Integration Study, performed by the National Renewable Energy Laboratory (NREL), evaluated the impacts of operating the Western Interconnect with high penetrations of wind and solar. The study found that CO_2 emissions could be reduced by 29 percent to 34 percent, or the equivalent of 260-300 billion pounds per year when the Western Interconnect obtains 33 percent of electricity from wind and solar.[28]

In February 2014, PJM, the nation's largest grid operator (with territory covering 13 states and Washington, DC), released a study analyzing a high penetration of renewable generation on the PJM grid. The study considered scenarios of up to 30 percent wind and solar and found no significant operating issues. In addition, the study found that CO_2 emissions could be reduced by 28 percent in the "High Solar Best Onshore" scenario compared to the business as usual (BAU) scenario in the target year 2026.[29]

In February of 2012, the U.S. Department of Energy (DOE) released the SunShot Vision Study, a detailed report that examines the potential for and barriers to solar PV and CSP in the U.S., while striving for reduced solar costs. The report states:

> Solar energy reduces GHG emissions compared with most other sources of energy. Compared with the reference scenario, the SunShot scenario is estimated to reduce electric-sector operational carbon dioxide (CO_2) emissions by 181 million metric tons (MMT) per year by 2030 (an 8 percent reduction), and the estimated reduction by

[28] While this study presumed that the various electrical assets in the Western Interconnect could be coordinated in an optimal fashion, setting aside institutional barriers presented by differing operating regimes within the Western Interconnect, it demonstrates both the strong carbon reduction potential as well as need to reduce those counterproductive barriers. Western Wind and Solar Integration Study, available at: http://www.nrel.gov/electricity/transmission/western_wind.html

[29] PJM Renewable Integration Study, available at: http://www.pjm.com/~/media/committees-groups/committees/mic/20140303/20140303-pris-executive-summary.ashx

> 2050 is 760 MMT per year for the SunShot scenario (a 28 percent reduction)…. Significant reductions in U.S. GHG emissions are projected under the SunShot scenario. Combined with other efforts worldwide, these reductions have the potential to contribute significantly to the deceleration of global climate change.[30]

Furthermore, life-cycle GHG emissions from PV and CSP, as assessed in the SunShot Vision study, are orders of magnitude lower than lifecycle GHG emissions from natural gas and coal power plants.[31]

[30] For additional figures, see http://www1.eere.energy.gov/solar/pdfs/47927_chapter7.pdf. Chapter 3 of the SunShot Vision study describes the SunShot and reference scenarios, including descriptions of the modeled electricity capacity and generation mixes and discussion of peak and baseload power resources.
[31] Id.

APPENDIX 3: RENEWABLE ENERGY PROVIDES CO-BENEFITS TO AID IN COMPLIANCE WITH OTHER CLEAN AIR ACT REQUIREMENTS

Renewable energy can also help states meet other air regulations under the Clean Air Act. The EPA is not only promulgating new regulations under §111(d), but it is also regularly revising and enforcing existing air regulations. For example, renewable energy can offer significant co-benefits when the new ozone and PM standards are implemented, and renewable energy can help meet state emission budgets for pollutants controlled under the Cross State Air Pollution Rule (CSAPR) and the National Ambient Air Quality Standards (NAAQs).

The Western Wind and Solar Integration Study found that with the Western Interconnect obtaining 33% of electricity from wind and solar, the SO_x emissions could be reduced by 14%-24%, or the equivalent of 80-140 million pounds per year, while the NO_x emissions could be reduced by 16%-22%, or the equivalent of 170-230 million pounds per year.[32] Likewise, the PJM Renewable Integration Study found that in the "High Solar Best Onshore" scenario, the SO_x emissions could be reduced by roughly 150 million pounds per year, and the NO_x emissions could be reduced by over 100 million pounds per year compared to the BAU scenario in the target year 2026.[33]

Mercury emissions and PM2.5 emissions are also avoided by using renewable energy. For example, the Mercury and Air Toxics Standards (MATS) require power plants to reduce emissions of mercury, other heavy metals, and acidic gases. The rule was signed on December 16, 2011 and grants affected industries/facilities up to 4 years to comply- 3 as granted by the Clean Air Act, and one additional year if a state permitting authority grants an extension. Not only can renewable energy help to comply with the 111(d) regulations, but also the MATS regulations.

Thermal electric power generation uses as much water as agriculture does, or in other terms, more than four times the amount of water used by households in the U.S. wind and solar use far less water for power generation than do conventional sources of power generation.[34] In fact, solar PV operates using no water. In all steam-cycle thermal power plants, whether fossil, nuclear or solar, heat is used to boil water into steam, which runs a steam turbine to generate electricity. The exhaust steam from the generator must be cooled prior to being heated again

[32] Western Wind and Solar Integration Study, available at: http://www.nrel.gov/electricity/transmission/western_wind.html

[33] PJM Renewable Integration Study, available at: http://www.pjm.com/~/media/committees-groups/committees/mic/20140303/20140303-pris-executive-summary.ashx. See also http://energy.gov/sites/prod/files/2014/05/f16/2014%20Wind%20Vision%20Presentation%20at%20AWEA%20WINDPOWER_3.pdf.

[34] Available at http://www.ucsusa.org/assets/documents/clean_energy/ew3/ew3-freshwater-use-by-us-power-plants.pdf; http://www.nrel.gov/docs/fy11osti/50900.pdf

and turned back into steam.[35] This cooling can be done with water (wet cooling) or air (dry cooling), or a combination of both (hybrid cooling). Solar PV and concentrating PV solar plants are not thermal cycle plants and therefore do not require water for cooling. When employing dry-cooling technology, parabolic trough and power tower solar plants consume less than 50 gallons/MWh, a small fraction of the water used by a natural gas fired (200 gallons/MWh), coal-fired (500 gallons/MWh) or nuclear power plant (800 gallons/MWh).[36]

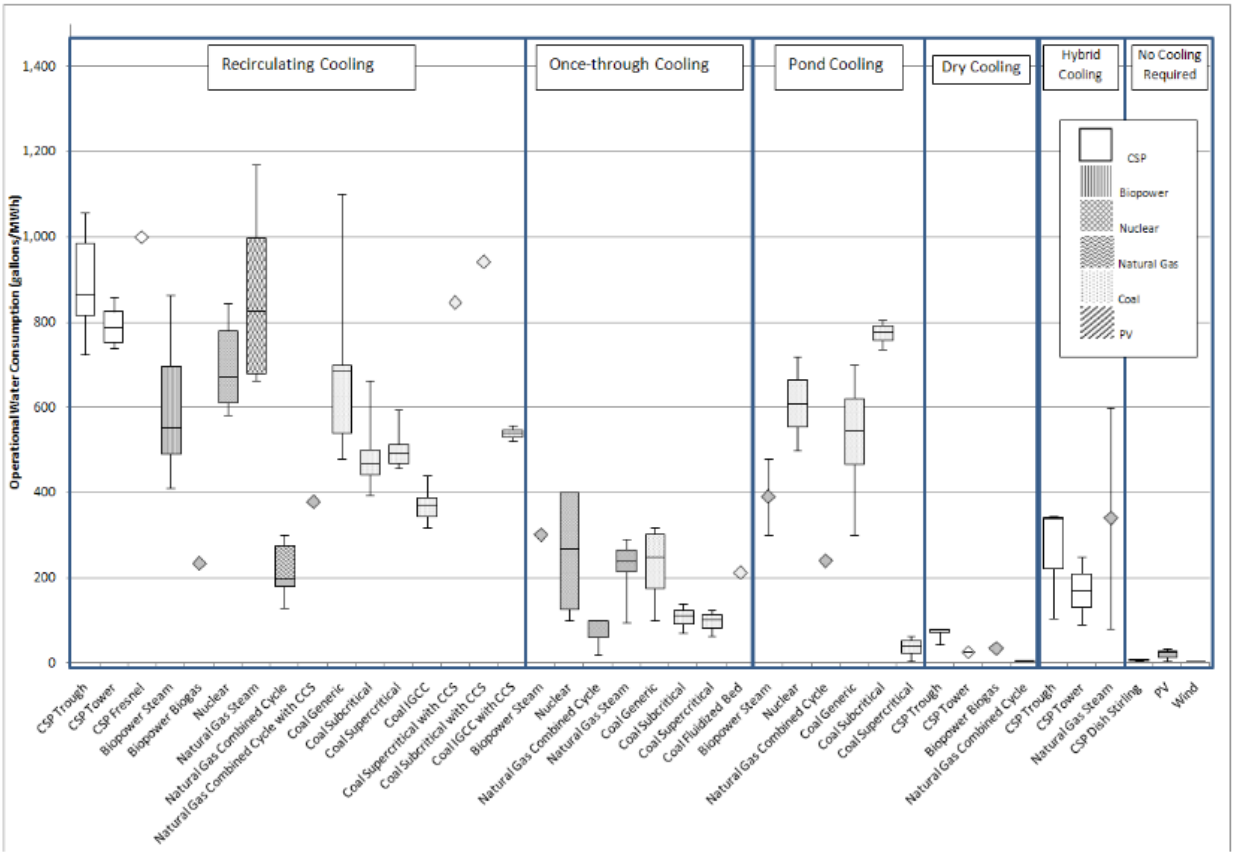

Figure 1. Operational water consumption factors for electricity generating technologies

Source: Macknick, Newmark, Heath, and Hallet, *A Review of Operational Water Consumption for Generation Technologies*, National Renewable Energy Laboratories, March 2011, 7.

[35] For more information: http://www.seia.org/policy/power-plant-development/utility-scale-solar-power/water-use-management

[36] Water consumption figures are approximate. For more information about water use and solar, see http://www.nrel.gov/docs/fy11osti/49468.pdf

APPENDIX 4: RENEWABLE ENERGY AVOIDS HEALTH COSTS AND ISSUES ASSOCIATED WITH CARBON AND OTHER AIR POLLUTANTS

In addition to reducing GHG emissions, renewable energy offers additional environmental benefits, particularly when compared to other forms of energy generation. Renewable energy requires no mining or drilling for fuel, produces negligible amounts of waste, and utilizes minimal amounts of water.

A key advantage for many states considering clean energy development is the benefit to human health brought by the expansion of emissions-free generation. For example, renewable generation helps avoid potential health issues linked to emissions and waste products traditional power sources— all in addition to climate change.[37] Estimates of the numbers of avoidable health impacts—from reduced school absences and lost work days to avoided premature deaths—have become standard and powerful techniques to describe the benefits of air-related programs. Quantifying the avoidable health effects associated with clean energy initiatives is an analytical step that typically builds on the estimates of emission reductions and air quality changes. Health research has established strong relationships between air pollution and health effects ranging from fairly mild effects such as respiratory symptoms and missing a day of school or work, to more severe effects such as hospital admissions, heart attacks, onset of chronic heart and lung diseases, and premature death.

Presenting the benefits of clean air initiatives in such tangible terms as reduced cases of health effects can be a valuable analytical tool to help differentiate between alternative program options, as well as a very effective technique for communicating some of the most important advantages of clean energy. The EPA has determined that particulate exposure costs Americans between $110 billion and $270 billion each year, which could potentially allow states to see significant and immediate health cost reductions through expanded clean generation development.[38] When energy sources are adjusted to account for these externalities, renewable energy becomes even more cost-competitive.[39]

Estimating the health benefits of air quality improvements can be achieved through basic or sophisticated modeling methods. Basic modeling approaches use results from existing studies, such as regional impact analyses, to extrapolate a rough estimate of the health impacts of a

[37] Towards the Full Cost of Coal: A review of the recent literature assessing the negative health care externalities associated with coal-fired electricity production (Caroline Burkhard Golin 2012).

[38] Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States (U.S. EPA Office of Air and Radiation 2011), per Solar Electricity: Economic Development and Impact (presentation by Lee J. Peterson, Esq. 2012).

[39] Solar Electricity: Economic Development and Impact (presentation by Lee J. Peterson, Esq. 2012).

single new facility or clean energy initiative. Sophisticated modeling approaches include screening-level analytical models that can run quickly on a desktop computer, and rigorous and complex computer models that often run on powerful computers and involve a linked series of separate models.

EXAMPLES OF AIR QUALITY HEALTH MODELS

COBRA (a screening-level integrated model)

- Suited to less-experienced modelers.
- Requires air pollution emissions data, which the model converts to air quality changes, as an input.
- Includes health effects of PM.
- Uses EPA-provided default concentration-response (C-R) functions and economic values.
- Available at http://epa.gov/statelocalclimate/resources/cobra.html

BenMAP (a linked model)

- Suited to experienced modelers, although a new one-step approach improves accessibility and training is available.
- Requires air quality data, which must be estimated exogenously, as an input.
- Includes health effects of PM and ozone.
- Uses EPA-provided C-R functions and economic values, and also allows user-specified functions.
- Available at http://www.epa.gov/air/benmap/

APPENDIX 5: RENEWABLE ENERGY TECHNOLOGIES ARE COST-EFFECTIVE FOR STATE COMPLIANCE

There are a number of ways to demonstrate that renewable energy technologies are a cost-effective means for a state to achieve compliance with carbon emission regulations under the Clean Power Plan. Not only are renewable energy policies, like the RPS, a cost-effective means to deploying renewable energy, but renewable energy is also a reasonable cost to utilities and ratepayers. Furthermore, renewable energy installed costs are forecasted to further decline.

RENEWABLE ENERGY POLICIES ARE COST-EFFECTIVE

Policies used to deploy renewable energy systems are proven to be cost-effective. For example, there are a number of LBNL and NREL studies that have examined the costs and benefits of state RPS policies. A May 2014 joint study from LBNL and NREL analyzing the state level cost and benefits estimates from RPS policies found that "over the 2010-2012 period, average estimated incremental RPS compliance costs in the U.S. were equivalent to 0.9% of retail electricity rates when calculated as a weighted-average (based on revenues from retail electricity sales in each RPS state) or 1.2% when calculated as a simple average."[40] For states with a restructured electricity market, this estimated incremental RPS compliance cost for retail rates can also be expressed in terms of the cost per unit of renewable energy required, estimated in the range of $2-$48/MWh.[41] For states with a regulated electricity market, the costs are in the range of minus $4-$44/MWh.[42] The study also looked at the cost of renewable energy to reduce emissions through state RPS policies. The estimates of the benefits ranged from approximately $4-$23/MWh of renewable generation, depending on the cost value assumed for CO_2, cumulating to roughly tens to hundreds of millions of dollars on an annual basis depending on the state. The joint study also looks at a number of other benefits, including economic impacts and wholesale market price reductions.

[40] Note that substantial variation exists around the averages, both from year-to-year and across states. See page V, VI, and VII. The study, "A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards" is available here:
http://emp.lbl.gov/publications/survey-state-level-cost-and-benefit-estimates-renewable-portfolio-standards
[41] Id.
[42] Id.

RENEWABLE ENERGY IS A REASONABLE COST MEASURE FOR UTILITIES TO USE IN 111(D) COMPLIANCE

Wind

Wind energy's costs are declining dramatically. The average power purchase price of wind energy has fallen by more than half over the last 5 years.[43] Lazard, a widely-respected financial advisory and asset management firm reported[44] (Figure) in 2013 that wind energy is now the most affordable source of new electric generation, even without including the impact of incentives or the cost of emissions. As a result, Lazard noted that wind energy has a negative cost of reducing emissions, and is by far the lowest cost generation option for reducing electric sector emissions. This analysis included operating, maintenance and transmission costs.

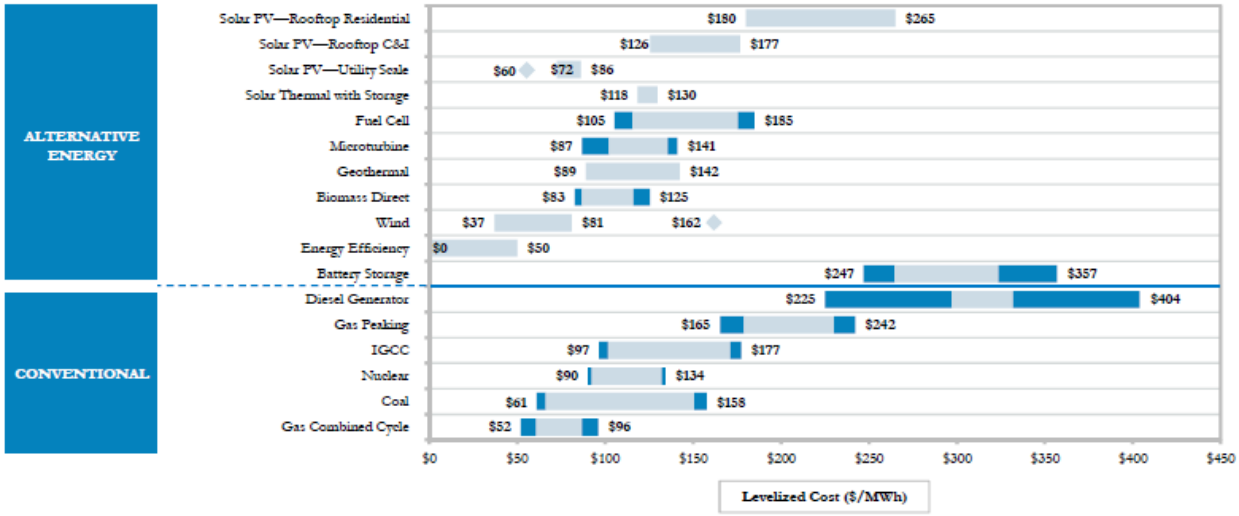

Figure: Levelized cost of energy (LCOE) analysis from Lazard

[43] DOE, 2013 *Wind Technologies Market Report*, August 2014, available at: http://emp.lbl.gov/sites/all/files/lbnl-6809e.pdf, page 70.

[44] Lazard's Levelized Cost of Energy Analysis Version 8.0, available at http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf . Wind's range of costs in the image are primarily due to regional variations in wind plant capacity factor and installed costs for wind. The dot at $162/MWh in the image represents offshore wind.

The U.S. Energy Information Administration projects similar results for 2019, with wind being one of the most affordable options second only to combined cycle natural gas.[45] Wind energy costs declined dramatically, more than 7 percent, since last year's EIA assessment.

A May 2013 report[46] by Synapse Energy Economics found that doubling the use of wind energy in the Mid-Atlantic and Great Lakes states would save $6.9 billion per year on net, after accounting for all wind and transmission investment costs. More than a dozen other studies confirm the finding that wind energy drives electricity prices down.[47] In addition to its current affordability, contracted wind energy is guaranteed to remain affordable tomorrow because it offers the stability of a long-term fixed energy price for 15-25 years. This is a major contrast to the volatile prices that can characterize non-renewable fuels.[48] Wind energy keeps energy prices low much like a fixed rate mortgage protects homeowners from interest rate spikes. As the Lawrence Berkeley National Lab reported, wind energy acts as a hedge to protect consumers against fuel price volatility, even in an environment in which gas prices are below historic averages.[49]

As further evidence of wind's consumer benefits, between 2005 and 2010, the ten states with the most wind energy saw their electric rates increase at less than half the rate of the states with the least wind energy.[50]

Solar

Utilities are increasingly procuring solar energy because solar energy technologies, including utility PV, distributed PV, and CSP, have become reasonable cost resources when compared to other resources. Further, the various forms of solar technologies provide significant economic benefits beyond cost, such as price certainty, hedge value, and avoided infrastructure investment. For more information on procurement of solar energy, see Section 2B6.

One of the primary methods of procurement is through a Power Purchase Agreement (PPA) with a solar developer. Many utilities are now signing PPAs in the $50-$60/MWh range over 20

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[45] http://www.eia.gov/forecasts/aeo/electricity_generation.cfm , Table 1

[46] Synapse Energy Economics, *The Net Benefit of Increased Wind Power in PJM,* by Bob Fagan, Patrick Luckow, Dr. David White, and Rachel Wilson (Cambridge, MA, 2013), available at: http://www.synapse-energy.com/Downloads/SynapseReport.2013-05.EFC.Increased-Wind-Power-in-PJM.12-062.pdf.

[47] See page 4 at http://awea.files.cms-plus.com/AWEA%20White%20Paper-Consumer%20Benefits%20final.pdf.

[48] See page 5 at http://awea.files.cms-plus.com/AWEA%20White%20Paper-Consumer%20Benefits%20final.pdf for examples of quotes from utilities acknowledging the affordability of wind energy.

[49] Ernest Orlando Lawrence Berkeley National Laboratory, *Revisiting the Long-Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices* 21 (March 2013), available at http://emp.lbl.gov/sites/all/files/lbnl-6103e.pdf

[50] DOE data summarized at http://awea.files.cms-plus.com/AWEA%20White%20Paper-Consumer%20Benefits%20final.pdf.

to 25 years, offering price certainty to both utilities and ratepayers without any of the fluctuation in costs that accompanies fossil-fuel plants, which are subject to variability in fuel costs throughout their operating lives, as discussed below. In fact, Recurrent Energy, a developer of utility-scale solar PV, recently executed a power purchase agreement with Austin Energy in Texas for less than $50/MWh.[51] These costs will continue to decline as economies of scale are achieved.

Solar projects being offered and installed today show that solar is already cost-competitive with new and existing fossil generation in certain circumstances. For example, in 2013 Xcel Energy received approval from the Colorado Public Service Commission to procure 170 MW of solar strictly on a cost competitiveness basis.[52] In addition, solar recently outbid natural gas in a competitive evaluation for utility resource planning in Minnesota.[53] Furthermore, a recent NY Times article notes the following: "According to a study by the investment banking firm Lazard, the cost of utility-scale solar energy is as low as 5.6 cents a kilowatt-hour, and wind is as low as 1.4 cents. In comparison, natural gas comes at 6.1 cents a kilowatt-hour on the low end and coal at 6.6 cents. Without subsidies, the firm's analysis shows, solar costs about 7.2 cents a kilowatt-hour at the low end, with wind at 3.7 cents."[54] These competitive costs are one of the reasons utilities are looking to include solar systems as part of a balanced energy portfolio.

In addition, solar energy offers price certainty to utilities because the fuel is free once the system is constructed. This allows costs to be transparent and fixed over the length of the contract, which may be anywhere from 10-30 years. Even when conventional fossil-based generators offer long-term contracts, the actual energy price paid usually varies along with the underlying fluctuating fuel prices.[55] As a result, solar is seen as a valuable hedge against volatile fossil fuel prices.[56]

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[51] Available at http://www.greentechmedia.com/articles/read/Austin-Energy-Switches-From-SunEdison-to-Recurrent-For-5-Cent-Solar.

[52] More info available at: http://www.xcelenergy.com/About_Us/Energy_News/News_Archive/Xcel_Energy_proposes_adding_economic_solar,_wind_to_meet_future_customer_energy_demands

[53] More info available at: http://www.renewableenergyworld.com/rea/news/article/2014/01/minn-judge-solar-beats-natural-gas-for-utility-procurement .

[54] NY Times Article "Solar and Wind Energy Start to Win on Price vs. Conventional Fuels" from Nov. 24, 2014. Available here: http://www.nytimes.com/2014/11/24/business/energy-environment/solar-and-wind-energy-start-to-win-on-price-vs-conventional-fuels.html .

[55] While fuel-price hedging contracts exist, the terms of the contracts can be limited and tend to be very expensive.

[56] More info available at: http://www.nrel.gov/docs/fy13osti/59065.pdf; In fact, Renewables Portfolio Standards, such as the California program, were initially adopted primarily for fuel diversity and hedging purposes, in response to the 2001 energy crisis that resulted in significant part from reliance on natural gas supplies.

Further, distributed PV allows utilities to avoid significant infrastructure costs. A recent McKinsey analysis notes the following avoided costs with the deployment of distributed PV:

> The impact on national energy systems can be significant. A recent report by the California Solar Initiative estimated that 1 to 1.6 GW per year of solar power generated by consumers would supply the equivalent capacity of adding a new 500kV transmission line, estimated to cost nearly $1.8 billion in capital costs. Distributed generation could also provide other benefits, such as lower line losses due to shorter distances transmitted, productive use of unutilized real estate (rooftops), and environmental benefits. It could be particularly relevant for heavily congested areas where adding new infrastructure is impractical. Distributed generation can also make the grid more resilient, since it would continue to function when central infrastructure is out of commission. If renewable generation costs continue to fall and energy storage capabilities grow rapidly, we can imagine entire neighborhoods or factory complexes being served through distributed solar power. This could make remote housing and manufacturing plants more viable by reducing the transmission capacity required from the grid or even eliminating the need to access the grid altogether.[57]

RENEWABLE ENERGY DOES NOT NEGATIVELY IMPACT THE RATEPAYER

Solar energy measures are being adopted by states and utilities around the country because they are a reasonable cost to ratepayers as well. Ratepayers are typically billed for their consumption of electricity in kWhs. The charge per kWh may include transmission and distribution services, or they may be billed separately. Utility-scale solar operates much in the same manner as a traditional fossil fuel plant, and the energy is generally sold to utilities at the wholesale price in the same manner as fossil plants. Therefore, the ratepayer will often see no difference on their electric bill when energy comes from a wholesale solar generator rather than a wholesale fossil fuel generator.

Similarly, distributed PV has a negligible impact on the ratepayer and has been shown to provide a benefit to ratepayers in many circumstances. The benefit to the ratepayer will depend largely on whether the system is owned or leased, as well as other factors including where on the grid the system is located. If the system is owned or leased by the ratepayer, they will often be able to sell the excess energy they generate back to their utility reducing their overall bill. If the system is installed pursuant to a power purchase agreement, the ratepayer

[57]See page 143-144. Analysis found here: http://www.mckinsey.com/insights/business_technology/disruptive_technologies

may be able to procure energy at a rate that is lower than the rate provided by the utility through a power purchase agreement. Further, ratepayers may be able to avoid some transmission and distribution service costs that they would be subject to if they were purchasing energy from a central station plant, as the solar system is located on the customer site.

There are numerous third party verified studies that have looked at the costs and benefits of distributed PV to the ratepayer.[58] While some studies show a net benefit and others a net cost to ratepayers, when taken as a whole the studies clearly show that distributed PV is reasonable cost to ratepayers. A recent report by the Rocky Mountain Institute completed a meta-analysis of 16 distributed PV cost-benefit studies, reflecting diverse levels of distributed PV penetration levels.[59]

SOALR ENERGY INSTALLED COSTS ARE EXPECTED TO DECLINE IN THE FUTURE

Costs across the solar industries are falling rapidly, which will lead to reduced overall costs for implementing renewable energy measures to reduce emissions from affected EGUs. These costs are: installed costs, future installed costs, balance of system costs, and raw material costs.

a. Installed Costs

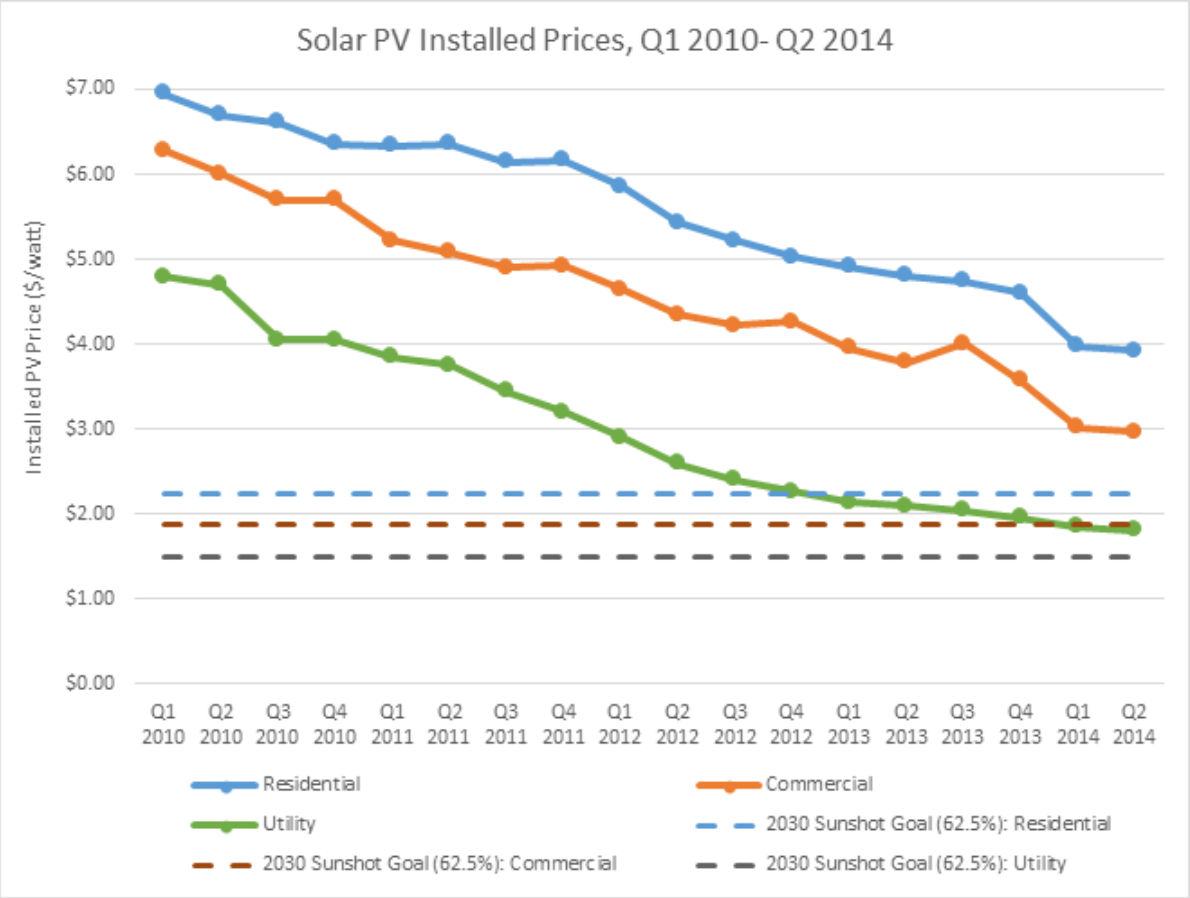
[58] The following are examples of recent studies that have looked at the costs and benefits of distributed solar to the ratepayer: IREC, A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, at http://www.irecusa.org/wp-content/uploads/2013/10/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG.pdf; Hoff et al., The Value of Distributed Photovoltaics to Austin Energy and the City of Austin (Mar. 2006), at http://www.ilsr.org/wp-content/uploads/2014/05/Value-of-PV-to-Austin-Energy.pdf; Tom Beach, Crossborder Energy, The Benefits and Costs of Solar Distributed Generation for Arizona Public Service" (May 2013), available at http://www.seia.org/research-resources/benefits-costs-solar-distributed-generation-arizona-public-service; Tom Beach, Crossborder Energy, Evaluating the Benefits and Costs of Net Energy Metering in California" (January 2013), available at http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf; Tom Beach, Crossborder Energy,The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina (2013), at http://energync.org/assets/files/Benefits%20and%20Costs%20of%20Solar%20Generation%20for%20Ratepayers%20in%20North%20Carolina(2).pdf; Energy & Environmental Economics, *Nevada Net Energy Metering Impacts Evaluation*, Prepared for NV PUC (July 2014), at http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study

