

THE
STATE CLEAN ENERGY
COOKBOOK

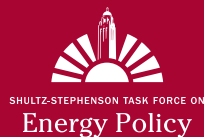
*A Dozen Recipes for State Action on Energy
Efficiency and Renewable Energy*



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HOOVER INSTITUTION



SHULTZ-STEPHENSON TASK FORCE ON
Energy Policy

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Introduction

WITH GROWING GRIDLOCK IN WASHINGTON, states are increasingly the locus of real progress in policymaking to advance energy efficiency and renewable energy. Like chefs in a kitchen, state governors, legislators, and public utility commissioners have been testing an array of recipes, to increase the deployment of solar, wind, and other renewables, to cut energy use in homes and businesses, to improve the operation of the grid, to expand financing, and, overall, to improve the efficacy—and economics—of clean energy.

Our team, from Stanford’s Steyer-Taylor Center for Energy Policy and Finance and the Hoover Institution’s Shultz-Stephenson Task Force on Energy Policy, has reviewed many of these recipes. In this report—our State Clean Energy Cookbook—we present a baker’s dozen of some of the best.

This report is issued at a moment of both significant opportunity and challenge for energy efficiency and renewable energy. On the one hand, the last several years have seen significant growth of clean energy in the United States. Between 2008 and 2013, non-hydro renewable power production in the United States more than doubled and in the last decade, more than tripled. This impressive growth occurred at a time when overall electricity consumption was essentially flat, in part due to the downturn in the economy but also the increasing efficiency of our homes and businesses. Efficiency over the last decade has been the “little engine that could” with residential electricity consumption, for example, essentially unchanged between 2007 and 2013—despite a 6 percent growth in the number of households. Commercial energy use was also unchanged over the same period.

On the other hand, there are stiff head winds in the further deployment of energy efficiency and renewable energy in our nation. The steep drop in US natural gas prices since 2008, while beneficial to the economy as a whole, has reduced the cost competitiveness of renewables and dampened the incentive for cutting energy use. At the same time, policy support from Washington has been inconsistent, with on-again, off-again clean energy incentives, steep declines in support for renewable energy from the federal loan guarantee program, and unreliable R&D funding. Additionally, while financing options have proliferated over the last several years, it often remains challenging to raise adequate capital for many clean energy projects because of the often more novel technologies being deployed, their frequently smaller scale, less familiar project developers and counter-parties, and unreliable incentives. At the same time, the US Environmental Protection Agency’s (EPA) recently proposed carbon emission standards could breathe new life into the federal role in advancing clean energy.

The policies we include in this report are designed to help address these challenges and seize the associated opportunities. They have, with a few exceptions, met several tests: they are already on the

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Our goal in this report is to highlight these clean energy policies in a straightforward and non-partisan manner. Like the best recipes in a good cookbook, we hope that a broad array of state leaders, in collaboration with the business, nongovernmental organization (NGO), and academic communities, will test some of these policies: in state-specific analyses, community meetings, formal hearings, and, ultimately, in legislative or regulatory decisions. Implemented broadly and well—across many states—these policies could fundamentally improve the deployment of clean energy in a manner that is both environmentally and financially sustainable.

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—Jeff Bingaman

Approach to the Study

The Steyer-Taylor Center and the Hoover Institution came together in this project to help bridge the all-too-common “blue state”, “red state” divide in energy policy. This objective was advanced by the different political backgrounds of the project’s leaders:

- **Jeff Bingaman**—a New Mexico Democrat and former Senate Energy Committee chair and Steyer-Taylor distinguished fellow
- **George Shultz**—a California Republican, former secretary of state and treasury, and Hoover Institution distinguished fellow and Shultz-Stephenson Energy Policy Task Force chair

The day-to-day work of the team was led by Steyer-Taylor and Hoover Institution staff:

- **Dan Reicher**—Steyer-Taylor Center executive director and faculty member at Stanford’s law and business schools
- **Jeremy Carl**—Hoover Institution research fellow
- **Alicia Seiger**—Steyer-Taylor Center deputy director
- **David Fedor**—Hoover Institution Shultz-Stephenson Energy Policy Task Force research analyst
- **Nicole Schuetz**—Steyer-Taylor Center project manager
- **Ernestine Fu**—Stanford University PhD student

As part of our collaboration, Hoover and the Steyer-Taylor Center interviewed businesses, policymakers, and NGOs. We also convened a conference at Stanford in October 2013 where some of the most promising policies were discussed.