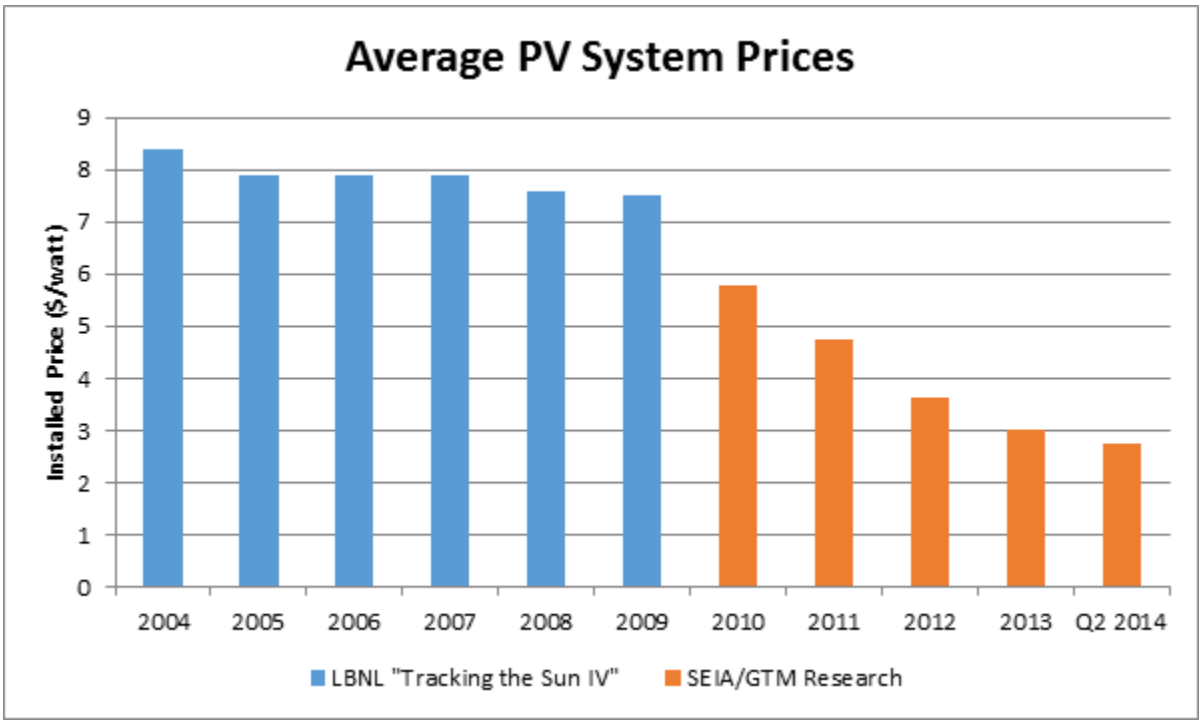
[59] Available at http://www.rmi.org/Knowledge-Center/Library/2013-13_eLabDERCostValue

Current installed costs for solar show that solar energy is already a cost-competitive emissions reduction technology and prices continue to decline rapidly. As of Q2 2014, installed distributed PV prices have dropped by 8% over the last year and 39% since Q2 2010. Utility-scale solar PV prices have seen even larger declines- by 14% over the last year and 61% from Q2 2010.[60] Looking back further, the price to install a distributed PV system has dropped by nearly 70% since 2001- from $10.00/watt to $3.13/watt as of Q2 2014.[61] For distributed PV, the national weighted average residential PV installed system price for Q2 was $3.92/watt. Further, the national weighted average of non-residential PV (commercial, industrial, gov't and non-profit) installed system price for Q2 was $2.39/watt.[62] The estimated utility scale PV national installed system price for Q2 was $1.81/watt, which is 14% lower than 2013 and 61% lower than 2010 (as noted previously).[63]

The two charts below help to illustrate these declining costs. The first chart shows quarterly cost declines by sector, while the second chart shows yearly blended average cost declines.[64]

[60] U.S. Solar Market Insight Q2 2014 Report. Available at: www.seia.org/smi.
[61] Lawrence Berkeley National Laboratory *Tracking the Sun V* and SEIA/GTM Research *U.S. Solar Market Insight Q2 2014*
[62] Id.
[63] Id.
[64] Lawrence Berkeley National Laboratory *Tracking the Sun V* and SEIA/GTM Research *U.S. Solar Market Insight Q2 2014.*


Solar PV Installed Prices, Q1 2010- Q2 2014
Installed PV Price ($/watt)
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
Q1 2010
Q2 2010
Q3 2010
Q4 2010
Q1 2011
Q2 2011
Q3 2011
Q4 2011
Q1 2012
Q2 2012
Q3 2012
Q4 2012
Q1 2013
Q2 2013
Q3 2013
Q4 2013
Q1 2014
Q2 2014
Residential
Commercial
Utility
2030 Sunshot Goal (62.5%): Residential
2030 Sunshot Goal (62.5%): Commercial
2030 Sunshot Goal (62.5%): Utility


Average PV System Prices
Installed Price ($/watt)
9
8
7
6
5
4
3
2
1
0
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
Q2 2014
LBNL "Tracking the Sun IV"
SEIA/GTM Research

b. Future Costs

Future costs of solar are forecasted to decline as well, according to several third-party verified studies. The DOE SunShot Vision study uses the NREL Regional Energy Deployment System (REEDS) and Solar Deployment System (SolarDS) models to develop and evaluate a SunShot scenario (-75% cost reduction) and a reference scenario. Two alternative cost scenarios were also modeled, including a -62.5% scenario and a -50% scenario. Current solar prices show that the industry is on track to meet the -75% scenario targets by 2030.

CSP, which historically has been limited to larger utility-scale plants and relatively fewer installations, has comparatively less price history and can be expected to have a more granular price trajectory. Pricing for utility-scale plants in many jurisdictions is also kept confidential. Although the first commercial deployment of CSP was in the late 1980s, large-scale deployment has only recently resumed and is now occurring worldwide. The DOE has issued multiple grants recently, which, along with company-funded R&D, has helped reduce the costs of CSP, particularly CSP combined with Thermal Energy Storage ("TES"; when combined with CSP "CSP+TES"), which offers dispatchable solar power, including the ancillary services needed for reliability that traditionally have come from fossil-fueled generators. Cost of electricity from CSP plants depends on many factors, including capacity, location, and cost of debt and equity. Current costs are therefore variable, as innovation and deployment continues. However, several studies have shown that CSP+TES projects provide substantial value to the energy system, reducing the overall costs that energy customers pay and increasing the extent to which PV and other intermittent renewables can be integrated onto the grid. For example, NREL issued a report in November 2012, entitled "Simulating the Value of Concentrating Solar Power with Thermal Energy Storage in a Production Cost Model".[65] In September 2014, the Concentrating Solar Power Alliance issued an updated report, entitled "The Economic and Reliability Benefits of CSP with Thermal Energy Storage: Recent Studies and Research Needs," which both summarizes recent studies by NREL and the LBNL, among others, and adds analyses that tie the results of those studies together. A recent NREL report shows that CSP+TES provides up to $30-60/MWh in flexibility benefits, enabling CSP+TES to contribute to reducing net system costs (the costs that energy customers ultimately pay for energy).[66]

[65] Available at http://www.nrel.gov/docs/fy13osti/57376.pdf.

[66] Jorgenson, J., P. Denholm, and M. Mehos, "Estimating the Value of Utility-Scale Solar Technologies in California Under a 40% Renewable Portfolio Standard," National Renewable Energy Laboratory, Technical Report, TP-6A20-61685 (May 2014).

c. Balance of System Costs

For PV systems, it is also important to recognize the balance of system costs in comparison to the panel costs. The RE Futures study identifies a capital cost breakdown for a non-tracking utility PV with a 10 MW (DC) install size project in 2012, as shown in the pie chart below.[67] At the time of the RE Futures study, module costs at $1,400/kW$_{dc}$ appeared to comprise approximately 50% of utility-scale PV installation costs. Since that time, module costs have declined by more than half while balance of system costs have also declined significantly, although to a lesser extent.

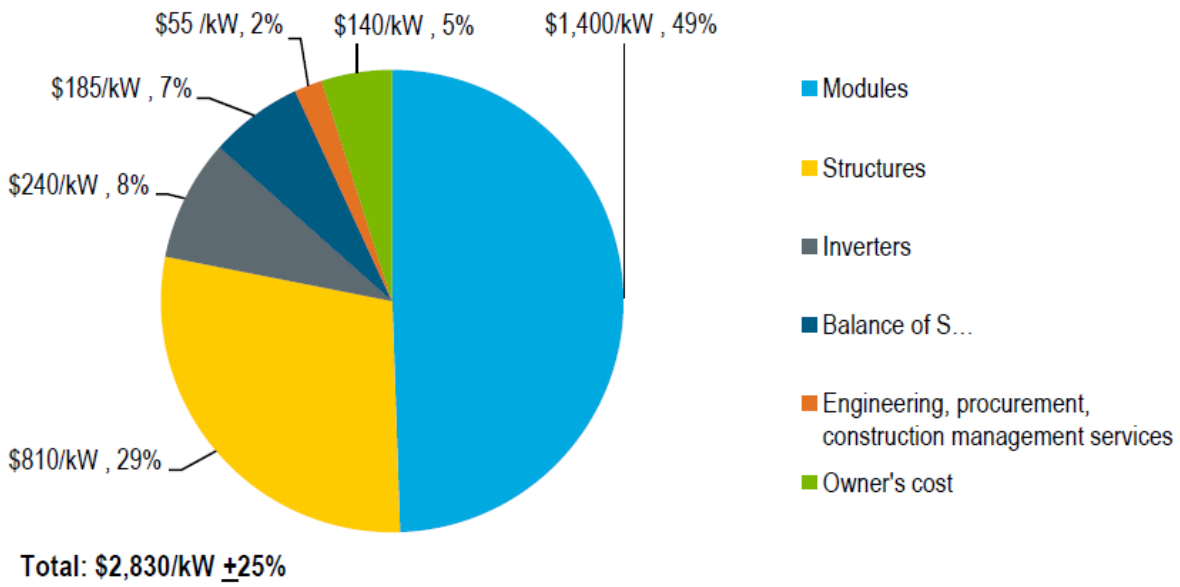


Figure 11. Capital cost breakdown for a solar photovoltaic power plant

Two recent reports from NREL acknowledged the balance of system costs for all solar and the fact that with falling module and other hardware costs, the total cost of a solar system is increasingly dependent on the "soft", or non-hardware costs. The reports found that solar financing and other non-hardware costs now comprise up to 64% of the total price of residential solar energy systems. The report notes:

> The authors found that in the first half of 2012, soft costs represented the majority of all costs — 64% of the total price for residential systems, up from 50% of the total price in the first edition. Similar results were found for small and large commercial installations — 57% of the total cost for small (less than 250

[67] See page 42 of: http://bv.com/docs/reports-studies/nrel-cost-report.pdf.

> kilowatts) commercial systems (up from 44%); and 52% of the total costs for large (250 kilowatts or larger) commercial systems (up from 41%).For residential systems, the greatest soft costs were supply chain costs ($0.61/watt), installation labor ($0.55/W), customer acquisition ($0.48/W), and indirect corporate costs ($0.47/W), such as maintaining office management and accounting functions. Other soft costs examined for the report included costs for permitting, inspection, interconnection, subsidy applications and system design.[68]

As total installation costs have declined and continue to decline at a more rapid pace than previously expected, solar is increasingly cost competitive with alternative sources of energy and other carbon emission reduction measures.

d. Materials Costs

In addition, the RE Futures study also examined the cost and availability of the future supply of sourced materials for PV panels. Ultimately, the study found no concern over the availability of PV materials even in the scenario of planned significant deployment of solar PV globally. The study notes:

> RE Futures does not identify any insurmountable long-term constraints to manufacturing capacity, material supply, or labor availability for any of the renewable technologies considered in this study (see RE Futures Volume 2). Growth in renewable capacity additions globally and in the United States has been considerable over the last decade, demonstrating the ability to scale manufacturing and deployment at a rapid pace. … The estimated annual capacity of PV deployment is high, especially in later years, but PV manufacturing and deployment are scalable. Worldwide PV production capacity has been growing rapidly and is already comparable to the deployment levels projected for the latter years in many of the 80%-by-2050 RE scenarios. Moreover, many of the renewable technologies are based on common materials that are not supply-constrained. Even for PV, which uses some materials that may be supply-constrained, worldwide production capacity is already sizable, and that capacity continues to scale rapidly. Even considering the High-Demand 80% RE scenario, and worldwide demand for PV, given the variety of PV feedstocks used today and the possibility of newer ones being developed in the future, reaching the required levels of installed capacity need not be limited by the availability of raw materials.[69]

[68] Report available here: http://www.nrel.gov/news/press/2013/5306.html.
[69] Available at http://www.nrel.gov/docs/fy12osti/52409-1.pdf page 138.

RENEWABLE ENERGY BRINGS SIGNIFICANT ECONOMIC BENEFITS TO ALL 50 STATES

Deployment of renewable energy also brings considerable economic benefits to all states. The wind energy industry currently employs around 50,000 people in the U.S. and serves as a major driver for domestic economic development, with more than 500 manufacturing facilities in 43 states. There is a component manufacturing facility or an operating wind project in every state. The solar industry provides jobs in every single U.S. state; according to The Solar Foundation's *Solar Job Census 2014*, there are nearly 175,000 solar workers in the U.S.[70] These workers are employed at 6,100 businesses operating at over 7,800 locations in every state.[71] The increasing value of solar installations has injected life into the U.S. economy as well. In 2013, solar electric installations were valued at $13.7 billion, compared to $11.5 billion in 2012.[72]

There is significant potential for the renewable industry as an employment and economic engine. According to the U.S. DOE's SunShot Vision Study, continued cost reductions and steady increases in installed solar capacity will lead the solar industry to employ over 340,000 workers by 2030.[73] The U.S. DOE's 20 Percent Wind Report projects that the wind energy industry could support 500,000 jobs in 2030 if 20 percent of the electricity generation in the U.S. came from wind energy.

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[70] National Solar Job Census 2014, available at: http://thesolarfoundation.org/research/national-solar-jobs-census-2014.

[71] SEIA National Solar Database.

[72] National Solar Job Census 2013, available at: http://thesolarfoundation.org/research/national-solar-jobs-census-2013.

[73] The Solar Foundation, *Financing the Next Generation of Solar Workers: An Exploration of Workforce Training Program Sustainability in the Context of Reduced Public Funding*. November 2012. Available at: http://thesolarfoundation.org/sites/thesolarfoundation.org/files/SWIC%20Final.pdf U.S. Department of Energy, *SunShot Vision Study*. February 2012. Available at http://www1.eere.energy.gov/solar/sunshot/vision_study.html[74] SEIA/GTM U.S. Solar Market Insight™ Year in Review 2013 Report. All U.S. Solar Market Insight Reports are available here: http://www.seia.org/research-resources/us-solar-market-insight..

APPENDIX 6: RENEWABLE ENERGY IS WIDELY AVAILABLE AS A COMPLIANCE TOOL

WIND ENERGY IS WIDELY AVAILABLE

AWEA's *U.S. Wind Industry Fourth Quarter 2014 Market Report* finds there are 6565,879 megawatts (MW) of wind energy capacity installed, with over 12,700 MW currently under construction, in 39 states and Puerto Rico (Figure 1), representing more than 488,000 operational utility-scale wind turbines. There are now 16 states with 1,000 MW or more of installed wind energy capacity.

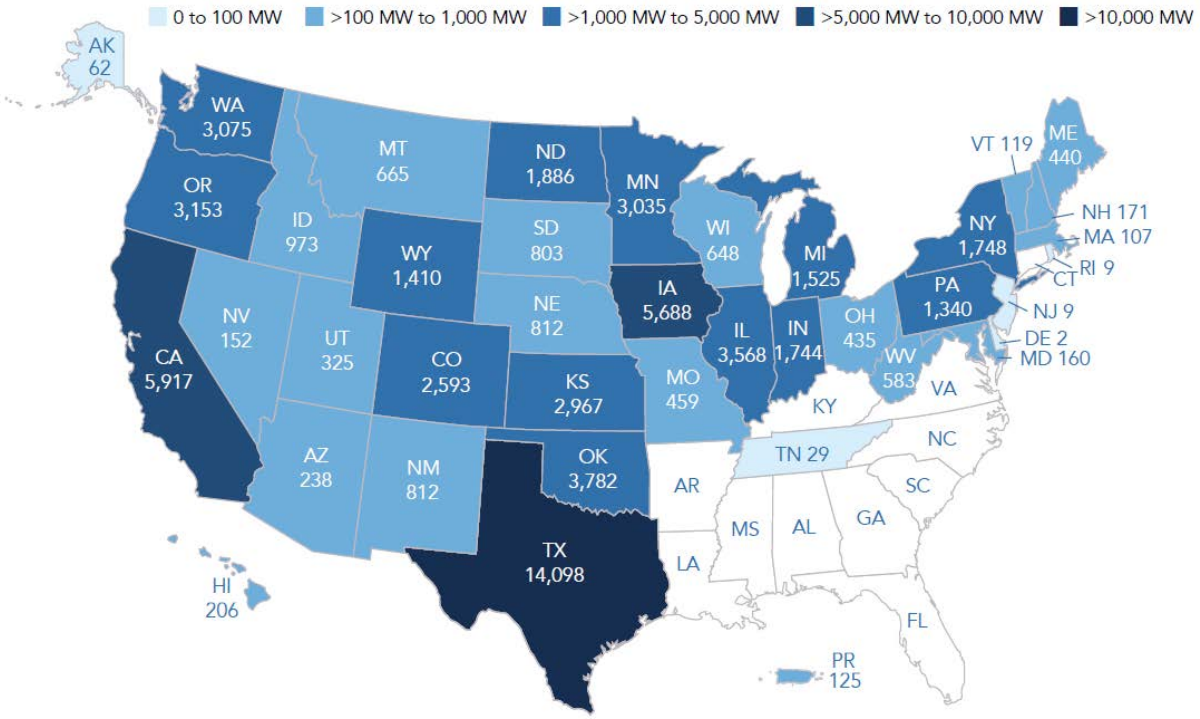


Figure 1: Installed U.S. Wind Energy Capacity in MW, by State through Q4 2014

This represents 5.7 percent of total installed U.S. electric generating capacity. In terms of actual electricity production, wind energy accounted for 4.1 percent of electric generation in 2013 (up from 2.9 percent in 2011 and 3.5 percent in 2012). The existing wind turbine fleet provides the electrical output equivalent to 53 average coal plants or 14 average nuclear plants.

Over the last five years, wind energy has accounted for 31 percent of all newly installed electric generating capacity, second only to natural gas. In 2012, wind energy was the largest source of all new capacity at 42 percent.

In some regions, such as the Pacific Northwest, Plains states and the Midwest, wind energy has been the primary source of new capacity over the last three years, providing 60 percent or more of all new electric generating capacity. In the Upper Midwest, wind energy provided more than 80 percent of all new generating capacity from 2011-2013.

On an average annual basis, wind energy produces more than 25 percent of the electricity in two states, 12 percent or more in nine states, and five percent or more in 17 (Figure 2).

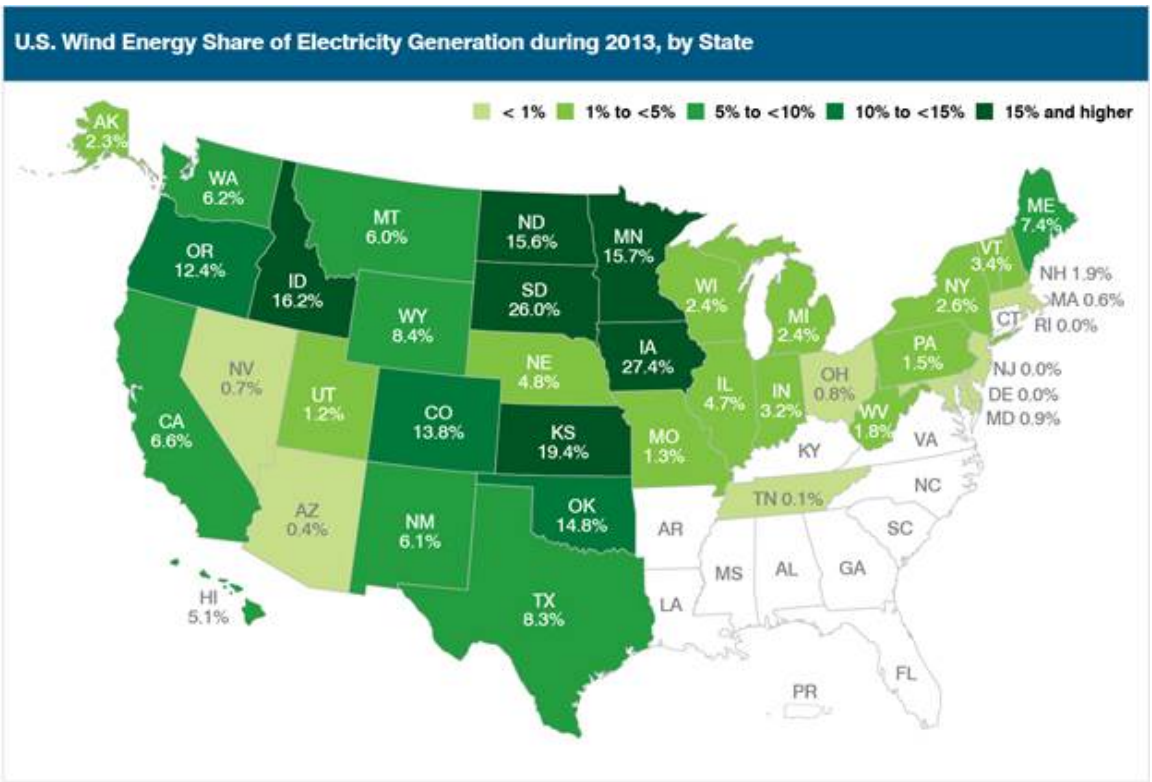


Figure 2: Percentage share of electricity generation by Wind during 2013, by State

Even the states not colored in on the two charts above increasingly have opportunities to take advantage of the environmental benefits of wind energy through both projects in-state as well as contracting for wind energy from out-of-state.

Wind energy technology is rapidly improving, mostly through the use of taller towers and longer blades that allow access to higher wind speeds and make lower-wind-speed sites more economic. As a result, wind project developers are now exploring opportunities in states where wind energy was not previously viable, such as much of the Southeast. In addition to the 39

states with existing installed wind energy capacity, wind energy project developers have publicly acknowledged the pursuit of wind projects in Kentucky, Virginia, North Carolina, Florida, and Alabama, with initial prospecting also being done in Georgia and Louisiana according to press reports. Moreover, utilities in Tennessee, Arkansas, Georgia, Alabama, and Louisiana have already signed power purchase contracts to buy electricity from wind energy facilities in other states, demonstrating that wind energy is a widely available compliance option nationwide.

SOLAR ENERGY IS AVAILABLE IN ALL 50 STATES

The United States has some of the richest solar resources in the world. The U.S. solar industry grew by 53% from 2012 to 2013, accounting for nearly 30% of all new electric generating capacity added to the U.S. grid in 2013.[74] An additional 7.3 GW of solar capacity are expected to be added in 2014, bringing the cumulative U.S. total to over 20 GW- enough to power more than 4 million homes. The U.S. solar industry now supports 143,000 employees at more than 6,100 companies spread across all 50 states. This phenomenal growth is the result of private investment, technological innovation, a maturing industry, customer demand, and smart federal and state policies.

A variety of solar technologies have been successfully deployed in the United States and around the world. From the first commercial solar projects installed in the 1980s, to the rapidly-increasing fleet of distributed and utility-scale solar assets providing a significant and growing percentage of the nation's power today, solar has demonstrated its capabilities and contributions to a cost-effective, reliable power supply.

1. Utility Scale and Distributed PV

PV technology is being installed on a utility scale and distributed basis at an increasing rate throughout the country. The following chart shows the total installed solar PV capacity by state from 2006-2013. The chart includes both distributed PV and utility-scale PV installations.

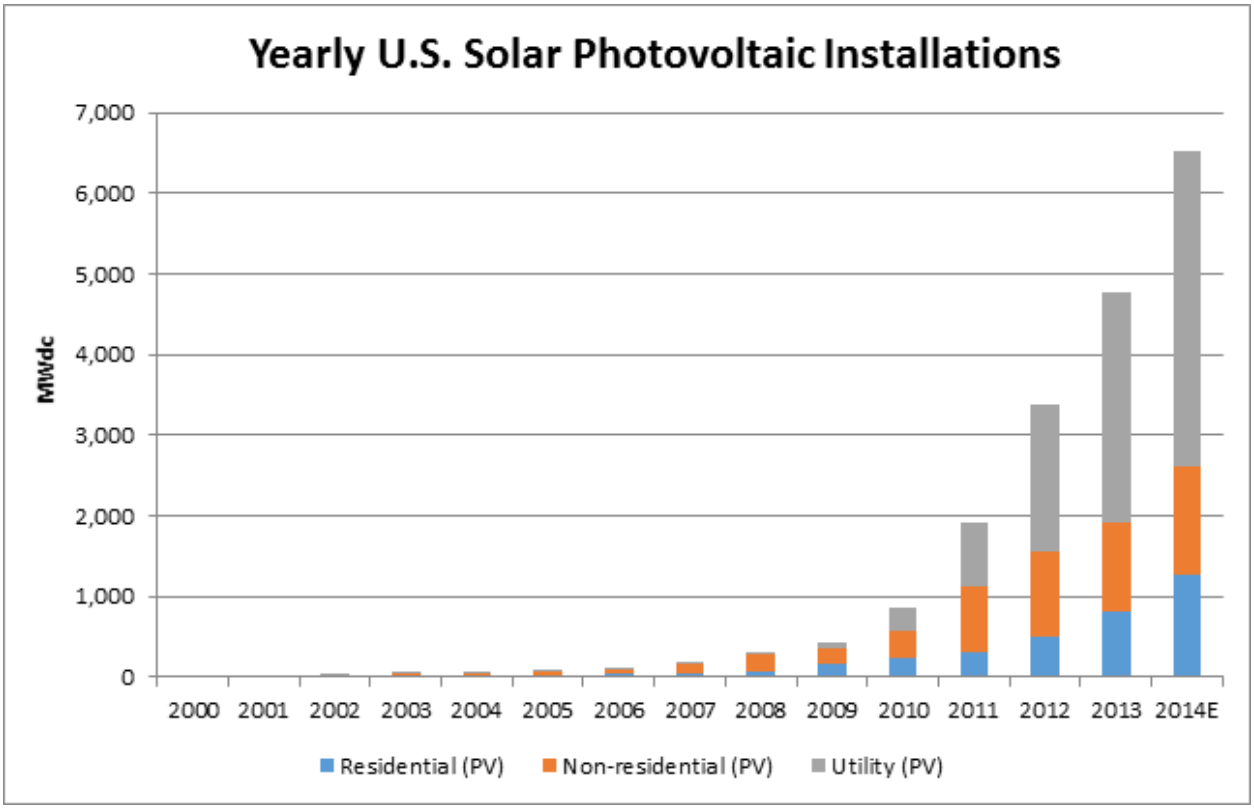
Solar Photovoltaic Installations 2006-2013 and Cumulative (MW_{dc})[75]									
State	2006	2007	2008	2009	2010	2011	2012	2013	Cumulative (through

[74] SEIA/GTM U.S. Solar Market Insight™ Year in Review 2013 Report. All U.S. Solar Market Insight Reports are available here: http://www.seia.org/research-resources/us-solar-market-insight..
[75] Compiled from SEIA/GTM Research U.S. Solar Market Insight 2012 and 2013 and IREC U.S. Solar Market Trends 2012 and 2013.

									2013)
Alabama	<0.1	<0.1	<0.1	0.1	0.2	<0.1	0.6	0.8	1.9
Alaska	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	0.2	0.2
Arizona	2.1	2.8	6.4	23.2	63.6	287.8	708.8	423.7	1,563.1
Arkansas	<0.1	<0.1	<0.1	<0.1	0.6	<0.1	0.6	0.2	1.8
California	69.5	91.8	178.7	210.3	255.6	537.8	983.2	2,607.7	5,183.4
Colorado	1.0	11.5	21.7	22.9	62.0	75.5	102.9	58.0	360.4
Connecticut	0.7	2.5	5.3	8.7	5.6	4.5	7.5	37.5	77.1
Delaware	0.3	0.4	0.6	0.7	2.4	20.9	19.7	16.7	62.8
Florida	0.2	1.0	0.9	35.9	34.8	21.5	21.9	20.4	137.3
Georgia	<0.1	<0.1	<0.1	0.1	1.6	5.1	8.2	88.5	109.9
Hawaii	0.7	2.9	8.6	11.5	18.5	40.5	114.3	153.0	358.2
Idaho	<0.1	<0.1	<0.1	<0.1	0.2	<0.1	0.7	0.7	1.8
Illinois	0.1	0.2	0.4	0.6	11.0	0.7	26.7	0.5	43.4
Indiana	<0.1	<0.1	<0.1	<0.1	0.2	3.0	0.9	45.0	49.4
Iowa	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	1.1	3.4	4.6
Kansas	<0.1	<0.1	<0.1	<0.1	0.1	<0.1	0.3	0.6	1.1
Kentucky	<0.1	<0.1	<0.1	<0.1	0.2	3.0	1.5	3.2	7.9
Louisiana	<0.1	<0.1	0.1	0.2	2.4	10.8	11.9	28.0	53.4
Maine	0.1	<0.1	<0.1	<0.1	0.2	0.6	1.7	2.5	5.3
Maryland	0.1	0.3	2.2	2.5	5.3	24.3	79.7	58.7	175.4
Massachusetts	1.5	1.4	2.9	9.5	20.4	36.4	123.2	222.6	445.0
Michigan	<0.1	<0.1	<0.1	0.3	1.9	6.2	11.1	2.3	22.2
Minnesota	0.1	0.3	0.3	0.9	1.7	1.2	6.5	3.8	15.1
Mississippi	<0.1	<0.1	<0.1	0.1	0.1	0.3	0.1	0.3	1.0
Missouri	<0.1	<0.1	<0.1	0.1	0.5	1.3	16.6	30.4	48.9
Montana	<0.1	0.2	0.1	0.2	<0.1	<0.1	1.4	0.9	3.0
Nebraska	<0.1	<0.1	<0.1	<0.1	0.2	0.1	0.1	0.2	0.6
Nevada	3.2	15.9	14.9	2.5	68.3	19.4	225.6	46.9	424.0
New Hampshire	<0.1	<0.1	<0.1	<0.1	1.3	1.0	2.3	4.1	9.6
New Jersey	17.9	20.4	22.5	57.3	132.4	306.1	390.7	202.3	1,184.6
New Mexico	0.2	0.2	0.6	1.4	40.9	122.1	37.9	49.1	256.6
New York	3.0	3.8	7.0	12.1	21.6	68.3	55.6	61.1	240.5
North Carolina	0.1	0.4	4.0	7.9	28.7	45.5	122.4	261.1	470.1
North Dakota	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	0.1	0.2
Ohio	0.1	0.1	0.4	0.5	18.7	10.9	48.3	18.5	98.4
Oklahoma	<0.1	<0.1	<0.1	<0.1	<0.1	0.1	0.2	0.4	0.7
Oregon	0.5	1.1	4.8	6.3	9.9	11.9	20.6	6.4	62.8
Pennsylvania	0.2	0.1	3.0	3.4	46.5	78.2	31.3	15.9	180.2

Rhode Island	0.2	<0.1	<0.1	<0.1	<0.1	0.6	0.7	5.7	7.6
South Carolina	<0.1	0.1	0.1	0.2	0.3	3.2	0.5	3.5	8.0
South Dakota	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1
Tennessee	0.1	<0.1	<0.1	0.5	4.8	16.3	23.0	19.8	64.8
Texas	0.7	0.6	1.2	3.8	25.9	51.5	54.7	75.6	215.9
Utah	<0.1	<0.1	<0.1	0.2	1.4	2.3	5.6	6.0	16.0
Vermont	0.1	0.2	0.4	0.6	2.2	7.8	16.3	13.6	41.5
Virginia	<0.1	<0.1	<0.1	0.3	1.9	1.8	5.2	2.2	12.6
Washington	0.4	1.2	0.8	1.8	2.9	4.2	7.2	7.9	27.4
Washington DC	<0.1	<0.1	0.2	0.3	3.5	7.2	2.3	2.6	16.5
West Virginia	<0.1	<0.1	<0.1	<0.1	<0.1	0.6	1.1	0.5	2.2
Wisconsin	0.3	0.6	1.7	2.2	3.5	4.2	8.2	1.4	22.5
Wyoming	<0.1	<0.1	<0.1	<0.1	0.1	<0.1	0.4	0.4	1.0

The below graph shows the yearly U.S. solar PV installations by market segment, showing the rapid growth of all sectors.[76]



[76] SEIA/GTM Research *U.S. Solar Market Insight.*

As the chart shows, like utility PV, distributed PV is growing rapidly year over year. Distributed PV is generally broken into two segments: residential and non-residential.