Conference attendees included state public utility commission chairs and members, utility executives, policy experts, environmental organization representatives, energy company leaders, national lab researchers, and Stanford faculty. Attendees represented both blue and red states, including California, Colorado, Hawaii, Kansas, New Mexico, New York, Texas, Vermont, and Washington.

Based on our research and input from the conference, we winnowed down the various ideas to a final set of thirteen policies selected jointly by Hoover and the Steyer-Taylor Center. These were compiled into this report.

In determining which policies to recommend, we looked at specific states where policies were introduced that, in the consensus view of the authors, were successful. Each of the recommended policies is, of course, context dependent. What works well in one jurisdiction may not work well in another. In some cases, we outline the implications of these successes and failures for broader policy design.

This report presents a menu of potential choices. As with any menu, all of the dishes may not be to everyone's taste and different states may only want to sample a handful. And while we believe that in the correct circumstances each of these policies can offer an attractive option, and many work well in combination, failure to consider interactions among them could be a recipe for policy failure. Furthermore, while in each case the text reflects a consensus of both the Hoover and Steyer-Taylor teams, as with any large group of authors there is not unanimous agreement about the specific merits or relative value of each recommended policy.

We have developed the thirteen recommendations for consideration by policymakers, businesses,

and NGOs. There is, however, no "one size fits all" approach to advancing clean energy. For example, in states that already have a Renewable Portfolio Standard (RPS), strengthening that standard may or may not be the optimum clean energy policy strategy at this time. In some situations, other policies we highlight may be more effective, including ways to improve the financing of renewables and accelerate energy efficiency improvements in homes and businesses. However, for the twenty-one states that do not have an RPS and seek to grow renewable deployment quickly, the adoption of this policy can provide perhaps the quickest jumpstart to clean energy deployment of any major policy studied.

In my experience in public office, opportunities come and go. You never know when they may come. And if you're ready, if you have ideas, then when the opportunity comes, you have the chance to move ahead and do something about it.

—George Shultz

Framework of the Report

This report presents a series of policies through a common structure. Each policy "recipe" includes:

- A description of the particular policy ("What Works?")
- A policy recommendation ("Recommendation")
- Specific state examples of the policy ("Where to Look")
- A brief discussion of the benefits of the policy ("Policy Benefits")
- Specific considerations regarding policy design ("Design Considerations")
- Additional policy resources ("Additional Resources")
- Highlighted quotes from attendees at our October 2013 conference

The twelve policies selected for inclusion fall broadly into three categories:

ENERGY EFFICIENCY

1. Energy Efficiency Resource Standard
2. Energy Efficient Building Codes
3. Building Energy Benchmarking and Disclosure
4. Utility and Customer Market Incentives

RENEWABLE ENERGY

5. Renewable Portfolio Standard
6. Net Energy Metering
7. Community Renewables
8. Renewable Energy Tariffs

FINANCING

9. Energy Savings Performance Contracts
10. Third-Party Ownership of Distributed-Power Systems
11. Property-Assessed Clean Energy
12. On-Bill Repayment

A final recommendation concerns the role of the US Department of Energy State Energy Program (SEP) in providing federal support for state action.

Recommendations

Our report makes the following recommendations:

ENERGY EFFICIENCY

1. **Energy Efficiency Resource Standard.** States should adopt an Energy Efficiency Resource Standard (EERS) to help improve energy efficiency and cut energy bills. An EERS should allow for flexibility in the types of efficiency measures covered, and it should address cost-effectiveness, total incremental costs, and cost shifting among customers.
2. **Energy Efficient Building Codes.** States should adopt or update energy efficient building codes following an independent analysis of cost-effectiveness, distributional impacts, and other factors. Building energy codes are a relatively straightforward and transparent energy efficiency strategy. Updating codes is likely to be most worthwhile in states with the oldest existing codes.
3. **Building Energy Benchmarking and Disclosure.** States should adopt a policy requiring benchmarking and relevant disclosure of energy performance information for larger nonresidential and residential buildings.
4. **Utility and Customer Market Incentives.** States should adopt some combination of both alternative utility revenue and customer rate models—for example, decoupling and time-variant pricing—if doing so would advance policy goals, such as increasing energy efficiency, grid security, and distributed generation cost effectively.