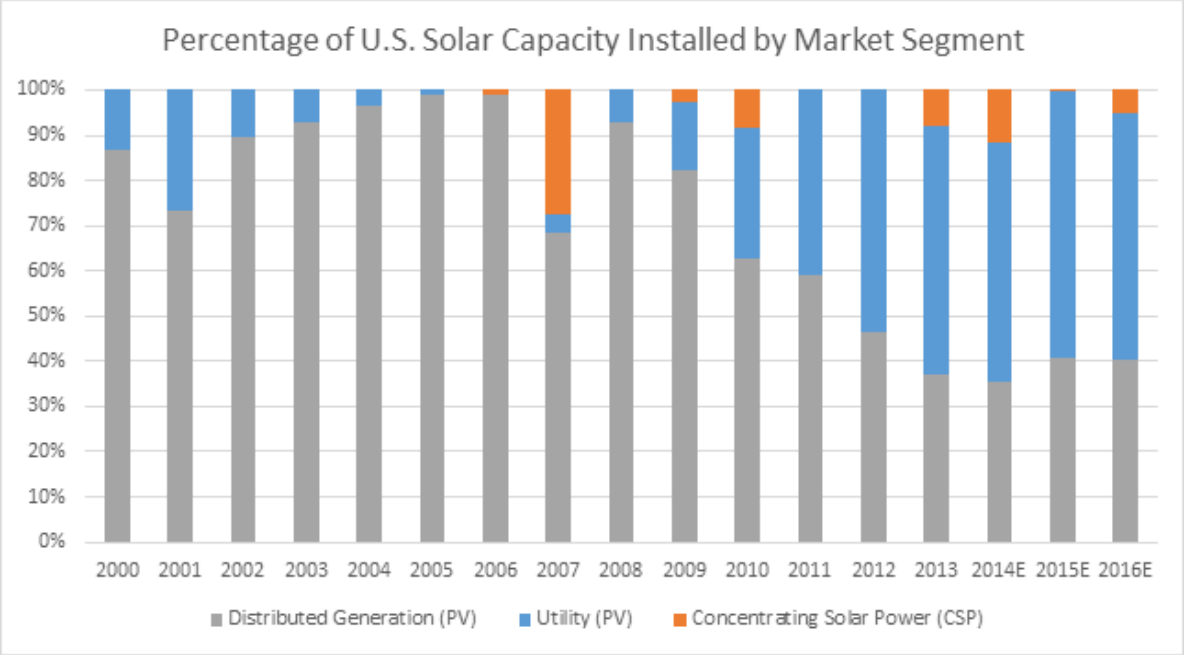
The residential PV sector represents homeowners who are installing solar. With falling solar prices and the rise of 3rd party financing, more homeowners are going solar than ever before. Homeowners are either directly purchasing these solar systems, or leasing them through solar companies. The energy produced by homeowners is often used to offset the need for generation from affected EGUs or is counted towards clean energy requirements such as renewable portfolio standards.

The non-residential sector typically represents those business owners who are installing solar systems. Solar energy generated from commercial units also reduces the need for generation from affected EGUs and is often counted towards clean energy requirements or used to make green claims by the companies that invest in the systems.

In addition to affected EGUs, some of the most well-run and efficient companies are turning to solar energy to reduce their carbon footprint and hedge against risks associated with energy prices and climate change. As of mid-2014, cumulative commercial deployment totaled 4,530 MW at over 41,800 facilities throughout the country, an increase of more than 34 percent over last year. A recent SEIA report "Solar Means Business 2014" shows that Wal-Mart leads all U.S. companies with 105 MW of installed capacity, with Costco, Kohl's, Apple, IKEA, and Macy's all having at least 20 MW. The report also found that growth in the commercial market is not limited to just California, as 129 million people – 41% of all Americans - live within 20 miles of at least one of the more than 1,100 commercial solar installations that were analyzed.[77]

It is also important to point out the percentage of the solar market that is comprised of distributed PV. Note that in all years, at least 40% or more of the total installed solar in each year comes from the distributed PV sector. This is shown the following graph, which breaks utility PV, CSP, and distributed PV from 2000-2016.[78]

[77] Solar Means Business Report, 2014. Available here: http://www.seia.org/research-resources/solar-means-business-report.
[78] SEIA/GTM Research *U.S. Solar Market Insight.*



2. <u>CSP Technology</u>

CSP technology is technically feasible and is being installed throughout the country today. The following chart shows the total installed solar CSP capacity from 2006-2013.

Concentrating Solar Power Installations, 2006-2013 and Cumulative (MW_{ac})[79]									
State	2006	2007	2008	2009	2010	2011	2012	2013	Cumulative (through 2013)
Arizona	1.0				2.0			280.0	283.0
California				10.0				125.0	1,006.0
Florida					75.0				75.0
Hawaii				2.0				5.0	7.0
Nevada		64.0							64.0

[79] Compiled from: SEIA/GTM Research Solar Market Insight 2013.

APPENDIX 7: RENEWABLE ENERGY IS FAST TO BUILD AND SCALABLE

Whereas the development and construction timeline for a large, centralized conventional fossil fuel power plant is typically a multi-year process (and longer for nuclear energy), the time from conception to operation for renewable energy projects can be much faster. While very large solar and wind plants are still subject to some of the same siting and permitting-related delays as large fossil plants, medium and small solar and wind facilities can be built quickly, especially with the right policies in place.

WIND ENERGY IS SCALABLE AND RAPIDLY DEPLOYABLE

Wind plants offer a rapidly deployable solution for reducing emissions of carbon dioxide and other pollutants. Wind developers already have a large backlog of wind projects in the development pipeline, and it is typically possible to build a wind project in a little over a year, far faster than many other low- or zero-carbon solutions.

Since the end of 2005, the U.S. wind energy industry has doubled its installed capacity, on average, every 36 months. Over the last decade, the industry has gone from a low mark of installing 396 MW in 2004 to a high of more than 13,000 MW in 2012, and there are currently more wind projects under construction in the U.S. than at any point in history. U.S. wind energy's five year average annual growth rate is 19.5 percent from 2009-2013. The previously mentioned DOE 20 percent wind report found that with existing technology, the industry can ramp up to sustained deployment of around 16,000 MW of newly installed wind capacity per year.

In 2003, wind energy generated only 11 million MWh, or 0.3 percent of the generation mix. By 2008, wind energy generated 55 million MWh, or 1.3 percent of the mix. In 2013, wind energy generated 167 million MWh, or 4.1 percent of total generation.[80]

SOLAR ENERGY CAN HELP TO ACHIEVE TIMELY COMPLIANCE FOR STATES

SEIA urges states to recognize the speed of solar deployment, along with the modularity of solar, which makes it a great choice for meeting incremental generation needs and assisting states in quickly achieving compliance with EPA regulations under §111(d). In states with

[80] The statistics in this section come for the AWEA annual market report for the year ending 2013.

streamlined permitting and interconnection procedures, it is possible for a 3-person crew to install between one and 3 residential PV systems in a single day. For larger commercial flat-roof PV systems, a 6-person crew can install 100 kW of PV in a single day.

APPENDIX 8: RENEWABLE ENERGY EMISSIONS REDUCTIONS ARE EASILY QUANTIFIED AND VERIFIED

WIND ENERGY'S EMISSIONS REDUCTIONS ARE EASILY QUANTIFIED AND VERIFIED

Wind energy's emissions reductions are readily quantifiable and verifiable, making wind energy an attractive solution for states to comply with 111(d). All utility-scale wind projects have revenue-grade metering equipment that measures the amount of wind energy production. Among other reasons, such equipment and verification is necessary to ensure compliance with power purchase contract generation requirements and for purposes of claiming the federal production tax credit (PTC), which is based on electricity actually generated, on tax returns. In addition, rigorous accounting mechanisms for renewable energy credits are in wide use in 29 states and the District of Columbia for compliance with state renewable portfolio standard requirements in those states, and accounting mechanisms are in place nationwide for verifying renewable energy production to satisfy voluntary purchases of renewable energy credits. These well-established accounting mechanisms could be readily adopted for compliance with section 111(d) to ensure that renewable energy production is not double-counted and can be precisely and rigorously quantified.

Several tools, such as marginal emissions calculations[81] and power system modeling, allow carbon emissions reductions to be calculated based on this measured wind energy production. EPA's Avoided Emissions and generation Tool (AVERT), used for the wind emissions savings analysis above, is one free and easy-to-use option for calculating wind energy's pollution reductions.[82]

WIND'S EMISSIONS REDUCTIONS HOLD UP EVEN WHEN CYCLING OF OTHER GENERATION IS TAKEN INTO ACCOUNT

While other generation may need to ramp up or down to accommodate the variability of wind energy (and other far larger sources of variability on the system like load and the failure of fossil

[81] Marginal generation and emissions data track which power plant or power plants are economically "on the margin" in each operating hour, and thus which generating units would have been dispatched down had demand been 1 MW lower or an additional 1 MW of low-cost supply (such as from wind) been available, allowing one to calculate the marginal emissions savings based on the heat or emissions rate for those marginal units. When combined with an hourly wind output profile for the region, that allows one to calculate wind's total emissions savings with a very high degree of accuracy. Some Independent System Operators (ISOs) and utilities already calculate and publicly release data on marginal fuel mixes and emissions, and other utilities should already have the data necessary to conduct such a calculation. For example, see http://www.iso-ne.com/genrtion_resrcs/reports/emission/.

[82] Available at: http://epa.gov/statelocalclimate/resources/avert/index.html.

fuel and nuclear generators), two recent studies from different regions in the U.S. document that such cycling has virtually no net effect on the emissions reductions from wind energy.

A peer-reviewed analysis by a Department of Energy lab found that wind energy produces 99.8 percent of the carbon emissions savings expected of a zero emissions resource.[83] The study examined real-world hourly emissions from every power plant in the western U.S. and analyzed the impact wind energy has on the efficiency of other power plants by causing them to change their output more frequently. The study found that for a scenario with wind and solar providing 33 percent of electricity on the Western U.S. power system, one MWh of wind energy saves more than 1190 pounds of carbon pollution on average, with those savings reduced by only 0.2 percent, or 2.4 pounds, as a result of increased cycling of fossil-fired power plants.

This finding was confirmed by PJM's March 2014 renewable integration study, which found scenarios with large amounts of wind energy still produced the expected emissions reductions after cycling impacts were taken into account.[84] DOE data also show that states that have ramped up their use of wind energy the most have seen the efficiency of their fossil-fired power plants hold up as well or better than states that use the least wind energy.[85]

[83] National Renewable Energy Lab Western Wind and Solar Integration Study, Phase 2 Results, available at: http://www.nrel.gov/docs/fy13osti/55588.pdf; all WWSIS documents available at: http://www.nrel.gov/electricity/transmission/western_wind.html.

[84] See http://www.pjm.com/~/media/committees-groups/task-forces/irtf/postings/pjm-pris-task-3a-part-g-plant-cycling-and-emissions.ashx at page 91. The differences in carbon emissions savings among the study's scenarios are driven by the fact that, due to their different output profiles, onshore wind tends to offset more carbon-intensive coal generation while other renewable resources, such as offshore wind and solar, tend to offset more gas generation. The high onshore wind cases all produce emissions reductions that are almost directly proportional to the quantity of fossil MWh displaced, indicating the impact of cycling is minimal.

[85] Goggin, M., 2013, "Wind energy's emissions reductions: A statistical analysis," available at http://ieeexplore.ieee.org/xpl/login.jsp?tp=&arnumber=6672865&url=http%3A%2F%2Fieeexplore.ieee.org%2Fiel7%2F6657332%2F6672065%2F06672865.pdf%3Farnumber%3D6672865.

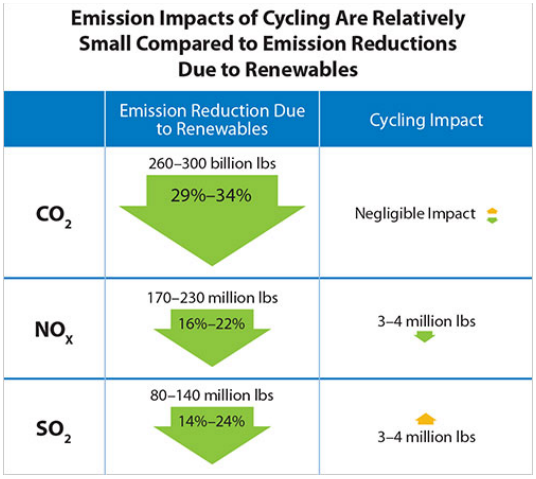


Figure 4: National Renewable Energy Lab, Western Wind and Solar Integration Study Phase II results

The impact of cycling is virtually non-existent because wind energy only minimally adds to total power system variability and flexible reserve needs, as explained in the next section.

SOLAR ENERGY'S EMISSIONS REDUCTIONS ARE EASILY QUANTIFIED AND VERIFIED

Existing protocols already exist for measuring, verifying, and crediting the renewable electricity generated from solar systems and the associated carbon emissions reductions. The two basic main steps are to, (i) track the output – i.e. meter the solar energy generated (MWh)- and (ii) to determine the emissions rate of electricity that is being displaced (lbs/MWh). It may also be necessary to adjust for transmission and distribution (T&D) losses if the solar energy is being generated at or near the customer, but is displacing central station generation.

Tracking the Output

Utility PV and CSP

For utility PV and CSP systems, EM&V is not difficult. All utility scale solar projects and CSP projects are already metered and monitored. The metered electricity is also usually assigned a renewable energy credit (REC), whether for compliance with RPS or for use in voluntary green power programs. One REC is typically equal to 1 MWh of generation. Rigorous accounting methods and transaction platforms for RECs already exist throughout the U.S.; for example, in almost every state that has an RPS policy, there is a method to track the RECs. More generally, these RECs are often part of broader generation attribute tracking systems, such as the GATS system used in the PJM control area and the GIS system used in the New England ISO.

Distributed PV

The distributed PV sector is comprised of the residential and commercial markets. Although not all distributed PV systems are metered and monitored, many are. For example, every system that is contracted under third-party ownership is metered and monitored, typically remotely (electronically) and often in near real time, such that time of day production can be recorded. Of existing solar capacity, nearly 70% of the residential market and 50% of the commercial market is contracted under third party ownership. Moreover, in states where distributed PV is used to meet state RPS requirements, metering and reporting is required for tracking of SRECs, regardless of the ownership of the system. The type of metering may be similar to that for third-party owned systems or may be less granular, for example using an analog meter to manually record monthly production. For the portion of the distributed PV market that is not metered, estimates of performance can be made by using any number of publicly and commercially available models including the NREL PVWatts model Sandia National Labs flat plate model, PVSyst, SolarAnywhere® FleetView®, and Homer.

Determining the Emissions Rate of Electricity that is Being Displaced

Once the generation is known, either through direct metering or from the sale of the RECs, the next step is to determine the fossil fuel energy that is being displaced by the solar energy and the associated avoided carbon emissions. The EPA has already provided guidance to states for incorporating more renewable energy into state implementation plans for compliance purposes with pollutants under Section 110 of the Clean Air Act, and has included an Appendix within the guidance that details some of the methods available for quantifying the carbon emissions reduced by renewable energy.[86] These methods include energy models, historic generation and emissions data, capacity factor emission rates, and system average emission rates.

One example of a model that uses historic dispatch data is the Avoided Emissions and Generation Tool (AVERT), developed by the EPA. The AVERT model uses historic dispatch data to statistically determine the marginal EGUs on an hourly basis. The AVERT model is free to use and comes with a simple user interface designed to meet the needs of state air quality planners and other interested stakeholders, and can easily be used to evaluate county-level emissions displaced at EGUs by renewable energy policies and programs, and to analyze the emission benefits of different renewable energy programs in multiple states within an AVERT region.

Another example of an energy model is the ForeSEE model. A Georgia Tech startup recently developed the ForeSEE model that examines the CO_2 emissions avoided from solar, including

[86]More information on the Roadmap can be found here: http://epa.gov/airquality/eere/ Appendix I on "Methods for Quantifying Energy Efficiency and Renewable Energy Emission Reductions" is available here: http://epa.gov/airquality/eere/pdfs/appendixI.pdf

DG PV, as well as the NO_x and SO_x emissions too. While this model is currently only available for Atlanta and the State of Georgia, as the model was designed to look at the impact of Georgia Power's distributed solar policies for the city of Atlanta, the startup (Cox and Golin Consulting) is expanding ForeSEE's application throughout the country to inform debates about the value of solar.[87]

Additional Solar Factors to Note

The methods that can be used to determine the emissions rate of electricity that is being displaced from solar all have advantages and disadvantages. Depending on the approach that is chosen, the calculated carbon emission reductions from solar will likely differ. For example, solar energy typically displaces fossil fuels at or near the peak demand hours, when the sun is shining. The EGUs on the margin at peak demand hours are almost always natural gas units; therefore, in a more complex approach to calculating the carbon emission reductions- such as a dispatch model- the carbon emission reductions from solar may be less than with an averaging approach, because averaging will tend to include higher-emitting baseload EGUs such as coal plants.

Solar heating and cooling (SHC) is another type of solar energy that is generally not accounted for in energy models. Solar heating and cooling systems should be a part of any state compliance plan for 111(d), as SHC systems displace the need for the combustion of fossil fuels for heating and cooling needs.

Finally, the use of solar storage affects the calculation of carbon emission reductions. With thermal energy storage, solar energy is able to displace EGUs operating at the margin during non-peak hours, and even potentially cut into base load EGU supply. With the development of all types of storage, solar can substantially displace natural gas and coal EGUs, and play an even more significant role in reducing carbon emissions. Any methods used to quantify the carbon emission reductions from solar should be able to account for solar with storage, as solar technologies such as CSP, and increasingly PV, offer storage capabilities that allow these technologies to operate like traditional fossil plants in many respects. Dispatch models and other approaches that rely on plant operating characteristics can take storage into consideration, and therefore are preferred over models that only consider resource availability.

[87] See "Sustaining the City: Understanding the Role of Energy and Carbon Dioxide Emissions in Sustainable Development in Major Metropolitan Areas" by William Matthew Cox, June 2014. Available here: https://smartech.gatech.edu/handle/1853/52316

The EM&V of solar output (MWh) is straight-forward and will increasingly include granular time of day output for large and small systems, which provides high confidence in the ability to track solar generation.

KEY CONSIDERATIONS FOR SELECTING AN APPROACH FOR QUANTIFYING EMISSION REDUCTIONS FROM CLEAN ENERGY

There are advantages and disadvantages to each approach for quantifying emission reductions. States can use this information as guidance in determining the most appropriate approach for their particular goals. It is important for states to:

- Consider the cost of each potential approach and/or tool and the resources required
- Determine whether the tools or methods can be used to estimate the pollutants and emissions of interest
- Decide between a complex, detailed approach and a simple, transparent screening-level approach based on their pros and cons and relative importance of each.

APPENDIX 9: RENEWABLE ENERGY CAN BE RELIABLY INTEGRATED INTO THE GRID

WIND ENERGY IS RELIABLE

Grid operators are now reliably accommodating very large quantities of renewable energy, in the U.S. and Europe. As explained above, wind energy produces more than 25 percent of the electricity in two states, 12 percent or more in nine states, and five percent or more in 17 states on an annual basis. In certain hours, wind has supplied more than 60% of the electricity on the main utility system in Colorado without any reliability problems, and other grid operators have also reliably integrated very large amounts of wind energy, as indicated in Figure 5 below.

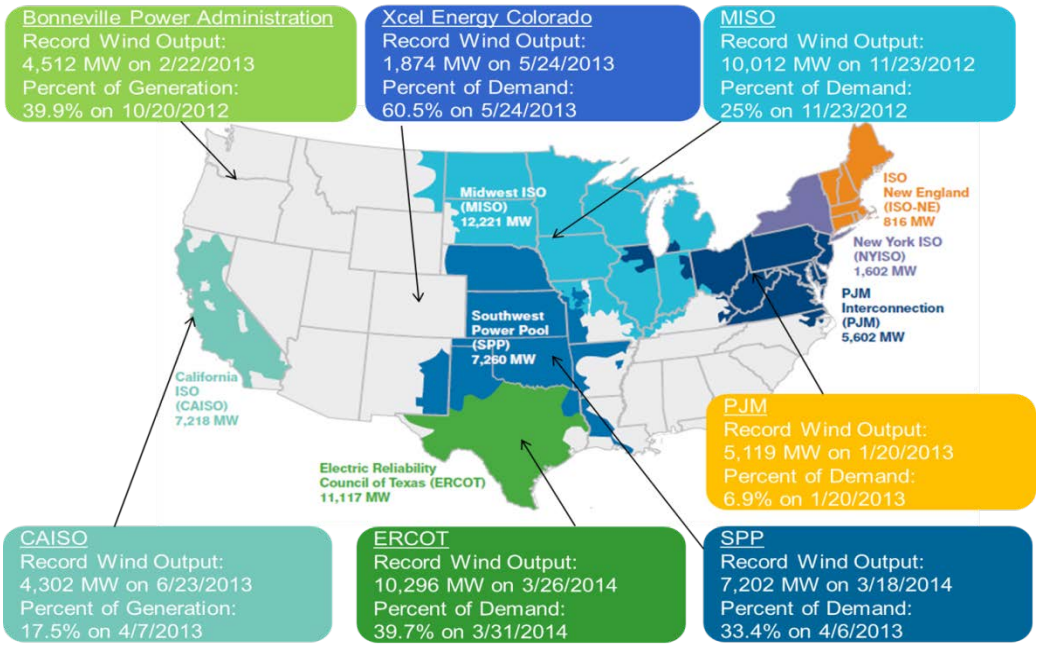


Figure 5: Wind energy integration records set in the U.S. 2012-2014
Source: AWEA Annual Market Report for the Year Ending 2013

Grid operators in Texas have integrated more than 10,000 MW of wind energy with only very small increases in their need for flexible reserves, with the need for fast-acting flexible reserves

increasing by less than 50 MW.[88] The Midcontinent Independent System Operator (MISO) has also stated that the impact wind power has on its need for the flexible reserves used to accommodate variability in electricity supply and demand has been "little to none."[89]

The March 2014 renewable integration study[90] by the PJM grid operator confirms that wind energy only minimally contributes to total power system variability, with the addition of 28,000 MW of wind capacity in the 14 percent renewable energy scenario causing an increase in operating reserve needs of only 340 MW. This is about 1/10 of the 3,350 MW of the operating reserves PJM needs at all times to maintain reliability in case a large conventional power plant abruptly fails, and less than one-third the amount of reserves necessary to deal with variability in electricity demand. Current data indicate the largest hourly changes in electricity demand are 10 times larger than the largest hourly changes in wind energy output for PJM.[91] PJM's integration study concluded that the "PJM system, with adequate transmission and ancillary services in the form of Regulation, will not have any significant issue absorbing the higher levels of renewable energy penetration considered in the study."[92]

Dozens of in-depth wind integration studies[93] confirm that far larger amounts of wind energy can be added to the power system without harming reliability. How is this possible when the wind doesn't blow all the time?

Every day, grid operators constantly accommodate variability in electricity demand and supply by increasing and decreasing the output of flexible generators – power plants like hydroelectric dams or natural gas plants that can rapidly change their level of generation. Thus, the water kept behind a dam or the natural gas held in a pipeline may be thought of as a form of energy storage, with operators using this energy when it is needed and "storing" it when it is not.

Grid operators have always kept large quantities of fast-acting generation in reserve to respond to abrupt failures at large conventional power plants, a challenge and cost that is far greater than accommodating any incremental variability added by the gradual and predictable changes in the aggregate output of a wind fleet. Grid operators use these same flexible resources to

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[88] Available at: http://variablegen.org/wp-content/uploads/2012/12/Maggio-Reserve_Calculation_Methodology_Discussion.pdf; for more detail, see http://aweablog.org/blog/post/fact-check-winds-integration-costs-are-lower-than-those-for-other-energy-sources.

[89] Available at: http://variablegen.org/wp-content/uploads/2012/12/Navid-Reserve_Calculation.pdf

[90] Renewable Integration Study for PJM, available at: http://www.pjm.com/~/media/committees-groups/task-forces/irtf/postings/pjm-pris-final-project-review.ashx, at page 111.

[91] http://www.pjm.com/~/media/committees-groups/task-forces/irtf/20130417/20130417-item-05-wind-report.ashx, and http://www.pjm.com/markets-and-operations/energy/real-time/loadhryr.aspx

[92] http://www.pjm.com/~/media/committees-groups/committees/mic/20140303/20140303-pjm-pris-final-project-review.ashx, page 12.

[93] For the full list, see: http://variablegen.org/resources/.

accommodate any incremental variability introduced by wind energy that is not canceled out by other changes in electricity supply or demand. Wind energy's impact on total power system variability and uncertainty, and hence its impact on reserve needs, is greatly reduced as most changes in wind output are offset by offsetting changes in supply or demand.

In addition, wind plant technology has matured significantly over the last decade so that modern wind turbines provide equivalent or better capabilities[94] for supporting power system reliability needs as conventional power plants in almost every category. Recent analysis by WECC, the entity responsible for power system reliability in the Western U.S., found that in a scenario with very high renewable penetration across the West, "the system results did not identify any adverse impacts due to the lower system inertia or differently stressed paths due to the higher penetration of variable generation resources."[95] Analysis conducted for the California grid operator identified no major concerns for frequency response in a transition to a high renewable future, finding that "None of the credible conditions examined, even cases with significantly high levels of wind and solar generation (up to 50% penetration in California), resulted in under-frequency load shedding (ULFS) or other stability problems."[96] This occurs in part because adding wind generation causes conventional power plants to have their output reduced, which provides them with more range to increase their output and provide frequency response.[97]

In addition, new techniques employing wind plants' sophisticated controls and power electronics enable wind plants themselves to provide fast-acting frequency response. The National Renewable Energy Laboratory recently released in-depth analysis that concluded "wind power can act in an equal or superior manner to conventional generation when providing active power control, supporting the system frequency response and improving reliability."[98] The report further documented how major utilities like Xcel Energy are using this capability of wind plants in some hours to provide all of the frequency response and regulation needed to maintain power system reliability, which has enabled Xcel's Colorado power system to at times reliably obtain more than 60% of its electricity from wind energy.

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[94] See this NERC report: http://www.nerc.com/docs/pc/ivgtf/IVGTF_Report_041609.pdf, at page 22

[95] Available at http://www.wecc.biz/committees/StandingCommittees/PCC/RS/RPEWG%20-%20RS%20Meetings8-21-13/Lists/Minutes/1/VGSStudy7-15-13.doc.

[96] Available at http://www.caiso.com/Documents/Report-FrequencyResponseStudy.pdf

[97] http://web.mit.edu/windenergy/windweek/Presentations/GE%20Impact%20of%20Frequency%20Responsive%20Wind%20Plant%20Controls%20Pres%20and%20Paper.pdf.

[98] Available at http://www.nrel.gov/news/press/2014/7301.html.

SOLAR ENERGY IS RELIABLE

Several studies have clearly shown that high levels of renewables, including solar energy, can be integrated into the grid without negatively impacting reliability or grid requirements. In fact, solar energy can improve grid reliability and provide benefits to the existing energy infrastructure, including reducing transmission losses and relieving congestion on the grid.[99]

Reliability and Transmission Benefits of Solar

Solar energy can be configured and operated to provide various reliability services and transmission benefits that will be essential to electric power system operations in conjunction with the state implementation of §111(d) regulations.

CSP technologies employ conventional synchronous turbine generators and inherently possess valuable system reliability attributes, such as, but not limited to, active and reactive power support, dynamic voltage support and regulation, voltage control and some degree of inertia response. With the integration of thermal energy storage, CSP facilities can be fully dispatched by utilities and system operators, meaning that the plants are capable of ramping power output up and down to meet changing energy demand and supply, without material efficiency losses. CSP with storage plants can be a significant source of essential grid flexibility services, such as ramping, regulation, load following reserves and spinning reserves, which are critical to a reliable system. These services are typically provided by fossil-fired generators operating at sub-optimal heat rates, which may increase their emissions.

To explain further, the ability to store and produce energy at any time enables CSP projects to provide or withhold power as needed for the grid. For all intents and purposes it has all the attributes of a fossil fueled power plant, without carbon emissions.[100] CSP plants can be built in a number of configurations, ranging from baseload to peaker. These attributes include:

a. **System Benefits:** The primary benefit provided to the grid system by CSP plants with storage is the ability to dispatch power whenever it is needed most, day or night. In addition, CSP with storage can provide ancillary services and reduce integration costs while

[99] See the NREL Renewable Electricity Futures Study, available here: http://www.nrel.gov/analysis/re_futures/ See also the study "Integrating High Penetration Renewables: Best Practices from International Experience" available here: http://www.jisea.org/high_pen.cfm

[100] Some CSP plants that do not incorporate storage; they use a de minimis amount of fossil fuels to increase efficiency at the beginning and end of the solar day, or during transient cloud cover.

providing the same reactive power quality attributes of traditional thermal plants. The important role of storage and reactive power in maintaining grid reliability is emphasized in NERC's report *Potential Reliability Impacts of EPA's Proposed Clean Power Plan, Initial Reliability Review*, November 2014.

b. **Energy Value**: Thermal energy storage allows CSP plants to shift electricity generation to the highest value hours across the operating day, overnight, or the next day as needed by the utility or system operator.
c. **Capacity**: At low penetrations of solar power on the grid, solar correlates well with daily peak demands. As solar penetration increases, however, peak demand shifts to the evening hours. CSP with storage allows for shifting energy into the periods of highest demand or value. CSP plants can also be hybridized to use natural gas or other fuels to provide high availability even on cloudy days.
d. **Power Quality**: Since CSP projects typically generate power with a steam turbine, just as most fossil-fueled plants, they have the same power quality characteristics as those plants. These attributes include reactive power support, dynamic voltage support, voltage control, inertia response, and primary frequency control.
e. **Ancillary Services**: CSP plants with thermal energy storage can provide spinning reserves, non-spinning reserves, and regulation and they can operate efficiently at part load.
f. **Integration**: CSP with storage can vary its production to complement other renewables that are more dependent on the times at which the resource is present (whether sunlight or wind),transitional periods, helping to lessen grid ramps and providing both rapid response and significant supply of power at times that other resources are unavailable.

With supportive policies and standards in place, utility-scale solar PV can include advanced features that enable it to operate more like conventional power plants and actively contribute to the stability and reliability of a regional grid as part of a balanced energy portfolio.[101] Some of these features include voltage regulation, active power controls, ramp-rate power controls, fault ride-through, and frequency response controls. These capabilities are managed through the use of a plant-level controller specifically engineered to regulate real and reactive power output of the solar facility such that it behaves as a single large conventional generator, although within the limits dictated by the intermittent nature of the solar resource. These advanced features can enable solar PV to provide a state or region with additional system flexibility by responding to utility and independent system operator instructions.

[101] See "Grid-Friendly" Utility Scale PV Plants, First Solar at 3 and 13 (August 13, 2013).

Distributed PV can also provide wholesale and local ancillary services. These services include but are not limited to frequency regulation, frequency response, spinning and non-spinning reserves, voltage and reactive power support. In addition, distributed PV can provide incremental ancillary services on the local or distribution level. Local voltage support is critical to operating the distribution system within system constraints, and distribution system operators rely on a distributed set of voltage regulating equipment to provide that support. Distributed PV can augment and sometimes replace this equipment, providing real and reactive power support as identified by the distribution operator.

On an aggregated basis, utility-scale and distributed PV resources provide significant reliability and transmission benefits to a state or regional grid. Even if solar PV output varies at a few individual locations due to localized cloud coverage, when the sum of the solar installations in a geographic area is assessed, the variability is reduced and can be managed by the grid operator. In a recent study regarding the integration of wind and solar in PJM, General Electric International, Inc. (GE) found that PJM's large geographic footprint significantly reduced the magnitude of variability-related challenges as compared to smaller balancing areas.[102] GE noted that an individual solar PV plant's variability is significantly reduced when solar plants are aggregated and located in a geographically diverse manner throughout PJM.[103]

Further, targeted deployment of solar generation in congested areas can provide relief to transmission and distribution systems, defer costly transmission upgrades, and help maintain grid reliability. For example, unlike central station power plants, solar installed on-site does not experience transmission and distribution system losses, which can be as high as 7 percent on a utility distribution system and up to 20 percent at the time of system peak.[104] These avoided line losses through solar DG contribute to further CO_2 reductions. Similarly, utilities may site small utility-scale power plants in specific locations to ease congestion on a particular transmission line.

Finally, solar technologies that require transmission investment often do not require pipelines, coal transport or the associated production and processing infrastructure needed by coal and gas industries. This has the potential to save immense costs as the energy infrastructure in the U.S. ages and requires repairs.

Solar Energy Can be Integrated into the Grid at High Penetration Levels

[102] See PJM Renewable Integration Study, General Electric International, Inc. at 12 (February 28, 2014) (GE Study).
[103] See Id. at 12 and 15.
[104] For more information, see the paper, "Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements" available at: www.raponline.org/document/download/id/4537

As renewable energy becomes a larger component of the electricity sector, the generation profile of the electric resources available throughout the day is changing. For example, solar and wind resources peak in terms of output at specific times depending on geography and other factors. The addition of renewable energy has spurred utilities and regulators to think differently about matching supply and demand. The EPA's proposal to require affected sources to shift generation correctly reflects regulator and utility actions to accommodate more renewables in the grid today.

Utilities and policymakers are already addressing the changes to grid operations presented by increased renewable penetration. For example, in areas of an electric grid where the peak energy use is in the late afternoon, solar systems can be configured to coincide with peak demand later in the day. Solar can also be coupled with storage technologies to match their output to local power demand patterns, including evening peaks. This can be done economically, if supported through appropriate policies, pricing options, and program offerings.[105] For a discussion of strategies to address the changes to grid operations presented by renewables, we recommend *Teaching the Duck to Fly*, a paper recently published by the Regulatory Assistance Project.[106]

Some stakeholders have expressed concerns that solar and wind energy can increase costs and energy system emissions due to an increased need to cycle conventional power plants in response to variable renewable output.[107] However, such claims have been proven to be overstated, and could largely be avoided through a balanced portfolio of complementary solar, wind and other clean energy resources. The Western Wind and Solar Integration study found that not only is a high renewable energy penetration achievable, but also that any increases in costs or emissions associated with increased cycling of fossil fuel power plants are nominal compared to the overall cost and emissions savings associated with reduced generation from fossil fuel power plants.[108] The PJM Renewable Integration Study reached a similar conclusion: any increased costs associated with increased cycling of conventional generators are dwarfed by the savings in fuel costs.[109]

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[105] See "Teaching the Duck to Fly: Integrating Renewable Energy," available here: http://www.raponline.org/featured-work/teach-the-duck-to-fly-integrating-renewable-energy

[106] Id.

[107] Western Wind and Solar Integration Study, available at: http://www.nrel.gov/electricity/transmission/western_wind.html (Citing cycling concerns at pg. vii)

[108] Western Wind and Solar Integration Study, available at: http://www.nrel.gov/electricity/transmission/western_wind.html

[109] PJM Renewable Integration Study, available at: http://www.pjm.com/~/media/committees-groups/committees/mic/20140303/20140303-pris-executive-summary.ashx

Further, a recently released NERC report expressed concerns regarding the impact of high penetration renewables on the grid as a result of the Clean Power Plan. The report cited concerns such as the need to build out new infrastructure, the inability for renewable energy to ramp up as needed, impacts on reliability, and an overreliance on natural gas. However, upon review the report appears to be very preliminary and not based on any modelling. In fact, the main concerns regarding renewables integration have been rebutted or are currently being addressed by regulators in states throughout the country. For example, The SunShot Vision Study, the Renewable Energy Futures Study, the Western Wind and Solar Integration Study, the forthcoming Wind Vision Study (all NREL), the Minnesota Renewable Energy Integration and Transmission Study[110], and the PJM Renewable Integration Study (GE) show that renewables, including solar, can be integrated at high levels without significant issue.

[110] Minnesota Renewable Energy Integration and Transmission Study, Final Report, October 31, 2014 (http://mn.gov/commerce/energy/images/FINAL-MRITS-Report14.pdf)

APPENDIX 10: DEVELOPING AND PROJECTING A BASELINE EMISSIONS PROFILE[111]

The initial step in measuring renewable energy emissions reductions is to prepare a state-level emissions inventory and projection that documents the baseline, or the emissions that occur without any additional clean energy policies. This baseline can include historical, current, and projected emissions data and provides a clear reference case against which to measure the emission impacts of a clean energy initiative. Once a state develops and projects its baseline, it can conduct a prospective analysis of potential emissions reductions from a future policy.

An emissions inventory that includes both criteria air pollutants and GHGs will facilitate a more comprehensive analysis of the effects of a state's entire electric sector and the value of renewable energy policies. This is important because many options that reduce carbon emissions may also reduce criteria air pollutants and yield indirect health benefits.

Developing a baseline that includes both carbon and criteria air pollutants serves as a future point of reference for retrospective program evaluation as well as a basis for making well-informed policy and planning decisions. Typically, a state's air agency creates the criteria air pollutant inventory every three years as part of its responsibility to meet National Ambient Air Quality Standards established under the CAA. GHG emissions inventories can be developed by state air or other agencies, but since states are not required by federal law to inventory their GHG emissions, the practice varies from state to state. State energy offices or universities sometimes develop GHG inventories on an annual basis or every few years. If inventories are available, states can use them in their assessment of clean energy policies rather than develop a new baseline emissions inventory. Sources of completed state and local inventories that states and localities can adopt for use in their analyses include:

- EPA eGRID data http://www.epa.gov/cleanenergy/energy-resources/egrid/
- EIA power plant generation, fuel use, and emissions data: http://www.eia.gov/electricity/data/eia923/
- Links to maps and summaries of existing state-compiled greenhouse gas inventories are also available on this Web site: http://epa.gov/climatechange/emissions/state_ghginventories.html

[111] This section liberally borrows from EPA, Assessing the Air Pollution, Greenhouse Gas, Air Quality, and Health Benefits of Clean Energy Initiatives, available at http://epa.gov/statelocalclimate/documents/pdf/epa_assessing_benefits_ch4.pdf.

The baseline should reflect all major environmental policies, including allowance trading for SO_2 under Title IV of the CAA, The Regional Greenhouse Gas Initiative and California's Carbon Cap-And-Trade Programs (if applicable), the federal renewable energy production and investment tax credits if they are in place, and all of the state renewable portfolio standards and renewable tax credit programs. The baseline should also include the Mercury and Air Toxics Standards, which have been finalized by EPA and fully take effect in 2016, and the Clean Air Interstate Rule for SO_2 and NO_x in the eastern United States. Demand and input prices should be calibrated to Annual Energy Outlook (AEO) 2012 forecasts, with the exception of natural gas prices, which are benchmarked to the updated AEO 2013 forecasts for both level and supply elasticity (US Energy Information Administration 2012, 2013).

Baseline Emissions Inventory Formula—Emission Factors

An emissions factor quantifies the amount of a pollutant released to the atmosphere from a "unit" of an activity or source (e.g., lbs carbon per therm of fossil fuel burned). The emissions estimates are calculated by multiplying the emissions factor (e.g., pounds of NO per kWh produced) by the activity level (e.g., kWh produced). Emissions factors can be calculated based on the chemical composition of the fuels burned or determined by emissions monitors.

Emissions factors for carbon, criteria, and other pollutants are available from:

EPA's Emissions Factors and Policy Applications Center

http://www.epa.gov/ttn/chief/efpac/.html

EPA's Emissions & Generation Resource Integrated Database (eGRID)

http://www.epa.gov/egrid

EPA's U.S. Greenhouse Gas Inventory Reports

http://www.epa.gov/climatechange/emissions/usinventoryreport.html

EIA Emission Factors

http://www.eia.gov/oiaf/1605/emission_factors.html

Intergovernmental Panel on Climate Change Emissions Factor Database (EFDB)

http://www.ipcc-nggip.iges.or.jp/EFDB/main.php

Methods

It is important to develop an inventory that adheres to a comprehensive and detailed set of methodologies for estimating emissions. For GHG emissions, these methodologies are usually

derived from standards established by the Intergovernmental Panel on Climate Change[112] or the EPA's Emission Inventory Improvement Program (EIIP). For criteria air pollutants, these methodologies are usually derived from standards established by EPA's EIIP, which also offers guidance for developing inventories of criteria air pollutants. (EPA, 2007).[113] The methods vary depending on the type of inventory data a state collects.

Data Needs

These data are available from national sources, such as the Energy Information Administration (EIA) State Energy Data System (U.S. DOE, 2008a). States may need data on economic activity and human population levels to supplement data sources. These data are also available from national sources such as the Bureau of Economic Analysis' Regional Accounts and the Census Bureau Population Estimates.

Tools

Tools to help state and local governments develop GHG and criteria air pollutant emissions inventories include:

- EPA's State Inventory Tool
- EPA's eGRID (Emissions & Generation Resource Integrated Data) (http://www.epa.gov/egrid) and DOE's EIA electric sector data.

This free, publicly available software from EPA has data on annual SO_2, NO_x, carbon, and Hg emissions for most power plants in the United States. eGRID also provides annual average non-baseload emission rates, which may better characterize the emissions of load-following resources. By accessing eGRID, states can find detailed emissions profiles for every power plant and electric generating company in the United States. http:// www.epa.gov/egrid

- Emissions Collection and Monitoring Plan System (ECMPS)

EPA collects data in five-minute intervals from Continuous Emissions Monitors (CEMS) at all large power plants in the country. The ECMPS replaces the Emission Tracking System (ETS) that previously served as a repository of SO_2, NO_x, and carbon emissions data from the utility industry. http://www.epa.gov/airmarkets/business/.

[112] IPCC 2008, 2006 IPCC Guidelines for National Greenhouse Gas Inventories – A primer, Prepared by the National Greenhouse Gas Inventories Programme, Eggleston H.S., Miwa K., Srivastava N. and Tanabe K. (eds). Published: IGES, Japan.
[113] http://www.epa.gov/ttn/chief/eiip/techreport/

- EPA AVERT tool

For determining the emissions caused by electricity use, as well as emissions reductions that can be provided by clean energy measures such as renewable energy and energy efficiency, EPA's AVERT tool can play a critical role in determining which power plants in an interstate grid see a marginal change in their emissions. This analysis is critical because in nearly all states, changes in electricity use or generation in a state can affect emissions at power plants outside of that state. Moreover, increasing or decreasing electricity use or generation affects generation and emissions at the marginal power plant (the last power plant required to operate to meet demand), which often has a very different emissions profile than the fleetwide average of all power plants. http://epa.gov/avert/.

APPENDIX 11: ANALYTIC APPROACHES FOR PROJECTING CARBON EMISSIONS FROM AFFECTED EGUS[114]

Forecasting Future Emissions

To conduct a prospective analysis of potential emission reductions from a future policy, it is necessary to develop forecasts of both the new policy case and the "business as usual" (BAU) case that does not include the new policy. Electric sector emission projections provide a basis for:

- Developing control strategies for State Implementation Plans (SIPs) or mitigation measures for Climate Change Action Plans;
- Conducting air quality attainment analyses; and
- Tracking progress toward meeting air quality standards or GHG reduction goals.

When developing emission projections, states should attempt to account for as many of the important variables that affect future year emissions as possible. These variables may include projections of population growth and migration, economic growth and transformation, fuel availability and prices, generator retirements and additions, technological progress, and climate change.

Several guidance documents and tools are available to help states understand methodologies and data sources for factors relevant to projections, including:

- *EPA EIIP Technical Report Series, Volume X: Emissions Projections*

This document provides information and procedures to state and local agencies for projecting future air pollution emissions for the point, area, and on-road and non-road mobile sectors. It describes data sources and tools states might use for their projections. http://www.epa.gov/ttn/chief/eiip/techreport/volume10/x01.pdf

- *EPA State GHG Projection Tool*

States can use this EPA spreadsheet tool to create forecasts of BAU GHG emissions through 2020. Future emissions are projected using a linear extrapolation of the results from the State Inventory Tool, described above, and combined with customizable economic, energy,

[114] This section liberally borrows from EPA, Assessing the Air Pollution, Greenhouse Gas, Air Quality, and Health Benefits of Clean Energy Initiatives, available at http://epa.gov/statelocalclimate/documents/pdf/epa_assessing_benefits_ch4.pdf .

population, and technology forecasts.
http://www.epa.gov/climatechange/wycd/stateandlocalgov/analyticaltools.html

- *The Clean Air and Climate Protection Software Tool*

States or localities can use this tool to project an emissions baseline of GHGs and criteria air pollutants into the future, and measure the effects of different policies upon the forecast. http://www.icleiusa.org/cacp

This section surveys different types of methods and tools for projecting carbon emissions from affected EGUs, including modeling tools and other tools that base projections on historical data and use algorithms to extrapolate future carbon emissions performance based on past performance.

A. Electricity System Modeling Approaches for Projecting EGU Carbon Emissions

1. National-scale capacity expansion and dispatch planning models

National-scale electricity capacity expansion and dispatch planning models are typically used for fundamentals-based projections of the power sector (i.e., projections of the expected response of the sector to factors such as electricity demand, fuel prices, and emission constraints) that may extend over a period of several decades. These models are built to evaluate the impacts of market, technical, and regulatory factors on the electric power sector and related markets. Typical outputs of such models include EGU dispatch, fuel consumption, fuel prices, wholesale electricity prices, emissions, EGU retirements, and infrastructure expenditures (e.g., addition of new EGU capacity and installation of retrofit pollution control technologies).

National-scale electricity capacity expansion and dispatch planning models have moderate spatial detail with broad scope, generally encompassing the entire country or transmission system interconnects (i.e. Eastern, Western, and ERCOT), which are subdivided into smaller areas, such as balancing authorities or control areas. For computational efficiency, these models generally model several representative hours of the year, or aggregate hours into representative bundles with similar electricity demand profiles (i.e. peak, shoulder, off-peak). In these models, to reduce model size, existing EGUs may be aggregated into “model plants” to the extent that such EGUs share key unit characteristics, such as location, size, efficiency, operating costs, pollution retrofit control status, age, and fuel type use/availability. These types of models are well suited to project dynamic entry and exit (capacity expansion and unit retirement) to meet energy and capacity requirements while minimizing system costs, maintaining reliability criteria, and following other constraints, such as minimum build times, transmission constraints, renewable energy availability, or emission limitations.

2. Utility-Scale Capacity Expansion and Dispatch Planning Models

Utility-scale capacity expansion and dispatch planning models are similar in concept to related national-scale models. However, utility-scale capacity expansion and dispatch planning models are typically used for evaluating narrower utility planning and investment decisions, such as procurement of a specific new electric generating facility and retirement or retrofit decisions for existing capacity within a specific utility's territory. Utility planning models typically project outcomes for periods of up to two decades. Utility-scale capacity expansion and dispatch planning models are an industry standard, used regularly in state electricity regulatory proceedings. Within the electricity sector there is broad familiarity with these models at state PUCs. Multiple vertically integrated utilities use capacity expansion and dispatch planning models to conduct forward planning and review the economics of specific EGU retrofit decisions. Utilities that submit integrated resource plans (IRP) typically use a utility-scale capacity expansion and dispatch planning model to examine long-term strategies and develop short-term action plans. Utilities have experience using these models to examine carbon emission reduction strategies or carbon emission constraints, as IRP scenarios may include greater penetration of end-use energy efficiency or renewable energy, proxy carbon emission prices, emission trading, and limits on carbon mass emissions.

Utility-scale capacity expansion and dispatch planning models tend to have relatively high spatial detail with limited geographic scope, generally encompassing a utility service territory or a sub-regional scale. These models generally have better temporal resolution than the national-scale capacity expansion and dispatch planning models, with each model year typically dispatched based on an annual hourly load duration curve. Utility-scale capacity expansion and dispatch planning models typically represent individual EGUs, where each EGU has specific operational characteristics.

Due to the additional spatial and temporal resolution of these models as compared to the national-scale models, the number of technology options for capacity expansion is generally limited to reduce the runtime of the model. This can be done through an outside-the-model screening analysis to pre-select the resources most likely to be economic in a planner's area of interest, or by running the model iteratively to eliminate rarely chosen technology alternatives.

3. Electricity System Dispatch Simulation Models

Dispatch simulation models are regularly used by utilities, grid operators, and independent power producers (IPP) for short-term planning, ratemaking, dispatch decisions, and market intelligence. Dispatch simulation models are typically driven by near-term economics, system restrictions and market constraints, including a typically more detailed representation of an EGU's operational constraints (e.g., ramp rates, heat input curves, and unit downtime for

maintenance). These models typically do not add or retire generating capacity on an economic basis, although EGU additions and retirements may be exogenously input to these models. As a result, projections from these models tend to be considered more robust in the shorter term. Grid operators, including utilities, and independent system operators (ISO) use dispatch simulation models in near real-time to match demand with electric generation from available generating units and dispatch EGUs on a least-cost basis. EGU owners and operators run dispatch simulation models to assist in fuel procurement, forecast revenues and costs, and calculate the avoided generation supply costs related to procurement of end-use energy efficiency and EGUs. In this case, these models can be used in the same time horizon as a capacity expansion and dispatch planning model (i.e., decades). Other utilities use dispatch simulation models to forecast retail rates for ratemaking proceedings and other planning purposes.

Electricity system dispatch simulation models (also called production cost models) utilize security constrained economic dispatch (SCED) algorithms to determine which EGUs operate on an hourly (or shorter) basis to meet electricity demand. These models typically have a very broad spatial scope, generally covering multiple Regional Transmission Organization (RTO) regions, and often modeling entire interconnects (i.e. Western, Eastern, and ERCOT). While individual EGUs are modeled in detail, including fuel and variable costs and operational constraints, transmission is simplified to characterize thermal constraints between zones, which typically represent control areas or balancing authorities. Zones contain both load (electricity demand) and EGUs; EGU dispatch and electricity demand are balanced to maintain transmission system reliability while providing least-cost service on a variable cost basis. Some versions of these models operate at a “nodal” level, where transmission constraints between individual EGUs and load are modeled as well. Dispatch simulation models typically operate chronologically, modeling either all 8760 hours of the year, or typical weeks of the year. These models contain substantially more detail about individual EGUs than regional or national capacity expansion and dispatch planning models, including EGU ramp rates, minimum outages, maintenance schedules, emission rates, fuel use constraints, and heat rate curves depicting expected efficiency changes at various levels of output.

4. Multi-Sector Models

Multi-sector energy models are typically used to examine the effect of energy and environmental policies that affect multiple economic sectors, such as multi-sector emission trading systems. They can have value for electric sector analysis by quantifying feedback impacts from changes in the electric sector, such as how changes in the electric sector fuel mix affect gas and coal prices, which in turn have a feedback effect on the electric sector. Multi-sector models are used to review trends in emissions, expected broad- scale resource use, and

energy sector impacts under changing regulatory and economic conditions, and often review changes over a period of decades.

Multi-sector models cover a broad range of energy sectors beyond the electricity sector, and can better reflect energy demand and technology choices by energy end-users. Such models typically have relatively limited spatial detail with broad scope, generally encompassing the entire country subdivided into from one to 30 regions. Such models tend to have much more limited temporal resolution and treatment of EGU dispatch. EGUs are typically aggregated to a few broad technology types. A key strength of multi-sector energy models is the ability to provide multi-sector feedback between energy resource use and price (i.e., tracking national fuel supplies and adjusting price to account for demand).

The range of national and utility scale capacity expansion and dispatch planning models, and dispatch simulation models identified above, all tend to focus on properly characterizing the electricity sector in order to answer sector-specific questions. Multi-sector energy models attempt to include many other energy-using sectors of the economy in order to better capture interactions between these sectors. The more aggregated representation of the electricity sector in multi-sector models may limit their use to providing input data for more specific analysis in an electricity sector model, and to better understanding variations in electricity load that may result from changes outside the electricity sector. However, it is important to keep in mind that, for purposes of compliance with the EPA Clean Power Plan, only emissions from electric sector EGUs are regulated and count for compliance.

B. Growth Tools for Projecting EGU Utilization and Carbon Emissions

Organizations use growth tools for a variety of reasons, including to estimate future emissions inventories for state and regional air quality modeling, and to estimate the impact of load-reduction measures such as end-use energy efficiency and distributed renewable energy on individual EGU emissions, and county, state, and regional emissions rates. Because these algorithms are generally based on publicly available data and do not rely on economic data or proprietary information regarding individual EGUs, they provide a low-cost, simple, and often transparent framework for estimating how EGUs will respond to changing system conditions.

Non-modeling approaches, such as growth tools, approximate future emissions and generation from existing and new fossil fuel-fired EGUs under different assumed growth, retrofit, and load-reduction scenarios. These forecast tools do not simulate economic EGU dispatch, but could use demand growth rates and electricity production trends from other energy modeling forecasts as an input assumption. The algorithms in these forecast tools assume that EGU dispatch behavior generally follows simple rules based on past operation. In the absence of significant shifts in fuel prices and electricity demand, EGUs may be expected to behave

similarly in the future as they did in the past. Several common features of these forecast tools are that they (a) generally build on historical generation and emissions output from individual EGUs, (b) are insensitive to fuel and emission price forecasts, (c) do not solve for optimal economic EGU dispatch or EGU capacity expansion, and (d) do not capture transmission constraints or limits. The algorithms in these forecast tools generally divide the contiguous US into regional power markets, following ISO boundaries, eGRID boundaries, NERC regional boundaries, or similar designations. These algorithms generally seek to examine how operation and emissions from individual EGUs could be expected to change with changes in environmental regulations or installed pollution control retrofits and additional or reduced hourly electricity demand. Some algorithms use the observed historical behavior of individual EGUs to approximate future behavior, while others add additional steps of differentiating EGUs into fuel groups and unit types, with implicit differentiation of economic outcomes for these different groups. Some of these algorithms may contain subroutines to add new generating capacity automatically to meet load requirements.

APPENDIX 12: QUANTIFY AIR AND GHG EMISSION REDUCTIONS FROM CLEAN ENERGY MEASURES[115]

Once states have developed their baseline emission estimate or business as usual forecast, they can estimate the emissions that are avoided when implementing clean energy measures. Although an emission reduction estimation can be performed independently from a baseline emissions forecast, aligning many of the assumptions in the baseline case and the clean energy measures case is a desirable exercise.

Basic approaches typically include spreadsheet-based analyses that use emissions factor relationships or other assumptions to estimate reductions. Sophisticated approaches are usually more complex and involve dynamic electricity or energy system representations that predict energy generation responses to policies and calculate the effects on emissions.

Key Considerations for Selecting an Approach for Quantifying Emission Reductions from Clean Energy

There are advantages and disadvantages to each approach for quantifying emission reductions. States can use this information as guidance in determining the most appropriate approach for their particular goals. It is important for states to:

- Consider the cost of each potential approach and/or tool and the resources required;
- Determine whether the tools or methods can be used to estimate the pollutants and emissions of interest; and
- Decide between a complex, detailed approach and a simple, transparent screening-level approach based on their pros and cons and relative importance of each.

Basic Approaches to Quantifying Emission Reductions

Basic, screening-level, approaches involve: 1) establishing the operating characteristics of the clean energy resource, also known as its load profile; 2) identifying the marginal generation unit and developing avoided emissions factors; and 3) calculating the total emissions reductions by multiplying the avoided emissions factor by the avoided electricity generation.

Step 1: Establish Clean Energy Operating Characteristics (Load Profile)

[115] This section liberally borrows from EPA, Assessing the Air Pollution, Greenhouse Gas, Air Quality, and Health Benefits of Clean Energy Initiatives, available at http://epa.gov/statelocalclimate/documents/pdf/epa_assessing_benefits_ch4.pdf .

Assessing the Potential Energy Impacts of Clean Energy Initiatives, the first step when applying a basic modeling approach is to determine the specific ways that the clean energy initiative will affect either demand for electricity or available supply. This involves considering the following issues related to the operating characteristics, or load profile, of the clean energy measures:

- How much energy will the clean energy measure generate or save?
- When and where will the electricity generation offset occur (e.g., season of year, time of day)?
- What, if any, are the emissions characteristics of the clean energy resource?

Data sources:

Empirical data on the hourly output profiles of the aggregate fleet of existing renewable energy resources are available from most Independent System Operators (ISOs) and other grid operators:

PJM: http://www.pjm.com/markets-and-operations/ops-analysis.aspx

SPP: http://www.spp.org/GenerationMix/

MISO: https://www.misoenergy.org/Library/MarketReports/Pages/MarketReports.aspx

CAISO: http://www.caiso.com/green/renewableswatch.html

ISONE: http://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-gen-fuel-type

ERCOT: http://www.ercot.com/gridinfo/generation/windintegration/

BPA: http://transmission.bpa.gov/business/operations/wind/

The National Renewable Energy Laboratory (NREL) has also developed multi-year datasets of hourly wind plant output for hypothetical wind projects for use in such planning studies:

Eastern U.S.: http://www.nrel.gov/electricity/transmission/eastern_wind_methodology.html

Western U.S.: http://wind.nrel.gov/Web_nrel/

When using these datasets, care should be taken to preserve the statistical properties that dictate that an aggregation of many wind plants will have a more stable and diverse output profile than any single wind project. A common mistake is to model the output of a large number of wind plants by taking the output profile of a single wind project or all existing wind projects and multiply it by a scaling factor. A better approach, particularly when using the NREL dataset, is to continue selecting new wind sites and adding their output data until one has reached the amount of wind output or nameplate wind capacity one is trying to model. If using

existing wind or solar plant output data, statistical methods can be used to scale the output data while adjusting it to account for how geographic diversity would further smooth the output profile.

Step 2: Identify the Marginal Generation Unit and Develop Emissions Characteristics

Next, identify the marginal generation source and its associated emissions characteristics. The marginal generating source, as described earlier, is the last generating unit to be dispatched in any hour, based on least-cost dispatch (thus it is the most expensive on a variable cost basis). The emissions characteristics of this unit can be expressed as an emissions factor for each pollutant, and are expressed in pounds per MWh.

There are several different approaches that can be used to characterize the marginal generation source and its associated emissions factor. These include (1) system average, (2) factors based on unit type or other characteristic that correlates (a) system average, (b) factors based on unit type or other characteristic that correlates with likelihood of displacement (e.g., capacity factor), and (c) factors derived from dispatch curve analyses.

Method	Advantages	Disadvantages	When to Use this Method
Regional or system average based on historical year	▪ Computationally simple. ▪ Less labor and data required than for unit type or dispatch curve analysis.	▪ Insensitive to dispatch process. ▪ Neglects power transfers between areas. ▪ History may not be good	▪ Rough estimates of clean energy benefits for displacing emissions.
Average based on unit type (capacity factor rule)	▪ Simpler and less labor required than dispatch curve analysis. ▪ Considers generation resource characteristics.	▪ Somewhat insensitive to dispatch process. ▪ Inaccurate for baseload clean energy resources.	▪ Preliminary planning and evaluation of clean energy resources, especially those that operate during

Marginal emissions calculation	■ More sensitive to dispatch process than regional or system average and unit type methods. ■ Can be adjusted to account for fuel price changes,	■ Higher data requirements than averaging methods.	■ Planning and regulatory studies.
Statistical analysis that identifies marginal unit characteristics, such as EPA's AVERT tool	■ Sensitive to dispatch process ■ Easy to use ■ Generation additions and retirements can be modeled	■ Cannot be readily adjusted to account for fuel price changes ■ In some cases the modeled regions may be larger than or otherwise not line up with the grid operating area	■ Planning and regulatory studies.
Power system modeling	■ Can be highly accurate, depending on the accuracy of input assumptions ■ Fuel price changes, generation additions and retirements, and	■ Expensive and time intensive ■ Requires a large amount of input data	■ Planning and regulatory studies.

■ Regional or system average emissions factors. This approach typically involves taking an average of the annual emissions of all electricity generating units in a region or system over the total energy output of those units. Data on emission rates averaged by utility, state, and region are available from EPA's eGRID database. For example, using eGRID, states can locate emissions factors by eGRID sub-region, state, or by specific boiler, generator, or plant.

While easy to apply, this method ignores the fact that some units (such as nuclear and other low-fuel-cost electricity generating units) are extremely unlikely to be displaced by clean energy

resources. Units with low variable operating costs (e.g., hydro, nuclear, and renewables) can be excluded from the regional or system average to partially address this shortcoming. Some approaches, therefore, take a fossil-only average.

Other methods for identifying the marginal unit and its emissions factors attempt to recognize that what is on the margin is a function of the time that clean energy load impacts (or energy generation) occurs. The most complete of these time-dependent methods would analyze the impact of changes in load for the 8,760 hours in a year using dispatch models.

■ Displaced unit and emissions factors identification based on type of unit. As described above, system or regional average emissions factors do not take into account the fact that some electricity generating units are much more likely to be displaced by clean energy resources than others. The unit type approach for estimating emissions factors takes into account that some classes of units are more likely to be displaced than others by the operation of clean energy measures.

Calculating Average Emissions Rates Based on Unit Type Involves the Following Steps:

1. Estimate the percentage of total hours each type of unit (e.g., coal-fired steam, oil-fired steam, gas combined-cycle, gas turbine, etc.) is likely to be on the margin (the highest-cost unit dispatched at any point in time is said to be “on the margin” and is known as the “marginal unit”) and thus to have its output displaced given the load profile of the new clean energy resource.

2. Determine the average emission rate for each unit type (in pounds of emissions per MWh output). This can be determined based on public data sources such as EPA’s eGRID database or standard unit type emissions factors from EPA AP-42, an available resource for estimated emissions factors.

3. Calculate an emissions-contribution rate for each unit type by multiplying the unit type average emissions (lbs/MWh) by the fraction of hours that the unit type is likely to be displaced. Using average emissions to approximate displaced emissions involves significant simplifications of electric system operations. For example, the emission rates for each existing generating unit may vary considerably. Similarly, plants of a certain type may have different operating costs and load-following capabilities. For example, baseload units operate virtually all the time, load-following units are routinely turned off at night and used most days to meet the higher daytime electricity demand, and peaking units only operate during the highest demand periods (such as hot summer afternoons). Generalizations must also be made about the type of generating unit that is on the margin, which may vary considerably across different control areas and time periods.

A limitation of this approach is that it misses important system-level dynamics. For example, reducing emissions of a regulated pollutant may result in shifts in other dispatch decisions in the short and long term. This is particularly true if those emission reductions have a market value (as in cap and trade system). For example, if an energy efficiency option allows for reduced output from a high-emitting oil/gas steam unit during the shoulder period (i.e., that period when demand falls below peak levels but above minimum, base load levels), it may allow increased operation of a coal plant (one not running at full utilization already) at an increased capacity factor. This may reduce system costs all while maintaining emissions at capped levels. In other words, the clean energy option has allowed the operator to reduce emissions compliance costs through dispatch changes. Over the longer term these impacts may include changes in retrofit or build decisions.

As an alternative to estimating the fraction of the time each unit type is on the margin, some analyses estimate the likelihood that a unit type could be displaced using a displacement curve based on capacity factors. The capacity factor is the ratio of how much electricity a plant produces to how much it could produce, running at full capacity, over a given time period. Historical data on, or estimates of, capacity factors for individual plants are available from EPA's eGRID database.

Displacement rules do not capture some aspects of electric system operations. For example, an extended outage at a baseload unit (for scheduled maintenance or unanticipated repairs) would increase the use of load-following and peaking units, affecting the change in net emissions from the clean energy project. According to a displacement rule, this plant would be more likely to be displaced even though it would rarely if ever be on the margin. Nevertheless, adding this level of detail when estimating emissions factors will generally produce a more credible and accurate estimate of displaced emissions than relying simply on an unweighted system average emissions rate.

■ Marginal Emissions Analyses

Curve analysis is a method for determining tons of emissions avoided by a clean energy resource for a period of time in the past. In general, generating units are dispatched in a predictable order that reflects the cost and operational characteristics of each unit. These plant data can be assembled into a generation "stack," with lowest marginal cost units on the bottom and highest on the top. A dispatch curve analysis matches each load level with the corresponding marginal supply (or type of marginal supply).

In many cases, dispatch curves are available from the local power authorities and load balancing authorities (e.g., a regional Independent System Operator (ISO)). This information can also be purchased through subscriptions with electric sector data and analysis vendors.

Constructing a Dispatch Curve Requires Data On:

1. Historical utilization of all generating units in the region of interest;

2. Operating characteristics, including marginal costs and emissions rates of the specific generating units, for each season;

3. Hourly regional electricity demand (or generation). Data on operating cost, historical utilization, and generator-specific emission rates can typically be obtained from the EIA (http://www.eia.gov/electricity/data/detail-data.html), the local load balancing authority, or private vendors. When generator cost data are not available, capacity factors (from the eGRID database, for example) for traditional generating units can be used to approximate the relative cost of the unit (those with the highest capacity factors are assumed to have the lowest cost). As an exception, variable power resources such as wind and hydropower are assumed to have lower marginal costs than fossil fuel or nuclear units.

If unit-level cost data are available, calculating the weighted average of each unit's emission rate is preferable to aggregating plants, especially when there is considerable variation in the emission rates within each unit type.

Operational data (or simplifying assumptions) regarding energy transfers between the control areas of the region and hourly regional loads can be obtained from the ISO or other load balancing authority within the state's region.

Load duration curve analysis is commonly used in planning and regulatory studies. It has the advantage of incorporating elements of how generation is actually dispatched while retaining the simplicity and transparency associated with basic modeling methods. However, this method can become labor-intensive relative to other basic modeling methods for estimating displaced emissions if data for constructing the dispatch curve are not readily available, and it also ignores diurnal dispatch patterns that may affect unit commitment and dispatch. Another disadvantage is that it is based on the assumption that only one unit will be on the margin at any given time; this is not generally true in most regions.

A more sophisticated approach to a marginal emissions calculation takes account of the fact that larger amounts of renewable energy will not just displace output and emissions from the marginal unit, but can fully displace multiple generating units from the commitment and dispatch stack, thereby changing the marginal emissions rate. This approach would sum the total emissions displaced from those units by renewable energy in each time period.

■ **Marginal Emissions Statistical Analyses, such as EPA's AVERT Tool**

An easy-to-use tool that employs a sophisticated statistical algorithm to identify which power plants are likely to have their output and emissions reduced by adding a clean energy resource. This tool models regional power system dispatch and accounts for how clean energy solutions can affect emissions in other states, though in some cases the regions may be larger or otherwise not coterminous with the power system one is attempting to model. More information is available at http://epa.gov/statelocalclimate/resources/avert/index.html, and in Appendix 24.

■ Power System Modeling

Private vendors will perform such analyses for a client, or will provide the client with the tools to run such an analysis. A large amount of data is required to accurately characterize individual power plants, transmission lines, and other components of the power system, though many vendors will provide this data as part of their analysis. More information is available in Appendix 24.

■ Summary of Emissions Factor Methods

In general, there are tradeoffs among these analytical options: the more detailed the analysis, the more accurate the results, but the more costly and time-consuming it is to collect the data and conduct the analysis. However, there are tools such as AVERT that already contain the needed data and calculations, allowing a detailed and relatively accurate calculation to be conducted with minimal time and no cost.

Step 3: Calculate Total Emissions Reductions

For modeling techniques that do not automatically provide total emission reductions as an output, this result can be calculated by applying the emissions factor developed during Step 2's identification of the marginal generation unit and development of emissions characteristics to the clean energy resource's level of activity, determined during Step 1's establishment of clean energy operating characteristics.

Tools

Several tools that take a basic modeling approach to estimating emissions reductions are available to states:

■ *The Clean Air and Climate Protection Software* (CACPS) tool can be used to estimate emissions reductions in addition to the functions already mentioned above. ICLEI updated and re-released this software in April 2009. Web site: http://www.icleiusa.org/cacp/

■ *The OTC Workbook*: The OTC Workbook is a free tool developed for the Ozone Transport Commission to help local governments prioritize clean energy actions. The Workbook uses a detailed Microsoft Excel spreadsheet format based on electric power plant dispatch and on the energy savings of various measures to determine the air quality benefits of various actions taken in the OTC Region. This tool is simple, quick, and appropriate for scenario analysis. It can calculate predicted emission reductions from energy efficiency, renewables, energy portfolio standards (EPSs), and multi-pollutant proposals. The tool contains two kinds of default emission rate: system average (for assessing EPSs) and marginal (for assessing displacement policies). Users can also input their own data. http://www.otcair.org

■ *Power Profiler*: The Power Profiler is a Web-based tool that allows users to evaluate the air pollution and GHG impact of their electricity choices. The tool is particularly useful with the advent of electric customer choice, which allows many electricity customers to choose the source of their power. http://www.epa.gov/cleanenergy/powerprofiler.htm

■ *eCalc*: eCalc is an online tool that identifies emission reductions from energy efficiency and renewable energy measures in the Electric Reliability Council of Texas (ERCOT) region. The eCalc tool incorporates both energy modeling (assessing the energy saved by a given measure) and emissions modeling (determining the emissions avoided by those energy savings). The energy modeling capability is extremely robust and detailed, accounting for a wide array of load types with weather normalization. It also includes energy production profiles for wind and solar power.

Note that many of these spreadsheet-based and other tools rely on models to estimate the underlying emission rates. For example, the OTC Workbook relied on runs of the PROSYM model to establish the emission rates, and eCalc integrates several legacy models depending on the user's desired analysis type. These tools thus have the same underlying concerns as those raised earlier, such as being dependent on key driving assumptions; to the extent that these tools and their inputs are not regularly updated, these key assumptions may no longer be applicable and relevant.

Limitations of Basic Approaches:

Basic approaches for quantifying displaced emissions are analytically simple and the data are readily available. However, they involve a less rigorous approach than sophisticated modeling approaches; policy-making and regulatory decisions typically require more rigorous analysis. Basic approaches:

■ Are best suited for estimating potential emission reduction benefits for a relatively short time frame (e.g., one to three years). Longer-term analyses would require emissions factors that

account for impacts on the addition and retirement of energy sources over time and changes in market conditions including fuel prices and environmental requirements.

■ Do not typically account for imported power, which may be from generating units with very different emissions characteristics than the units within the region or system. These methods also do not account for future changes in electricity import/export patterns, which may change the marginal energy sources during operation of the clean energy measure.

■ Do not account for the myriad of factors that influence generating unit dispatch on a local scale. For example, the emissions impacts of a clean energy resource within a load pocket (an area that is served by local generators when the existing electric system is not able to provide service, typically due to transmission constraints) would affect unit dispatch very differently than measures in an unconstrained region. Higher-cost units must be dispatched in a load pocket because energy cannot be imported from lower-cost units outside of the area.

For these reasons, use of basic approaches is often limited to providing preliminary estimates of emission reductions and reporting approximate program impacts data for annual project reports and program evaluations that do not involve regulatory compliance. Nevertheless, when using basic approaches it is important to remember that the more detailed the representation of the study area, the more precise and reliable the emissions estimates.

Sophisticated Approaches to Quantifying Emissions Benefits:

Sophisticated modeling approaches, such as electric dispatch and capacity expansion models, can be used to compare baseline energy and emissions forecasts with scenarios based on implementation of clean energy measures. Using sophisticated models to estimate emissions that are displaced as a result of clean energy measures generally results in more accurate estimation of emission impacts than using the basic approaches, if the input assumptions are accurate, but can be more resource-intensive.

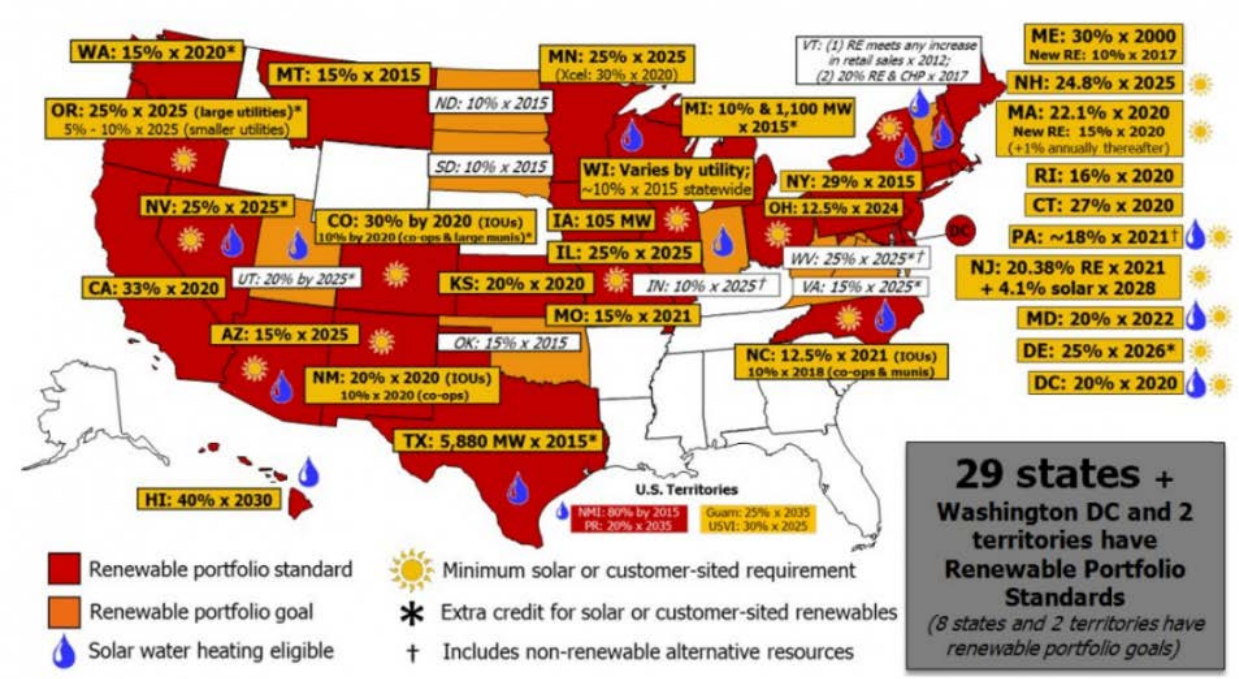
Many of the models used to characterize or project changes in electricity supply and demand also provide estimates of the air pollution and GHG impacts associated with clean energy policies. Thus, by comparing clean energy policy scenarios with the BAU case, they facilitate quantification of emissions benefits. Two key types of models used to estimate emissions are electric dispatch models and capacity expansion (also referred to as system planning or planning) models. An electric dispatch model typically answers the question: how will this clean energy measure affect the operations of existing power plants? In other words, the model quantifies the emission reductions that occur in the short term. A capacity expansion model answers the question: how will this clean energy measure affect the composition of the fleet of plants in the future? A capacity model typically takes a long-term view and can estimate

emission reductions from changes to the electricity grid, rather than changes in how a set of individual power plants is dispatched.

Some capacity expansion models include dispatch modeling capability, although typically on a more aggregate time scale than dedicated hourly dispatch models. Models that address dispatch and capacity expansion handle both the short and long term.

APPENDIX 13: RENEWABLE PORTFOLIO STANDARDS[116]

Renewable portfolio standards (RPS) are state legislation and regulations aimed to increase production of energy from renewable resources such as wind and solar as an alternative to fossil fuel generation. An RPS requires load serving entities to purchase a designated percentage of their electricity from renewable resources. This percentage is usually increased steadily over fixed periods of time, which stimulates the continued development of new renewable resources. States often design their RPS to drive a particular renewable technology by providing "carve out" or "credit multipliers" provisions. "Carve out" provisions require that a percentage of electricity be generated from a specified resource (e.g., wind or solar energy). Currently, 29 states and Washington, DC have RPSs, of which 18 have solar and/or distributed generation "carve out" provisions.[117] "Credit multipliers" provisions offer additional credit toward compliance for energy derived from particular renewable energy sources. The figure below provides a summary of the state RPSs as well as the states that have renewable portfolio goals, which means the percent of renewables that would be purchased by load serving entities is not compelled by state law.



Source: Database of State Incentives for Renewables and Efficiency (DSIRE) RPS Policies summary map, March 2013

[116] Parts of this section are borrowed from EPA, Technical Support Document (TSD) for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf .

[117] For more information on state RPS policies, see http://www.dsireusa.org/.

Policy Mechanics

Design

RPS requirements typically start at modest levels and ramp up over a period of several years. An RPS relies on market mechanisms to increase electricity generation from eligible sources of renewable energy.

Retail electricity suppliers can comply with RPS requirements through several mechanisms, which vary by state, including:

- Ownership of a qualifying renewable energy facility and its electric generation output,
- Purchasing electricity bundled with renewable energy certificates (RECs) from a qualifying renewable energy facility, and
- Purchasing RECs separately from electricity generators. Unlike bundled renewable energy, which is dependent on physical delivery via the power grid, renewable energy certificates (RECs) can be traded between any two parties, regardless of their location. However, state RPS rules typically condition the use of RECs based on either location of the associated generation facility or whether it sells power into the state or to the regional grid.

Authority

Most state RPS are established through legislation and administered by state PUCs.

Obligated Parties

RPS applicability varies by state. All state RPS apply to investor-owned utilities, while some state RPS obligate municipal utilities, rural cooperatives, and/or other retail providers, often depending on a minimum number of customers served.

Measurement and Verification

Some state RPS include an alternative compliance payment (ACP) option, wherein a retail electricity supplier may purchase compliance credits from the state at a known price, which acts as a de facto price cap, if it has not procured sufficient electricity from renewable energy sources or RECs to meet the RPS compliance requirement. State PUCs typically require annual compliance reports from retail electricity suppliers subject to a RPS. Most states use regional tracking systems (e.g., Western Renewable Energy Generation Information System, PJM

Generation Attribute Tracking System) to issue, track, and retire RECs for RPS compliance purposes.

Penalties for Noncompliance

States have developed a range of compliance enforcement and flexibility mechanisms. As of 2007, despite the fact that several states had not achieved the RPS targets, only Connecticut and Texas had levied fines. A $5.6 million penalty was incurred in Connecticut in 2006. In 2003 and 2005, two competitive electricity service providers in Texas were penalized a total of $4,000 and $28,000 respectively. Flexible enforcement and opportunities to "make-up" shortfalls in subsequent years or ACPs that are recycled to support other renewable measures have helped other states avoid penalties for noncompliance. An RPS is designed to increase the amount of renewable energy a distribution utility or load-serving entity provides to retail electricity customers. This increased customer demand in turn increases the production of renewable energy to meet demand. To achieve compliance with an RPS, an increasing share of a distribution utility's electricity retail sales is required to be produced or acquired from renewable energy resources and delivered to customers. To verify compliance, RPSs have been complemented by tracking systems for renewable energy generation and use.

The point of regulation for state RPSs is typically investor-owned electric distribution utilities, because most RPS apply to entities under the jurisdiction of state PUCs. In a number of states, municipally-owned utilities and electric cooperatives are exempt from state RPS, have lower RPS requirements, or are required to develop their own renewable energy procurement targets. Additionally, some states have created separate renewable energy requirements for each of their affected distribution utilities. The absolute amount of renewable energy that each distribution utility is obligated to deliver will vary, with requirements in the form of a fixed amount of renewable energy (either MWh or MW of capacity) or percentage of retail sales.

Pathways for Meeting RPSs

There are several pathways that affected distributed utilities typically have to meet state RPS requirements, including building and operating renewable energy generating capacity, purchasing electricity from renewable energy generators, and purchasing the attributes from renewable energy generation. Many state RPSs take this latter approach. Rather than requiring each distribution utility to generate electricity from its own renewable energy facilities or purchase electricity from a renewable facility owned by others, many states require distribution utilities to acquire renewable energy certificates (RECs) that represent the attributes of the unit of renewable electricity produced.

By allowing REC trading, many states have created markets for RECs based on specific state RPS requirements. Renewable energy generators can sell RECs as another product bundled with the

underlying power they produce or sell RECs separately to different customers. Once the RECs are separated from the power generated, the power has no attributes associated with it and is considered generic or "null" power.

There are a number of key aspects of RPS design and implementation that affect the quantification, monitoring, and verification of renewable energy generation used to meet a RPS:

- *Eligible renewable energy resources*. While most RPS-eligible resources in most states will result in avoided carbon emissions from fossil fuel-fired EGUs, some RPS-eligible resources in some states are responsible for greenhouse gas (GHG) emissions or do not meet common definitions of renewable energy (e.g., waste coal, coal-bed methane, and fuel cell operation using fossil-fuel feedstocks).
- *Existing and new resources*. RPS-eligible resources can include facilities that began operation prior to the enactment of the RPS and, more importantly, prior to the proposal of the emission guidelines by EPA.
- *Scope of coverage*. In some states an RPS applies to all retail sales in a state, but in others only a subset of retail sales (e.g., only investor-owned utility retail sales) are subject to a RPS.
- *Credit multipliers*. Some states provide additional incentives for specific eligible resources in the form of bonus credit toward compliance in their RPS accounting framework. For example, these states may favor certain resources (e.g., distributed solar PV), or locally-important resources or technologies. The MWh produced or RECs related to MWh production from such facilities may be counted twice or three times toward compliance with a RPS in such states. However, these credit multipliers and bonuses are not an accurate representation of the amount of renewable energy generation that is attributable to a RPS. For the purpose of quantifying the amount of renewable energy produced as a result of a RPS included as a measure in a state plan, only the actual renewable energy generation used to comply with an RPS is relevant.
- *Banking*. Some states permit the carryover of renewable energy produced in one year to satisfy RPS requirements in a subsequent year. Accounting for year-to-year carryover should be addressed in a state plan, in order to determine the renewable energy generation that occurred in a respective reporting year or compliance period.

- *Alternative compliance payments (ACP)*. Many states allow a compliance alternative which requires obligated entities to pay a predetermined fee to the state for each MWh of RPS shortfall. Although these ACP payments may be directed to programs to promote the deployment of renewable energy technologies, these payments are not equivalent to renewable energy generation and should not be accounted as such.

- *Interstate issues*. While treatment of interstate emission effects is discussed herein, for quantification, monitoring, and verification of renewable energy generation under a RPS it is important to note that most states allow use of eligible renewable energy resources located in other states to satisfy the state RPS requirements.

Considerations related to the quantification, monitoring, and verification of renewable energy generation used to meet a RPS depends on the design and implementation of the RPS. Distribution utilities subject to a RPS may meet their RPS obligations by building and operating their own renewable energy generating facilities, entering into bilateral contracts with other parties to purchase renewable energy, and participating in the REC market. Each compliance method has specific implications for the quantification, monitoring, and verification of renewable energy generation used to meet RPS obligations. Implications under these different pathways are discussed below.

- **Building renewable generating facilities**

In many states, utilities with RPS obligations may build, own, and operate their own renewable energy generating facilities. This pathway is often used by vertically integrated utilities subject to a RPS. For large renewable energy generating facilities, production is measured through a revenue-grade utility meter as it enters the grid at the point of interconnection. This meter is subject to the same verification standards as for any other generator participating in the wholesale market.

Some utilities with RPS obligations also build, own, and operate smaller distributed renewable energy generating facilities. Smaller generators, such as residential rooftop solar PV systems of less than 10 kW capacity, often don't have discrete metering of their total generation. State RPS requirements may permit these distributed generators to qualify for use in meeting utility RPS obligations based on an engineering estimate of their renewable energy generation output, provided the distributed generators are registered with a REC tracking system and the generation output is verified according to tracking system and RPS rules.

- **Bilateral Contract Model**

Under the bilateral contract model, distribution utilities with RPS obligations contract with renewable energy generators for supply. These contracts typically specify a delivery amount in MWh over a specified contract period. These supply contracts may be short- or long-term, may specify generation from certain renewable energy EGUs, and may be solicited through an RFP or entered into through negotiation. Quantification of renewable energy generation (in MWh) is accomplished through the use of a revenue-grade meter that measures the flow of electricity from the generator into the transmission grid. A contract may also stipulate an adjustment to the metered MWh generation data to account for transmission losses that occur between the point of injection of electricity to the transmission grid and the point of receipt at a utility transmission or distribution system. A renewable energy supply contract also generally addresses the ownership of the RECs related to the renewable energy generation. Under such a contract, purchase of the RECs should accompany the purchase of the electricity, in order for the utility to satisfy its RPS obligations through the contract.

State RPS compliance processes may provide for PUC review of supply contracts, including inspection of meters and verification of electricity delivery from the generator to the utility distribution network through a specified contract path (e.g., through evidence of transmission rights held or scheduled). The purchasing utility also reports their purchase and delivery of RPS-compliant renewable energy pursuant to the contract to the state agency responsible for RPS enforcement, typically the state PUC or state energy office. Verification is accomplished by audit of electricity supply contracts along with REC tracking system reports of RECs held by the utility and submitted for retirement by the tracking system administrator. Some state RPS require that electricity from qualifying renewable energy sources be produced within the state or a specified grid region, or if outside the state or specified grid region, that electricity be delivered to the state or grid region. In such cases, the verification of electricity delivery is typically done by the REC tracking system administrator before issuing RECs for the imported energy. Verification can be provided, for example, by demonstration of scheduled delivery through the ISO or RTO serving the state or region, through demonstration that the seller holds transmission rights for delivery or possession of NERC tags for the energy. Bilateral contracts also typically require certification by the seller that attributes related to the sold electricity have not been and will not be otherwise sold, retired, claimed, represented as part of energy sold elsewhere, or used to satisfy obligations in another jurisdiction.

- **REC Model**

Under the REC model, renewable energy generators register their EGU with a renewable energy tracking system, which have been established by several regional groupings of states, as well as a few individual states. Currently, nine regional renewable energy certificate (REC) tracking systems operate in different regions of North America, including: Texas Renewable Energy

Credit Program, run by the Electric Reliability Council of Texas (ERCOT), NEPOOL Generation Information System (GIS), PJM Generation Attribute Tracking System (PJM-GATS), Western Renewable Energy Generation Information System (Wrenewable energyGIS), Midwest Renewable Energy Tracking System (M-renewable energyTS), North American Renewables Registry (NARR), Michigan Renewable Energy Certification System (MIRECS), Nevada Tracks Renewable Energy Credits (NVTREC), and North Carolina Renewable Energy Tracking System (NC-renewable energyTS). For more information see http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=3.

The registration process collects data about the generator's attributes: type of resource (e.g., wind), plant-level emissions, geographic location, nameplate capacity (MW), commercial operation date, ownership, and the eligibility for RPS compliance or voluntary market certification. After the generator is registered, revenue-meter data is transmitted to the tracking system. Meter accuracy is verified for renewable energy generators in the same manner as for any other generator participating in wholesale electricity markets.

Each MWh of renewable energy generation reported to the tracking system by a registered generator results in the issuance of a REC, with its own unique serial number and information about the generator, location, resource type, and the month in which the MWh was generated, and the month or quarter in which the certificate was issued. The renewable energy generator can then sell the renewable electricity as a bundle (both the commodity electricity and the associated REC) or unbundle the RECs from the electricity and sell the two products separately. Other market participants, such as brokers, REC marketers, and load-serving entities also maintain accounts with the tracking system so that REC electronic transactions can be recorded within the tracking system platform. The system tracks each REC through these transactions and ultimately "retires" the REC when the final purchaser designates it for retirement. Retirement could result from the REC being used to satisfy a state RPS, or as a result of a voluntary buyer retiring the REC to demonstrate that they had purchased and used renewable energy to meet their electricity demand.

Because the tracking system follows the REC from the point of issuance to retirement, including all interim transactions, it minimizes the opportunity for renewable energy to be double-counted across, for example, two different state RPSs, or between two voluntary purchasers. In recent years, the various tracking systems have developed interchange standards so that RECs generated within one tracking system can be transferred to and used within another tracking system. Note that not every potential interchange possibility is currently supported, and that many states have additional eligibility restrictions within their RPS that may limit the use of RECs related to electric generation from distant locations. These include requirements in some state RPSs for the seller to hold firm transmission rights for delivery of the accompanying

electricity from the renewable energy generator into the respective ISO/RTO system or grid system in which a state is located.

- **Small Distributed Generators**

Small distributed generators, such as distributed PV, are usually metered and monitored. For example, every system that is contracted under third-party ownership is metered and monitored, typically remotely (electronically) and often in near real time, such that time of day production can be recorded. Of existing solar capacity, nearly 70% of the residential market and 50% of the commercial market is contracted under third party ownership. Moreover, in states where distributed PV is used to meet state RPS requirements, metering and reporting is required for tracking of SRECs, regardless of the ownership of the system. The type of metering may be similar to that for third-party owned systems or may be less granular, for example using an analog meter to manually record monthly production. For the portion of the distributed PV market that is not metered, estimates of performance can be made by using any number of publicly and commercially available models including the NREL PVWatts model Sandia National Labs flat plate model, PVSyst, SolarAnywhere® FleetView®, and Homer. Where such projects are third-party owned and operated, the project developer will own the RECs and factor their revenue value into their pricing offered to the site host for electricity supply. Note also that many utility-sponsored renewable energy incentive programs stipulate that all RECs resulting from the project must be transferred from the generation owner to the utility as a condition of participation in the incentive program. These RECs can then be used by the utility to meet its RPS obligations, or can be sold to other parties.

- **State Agency Role**

In many states, the PUC or its equivalent is responsible for establishing the detailed rules and procedures that obligated parties must follow to comply with a RPS. The PUC is usually responsible for receipt and review of obligated parties' periodic compliance reports, imposing compliance penalties as needed, and for evaluating the impacts of the program on energy costs, generation diversity, and market operations. The list of eligible resources and MWh requirements are often set through state legislation, but these decisions may also be delegated to the PUC for study and promulgation through regulations of commission orders.

In some states the energy office may be responsible for certifying the eligibility of specific generators to participate in the RPS and for making siting determinations. In New York, for example, the New York State Energy Research and Development Authority (NYSERDA) is responsible for the centralized procurement of the renewable energy needed to meet the RPS for all of the state's investor-owned utilities.

APPENDIX 14: TRADING PROGRAMS (CAP AND TRADE, EMISSIONS TRADING/CREDIT SYSTEM)

CAP-AND-TRADE PROGRAMS

AB 32: California's Cap and Trade Program

The State of California requires all entities emitting more than 25,000 Metric Tonnes of carbon equivalent to comply with their Cap-and-Trade Program regulations. All covered industries, which include more than the electric power sector, must report their emissions annually. Emission estimates must be independently verified by qualified third parties.

The Air Resources Board ("ARB") set annual emission allowances for 2013–2020. Each year, covered entities turn in 30% of the required number of compliance instruments equivalent to 30% of the previous year's emissions to meet their obligations under the Program. Every third year, each entity provides compliance instruments equal to the remainder of emissions from the previous three-year period. Allowable instruments include:

a) Allowances issued by a program approved by ARB;
b) Offset credits issued by a program approved by ARB;
c) ARB offset credits issued for purposes of early action;

Full "payment" every three years and the availability of credits increases entities' options to comply with the program through activities like renewable power purchase agreements and demand-side response.

ARB set the cap for emissions at 2% below business-as-usual projections for the state in 2012, declining between 2% and 3% annually thereafter. Allowances for each sector were set at 90% of average emissions. The regulations spell out what percent of total electric power sector allowances are allocated to each utility and mandate that the allowances be used to benefit the ratepayer. Those facilities which have emissions greater than the number of allowances they receive will thus need to take measures to reduce their emissions, purchase allowances from more efficient entities, or purchase offset credits. Entities are allowed to bank emission allowances for use in future years.

In order to claim compliance obligations for imported renewable energy, the electricity importer must: (1) calculate and report emissions following their mandatory reporting regulations; (2) be the facility operator or have right of ownership or a written power contract

to the amount of electricity claimed and generated by the facility or unit claimed; (3) ensure the electricity is directly delivered to the California grid; and (4) must retire all renewable energy credits.

The Cap-and-Trade Program is enforced through civil and criminal penalties in the Health & Safety code and in instances where a signature is required, perjury statutes for violations of the regulations. If an entity misses a filing deadline or does not file enough instruments, the entity must file four times the allowances or offset credits that were missing.

Regional Greenhouse Gas Initiative ("RGGI"): An Initiative of the Northeast and Mid-Atlantic States of the United States

RGGI is an example of a regional cap-and-trade program for the electric power sector. States participating in RGGI are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

Each state created and implemented a Carbon Budget Trading Program, based on the RGGI Model Rule, to limit emissions of carbon from electric power plants. The programs detail how the state issues carbon allowances and establishes participation in the regional carbon allowance auctions.

RGGI's program, most recently reviewed in 2012, set the 2014 cap at 91 million short tons of carbon. The cap then declines 2.5% annually from 2015 to 2020. Fossil fuel-fired electric power generators with a capacity of at least 25 MW use allowances purchased at auction and issued by any participating state to demonstrate compliance with their individual state's program. The generator must hold allowances equal to their carbon emissions over a three-year period. Generators may also use offsets from outside the electric power sector to meet their compliance obligations. All emissions and allowance transactions among market participants are tracked.

Each state allocates allowances as defined in their Carbon Budget Trading Program statutes. RGGI also includes a Cost Containment Reserve that creates a fixed additional supply of allowances that are only available for sale if the allowance price exceeds certain price levels (e.g., $4 in 2014). The proceeds from the carbon allowance auctions are invested in consumer benefit programs to improve energy efficiency and accelerate the deployment of renewable energy technologies.

Former RGGI Chairman Collin O'Mara said that he is "fairly confident that it'll be one of the allowable paths forward to meet the [111(d)] standard," because "it's already designed, it's already implemented, it's really plug and play."

APPENDIX 15: INTEGRATED RESOURCE PLANS

An integrated resource plan (IRP) is a strategic plan mandated by a state's Public Utility Commission (PUC) in which a plan is developed for a utility to meet forecasted peak (MW) and total energy (MWh) demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period. States frequently require utilities through legislation or regulation to undertake planning efforts that are then reviewed by the state PUC.

These planning efforts are broad and systematic and include considering the addition of new and retirement of old supply resources, investing in grid infrastructure improvements, and implementing programs to help customers use energy more efficiently. In some cases these planning processes explicitly take environmental goals or requirements into account and may use carbon prices as a risk assessment tool. For example, Georgia Power incorporated in its IRP cost-effective renewable resources, including 63 MW of solar generation in service or under contract. Thus, the resource choices made in the IRP have a clear impact on carbon emissions from a utility and will help to comply with 111(d) requirements.

IRP rules governing utilities have been created in a number of ways. Bills that mandate integrated resource planning can be passed into law by state legislatures; rules can be codified under state administrative code; and state utility commissions can adopt IRP regulations as part of their administrative rules or order it to be done as a result of docketed proceedings. Although some state IRP rules have remained unchanged since they were first implemented, other states have amended, repealed, and in some cases reinstated their IRP rules. Examples can be found in the rules of Arizona, Colorado, and Oregon. Rules that have been amended recently often reflect current concerns in the electric industry, such as climate change, fuel costs and volatility, the effects of power generation on air and water, issues of national security, electricity market conditions, and individual state concerns.

A utility's resource plan normally includes consideration in detail of the following elements: a load forecast, reserves and reliability, demand-side management, supply options, fuel prices, environmental costs and constraints, evaluation of existing resources, integrated analysis, time frame, uncertainty, valuing and selecting plans, action plan, and documentation. Below are examples of different PUC IRPs.

PacifiCorp

PacifiCorp's IRP is developed with considerable public involvement from state utility commission staff, state agencies, customer and industry advocacy groups, project developers, and other stakeholders. The key elements of the IRP include: a finding of resource need, focusing on the first 10 years of a 20-year planning period; the preferred portfolio of supply-side and demand-side resources to meet this need; and an action plan that identifies the steps to take during the next two to four years to implement the plan.

PacifiCorp prepares its integrated resource plan on a biennial schedule, filing its plan with state utility commissions during each odd numbered year. For five of its six state jurisdictions, the Company receives a formal notification as to whether the IRP meets the commissions' IRP standards and guidelines, referred to as IRP acknowledgement. For even-numbered years, the Company updates its preferred resource portfolio and action plan by considering the most recent resource cost, load forecast, and regulatory and market information.

The IRP uses system modeling tools as part of its analytical framework to determine the long-run economic and operational performance of alternative resource portfolios. These models simulate the integration of new resource alternatives, thereby informing the selection of a preferred portfolio judged to be the most cost-effective resource mix after considering risk, supply reliability, uncertainty, and government energy resource policies.

Tennessee Valley Authority

Tennessee Valley Authority (TVA) develops scenarios that are evaluated for viability and environmental impact based on public concern regarding energy sources (e.g., fossil fuels, renewables, nuclear), demand-side management, electric power delivery (e.g., transmission, environmental impact, pricing), and social factors impacting electric power supply (economic factors, weather scenarios, cost). With the information received from the public and partners during scoping, TVA develops a draft integrated resource plan and a draft Supplemental Environmental Impact Statement (SEIS) that assess the environmental impacts of the scenarios proposed in the draft integrated resource plan.

TVA also works with the IRP Working Group, stakeholders who represent broad perspectives such as customers, businesses, activists, elected officials, and economic development experts. The group works with TVA over two years to create and test 20-30 year plans to meet TVA's power needs for the Valley. The 2015 IRP Working Group is composed of two state agencies, four local power companies, three industrial customers, four environmental/energy NGO's, three academia /research entities, and two businesses.

Idaho Power

The Idaho Power IRP is a comprehensive look at present and future demands for electricity, as well as a plan for meeting those demands. The IRP describes the company's projected need for additional electricity and the resources necessary to meet that need while balancing reliability, environmental responsibility, efficiency, and cost.

Idaho Power enlists the assistance of its customers in developing the IRP through an advisory council—the Integrated Resource Plan Advisory Council (IRPAC). The IRPAC consists of members of the environmental community, major industrial customers, irrigation representatives, state legislators, public utility commission representatives and other interested parties. The council's responsibilities include: representing the interests of Idaho Power's more than 500,000 customers, participating in open and active discussions of relevant issues, and working with Idaho Power to develop ways to engage the public-at-large in the IRP process.

APPENDIX 16: INCENTIVE PROGRAMS

Several states offer a variety of tax incentives to promote the production and use of renewable energy. These currently include sales tax exemptions for certain kinds of equipment (e.g., PV panels), property tax abatement for improvements to a building or facility related to the asset value of the renewable energy generating system, and income tax credits for the installation of renewable energy systems based on capacity or investment level. Several states provide a renewable energy production tax credit based on the amount of renewable energy generated. This approach is useful because it results in a measureable quantity of renewable energy electricity generation.

With a production-based tax incentive, the renewable energy generator might claim a tax credit for each MWh of qualifying renewable energy generation within the state. One design consideration for a production-based tax incentive that affects quantification of renewable energy generation output is whether the electricity must be sold to a third party as opposed to being used by the site host. In the former case, a revenue-grade utility meter would be present at the point of interconnection to the electricity grid, which provides measurement of MWh generation output for tax compliance purposes. Site-host use might necessitate the installation of an additional meter within the project site to permit reliable measurement of the renewable energy generator's output.

DIRECT INCENTIVES

Direct incentives come in a variety of forms, including rebates, buy downs, grants and performance based incentives. One of the most successful solar incentive programs is the California Solar Initiative (CSI), which was launched in 2007 to provide over $2 billion in incentives for solar-energy projects with the objective of installing 1,940 MW by 2016. Under the CSI, incentive levels are automatically reduced over the duration of the program in 10 steps based on the aggregate capacity installed.

The New York State Energy Research and Development Authority (NYSERDA) introduced the availability of approximately $13.8 million in incentives to encourage the installation of end-use wind energy systems for residential, commercial, institutional or government use. The incentives, of up to $1,000,000 per site/customer, will be paid to Eligible Installers who install new approved grid-connected wind energy systems using qualified equipment, in accordance with the eligibility requirements. The maximum equipment size is 2 MW (2,000 kW) per site/customer. NYSERDA's incentive shall not exceed 50% of the total installed cost of the

system. The program will continue through December 31, 2015 or until funds are fully committed, whichever comes first.

PROPERTY TAX INCENTIVES

When a solar system is installed on property, it can increase the assessed value of that property. Property tax incentives provide exemptions, abatements, credits, and special assessments that reduce or eliminate the increase in a property's assessed value once a solar system is installed. For example, New York City allows building owners to deduct 2.5-5% of PV installation expenditures from their total real property taxes annually for four years, with a total tax benefit of up to 20% of the installed system cost. The maximum abatement during a year is the lesser of $62,500 or the amount of real property taxes owed during the year. The goal of property tax incentives is to bring the cost of owning a solar energy system in line with using a conventional heating and cooling system, or drawing electricity from the utility grid.

Texas has the Solar and Wind-Powered Energy Devices Property Tax Exemption. Texas offers this property tax exemption that allows residents to take an exemption from taxation of the amount of the appraised value of the property that arises from the installation or construction of a solar or wind-powered energy device that is primarily for the production and distribution of thermal, mechanical, or electrical energy for on-site use, or devices used to store that energy. "Solar" is broadly defined to include a range of biomass technologies. For example: If your property is valued and taxed at $150,000 and you add a $15,000 system that increases the property value, the exemption applies to the added value, so with the exemption you will only be taxed on the property value before you added the system. This incentive type includes Property tax exemption for commercial, industrial & residential. Eligible Renewable Technologies include: Passive solar space heat, solar water heat, solar space heat, solar thermal electric, solar thermal process heat, photovoltaics, wind, biomass, storage technologies, solar pool heating, anaerobic digestion. The Texas Comptroller's Office provides Solar and Wind-Powered Device Exemption Guidelines that outlines a list of the eligible solar and wind-powered devices, valuation methods and application requirements.

SALES TAX INCENTIVES

Sales tax incentives provide an exemption from (or refund of) sales tax for the purchase and installation of renewable energy. The goal of these policies is to reduce the investment costs of acquiring a renewable-energy system. Although wind and sun are free fuels, the capital costs for wind turbines or solar energy systems are high relative to traditional energy sources. Fossil

fuel inputs are typically exempt from sales taxes, resulting in a relatively higher sales tax burden on renewable energy investments. For example, Florida exempts solar-energy systems and components from the state's sales tax. The Florida Solar Energy Center certifies a list of equipment and hardware eligible for the incentive, including solar components related to space heating and cooling, domestic water and pool heating, and PV.

Tennessee allows a taxpayer to take a credit, to apply for a refund of taxes paid, or to apply for authority to make tax-exempt purchases of machinery and equipment used to produce electricity in a certified green energy production facility. A certified green energy production facility is a facility certified by the Department of Environment and Conservation as producing electricity for use and consumption off the premises using clean energy technology. Clean energy technology is technology used to generate electricity from geothermal, hydrogen, solar, or wind sources.

A contractor who is installing pollution control or green energy machinery and equipment must file an application with the department and must attach a copy of the contract to its application. The taxpayer who hires a contractor must also file an application with the department. If both applications are approved, authority to purchase tax exempt will be extended to the contractor for the certified green energy production facility project described in the application. If taxes have been paid, the approved application will be used to support a refund or credit directly to the taxpayer.

TAX CREDITS

Investment tax credits reduce a taxpayer's liability for part of the cost of purchasing and installing a renewable-energy system. Solar tax credits have been used by federal, state, and local governments as a successful means of encouraging solar deployment. Tax credits are simple to administer and may be more politically viable than direct cash incentives because tax credits generally do not require an annual appropriation. Louisiana offers a 50% tax credit on the first $25,000 of the cost of residential solar-electric and solar-thermal systems.

In addition, there is the federal renewable electricity production tax credit (PTC). The PTC is a per-kilowatt-hour tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. Originally enacted in 1992, the PTC has been renewed and expanded numerous times.

Similarly, the Investment Tax Credit (ITC) is a 30 percent federal tax credit for solar systems on residential and commercial properties. The ITC has proven to be one of the most successful solar policies to date, helping annual solar installation grow by over 1600% since it was first

implemented in 2006. This has led to the creation of thousands of solar jobs and significant economic development in states around the country. Multi-year tax credits such as the ITC are especially effective because they provide market certainty that allow companies to develop long-term investments that drive competition and technological innovation, which in turn, reduces costs for consumers.

The rebate amount is 2.3¢/kWh for wind, geothermal, closed-loop biomass; 1.1¢/kWh for other eligible technologies. This generally applies to first 10 years of operation. The rebate is provided by the Internal Revenue Services (IRS).

STATE AGENCY ROLE

Currently, existing state tax policies are primarily under the authority of the state revenue agency. The state revenue agency might have the primary responsibility for establishing the rules for production-based tax incentives, although it may seek advice from state energy agencies regarding the technical aspects of renewable energy generator operation and the behavior of energy markets. The renewable energy generator might claim the tax incentive through the state tax collection process and report MWh generation to claim the tax credit. The revenue agency could receive tax filings from the owner and operators of renewable energy generators and be responsible for determining whether the taxpayer's claim for tax incentives is supported by the MWh generation evidence. Assuming the state revenue authority retains its ability to audit the taxpayer's return, it could verify claimed MWh generation.

As with FITs, the renewable energy generation resulting from production-based tax incentives might be used for RPS compliance. If that were to become the case, then it should not be counted separately in a state plan from MWh generation used to comply with a state RPS.

APPENDIX 17: INCORPORATION OF CARBON ADDERS TO ECONOMIC DISPATCH

Traditionally, electric power systems are operated in such a way that the total fuel cost is minimized without regard for emissions produced. Under traditional practice, dispatch is strictly on a minimum cost basis. Externalities do not affect the dispatch and emissions do only to the extent that they affect direct costs.

States can use the addition of carbon cost adders to economic dispatch in electric power systems to internalize the cost of carbon externalities and therefore dis-incentivize the production of carbon caused by the operation of fossil-fueled thermal generation. Dispatch is performed based on the sum of fuel cost, variable operation and maintenance costs, and environmental cost.

If dispatching practices incorporate environmental goals, incremental environmental costs will be included in marginal costs, which can result in changes in the dispatch order. Therefore, with an environmental dispatch approach, the amounts of pollution from the generating units are factored into the dispatch protocols, and, depending on how emissions are valued relative to direct operating cost, the dispatch of the power production system changes.

CARBON PRICE MARKET

Working with Minnesota-based Great River Energy, Brattle Group economists developed a regional market-based approach[118] to implement EPA's section 111(d) rule. The approach attempts to use existing energy market infrastructure to achieve emission reduction targets while ensuring reliability and minimizing cost impacts.

The foundation of the proposed approach involves a three-step process: (1) translating greenhouse gas emissions reduction targets into targets for regional power markets of independent system operators (ISOs); (2) meeting the required emissions reductions by applying an ISO-administered carbon price to electric generation in the market; and (3) refunding the carbon revenues collected through the carbon price to load serving entities.

[118] Judy Chang, Jurgen Weiss, Yingxia Yang, *A Market-based Regional Approach to Valuing and Reducing GHG Emissions from Power Sector*, Brattle Group, April 2014; available at http://www.brattle.com/system/news/pdfs/000/000/616/original/A_Market-based_Regional_Approach_to_Valuing_and_Reducing_GHG_Emissions_from_Power_Sector.pdf?1397501081 .

The new proposed approach would allow states within a regional power market to commit to meeting the regional targets, as opposed to setting state- or plant-specific caps on greenhouse gas emissions. This would be accomplished by charging a carbon price to electric generating units that will be collected by the ISO and could affect the order of dispatch of generating units in the market. Over time, emissions can be compared to target levels and the carbon price can be adjusted periodically to achieve the target emissions levels.

By adding carbon prices of sufficient magnitude to the bids of individual generators, lower carbon-emitting resources will be dispatched more frequently than higher carbon-emitting resources and also will enjoy higher energy margins. The carbon price would also be reflected in wholesale prices, which would send an efficient price signal to both buyers and sellers in the wholesale power market. This should lead to lower emissions in the short run and to a changing generation mix through entry and retirement over time.

Under the proposed approach, the ISO would charge carbon-emitting power plants a rate per ton of carbon emissions. Plants with higher carbon emissions would face a higher charge per megawatt-hour produced. In return, the charges collected would be refunded back to consumers through the load-serving entities (on a per-customer basis instead of a per-MWh of consumption basis to maintain the incentive for customers to use energy efficiency), thereby limiting the initial cost impacts on consumers.

To show compliance with 111(d), states would need to demonstrate that the approach can be implemented and enforced to achieve the emissions reduction required by the federal guidelines. States could do so by:

- Requiring covered power plants to adhere to the relevant ISO rules (as an enforceable condition in the generators' air permits)
- Using a transparent approach to adding a "carbon value" to generators' bids to ensure compliance
- Demonstrating their ability to achieve the desired emission outcome by ex-ante modeling and setting procedures to adjust the carbon value based on the projected emissions reductions relative to targets

APPENDIX 18: UTILITY PROCUREMENT

Utilities have two options to procure renewable energy: buy or build. With the buy option, a utility signs a power purchase agreement (PPA) to buy electric output from a third party renewable energy generator. Utilities can also buy renewable energy from customers themselves to build a community program or to allow for compliance.[119] Under the "buy" option a utility owns and operates the renewable energy (usually with the help of a third party for construction). A utility can also reallocate existing power sources.

Direct ownership naturally gives the utility more power and control over site selection, permitting, development and operations. PPA, on the other hand, offers the convenience of construction, technology and operational risk remaining with the developer as payments are based on the system's actual performance, and typically PPA payment terms more closely resemble the per-MWh nature of utility rates.

REVERSE AUCTIONS

A reverse auction mechanism is an auction approach to procurement, wherein sellers which meet certain minimum criteria are eligible to submit non-negotiable price bids. The buyer (typically a utility) then selects winning sellers based on the lowest-priced bids first, and signs non-negotiable standard contracts with the winning sellers, incorporating the prices bid by that seller. For example, California's Renewable Auction Mechanism was designed to procure distributed generation projects greater than 3 MW and up to 20 MW. The program has undergone three auctions resulting in the deployment of hundreds of MWs of solar energy capacity and carbon emission reduction.[120] For more information on Reverse Auction Mechanisms, see Clean Energy Alliance's Review of Emerging State Finance Tools to Advance Solar Generation.[121]

STANDARD OFFER CONTRACTS

[119] http://www.solarelectricpower.org/media/71959/solarops-community-solar-handbook.pdf
[120] http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm
[121] http://www.cesa.org/assets/Uploads/Resources-pre-8-16/CESA-review-state-finance-tools-solar-2010.pdf

To comply with the Public Utility Regulatory Policies Act (PURPA), some states offer Standard Offer Contracts to producers. For example, California's Public Utility Commission established, among others, a standard offer contract to Qualifying Facilities less than 20MW.

APPENDIX 19: FEED-IN TARIFFS

FITs typically have caps on the amount of renewable energy that will be purchased by a utility (in MWh of energy or MW of capacity). FITs may also include customer impact caps for the tariff as a whole (in total dollars spent or in specified retail rate impacts allowable), and may also have limits on the size of any participating renewable energy generator from which the utility will purchase electricity through the FIT. FITs may also have pricing formulas that are differentiated by resource or that change through time as specified benchmarks are achieved (e.g., MW of renewable energy generating capacity subject to the FIT, amount of electricity purchased through a FIT as a percentage of utility sales, or retail rate impact level reached). Typically, the tariff treats all similarly-situated generators in a consistent manner.

Quantification of renewable energy generation output under a FIT is accomplished through the use of a revenue-grade meter to measure the generator's injection of electricity into the grid. The utility's tariff will typically specify the minimum performance characteristics and/or certifications that a meter must meet in order to be used on its system. Utilities retain the right to inspect and test the calibration of meters connected to their systems. As the utility will be paying the generator each month based on the meter reading, it is in the utility's interest to ensure that the meter is reading precisely and accurately through time.

Both the utility and the state will need to consider the ownership of the environmental attributes arising from the renewable energy generation purchased by a utility through a FIT, and whether the renewable energy can be counted toward RPS compliance. If renewable energy generation purchased by a utility through a FIT may be counted toward RPS compliance, then it should not be counted separately as another renewable energy program in a state plan.

FITs are usually authorized by state statutes that specify which utilities must offer a FIT, eligibility criteria (e.g., renewable energy resource type, location, project MW generating capacity limits), and sometimes overall program targets (e.g., total installed MW of generating capacity subject to the FIT). State statutes may also specify whether the utilities offering a FIT will receive the RECs related to purchased electricity generation output for use in complying with a state RPS, and whether customers receiving FIT payments may also receive incentives under other utility and state programs. Typically state statutes leave implementation details to the PUC (or other utility governing body, if applicable, for municipal and cooperative utilities), but may provide guidance on what to consider in setting FIT payment levels. Based on this statutory authority, PUCs develop detailed rules governing implementation, which can include payment levels and contract length. PUCs may direct the affected utilities to develop standard contracts with all the terms and conditions spelled out, and these standard contracts must be approved by the PUC. As with state RPS, the PUC is responsible for receipt and review of the

utility's periodic status reports, approving changes to a tariff if needed, and evaluating the impacts of the tariff on retail prices, generation diversity, and electricity system operations.

Over the last several years, a number of states and countries have seen significant deployment of renewable energy as a result of FITs. However, stakeholders have also expressed concern that FITs may lead to boom and bust cycles or rapid renewable energy penetration that is difficult for grid operators to handle. To address these concerns, policymakers can ensure that their FITs are readily adjustable to react to market growth as it occurs, and allow for additional policy support to be provided in parallel with FITs to ensure long term sustainable growth that is compatible with utility planning and grid operations. For more information, see Solar Energy Support in Germany: A Closer Look.[122]

[122] http://www.seia.org/research-resources/solar-energy-support-germany-closer-look

APPENDIX 20: CUSTOMER GENERATION

NET METERING

Net metering is a billing mechanism that allows owners of distributed generation systems to generate their own electricity, track their electricity use, and bank excess energy on the grid in the form of kilowatt-hour credits. These credits are used to offset electricity consumed by the customer at a different time during the same billing period at the utility's retail rate. Net metering has been especially effective at deploying significant distributed solar capacity, which provides immediate environmental and grid benefits, and is now allowing thousands of homes and businesses throughout the United States to generate and manage their own energy. Currently, more than 40 states and the District of Columbia allow net metering. For example, Colorado allows net metering for systems sized up to 120% of customers' average annual consumption for all customers of investor owned-utilities. The recent trend towards installing smart meters allow utilities to track the number of net metered systems in their territory and calculate the amount of energy produced by DG systems, and the corresponding avoided GHG emissions.. However, net metering and emissions reductions calculations can also be done without smart meters. For more information regarding net metering, see the "Net Metering" section of DSIRE's Solar Policy Guide or visit Freeing the Grid.[123]

COMMUNITY PROGRAMS

Solar

Community Solar programs allow multiple community members to procure solar energy where they may not otherwise be able to do so. For example, renters, multi-family units, and other individuals who would not otherwise have access to solar. Examples of popular community solar programs include the Community Solar Gardens program in Minnesota and Colorado. For more information regarding community solar programs, visit NREL's Guide to Community Solar Programs.[124]

Wind

Community wind projects are in significant part owned by the local community. Community wind projects are defined by an ownership model instead of by the type or size of turbine. Community wind projects have multiple applications and can be used by schools, hospitals, businesses, farms, ranches, or community facilities to supply local electricity. Rural electric

[123] http://freeingthegrid.org/
[124] http://www.nrel.gov/docs/fy11osti/49930.pdf

cooperatives or municipal utilities can own community wind projects. Community wind projects can also consist of groups of local individuals who form independent power producer groups or limited liability corporations to sell the power the turbines produce to a local electricity supplier.

APPENDIX 21: STATE PLAN PATHWAYS[125]

A. DIRECT EMISSION LIMITS

The first basic state plan approach is carbon emission limits that apply directly to affected EGUs, and includes two pathways:

- rate-based carbon emission limits applied to affected EGUs; and
- mass-based carbon emission limits applied to affected EGUs.

For both types of emission limits, renewable energy measures that avoid EGU carbon emissions could be a major component of a state's overall strategy for cost-effectively reducing EGU carbon emissions.

1. RATE-BASED CARBON EMISSION LIMITS APPLIED TO AFFECTED EGUS

Under this approach, rate-based emission limits would apply a lbs of carbon/MWh emission limit to affected EGUs. Depending on a state's approach, compliance flexibility could be provided through different mechanisms, such as averaging among affected sources, or the use of tradable credits for avoided carbon emissions resulting from renewable energy measures.

Rate-based emissions limits could incorporate renewable energy measures that avoid EGU carbon emissions, through an administrative adjustment by the state or tradable crediting system. These adjustment credits could be used by an affected EGU to comply with the rate-based emission limit, by adjusting the unit's reported carbon emission rate.

Under this approach, renewable energy measures that avoid EGU carbon emissions would be enforceable components of a state plan. These actions would need to be enforceable components of a state plan to provide assurance that a sufficient amount of adjustment credits will be available to facilitate EGU compliance with the emission rate limit, and that renewable energy measures that generate adjustment credits are properly quantified, monitored, and verified.

[125] Parts of this section are borrowed from EPA, Technical Support Document (TSD) for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf.

2. MASS-BASED CARBON EMISSION LIMITS APPLIED TO AFFECTED EGUS

Mass-based emission limits would apply either an individual limit on carbon tons emitted from an affected EGU or establish a finite carbon emissions budget for a group of affected EGUs. The latter approach is typically implemented through a tradable allowance system.

B. PORTFOLIO APPROACH

The second basic state plan approach uses a portfolio of actions, in which a state plan includes multiple programs and measures that are designed to achieve either a rate-based or mass-based emissions performance goal for affected EGUs. This approach includes two pathways:

- a state-driven portfolio approach; and
- a utility-driven portfolio approach.

A portfolio approach would include emission limits for affected EGUs along with other enforceable renewable energy measures that avoid EGU carbon emissions. A portfolio approach could be state-driven or utility-driven, depending on the utility regulatory structure in a state.

In general, a portfolio approach is distinguished from an emission limit approach by the fact that achievement of the full level of required emission performance for affected EGUs specified in the plan is not ensured through the application of direct emission limits that apply to affected EGUs. A portfolio approach could include both direct emission limits that apply to affected EGUs and other indirect measures that avoid EGU carbon emissions. Under a portfolio approach, renewable energy measures that avoid EGU carbon emissions would be enforceable components of a state plan. This would be necessary because the emission limit applied directly to affected EGUs would not assure full achievement of the required level of emission performance specified in the state plan.

Under a portfolio approach, either a rate-based or mass-based emission limit might be applied. Such plans might also include application of a direct emission limit to a subset of affected EGUs. Both scenarios would necessitate inclusion of supplemental measures, such as renewable energy, or other measures that directly apply to affected EGUs (e.g., repowering or retirement of one or more high-emitting EGUs), in order to achieve the required level of emission performance for affected EGUs specified in the state plan.

As discussed below, due to differences in state utility regulatory structure, a portfolio approach implemented in a restructured state with retail competition will likely look quite different from one implemented in a state with vertically integrated, regulated electric utilities. This includes the process for developing the portfolio approach, the mechanisms for implementing it, the

responsible parties, and the regulatory and legal relationships among parties and state regulators.

1. STATE-DRIVEN PORTFOLIO APPROACH

A state-driven portfolio approach – rather than a utility-driven approach – is probably more appropriate for a state with a restructured electricity sector. Under a state-driven portfolio approach a mix of entities might have enforceable obligations under a state plan. This includes owners and operators of affected EGUs subject to direct emission limits, as well as electric distribution utilities, private or public third-party entities, and state agencies or authorities that administer end-use energy efficiency and renewable energy deployment programs or are subject to portfolio requirements.

2. UTILITY-DRIVEN PORTFOLIO APPROACH

For a state with vertically integrated, state-regulated electric utilities, it is probably more appropriate to adopt a utility-driven portfolio approach. Under a utility-driven portfolio approach, a vertically integrated utility would develop and implement a portfolio of measures designed to meet the rate-based or mass-based emission performance level for its affected EGUs specified in the state plan. This plan would likely be developed and approved through an IRP-like process overseen by the state public utility commission. If there is more than one rate-regulated electric utility in the state, the state might apportion the state emission performance level for affected EGUs among utilities.

Under a utility-driven portfolio approach, the entire suite of obligations under the plan would be enforceable against the utility company, which would also be an owner and operator of affected EGUs. If there are other affected EGUs in the state that are not owned and operated by a vertically integrated utility, a state plan might need to include other measures that address carbon emission performance by these affected EGUs.

APPENDIX 22: APPROACHES FOR ADJUSTING EGU CARBON EMISSION RATES[126]

Credits or adjustment to an EGU carbon emission rate, based on the effect of renewable energy programs and measures, might represent avoided MWh of electric generation or avoided tons of carbon emissions. Per the guidance and questions included in EPA's October 2014 Notice of Data Availability,[127] if the adjustment or credits represent avoiding future increases in fossil MWh, they could be added to the denominator of the lbs of carbon/MWh emission rate when determining an adjusted lb carbon/MWh emission rate. If adjustment or credits represent avoided carbon emissions from current power plants, they could also be subtracted from the numerator when determining an adjusted lb carbon/MWh emission rate. The approach chosen could affect the amount of credit or adjustment provided for renewable energy programs and measures.

Adjustment of Carbon Emission Rate Based on Avoided MWh

One approach is to adjust an EGU's carbon emission rate based on avoided MWh of generation from an EGU, or cohort of EGUs, resulting from renewable energy programs and measures. A MWh crediting or adjustment approach implicitly assumes that the avoided carbon emissions come directly from the particular affected EGU (or group of EGUs) to which the adjustment or credits are applied. It assumes, in effect, that an additional emission-free MWh is being generated by that respective EGU, and that the renewable energy measure reduces carbon emissions from that individual EGU or group of EGUs. In practice, the marginal carbon emission rate in the power pool or identified region – more closely approximating the avoided carbon emissions from the generating sources being displaced by MWh of renewable energy generation – could differ significantly from the calculated avoided carbon emissions derived by adjusting the MWh output of an affected EGU.

Adjustment of Carbon Emission Rate Based on Avoided Carbon Emissions

An alternative approach is to provide an adjustment to the carbon emission rate of an EGU, or cohort of EGUs, based on the estimated carbon emissions that are avoided in the power pool or

[126] Parts of this section are borrowed from EPA, Technical Support Document (TSD) for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf.

[127] http://www2.epa.gov/sites/production/files/2014-10/documents/20141028noda-clean-power-plan.pdf, pages 51-58

identified region as a result of renewable energy programs and measures. This approach acknowledges that the avoided carbon emissions may come from the electric power pool or other identified region as a whole, rather than an individual EGU. The avoided carbon emissions are determined based on the MWh saved or generated, multiplied by a carbon emission rate for the power pool or region.

This carbon emission rate could be based on the average or marginal emission rate in the power pool, region, or state. A marginal avoided emission rate represents the generation that is displaced at the margin for every MWh generated through a renewable energy program or measure. An average avoided emission rate is based on either all fossil generation in a region or total generation. This approach assumes that every MWh saved or generated equally displaces generation from every generator in a power pool or region.

APPENDIX 23: MULTI-STATE/REGIONAL APPROACHES[128]

The Clean Power Plan proposes that states that participate in multi-state plans would have the flexibility to distribute the carbon emission reductions among the states in the multi-state area, as long as the total carbon emission reductions claimed are equal to the total of the emissions reductions that result from renewable energy measures implemented in those states.

The EPA is also proposing that states could jointly demonstrate carbon emission performance by affected EGUs through a multi-state plan in a contiguous electric grid region, in which case attribution among states of emission reductions from renewable energy measures would not be necessary. While multi-state plans have their advantages, states may also cooperate on compliance methods – such as renewable energy crediting and trading – without the creation of an all-encompassing multi-state compliance plan.

In addition, for states wishing to participate in a multi-state plan, the EPA is proposing that only one multi-state plan could be submitted on behalf of all participating states, provided it is signed by authorized officials for each of the states participating in the multi-state plan and contains the necessary regulations, laws, etc. for each state in the multi-state plan. In this instance, the joint submittal would have the same legal effect as an individual submittal for each participating state.

For states participating in a multi-state program, the initial submittal should include executed agreements among the participating states and a road map for both design of the multi-state program and its implementation at the state level. The Clean Power Plan states that the RGGI provides an example of such an approach.

The RGGI participating states signed a Memorandum of Understanding (MOU) in December 20, 2005, in which the states "express[ed] their mutual understandings and commitments." The MOU included a detailed outline of the multi-state emission budget trading program, which served as a guide for drafting a model rule. The MOU also included commitments by the participating states to draft and finalize the model rule by specified dates, and a commitment to

[128] Parts of this section are borrowed from EPA, Technical Support Document (TSD) for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf.

seek to establish in statute and/or regulation. *See Regional Greenhouse Gas Initiative Memorandum of Understanding*, available at http://rggi.org/design/history/mou.

A multi-state plan may be submitted, provided it is signed by authorized officials for each of the states participating in the multi-state plan. In this instance, the joint submittal will have the same legal effect as an individual submittal for each participating state.

A multi-state plan should include all the required elements for a single-state plan specified in § 60.5740(a). States may submit a multi-state plan that:

- Demonstrates carbon emission performance jointly for all affected entities in all states participating in the multi-state plan, as follows:
    - For states demonstrating performance based on the carbon emission rate, the level of performance identified in the multi-state plan pursuant to § 60.5740(a)(3) will be a weighted (by net energy output) average lb carbon/MWh emission rate to be achieved by all affected EGUs in the multi-state area during the plan performance period; or
- For states demonstrating performance based on mass carbon emissions, the level of performance identified in the multi-state plan pursuant to 60.5740(a)(3) will be total carbon emissions by all affected EGUs in the multi-state area during the plan performance period.
    - Assigns among states, according to a formula in the multi-state plan, avoided carbon emissions resulting from emission standards contained in the plan, from affected entities in states participating in the multi-state plan.

APPENDIX 24: CALCULATING THE CARBON EMISSION REDUCTIONS FROM RENEWABLE ENERGY

Credit non-emitting sources at the emissions rate set for the state

The easiest option for awarding credit to non-emitting sources under the rate-based system is to simply credit non-emitting resources at the annual emissions rate standard set for the state. For example, if a state's emissions rate standard is 1,300 lbs/MWh, then 1 MWh of zero emissions renewable energy should generate a 1,300 lbs/MWh credit that can be sold to a covered generation source. Credits generated in one state should be tradable to another, based upon the emissions rate standard of the state in which the zero emitting resource is located. This system also has the benefit of incentivizing the deployment of renewable resources in the states with the highest carbon emissions per MWh generated, yielding the greatest emissions reductions.

This accounting system is relatively straightforward, compliance is easily demonstrated, and it provides a predictable incentive for the deployment of non-emitting sources. In general, this method should produce calculated emissions savings that reasonably approximate reality. With the exception of extremely rare instances, zero emitting resources will directly displace covered generating resources (and not other non-emitting resources, such as nuclear, hydro, and other renewables) because fossil generating resources have significantly higher fuel costs and thus higher marginal production costs than non-emitting resources. Any deviation from the results of other calculation methods falls well within the uncertainty inherent in any prediction of future emissions reductions, given unpredictable factors such as fuel price changes, electricity supply and demand changes, and the addition and retirement of covered power plants.

Credit non-emitting resources using a marginal emissions calculation

Marginal generation and emissions data track which power plant or power plants are economically "on the margin" in each operating hour, and thus which generating units would have been dispatched down had demand been 1 MW lower or an additional 1 MW of low-cost supply (such as from wind) been available, allowing one to calculate the marginal emissions savings based on the heat or emissions rate for those marginal units. When combined with an hourly wind output profile for the region, that allows one to calculate wind's total emissions savings with a very high degree of accuracy.

Some Independent System Operators (ISOs) and utilities already calculate and publicly release data on marginal fuel mixes and emissions, and other utilities should already have the data

necessary to conduct such a calculation.[129] In addition, EPA's Avoided Emissions and generation Tool (AVERT), which is a marginal emissions calculation tool, is expected to be available in early 2014. It should provide users with an easy-to-use tool for calculating the marginal emissions savings for zero emissions investments in their geographic area. While other marginal emissions tools use an economic dispatch method to determine which units are on the margin at each point in time, the AVERT tool evaluates actual system dispatch for the previous year and statistically identifies which generators are on the margin based on their actual dispatch pattern.

Credit non-emitting resources using power system modeling

Power system modeling, often referred to as production cost modeling, is a tool that is widely used for utility and ISO planning purposes. This approach consists of building a detailed model of the power system from the bottom up, typically including transmission constraints and generator-specific data. The model dispatches power plants so as to minimize cost while meeting electricity demand in all hours or a sample set of hours. The model is run with and without a set amount of wind energy, and the difference in emissions can be calculated.

The main benefit of this approach is that it accounts for how the avoided emissions provided by wind will respond to changing factors on the power system, subject to the assumptions that are input into the model. However, conducting this modeling is expensive, difficult, and time-consuming, and the results are still highly dependent on assumptions about future fossil fuel prices, electricity demand, wind output profiles, and generator additions and retirements. A lower cost tool for conducting such calculations that is currently under development by state government officials is the Eastern Regional Technical Advisory Committee Electric Generating Unit Forecasting Tool.[130]

[129] *See, e.g.,* PJM, CO2Emissions Rates of Marginal UnitsAverage CO2 Emissions Rates, available at http://www.pjm.com/documents/~/media/documents/reports/co2-emissions-report.ashx and http://www.iso-ne.com/genrtion_resrcs/reports/emission/.

[130] Connecticut Department of Energy and Environmental Protection, Eastern Regional Technical Advisory Committee (ERTAC)Electric Generating Unit (EGU) Forecasting Tool, available at http://www.ct.gov/deep/lib/deep/air/siprac/2013/siprac_ertac_may_2013.pdf .

APPENDIX 25: ENFORCEMENT[131]

Clean Air Act Program Enforcement

The Clean Air Act (CAA) "establishes a comprehensive program for controlling and improving the nation's air quality through state and federal regulation." Typically, EPA sets the Federal floor by establishing air quality standards, performance standards, or emission guidelines, and States take the lead on implementation and enforcement of those standards and guidelines.

The mechanics of this Federal-State relationship is delineated by the U.S. Constitution. Under Constitutional principles, "[t]he Federal Government may not compel the State to enact or administer a federal regulatory program" or compel the State to enforce Federal law. However, the Supreme Court has "identified a variety of methods, short of outright coercion, by which Congress may urge a State to adopt a legislative program consistent with federal interests;" including the attachment of conditions to Federal funding, and the preemption of State regulation by Federal authorities.

The CAA's structure generally fits this constitutional framework. Congress conditioned Federal funding on State compliance with the CAA, and wrote conditional preemption triggers into the statute. States have the option of writing and enforcing plans approved by EPA. If they do not, EPA may occupy the regulatory field, and write a plan or enforce a State plan directly against regulated entities.

Enforcement of a State Plan under the Clean Air Act

Under Section 111(d) of the CAA, once EPA issues an emission guideline, each State is responsible for submitting a plan to meet the performance standard it develops to comply with EPA's guideline. Although Section 111(d) is a little-used provision of the CAA, State plans are a core element of the CAA, and every State has experience submitting plans to EPA. The typical CAA State plan is designed to meet national ambient air quality standards, under Section 110. Section 110 details the process of writing, submitting, implementing and enforcing a plan. In fact, Section 111(d) references this detailed description. Therefore, reviewing the Section 110 process is highly relevant for a discussion about 111(d) planning.

Once EPA sets an ambient air quality standard for pollutants such as ozone and sulfur dioxide, Section 110 directs each State to submit a plan to EPA, describing how the State will meet the

[131] Kate Konschnik and Ari Peskoe, Power Over Pollution, Exploring State Plan Enforcement Under EPA's GHG Power Plant Rule, available at http://blogs.law.harvard.edu/environmentallawprogram/files/2014/07/Power-Over-Pollution.pdf.

standard. EPA reviews each submittal to ensure it meets the Act's minimum requirements, as detailed by EPA in regulation.

To meet with EPA approval, each plan must demonstrate that the State has legal authority to enforce the plan's requirements. Over the years, EPA has issued general guidance to States on crafting "practicably enforceable" requirements under the CAA. Under this guidance, a practicably enforceable requirement must specify: (1) a technically accurate limitation; (2) the time period for the limitation; (3) a method to determine compliance (including monitoring, record keeping, and reporting); (4) the categories of sources covered by the rule; and (5) the consequences for failing to meet the requirement. By following this format, States can craft clear standards that put regulated entities on notice of their obligations and facilitate compliance.

Beyond the minimum requirements set forth by the CAA and EPA's rules, a State may write an implementation plan as it sees fit. EPA cannot mandate the passage of specific State laws or otherwise prescribe the substantive contents of a State plan. If a State does not submit a plan, or submits a plan that "does not satisfy [EPA's] minimum criteria," EPA must promulgate a Federal plan and implement it directly in that State. EPA may induce the State to write (and later, to implement) a plan by barring Federal highway funds to the State, or by tightening emissions offset requirements in regions that have not attained an air quality standard.

Once a State plan is approved, the State or EPA may enforce its requirements. Under Section 113, EPA may initiate an enforcement action against "any person" (including a State) that has violated a specific requirement or prohibition of a State plan or permit. This provision makes a requirement or prohibition in a State plan or permit "federally enforceable." The State, however, is charged with implementing the plan, and so is primarily responsible for determining compliance with plan requirements.

Courts expect the EPA to defer to the State's interpretation of its plan so long as it is reasonable and does not conflict with the Clean Air Act. If EPA finds that violations "are so widespread that they appear to result from a failure of the State to enforce the plan or program," EPA can step in and assume all plan enforcement in that State. In addition, EPA may require a State to revise a plan, if EPA determines that strategies in the existing plan will not achieve the Federal standard or guidelines. CAA Section 114 grants EPA broad information-gathering authority to facilitate this compliance monitoring.

Congress also empowered private citizens to file a civil action against "any person" who has violated or is in violation of a CAA emission standard or limitation. Citizens may not seek to enforce an emissions standard or air quality standard against a State, but may enforce a "specific strategy or commitment." While EPA's federal enforcement authority under Section

113 is broader than that for private citizens, both authorities (and State enforcement authority) can turn on the wording of State plans. Aspirational or "insufficiently clear" measures may not be enforceable by anyone.

Enforcement language in Section 111(d) grants EPA the "same authority" to enforce a State 111(d) plan "in cases where the State fails to enforce them as [EPA] would have under sections" 113 and 114. Likewise, private citizens may rely on Section 304 to file actions to enforce specific requirements of a Section 111(d) plan.

Enforcement in EPA's June 2014 Section 111(d) Proposal

When designing a plan to reduce power sector carbon intensity, most States will look to two State entities to implement and enforce the plans: the public utility commission (PUC) and State environmental protection agency. Typically, these entities are created by the legislature, so their authority is defined by statute. In some States, the State Constitution establishes the PUC, providing the PUC with a source of authority independent from the Legislature. Ideally, environmental agencies and PUCs will work together, with input from utilities, to craft a 111(d) plan. In most cases, environmental regulators will submit State plans under Section 111(d).

Depending on the State, different entities could be responsible for implementing each block. In States with a vertically integrated electric sector, utilities could implement measures in all four blocks. On the other hand, in restructured States, merchant generators, distribution companies, and third-party EE providers may be better suited to implement particular measures.

States must submit Section 111(d) plans to EPA describing how they will implement a 2030 performance standard and demonstrate interim progress between 2020 and 2029. The 2030 standard must be no less stringent than EPA's final emission guidelines. In its June 2014 proposal, EPA suggested ways State plans could approach enforcement, given potential roles for multiple non-emitting actors in meeting State performance standards.

A State could choose to hold EGUs responsible for achieving the entire performance standard, directing them to demonstrate compliance through Continuous Emissions Monitoring Systems (CEMS) reporting, or by holding sufficient credits for strategies taken at the plant and beyond the fenceline. Under this approach, which is similar to the northeastern Regional Greenhouse Gas Initiative (RGGI), a State would not write renewable energy and EE programs (and other beyond the fenceline measures) directly into the plan. Instead, these activities would be encouraged or required at the State level, to provide credits for EGUs. In such a scenario, only EGUs would be subject to federally enforceable requirements.

Alternatively, a State could choose a "portfolio" approach for its plan. Under that option, a State plan "could include enforceable carbon limits that apply to affected EGUs as well as other

enforceable measures, such as renewable energy and demand-side EE measures, which avoid EGU carbon emissions and are implemented by the state or by another entity." The limits and measures would be federally enforceable. The State would have to demonstrate to EPA that it has legal authority to enforce each element of the portfolio plan, by pointing to relevant statutes and regulations.

Finally, EPA is seeking comment on a "State commitment" approach, whereby a State would commit to implement and enforce renewable energy and EE programs and other measures under State law. These State commitments might account for some or all of a plan. In this scenario, these State programs would not be federally enforceable. Should a State not achieve expected results, EPA and citizen groups could enforce these programs only against the State, and not against any entity with an underlying State obligation to deliver renewable energy or EE results.

EPA's proposal also describes minimum enforcement features for any plan. These specific requirements track the requirements generally called for in CAA plans. First, regardless of the approach a State would take, any emission standard or measure described in the plan must be enforceable. A measure is enforceable if (1) a technically accurate requirement and the time period for the requirement are specified; (2) compliance requirements are clearly defined; (3) enforcement targets can be identified; (4) the measure is enforceable as a practical matter; and (5) EPA and the State can enforce the measure. Second, the State must demonstrate that all of the standards and measures, taken together, will achieve the 2030 performance standard. Third, if the State plan opts for the portfolio or State commitment approach, the plan must include program implementation milestones and identify corrective measures that will be taken if the initial measures fall short of expectations. Finally, after a plan is approved, the State must file annual progress reports with EPA.

States can draw from their experience submitting plans under Section 110 and EPA enforcement guidance to craft plans that work for them. They can also leverage existing environmental and power sector rules, programs, and expertise to minimize the effort of crafting a plan, and to embed Section 111(d) compliance into ongoing power sector planning and policy.

Below this appendix describes possible scenarios of responsible entities and legal mechanisms and approaches that might be used to address enforceability considerations under different types of state plans. These scenarios were developed to capture the range of entities that are currently implementing renewable energy deployment programs in states, or are subject to states requirements, such renewable portfolio standards. For each of these examples, this appendix describes current legal relationships between these entities and the state, and discusses possible legal instruments that might provide the state with the authority to ensure

that obligations in a state plan are met and to address failure to meet those obligations. The mechanisms discussed take different forms, but would specify three elements: obligations, compliance demonstration, and enforcement mechanisms.

A. Parties Regulated By The State Other Than Affected EGUS

One likely state plan scenario involves inclusion of enforceable obligations for state-regulated entities other than affected EGUs. An example of a state-regulated entity that is not an owner or operator of affected EGUs may be an electric distribution utility. These entities are typically regulated by a state public utility commission. An example of an enforceable state plan measure that might apply to an electric distribution utility is a compliance obligation under a renewable portfolio standard (RPS), or implementation of incentive programs for the deployment of renewable energy technologies.

Another example is where a vertically integrated, state-regulated utility implements a portfolio of enforceable actions under a state plan, which may include actions that apply directly to affected EGUs as well other actions such as renewable energy deployment programs. While vertically integrated utilities may own and operate affected EGUs, some of the measures implemented may require different enforceability mechanisms than an emission limit applied to an affected EGU.

1. Electric Distribution Utility With Obligations To Meet An RPS Pursuant To State Regulations

RPS requirements are typically implemented through state regulations, but may also be implemented through a public utility commission order. State RPS regulations provide legal instruments generally comparable in enforceability to regulatory emission limits applied to EGUs. These regulations typically specify compliance obligations, reporting, and enforcement. However, many state RPS regulations include alternative compliance payment (ACP) provisions that provide the utility with the option of making a payment in lieu of full compliance with the portfolio requirement. Thus, state RPS mandates may not guarantee achievement of a given level of renewable energy deployment during a plan performance period.

2. Vertically Integrated Electric Utility With Obligations Under A State-Approved Integrated Resource Plan

A utility integrated resource plan (IRP) may include a number of direct and indirect actions that affect EGU carbon emissions, and may also include compliance with RPS regulations. Broadly, IRPs may prescribe or authorize actions for which utilities can recover capital investments and

operating costs through regulated retail electricity rates. This creates strong financial incentives for implementing an action, but may not mandate an action.

For a state plan under this scenario, an enforceability consideration is whether an IRP, and related public utility commission orders, must include additional requirements to implement certain actions, beyond denial of rate recovery or a change to utility tariffs if a utility fails to meet specified obligations in the IRP. If so, this may require state legislation to provide additional authority to state public utility commissions in some states, or confer additional authority to other agencies (e.g., a state environmental agency).

B. Private Or Public Third-Party Entity Not Regulated By The State

Another state plan scenario involves public or private third-party entities with enforceable obligations under a state plan. A private or public third-party entity could be a utility entity that is not regulated by a state public utility commission, such as a municipal utility or a utility cooperative. It could also be a private non-profit entity established to renewable energy deployment programs. In most cases, since they often expend electricity ratepayer funds, such non-profit entities are created by state legislation and overseen by state public utility commissions or state-regulated private utilities.

An appropriate legal instrument or agreement applicable to such entities included in a state plan might include legal arrangements similar to those currently used to establish independent entities that expend electricity ratepayer dollars in multiple states. For entities not subject to state oversight, such a mechanism might also include mechanisms where an entity voluntarily submits to the authority of a state, pursuant to state statutory or regulatory authority specified in a state plan. Such agreements might be attached to a funding source. For example, the entity would voluntarily submit to such authority as a condition of receiving certain funds, such as state appropriated funds or funds collected through state-regulated electricity rates.

Alternatively, a municipal utility or utility cooperative might voluntarily submit to state authority as a condition of the state agreeing to let the entity implement a portfolio approach, in lieu of the application of certain direct carbon emission limits for affected EGUs owned and operated by such entities through a state regulation. In some cases, new state statutory authority might be enacted to support a state plan, specifying enforceable obligations for these private or public third-party entities under the plan.

C. State Agency, Authority, Or Entity

This state plan scenario involves a state entity with an enforceable obligation in a state plan. For example, state authorities in some states implement renewable energy deployment

programs. In this scenario, the requirement for the state entity would be an enforceable component of the state plan.

One type of legal arrangement that might be applied under this scenario is legislation directing state executive branch agencies or independent state authorities to follow through on obligations under a state plan. Such legislation might provide independent legal authority under state law to compel executive branch actions, or actions by independent state authorities under the plan, if obligations are not met. Depending on the form of legislation, this could also provide citizens with the ability to compel state action under state law, if obligations are not met under a state plan.

D. Multi-State Approaches

For states participating in a multi-state approach, the individual state performance goals in the emission guidelines would be replaced with an equivalent multi-state performance goal. For example, states taking a rate-based approach would demonstrate that all affected EGUs subject to the multi-state plan achieve a weighted average carbon emission rate that is consistent, in aggregate, with an aggregation of the state-specific rate-based carbon emission performance goals established in the emission guidelines that apply to each of the participating states. If states were taking a mass-based approach, participating states would demonstrate that all affected EGUs subject to the multi-state plan emit a total tonnage of carbon emissions consistent with a translated multi-state mass-based goal. This multi-state mass-based goal would be based on translation of an aggregation of the state-specific rate-based carbon emission performance goals established in the emission guidelines that apply to each of the participating states.

1. Multi-State Emission Budget Or Rate-Based Emission Trading Programs

The Regional Greenhouse Gas Initiative (RGGI) is an example of a multi-state approach to regulation of carbon emissions. The program works as a coordinated regional whole through a shared emission and allowance tracking system and allowance auction process, but is implemented in accordance with materially consistent stand-alone state regulations and individual statutory authority. These regulations recognize carbon allowances issued by other participating states for use by affected EGUs when complying with each state's emission limitation, but contain all the necessary components to administer the program requirements on an individual state basis. As a result, while the initiative is implemented regionally, each carbon emission budget trading program regulation is enforceable against affected EGUs at the state level and functions as a discrete program.

As a result, a multi-state emission budget trading program approach, such as RGGI, is enforceable in practice at the state level. A multi-state rate-based emission trading program could also be established in much the same manner as a multi-state emission budget trading program, and could therefore be enforceable at the state level.

2. Multi-State Portfolio Approaches

A multi-state portfolio approach could introduce novel enforceability considerations. If it were based on interdependent emission reduction strategies among states that are not tied to emission limits that directly apply to affected EGUs, the emission performance of affected EGUs in one participating state may be dependent, in part, on actions taken in other participating states. If a state (or states) failed to implement commitments under the multi-state plan, this raises the question of whether the EPA should address non-performance of one or more participating states in the context of failure to achieve the required level of multi-state emission performance under the plan, or instead enforce actions at the individual state level for those states that are failing to meet commitments under the multi-state plan.

Four Hypothetical Examples From States For Making An RPS Enforceable

Twenty-nine States, including Arizona, Illinois, and Pennsylvania, have RPSs that are enforceable under State law. Regulators and entities that comply with these mandates can benefit from their experiences implementing these programs. At the same time, current laws feature restrictions that limit the roles they can play in achieving the States' 2030 performance standards.

Pennsylvania's RPS was passed by the General Assembly in 2004. The law requires eighteen percent of the State's retail sales to come from "alternative" sources by 2021. Alternative sources include those fueled by coal gasification and coal waste, neither of which are renewable energy as described in EPA's proposed 111(d) rule. The General Assembly would need to act, to expand the program beyond 2021 or limit the program to zero- emission generation.

The Illinois RPS, passed by the Legislature in 2007, requires utilities to procure twenty-five percent of their energy from renewables by 2025. Procurement of renewable energy is falling short of expectations, primarily because a larger than expected number of utility customers switched to competitive suppliers.

This customer shift lowered utilities' renewable energy needs and undermined the design of the law. Regulators are constrained by the statute; new legislation is needed to fix these problems if the State is going to achieve a twenty-five percent statewide goal.

Regulators in Arizona have more flexibility than those in Pennsylvania and Illinois to extend and expand the State's existing renewable energy mandate. The AZ-ACC established the RPS based on its authority under the Arizona Constitution, so the RPS is not constrained by any specific statute. The AZ-ACC adopted an RPS that requires utilities to procure fifteen percent of retail sales from renewable generators by 2025. To increase the mandate, the AZ-ACC would have to follow ordinary rulemaking procedures and support the increase with sufficient facts. However, the AZ-ACC cannot apply the RPS to Salt River Project, so the mandate can only cover about sixty percent of the State's demand.

By statute, the FL-PSC may establish requirements for small-scale demand-side renewable generation such as rooftop solar. The FL-PSC relied on this authority to set modest goals for utilities in 2009. When considering new generation projects, the FL-PSC holds additional authority that allows it to give a strong preference to new renewable energy projects over fossil fuel alternatives. The FL-PSC could also increase the rate paid to renewable generators in standard offer contracts that utilities are required by law to offer.

The demand-side generation requirement could be an enforceable component of a 111(d) plan. In addition, the FL-PSC can commit to reevaluating the standard offer rate, in light of the 111(d) rule. However, the PSC could only exercise a preference for new renewable energy over fossil fuel generation when a utility proposes to construct new generation. Neither this authority nor an increase in the standard offer rate would guarantee a specific amount of renewable energy generation. If the FL-PSC could make a reasonable projection about future renewable energy deployment based on a higher standard offer contract and future proceedings to site new generation, it could include in its plan a milestone of a specified level of renewable energy by a date certain, as discussed in Block 2. EPA would likely require an enforceable measure to kick in automatically under the plan, if the milestone was missed.

APPENDIX 26: METHODS AND TOOLS FOR VERIFYING AVOIDED CARBON EMISSIONS FROM RENEWABLE ENERGY[132]

A key consideration for state plans is the process and requirements for quantifying, monitoring, and verifying the effect of renewable energy measures that result in electricity generation or savings. In the preamble, the EPA proposes that a state plan that includes enforceable renewable energy must include an evaluation, measurement, and verification (EM&V) plan that explains how the effect of these measures will be determined in the course of plan implementation. An EM&V plan will specify the analytic methods, assumptions, and data sources that the state will employ during the state plan performance periods to determine the energy generation and energy savings related to renewable energy measures.

As discussed in the preamble, an EM&V plan would be subject to EPA approval as part of a state plan. In the preamble, the EPA also discusses its intent to develop guidance for acceptable EM&V methods that could be incorporated in an approvable EM&V plan included as part of an approvable state plan. This section further elaborates on these considerations.

The appropriate type of EM&V for renewable energy programs and measures will depend on the state plan approach. Some has incorrectly posited that for states implementing a mass-based portfolio approach, the effect of renewable energy and measures in helping to achieve the required level of carbon emission performance under a state plan will be directly accounted for in reductions in the monitored carbon emissions from affected EGUs. However, this is only the case when the grid operating area is fully contained within the area bounded by the mass-based standard and there is only a small amount of interstate electricity exchange, which is likely only the case for Hawaii, some parts of Alaska, and potentially the ERCOT portion of Texas. In all other cases, under either a rate-based or mass-based system, renewable generation will offset emissions at EGUs outside of the regulated state, requiring interstate accounting measures like those outlined herein.

As a result, for nearly all rate- and mass-based plans, an approvable plan will need to include quantification, monitoring, and reporting requirements related to renewable energy requirements, programs, and measures incorporated in a state plan. These same interstate accounting issues are likely to apply to any compliance measures that include steps outlined in EPA's Building Blocks 2, 3, or 4 of the BSER.

[132] This section borrows from EPA, Technical Support Document (TSD) for
Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf.

Utilities and states have conducted ongoing EM&V of renewable energy measures and programs for several decades. These evaluations, which include quantification, monitoring and verification of results, generally rely upon a well-defined set of industry-standard practices and procedures. However, measurement approaches vary by state based on multiple factors, including the measure and program type being evaluated, the level and nature of regulatory oversight, the degree of state and utility experience with these measures and programs, and the overall magnitude of program impacts.

In the preamble, the EPA notes that it is not proposing to limit the types of renewable energy programs and measures that may be included in a state plan. More established types of measures and programs, such as RPSs, should not pose quantification and verification challenges, aside from the interstate issues discussed in Appendix 27.There are a number of approaches for quantifying the avoided carbon emissions resulting from renewable energy programs, requirements and measures in the electric sector. These approaches range from the application of basic avoided emission rates to using sophisticated electric sector models. Annual average avoided emission rates have often been used for rough approximations of carbon emissions avoided from reduced electric energy use. An annual average avoided emission rate assumes that renewable energy programs and measures reduce electric generation from all generating types on a proportional basis consistent with the generation mix in a region. A marginal emission rate represents the emission rate of an EGU or cohort of EGUs likely to be displaced by renewable energy measures (i.e., a marginal avoided emissions rate), based on the last unit(s) to come online to meet electricity load and the first unit(s) to be brought offline when electricity load is reduced.

The primary question underlying estimating carbon emissions reductions from renewable energy measures is the determination of which electric generators will be displaced (i.e., cease generation or reduce generation output) in the presence of incremental EE/renewable energy. This section briefly describes a range of avoided emission rates approaches, their underlying assumptions, and considerations associated with the use of different avoided emission rate approaches.

A. Avoided Emission Rate Approaches

i. Average Emission Rate Approach

An average emission rate (typically expressed in tons of carbon/MWh) is usually understood to mean the average of all generators' emissions rates, weighted by annual generation. Because the average emission rate puts the sum of all generation in the denominator (as MWh), including renewable generating resources, the rate fundamentally assumes that renewable energy reduces all generating types by an equal proportion, regardless of their type or

contribution to the margin. EGUs are generally dispatched on an economic merit order, where the least-cost EGUs (on a variable cost basis) are dispatched first, and higher cost resources are dispatched later. Since wind and solar resources operate at a very low cost, they are generally dispatched before most fossil units. Under current and historical operating conditions, there are few circumstances in which non-fossil resources reduce output in the presence of lower demand. As a result, in states with a moderate contribution of non-emitting resources to total generation, the average emission rate may be lower than could reasonably be expected for reductions from renewable energy programs and measures. Conversely, in states that have significant baseload fossil generation and few non-emitting resources, a state-average emission rate may reflect an emission rate that is too high. This may occur by incorporating emissions from coal-fired EGUs that are less likely to reduce generation with a reduction in electricity load, compared with other lower-emitting fossil fuel-fired EGUs.

ii. Marginal Emission Rate Approach

A marginal emission rate represents the emission rate of the EGU or cohort of EGUs likely to be displaced by EE/renewable energy (i.e., an avoided emission rate). A marginal unit is the highest-cost unit dispatched at any point in time. Under most circumstances, and at any given time, the marginal unit is the last unit to be brought online to meet electricity demand and the first unit to be brought offline when electricity load is reduced. Due to constraints on generating unit ramp rates and transmission availability, it is not uncommon for multiple units to be dispatched incrementally simultaneously, thus creating a cohort of marginal units. Marginal units change on a moment-to-moment basis, determined by load requirements and the variable cost of each unit available to generate another unit of power. A marginal unit can either be a unit brought online to meet load or may be an EGU that is already operating, but that is dispatched at a greater level of output to meet load.

The marginal emission rate (marginal) can be expressed for any given hour (t) as a function of the difference between two distinct cases – the reference case (i.e., in the absence of incremental EE/renewable energy programs and measures) and the change case, where the EE/renewable energy programs and measures have been implemented. A formula describing this rate is written as follows:

The magnitude of the renewable energy program and the renewable energy load impact shape is a key element in determining marginal emissions reductions. In order to obtain a valid estimate of the emission reduction effect of a renewable energy program, an annual marginal avoided emission rate should be calculated that reflects the renewable energy program's load impact shape and magnitude. This annual marginal avoided emission rate may then be applied to other renewable energy programs with similar load impact shapes and magnitudes.

B. Tools for Estimating Avoided Carbon Emission Rates and Avoided Carbon Emissions

i. Calculation Tool Method

The EPA has developed a user-friendly tool to estimate the emission reduction impacts of renewable energy requirements, programs and measures. The "Avoided Emissions and Generation Tool" (AVERT) was developed to help air quality planners quantify NOx and SO2 emission impacts, as specified in EPA's Roadmap for Incorporating EE/renewable energy Programs in NAAQS SIPs. AVERT can also be used to quantify the displaced carbon emissions of renewable energy measures within the continental United States. AVERT is available without charge at http://epa.gov/avert/.

The AVERT method uses historical hourly emissions rates based on recent EPA data on fossil fuel-fired EGUs' hourly generation and emissions reported through EPA's Acid Rain Program. This method couples historical hourly generation and emissions with the hourly load reduction profiles of renewable energy programs and measures to determine hourly emissions reductions on the margin. AVERT can be used to estimate renewable energy-related emissions reductions in a current or near-future year. However, AVERT estimates for current or future years are based on historical behavior rather than projected economic behavior. As a result, AVERT does not use projections of future fuel or electricity market prices that affected EGU dispatch, and is therefore not an appropriate tool for longer-term projections.

Users of AVERT can analyze how the different load profiles of a variety of wind and solar technologies, affect the magnitude and location of carbon emissions at the county, state, and regional level. AVERT has a flexible framework with a simple user interface designed specifically to meet the needs of state air quality planners and other interested stakeholders.

AVERT may be used to derive marginal emission reductions from historical generation and emissions data, which can be used to derive a marginal avoided carbon emission rate. However, AVERT does not quantify average emissions rates. AVERT approximates historical dispatch behavior using a statistical algorithm. It does not represent transmission constraints, or significant changes in grid structures or future economic conditions. To estimate a recent historical marginal carbon emissions reduction from existing renewable energy programs or measures, a user would input the MWh related to results from renewable energy programs or measures (representing either MWh of electricity savings or MWh of generation) in a representative historical baseline year as a positive increment to electricity load, and record the emissions incrementally added in the tool. The calculated marginal carbon emission rate is the incremental carbon emissions added by AVERT, based on historical EGU dispatch patterns, divided by the incremental MWh of renewable energy savings or generation input to AVERT as

an increase in electricity load. This approach reflects the marginal impact of renewable energy measures based on historical recorded patterns of emissions and generation.

ii. Electricity Sector Modeling Method

Quantification of avoided carbon emissions from EE requirements, programs, and measures can be achieved through retrospective modeling approaches. Models can be used to calculate avoided carbon emissions by comparing actual realized EGU carbon emissions to projected EGU carbon emissions that would have occurred in a historical reference case that does not include implementation of the renewable energy that is being evaluated. The appropriate choice of model depends on the look-back period. For short look-back periods of one to three years, an electricity system simulation dispatch model can determine the marginal generation contribution to emissions in a historical reference case (i.e. absent incremental EE/renewable energy programs). Over the short term, simulation dispatch models properly account for EGU economic dispatch considerations, such as fuel and emission allowance prices, and operational constraints, such as ramp rates, outages, and heat rate curves. Look-back periods beyond three to five years would benefit from use of a utility-scale capacity expansion and dispatch planning model to understand the change in build out of new generating capacity, as well as transmission and distribution infrastructure, and its impact on generation between the historical reference case and actual realized historical outcome.

iii. Electricity System Simulation Dispatch Models

Quantifying the carbon emissions reductions achieved by renewable energy measures through modeling of a near-term look-back period requires a counterfactual historical reference case model run, which examines how the electric system would have operated in the absence of the renewable energy emission reduction measures under consideration. The emissions projected in this model run may be compared against actual realized emissions during the historical period. The look-back model should be calibrated by running the same model with the renewable energy measures in place and comparing the outcome of that model against realized generation and emissions at an appropriate spatial scale.

Simulation dispatch models can be readily run for historical years provided they are loaded with the accurate input assumptions, including actual historic fuel costs, emission allowance prices, and transmission constraints. While these models will not choose economically optimal EGU retrofit or retirement decisions, they will provide a change in EGU dispatch and the associated change in emissions across a large region in a more detailed manner than capacity expansion planning models.

Simulation dispatch models may be most relevant as part of ex-post plan reporting, for estimating the avoided carbon emissions from affected EGUs that occurred as a result of EE/renewable energy measures included in a plan, during a specified plan reporting period.

iv. Utility-Scale Capacity Expansion and Dispatch Planning Models

Quantifying the carbon emissions reductions achieved by renewable energy measures through modeling over a longer-term look-back period requires a counterfactual historical reference case model run, which examines how the electric system would have operated and have been built out, in the absence of the renewable energy measures under consideration. The critical difference between this type modeling approach and the use of a simulation dispatch model is the assessment of changes made at the "build margin" – i.e., new additions to generating capacity that may have been avoided or compelled, or retirements of existing units that may not have occurred in the reference case. The emissions projected in this model run may be compared against actual realized emissions during the historical period. The look-back model should be calibrated by running the same model with the renewable energy measures in place and comparing the outcome of that model run against actual realized generation and emissions at an appropriate spatial scale.

Capacity expansion and dispatch planning models could be run for a longer-term historical period to better reflect what the electricity system would have looked like in the absence of the renewable energy measures. When renewable energy resources have been added over the course of three to five years, these models will reflect how these resources have avoided new power plants, retrofits, or fuel switch decisions. Some models may also be able to reflect avoided transmission investments.

Capacity expansion and dispatch planning models may be more relevant than simulation dispatch models for projecting the emission performance that will be achieved by affected EGUs under a plan. As discussed below, these models are able to assess both the "operating" and "build" margins that impact EGU carbon emissions as the result of renewable energy measures.

APPENDIX 27: REPORTING FOR RENEWABLE ENERGY PROGRAMS AND MEASURES[133]

Typical Reporting and Compliance Requirements under State RPS

Each state has different reporting and compliance requirements for its RPS, but all states with mandatory RPS require obligated entities to provide compliance reports to the state PUC or equivalent state oversight agency. Compliance obligations are typically specified in authorizing legislation, regulations, or PUC orders. Compliance is typically on an annual basis, and includes a list of required reporting elements. Some states also require load-serving entities to provide an implementation plan describing how they will comply with the state RPS rules in the future.

Data requirements for reporting may vary based on the design and implementation of an RPS. However, for nearly all state RPS requirements, annual compliance report data is based on measurable electric generation results and verified through tracking system data. In some states, compliance reports may also include state-level projections of renewable energy generation resulting from current or proposed state RPS policies.

The most common form of tracking system for RPS compliance is a regional or state REC tracking system or registry. These systems track RECs for both the compliance and voluntary markets. RECs are typically provided with a unique identification number and may be certified by a third-party verifier. Annual compliance reports containing REC data typically include the number of RECs the utility or load-serving entity procured and retired, what renewable energy generators supplied the RECs, and how much the utility spent on procuring the RECs.

Typical Reporting for Renewable Energy Deployment Programs

Renewable energy deployment programs involve the provision of a payment or credit for a renewable energy project, or for a quantified amount of electricity generation, in the case of performance-based incentives. Qualification of eligible projects and payment for qualifying electric generation (or related attributes) require reporting of electric generation and other projects for each specific program. Program administrators use this information to track program progress and report to PUCs or other oversight entities. The summary below addresses typical reporting required for utility-administered programs, as well as programs administered by non-profit entities and state agencies and authorities.

[133] This section borrows from EPA, Technical Support Document (TSD) for
Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf..

- **Reporting for utility administered renewable energy incentive programs**

Some utilities offer incentives to electricity consumers to accelerate the deployment of renewable energy technologies, such as rebates, and feed-in tariffs. Utilities administering FITs will track the number of customer contracts, resource type, capacity of each contracted project, MWh generated, and utility expenditures for that generation under the tariff. Utilities administering a rebate or loan program are more likely to track the number of customer participants, the type and size of the projects, the cost of the projects, and the amount of rebates paid or loans provided. Measuring the electric generation output of these projects may not necessary to evaluate program status.

Many of these renewable energy deployment programs are developed as part of requirements by PUCs, and therefore utilities must provide reporting on a routine basis to the PUC about program expenditures and outcomes (typically quarterly or annually). These records should be readily accessible to states for estimating the impacts of their renewable energy deployment programs included in a state plan. However, some utility incentive programs are administered by distribution utilities that are not regulated by a state PUC (e.g., municipal and cooperative electric utilities). In these instances program reporting data may not be readily available to a state, unless separately required by a state if such programs are included in a state plan.

Renewable energy deployment programs may be designed and implemented under the auspices of a utility integrated resource plan (IRP). IRPs document how a utility will meet forecasted annual peak and energy demand over a defined period of time through a combination of supply-side and demand-side resources. IRPs are typically mandated through state legislation or PUC orders and may include renewable energy generation planning, particularly as it relates to compliance with in-state requirements. IRPs are typically submitted on an annual basis to a state utility commission and/or other state entity, and address a multi-year period (e.g., 10 years is a typical period for an IRP). IRPs are a good resource for tracking and forecasting utility renewable energy developments within a state. Though they may not include renewable energy production data, data included in IRPs may help states project renewable energy generation trends in subsequent years, and are a good resource for the development of state plans.

- **Reporting for renewable energy incentive programs administered by non-profit or state entities**

State renewable energy financial incentives are typically administered by a PUC, state revenue agency, other state agency (e.g., state energy office), or a private non-profit or for-profit entity contracted by a state agency. These programs may include an administrative process for pre-qualification, which in some instances may be competitive (e.g., performance-based contracts)

or available on a first-come, first-serve basis (e.g., capped production tax incentive). Applications to incentive programs are good sources of data, and program administrators usually compile data from approved applications to track program status. Additional reporting data is also typically required to receive the incentive. For example, a production-based tax incentive is calculated based on the amount of electricity generated by a renewable energy installation, which may be tracked and verified through utility or third-party metering protocols. These reports, which are currently used for internal reporting for budgetary control and performance evaluation, and to track other performance metrics for regular public program reporting, could form much of the basis for reporting under state plans for such measures.

- **Considerations for Reporting Requirements for Renewable Energy Measures in State Plans**

State renewable energy requirements, such as RPS and FITs, and incentive programs typically include robust reporting requirements. For nearly all state RPS requirements, annual compliance report data is based on measureable electric generation, using revenue-quality meters, and verified through tracking system data. Other requirements and programs that provide performance-based payments and incentives, such as FITs, performance-based tax incentives, also require reporting of metered generation output. State and utility incentive programs where payment of incentives is not based on electric generation may not currently be sufficient for reporting under a state plan. Additional reporting requirements may be necessary if these programs are included as enforceable measures in a state plan.

In addition to the reporting states currently require for renewable energy requirements and programs, supplemental reporting information or adjustments may be necessary for state plans to demonstrate the avoided carbon emissions associated with these requirements, programs, and measures. States may need to require additional reporting detail, such as the location of renewable energy generating units that supplied output used to comply with a state RPS. Additional reporting detail about when renewable energy was generated may also be valuable for estimating the avoided carbon emissions from renewable energy generation, especially if a marginal avoided emission rate approach is used. This includes reporting of the typical generating profile of a renewable energy generating unit, group of units, or renewable energy resource type. For distributed renewable energy resources, reporting of the MW capacity of generating systems that are installed as a result of state requirements or programs during a reporting period would also be useful for estimating avoided carbon emissions. These distributed resources, since they are located “behind” the utility meter at a customer location, have a similar effect in reducing the demand for electricity supplied from the grid as end-use energy efficiency measures.

Example reporting requirements that provide sufficient data for estimating the avoided carbon emissions from renewable energy requirements and programs might include the following:

- Metered MWh generation, using a revenue quality meter, or estimates of annual output for small systems below 10 kW in capacity
- MW capacity of "behind-the-meter" distributed renewable energy generating systems added during a reporting period as the result of a state program
- For renewable energy resources reported, including through REC data, the typical generating profile of a renewable energy generating unit, group of units, or renewable energy resource type
- For REC data, information including the following generator attributes: type of resource (e.g., wind), plant-level emissions, geographic location, grid operating area to which the output is being physically delivered as this determines which conventional generators are having their output displaced and thus the emissions savings created, nameplate capacity (MW), commercial operation date, ownership, and the eligibility for RPS compliance or voluntary market certification

APPENDIX 28: RENEWABLE ENERGY CERTIFICATES AND TRACKING SYSTEMS[134]

Renewable energy has been tracked and traded for nearly 20 years in the United States, and during this time, integrated electronic tracking systems and standardized approaches to trading and establishing ownership of renewable energy have been developed. Using renewable energy as part of 111(d) compliance strategies will be made possible by the continued use of existing tools in renewable electricity markets to assure regulators that these resources are actually producing electricity and that it is being counted correctly.

In order to determine how renewable energy should be accounted for in a state's 111(d) Plan, it is important to understand the existing policies and rules governing the use and claims made about renewable energy production. The use of this existing infrastructure can provide essential support for the inclusion of renewable energy as a compliance component of 111(d) Plans.

Renewable Energy Certificates: Defining the Environmental Benefits of Clean Energy Generation

The REC is the basis upon which ownership rights to renewable electricity are documented and traded across the United States. A REC is created when one MWh of renewable electricity is generated, and the REC represents the environmental attributes or the "renewable-ness" of that MWh of energy.

The precise content of a REC is typically defined by state law, but usually includes all ownership rights to the attributes of renewable electricity generation, including the carbon-free emissions profile of the generation. Under Kansas law, for example, a REC that is used towards the state renewable energy requirement is defined as "a certificate representing the attributes associated with one megawatt-hour (MWh) of energy generated by a renewable energy resource that is located in Kansas or serves ratepayers in the state." By assigning a unique serial number to each MWh of renewable electricity generation, the tracking systems have the capability to ensure that each REC is used (or "retired") only once. A REC can be sold separately from the underlying electrical energy. Thus, one MWh of wind generation becomes a REC, (a tradable MWh of wind attribute) and one MWh of energy.

[134] This section borrows from EPA, Technical Support Document (TSD) for
Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf..

When a REC is sold separately from the underlying MWh of electricity, the remaining MWh is called "null power" and is no longer considered renewable. Null power is described by the EPA in the Clean Power Plan Proposed Rule: State Plan Considerations Technical Support Document: "Once the RECs are separated from the power generated, the power has no attributes associated with it and is considered generic or 'null' power." If it is represented as renewable—while the REC is used or sold elsewhere—that is a "misrepresentation," often simply referred to as "double counting," and must be guarded against, as it can result in two states taking credit for the same unit of renewable generation.

In its Clean Power Plan, the EPA "recognizes the complexity of accounting for interstate effects associated with measures in a state plan in a consistent manner, to allow states to take into account the CO_2 emission reductions resulting from these programs while minimizing the likelihood of double counting."

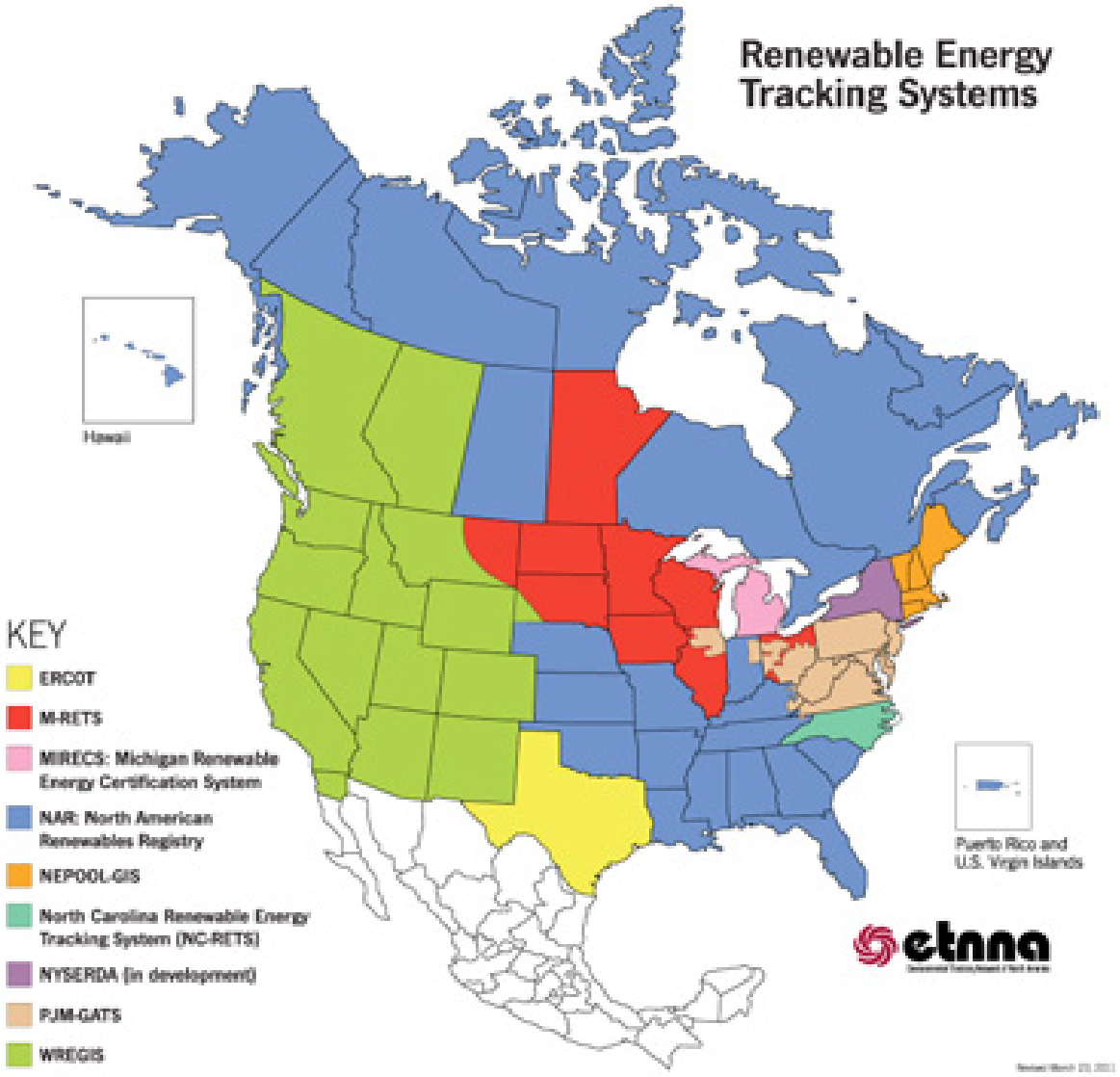
REC trading is a commonplace occurrence in electric markets today; more than half the U.S. states currently have RPSs. Federal and state agencies, regional electricity transmission authorities, non-governmental organizations, trade associations, and electricity market participants recognize and rely on RECs to convey the environmental attributes of renewable electricity generation, including the legal right to claim delivery and usage of renewable energy. RECs are also used around the country to track renewable energy acquisition and use in voluntary markets, which exist in all states. Individuals or companies that voluntarily purchase renewable energy, and load-serving entities that are required to do so, need a way to demonstrate that they have purchased a MWh of renewable energy and that they, and no one else, have the ownership rights to it. The same basic rules and definitions exist in the voluntary market as those found in RPS markets and disclosure programs: RECs and tracking systems are the basis for tracking and demonstrating ownership. Whether a utility customer is using renewable energy as a result of its utility company's regulatory obligation or as a result of the customer's voluntary purchase, each renewable MWh must be delivered and claimed only once.

Tracking Systems: a Reliable and Convenient Tool for State Regulators

Renewable energy certificate tracking systems are regional electronic databases that provide a platform for producing, managing, and retiring RECs, and also for ensuring that each REC is counted only once. There are ten regional REC tracking systems in operation in the U.S. These systems provide a valuable service to state regulators and to market participants. Retail electric companies and regulators use these systems to demonstrate compliance with state policies like an RPS.

Other renewable energy market participants rely on these systems for quality assurance. The tracking systems are intended to serve the needs of states and market participants and can be modified to suit the needs of regulators. Tracking systems are essentially databases and, in a simplistic sense, work like checking accounts. Account holders can view and use the RECs currently in their accounts and transfer RECs to other account holders, but they are unable to view RECs in another user's account. Generators can register in their regional tracking system and have REC accounts. Retail electricity companies and other would-be purchasers have accounts as well. For each MWh of electricity produced, a certificate is issued and deposited into a generator's account. When the generator sells the REC, it is transferred from the generator's account into a buyer's account. The REC exists in only one account at a time. Given the manner in which these tracking systems operate, it is possible to substantiate a claim about REC ownership and ensure proper accounting through the relevant tracking system.

Each REC has its own serial number and contains various descriptive "certificate fields." Certificate fields include information such as plant name, month and year of generation, generation unit location, and program eligibility, e.g. for Connecticut, Oregon, and New Jersey Renewable Portfolio Standards.


Renewable Energy Tracking Systems
Hawaii
Puerto Rico and U.S. Virgin Islands
KEY
ERCOT
M-RETS
MIRECS: Michigan Renewable Energy Certification System
NAR: North American Renewables Registry
NEPOOL-GIS
North Carolina Renewable Energy Tracking System (NC-RETS)
NYSERDA (in development)
PJM-GATS
WREGIS
etnna

APPENDIX 29: POTENTIAL APPROACHES FOR THE TREATMENT OF INTERSTATE EFFECTS[135]

This section surveys the range of potential approaches that could be applied for individual state plans, as well as approaches that could be applied on a regional basis. The surveyed approaches include those proposed, as well as alternatives. These basic approaches, including variants of some approaches, include:

- State may only claim the impact of a measure in reducing in-state EGU carbon emissions.
    - For plan measures such as renewable energy regulations and programs, estimating the avoided carbon emissions from in-state versus out-of-state EGUs could be addressed through modeling, other analytical tools, or proxy metrics (e.g., net import factor). EPA seems unlikely to pursue this approach, as in any state with interstate power flows this would greatly understate the actual emissions reductions attributable to renewable energy, a large share of which occur in other states.
- State that implements the measure claims the emissions reduction benefit.
    - Under this approach, the state that implements the measure (e.g., renewable energy regulations or programs, or an emission limit that addresses out-of-state generation) claims the avoided carbon emissions, regardless of where they occur. EPA seems likely to pursue this approach for individual state plans. To avoid double-counting under either a rate-based or mass-based approach, this will require ex post "trueing up" emissions in all affected states. The state that purchases the renewable energy will be credited for the total emissions reductions, while states with fossil-fired power plants that had their emissions reduced because of that renewable energy will lose credit for those emissions reductions as they were not due to actions of that state.
- Cooperative multi-state accounting.
    - Multiple states are allowed to mutually agree to how they will distribute avoided carbon emissions from state plan measures (e.g., renewable energy regulations or programs, or an emission limit that addresses out-of-state generation) across their respective EGU fleets. Avoided carbon emissions are distributed among

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states under an agreed-upon formula they derive – an accounting "credit" in one state for out-of-state avoided carbon emissions is complemented by an accounting "debit" in the other state where the avoided carbon emissions occurred (i.e., through an increase in reported carbon emissions or carbon emission rate).

- Tradable regional renewable energy credit market.
    - This is a variant of the multi-state accounting approach, which could be applicable where multiple states in a region are implementing rate-based state plans. Under this approach, renewable energy regulations and programs that meet EM&V guidelines or requirements are allowed to generate credits, based on MWh of energy savings or renewable energy generation. These credits, which are denoted in avoided tons of carbon or avoided MWh, could be used by affected EGUs toward demonstration of compliance with state rate-based carbon emission limits within a designated region. EE/renewable energy credit issuance could be on a project and/or program basis. State accounting for interstate emission effects would be addressed through the credit market and determined based on credits held by affected EGUs.
- Regional demonstration by states of EGU emission performance.
    - States are allowed to regionally demonstrate emission performance by affected EGUs. States jointly demonstrate emission performance for affected EGUs, in terms of total carbon emissions (under a mass-based multi-state plan) or weighted average carbon emission rate (under a rate-based multi-state plan).
- The EPA jointly assesses regional performance achieved in aggregate by all individual state plans in a grid region.
    - The EPA assesses interstate effects on a regional basis during the plan review process. The EPA requires states to agree to an interstate attribution process only if necessary (i.e., if regional performance falls short of the aggregated identified performance levels for affected EGUs in individual state plans). Alternatively, the EPA requires plan revisions if regional performance falls short of the aggregated regional performance level (i.e., the aggregated identified performance levels for affected EGUs in individual state plans).

The table below includes illustrative examples of the application of some of the different approaches for addressing interstate emission effects summarized above. The table explains how these approaches might be applied in different state plan contexts. The illustrative examples consider the range of approaches states are currently using to implement electricity sector policies, which all interstate effects, such as multi-state emission budget trading

programs, are used by regional renewable energy certificate markets for state RPS compliance programs.

State claims reductions from in-state EGUs	State that implements measure claims reductions	Regional agreed-upon attribution process	Regional demonstration
EE program in Virginia saves MWh	New Jersey RPS yields new RE capacity and RE generation throughout PJM	States mutually agree to an accounting approach for interstate effects	RGGI states demonstrate emissions performance jointly on a multi-state basis

• VA is a 35% net annual importer of electricity.
• VA estimates the effect that the reduction in MWh demand in VA has on generation in PJM and related avoided CO_2 emissions.
  • Could be done through modeling, other analysis tools (e.g., EPA AVERT tool), or proxy estimate (e.g., net import factor).
• For example, using proxy estimate:
  • Energy: MWh savings x 0.65 (proxy net import factor) = avoided VA MWh generation
  • CO_2 Emissions: MWh savings x 0.65 (proxy net import factor) x PJM average or marginal CO_2 emission rate = CO_2 emissions avoided from EGUs in VA
	• Utilities in NJ purchase RECs to meet RPS requirement.
	• RECs held by NJ utilities to meet RPS requirements represent MWhs of generation from RE in multiple states in PJM (e.g., wind turbines in PA and WV).
	• To demonstrate that the CO_2 emission rate requirement for affected EGUs in NJ is met, NJ applies MWh of RE generation used to meet NJ RPS (based on RECs held NJ utilities) to adjust CO_2 emission rates of affected EGUs in NJ.
		• Assume a mix of states in a region, with different states using mass-based and rate-based portfolio approaches
		• States agree to attribute effects of RE through the existing regional REC market used for compliance with state RPSs; RE effects are attributed based on the party that holds RECs
		• States with a mass-based approach add CO_2 emissions to their reported emissions total, based on any out-of-state transfer of RECs
		• States with a rate-based approach reduce CO_2 emission rate based on amount of RECs held (including RECs from out-of-state RE generation)
		• As a result, a "credit" in one state is complemented with a "debit" in another state
			• A mass-based goal would be based on a translation from the aggregated rate-based goals for each of the 9 participating RGGI states
			• A weighted-average rate-based goal is calculated for the 9 RGGI states and then this is translated to a joint mass-based goal
			• State emissions may vary among states, provided the multi-state mass emissions level is met
			• This type of multi-state demonstration will be necessary for programs like RGGI, where state-by-state emissions may vary based on CO_2 allowance market prices and EGU marginal abatement costs

1. State May Claim the Impact of a Measure on carbon Emissions from Affected EGUs Within its Borders

Under this approach, the effect of a state measure could be applied to help demonstrate emission performance by affected EGUs in the state if it has the effect of avoiding carbon emissions from those in-state EGUs. This approach is not recommended as it will greatly understate the actual emissions reductions produced by renewable energy, a large share of which occur outside of the state.

Estimating the effect of renewable energy measures on in-state versus out-of-state EGU carbon emissions could be addressed through modeling, other analytical tools, or proxy metrics such as a net import factor. Modeling could be used to assess the interstate effects of state measures on EGU carbon emissions, both for projections of emission performance under the plan and ex post demonstration of performance achieved. Under this approach, both projected plan performance and performance achieved is assessed on a state-by-state basis.

2. State that Implements the Measure Claims the Emission Effects

Under this approach, the state that implements the measure (e.g., an RPS, or an emission limit that addresses the attributes of purchased electricity from out-of-state generation) claims the avoided carbon emissions, regardless of where they occur. If the avoided carbon emissions from state plan measures at the regional level are greater than avoided emissions from affected EGUs within the state, these interstate effects would need to be accounted for and applied to affected EGUs within the state. This could be achieved through an administrative adjustment by the state, or through a tradable credit system that is limited to affected EGUs in the state.

Under an administrative adjustment approach, out-of-state avoided emissions would be applied to the in-state EGU fleet by the state program administrator when determining average fleet carbon emission rate or tonnage carbon emissions. Under a tradable credit approach, credits would be issued for all avoided carbon emissions resulting from applicable state plan measures, without regard to where the avoided emissions occurred. Since the tradable credit system would be limited to affected EGUs in the state, use of the credits by affected EGUs when demonstrating compliance with a rate-based emission limits would functionally apply the avoided carbon emissions to the state that was responsible for the measure.

This approach provides a clear policy signal and incentives that reward state actions that reduce EGU carbon emissions on a system-wide, regional basis. However, this approach requires accounting among states in a grid region to avoid double counting of emission impacts among states. That accounting will likely include an ex ante analysis during plan development and approval, and an ex post analysis during the process of trueing up actual emissions reductions for compliance purposes. The marginal emissions calculation and power system modeling approaches outlined earlier in the Appendices would form the basis for this analysis.

- *Ex ante projections of plan performance*

To project the effect of renewable energy measures under a state plan, a dispatch model would be applied to a grid region to estimate the marginal or average avoided carbon emissions impact of the plan measures on a state-by-state basis within the region. To the extent that a state's renewable energy measures were projected to avoid carbon emissions from its own in-state EGUs, these effects could be applied to meet the required level of carbon emission performance for affected EGUs in the state plan.

- *Ex post demonstration of plan performance*

To assess the state-by-state avoided carbon emissions that result from the implementation of a plan, a dispatch model would also be applied to a grid region, on a retrospective "look-back" basis. This modeling would assess the avoided carbon emissions resulting from reported MWh

of reported renewable energy generation, as a result of implementation of renewable energy measures in the plan. Under a rate-based plan approach, modeled estimates of avoided carbon emissions, based on reported renewable energy generation, could be applied through an administrative adjustment by the state program administrator or through the issuance of tradable renewable energy credits within the state. For ex post demonstration under a mass-based plan approach, performance would be determined based on reported stack carbon emissions from affected EGUs.

3. Cooperative Multi-State Accounting of Interstate Emission Effects

Under this approach, multiple states would be allowed to mutually agree on how they will distribute avoided carbon emissions from renewable energy across their respective EGU fleets. Avoided carbon emissions would be distributed among states according to a formula that they specify. Based on this agreed formula, each state would adjust its demonstrated emission performance by affected EGUs accordingly. In effect, a "credit" for out-of-state emission effects in one state would be complemented by a "debit" for such effects in another state.

This approach provides states with discretion about how to attribute interstate effects, based on their situations and policy preferences in a grid region. Importantly, this approach also avoids the potential for double counting of interstate emission effects among states. However, this approach is premised on regional collaboration among all states in a grid region. Not all states in a grid region may be willing to cooperate in implementing such an accounting approach.

4. Tradable Regional EE/renewable energy Credit Market

Under this approach, renewable energy actions that meet applicable quantification, monitoring, and verification requirements would be issued tradable credits that could be applied by affected EGUs to their reported carbon emission rates when demonstrating compliance with an emission limitation in a state plan. A credit issued in one state could be used by an affected EGU in another state toward meeting its respective rate limit.

A regional credit market would be premised on agreement among states that credits issued throughout a region could be used in multiple states. The distribution among different states of usage of the credits would be determined by economic factors such as credit prices and EGU marginal emissions abatement costs. In effect, accounting of interstate effects would be allocated among states based on prices in the credit market.

This approach is applicable if multiple states are implementing rate-based state plans. Where states were implementing a mix of rate-based and mass-based state plans in a shared grid region, this approach could lead to double counting of emission effects among plans, unless this

market-based renewable energy credit approach was also coupled with a cooperative accounting agreement among states. In this latter instance, for states implementing a mass-based approach, where credits for avoided carbon emissions are transferred to affected EGUs located in another state for compliance purposes, the state from which credits were transferred would adjust its reported carbon mass emission from affected EGUs when demonstrating achievement of the required carbon emission performance level by affected EGUs identified in the state plan.

5. Regional Demonstration by States of Emission Performance

Under this approach, multiple states would demonstrate carbon emission performance by affected EGUs on a regional basis. This could allow states in a contiguous grid region to implement a portfolio of renewable energy measures without the need for state-by-state attribution of avoided carbon emissions. Instead, states would assess the impact of state measures in avoiding carbon emissions from the fleet of affected EGUs in the multi-state region.

This approach creates incentives for the implementation of system-based approaches that collaboratively reduce EGU carbon emissions on a regional basis, while also avoiding the need to attribute interstate emission effects among states. However, regional collaboration will require more time for the development of multi-state plans.

6. Assessment of Interstate Effects by the EPA in the Course of State Plan Review

Under this approach, the EPA would evaluate interstate effects on a regional and ex ante basis during the plan review process. The EPA would assess the emissions performance of affected EGUs on a regional basis, considering the measures contained in the group of state plans for a respective grid region. Under this approach, the EPA might conduct an analysis that considers all of the state program measures together on a combined basis and evaluates projected emissions performance achieved by affected EGUs in the region.

To the extent that all affected EGUs in a region are projected to achieve the required level of performance represented in individual state plans, or are projected to achieve an aggregate regional level of performance consistent with the level of required performance included in all state plans in the region, instances of double counting of interstate effects among states are less important. The EPA could indicate as part of plan approval that it will review actual emission performance achieved by affected EGUs during the plan period on a regional basis.

A similar review process could be conducted ex post for purposes of trueing up emissions reductions, using more detailed and precise analysis of the emissions reductions attributable to renewable energy based on actual grid dispatch data and other empirical information.