RENEWABLE ENERGY

5. **Renewable Portfolio Standard.** States seeking to increase renewable power generation significantly should consider adopting or expanding a Renewable Portfolio Standard (RPS). RPSs are well understood and have proven effective at increasing deployment of renewable power generation. The extra costs of an RPS should be reasonable and should be shared fairly and transparently across customers.
6. **Net Energy Metering.** States should increase the power-generation choices available to utility retail customers, by adopting a Net Energy Metering (NEM) policy that compensates customers for offsetting their energy use through a small, on-site, clean-power system. Compensation for the value of the on-site system and any excess generation should be provided in the form of a credit on the customer's utility bill under a rate mechanism that has been determined in a fair and transparent manner.
7. **Community Renewables.** States should enact legislation to permit distributed "community renewables" projects that enable multiple customers to share in the economies of scale and other benefits of an off-site renewable energy system via their individual utility bills.
8. **Renewable Energy Tariffs.** States should permit contracting between utilities and large commercial and industrial energy consumers to procure additional renewable power at the request of, and paid for by, the relevant consumer. Steps should be taken to avoid cost shifting to nonparticipants and to ensure that new generation would not have been developed otherwise.

FINANCING

9. **Energy Savings Performance Contracts.** States should adopt legislation authorizing Energy Savings Performance Contracts (ESPCs). States with existing authority should ensure that the benefits available through this financing mechanism are being effectively realized.
10. **Third-Party Ownership of Distributed-Power Systems.** Third-party financing and ownership of on-site and, where applicable, community-based distributed-power systems has proven effective at broadening the availability of such infrastructure. States should authorize this form of financing and, as necessary, clarify that providers of this financing option are not classified as regulated utilities.
11. **Property-Assessed Clean Energy.** States should authorize Property-Assessed Clean Energy (PACE) programs allowing property owners to finance the up-front costs of energy improvement projects through an assessment on their property taxes.
12. **On-Bill Repayment.** States should authorize On-Bill Repayment (OBR) programs to enable property owners to finance cost-effective energy efficiency and distributed-power upgrades through a third-party investment that is repaid through the owner's utility bill.

FEDERAL SUPPORT OF STATE ACTION

13. The Administration and Congress should expand funding for the US Department of Energy (DOE) **State Energy Program** (SEP), the key federal grant program supporting the states in advancing energy efficiency and renewable energy.

An Encouraging Conclusion: Both Red States and Blue States are Turning Green

This study reached an encouraging conclusion: Many states, from all parts of the country and from all political perspectives, are taking steps to promote energy efficiency and renewable energy. Put simply, both red states and blue states are turning green, whether measured in dollar-savings or environmental benefit.

Among the examples we highlight in this report:

- **Wisconsin** has been pursuing efficiency improvements since the 1980's but in 2011 enacted an Energy Efficiency Resource Standard (EERS) that both accelerated energy efficiency investments and demonstrated the benefits of undertaking—and responding to—ongoing program evaluation.
- The **Mississippi** legislature directed the state administration to update its commercial building energy code to the latest national standard, the first state in the Southeast to do so. The move was part of a broader package to improve that state's overall energy efficiency, including cutting energy use in state buildings.
- **Arizona** leads the nation in time-of-use electricity pricing, with two of the state's leading utilities offering rates to residential customers that encourage them to shift their electricity use away from summer peak periods, thereby reducing the need to start up more expensive and polluting existing power plants and avoiding the need to build new ones.
- **Washington** State regulators, utilities, and other stakeholders recently concluded a “decoupling” process aimed at reforming the current utility regulatory model and thereby delivering energy efficiency improvements more effectively, without unduly affecting customer and investor interests.
- **North Carolina** in 2007 became the first and remains the only state in the Southeast to adopt a Renewable Portfolio Standard (RPS). North Carolina's standard allows a broad mix of eligible technologies including combined heat and power systems and energy efficiency and also includes technology “carve-outs” for solar power and energy from animal waste. These carve-outs were important for gaining political support. North Carolina's RPS is modest compared with others around the country, but it is tailored to the state's specific needs and politics and its very existence is groundbreaking within the Southeast.
- A **Texas** utility, Austin Energy, was the first utility in the country to update its existing Net Energy Metering (NEM) framework with a so-called Value of Solar Tariff (VOST) that enables the utility to better understand the costs and benefits of distributed customer-owned generation and to regularly update the value of solar electricity to the City of Austin.
- The **Colorado** legislature was the first in the nation to adopt a “community renewables” law that enables multiple customers to share the economic benefits of a single renewable energy system via their individual utility bills and by doing so participate in the deployment of distributed generation, even if they do not own property where it can be sited.
- In **Virginia**, Dominion Power offers one of the country's first “renewable energy tariffs”, allowing larger customers to identify specific renewable projects that meet their needs—with the utility entering into a power purchase agreement with the supplier—thereby creating competition among generators and helping to lower renewable energy prices.
- **Pennsylvania** built the nation's most successful program harnessing private capital for energy efficiency upgrades of public buildings through Energy Savings Performance Contracts (ESPC's), and accomplishing over \$590 million in energy efficiency retrofits in state buildings between 2000 and 2010, all at no up-front cost to taxpayers.
- **New Mexico** has enacted legislation that enables third parties to finance the deployment of distributed solar systems through payback agreements with the property owner. The legislation establishes that firms can offer such financing with certainty that they will not be considered regulated utilities.

- **Nebraska** has made extensive use of funding from the U.S. Department of Energy State Energy Program (SEP) for two decades to help finance energy efficiency upgrades to homes, schools and businesses. Federal SEP funds are leveraged with utility and other funds.

An important lesson from these examples is that the divide between Democratic and Republican-led states on efficiency and renewables is narrower than one might think, and smaller than the partisan gulf in Washington, D.C. these days. States—red, blue and purple—are indeed Justice Brandeis’ “laboratory” when it comes to clean energy policy – or perhaps we should say “test kitchen”.

And the good news is that the baker’s dozen of recipes we highlight in this report are producing economic benefits today: from cutting energy costs in homes, schools, and businesses to creating jobs in the construction and operation of new clean energy projects to jumpstarting a new clean energy finance industry.

Looking to the future, state clean energy policies are part of the “outside the fence” approach EPA is taking to compliance with its proposed carbon emission standards. States with smart policies on the books are more likely to be able to meet whatever emission standards EPA adopts, in a more efficient and cost-effective manner.

At a time of many challenges to bipartisan collaboration on energy policy, we hope this clean energy cookbook will highlight some potential areas where key players from different political perspectives can take a seat at the table and try out policies that advance clean energy. The potential benefits—environmental, economic, and security—are real and significant. *Bon appétit!*



Energy Efficiency



Energy Efficiency
Resource Standards



Energy Efficient
Building Codes



Building Energy
Benchmarking
and Disclosure



Utility and Customer
Market Incentives



Energy Efficiency Resource Standards

AN ENERGY EFFICIENCY RESOURCE STANDARD (EERS) is a policy that sets energy savings performance targets for utilities or a third-party administrator. Utilities or an administrator implement a portfolio of efficiency programs to meet that target, generally focused on energy use by various customer classes. Such programs typically include a wide variety of measures, some of which may already be in use. Twenty-six states, ranging greatly in size and geography, have adopted a formal EERS, while several others have established energy efficiency goals.

EERS programs are generally justified by an array of potential economic and environmental benefits. One aim of EERS policies is to motivate investment in energy efficiency upgrades that otherwise might not be implemented by end-users for a variety of reasons, including lack of information or consumer impediments. Under some EERS programs, a utility or third-party administrator expends funds collected from customers to provide, for example, discounted energy efficient appliances, home weatherization upgrades, energy audits, or consumer education.

Implementing an EERS may result, initially, in increased utility rates, but, in the medium and long term, any added costs are often reduced or even fully paid for by lower energy use among some customers. This in turn can constrain bill increases for all customers as improved system-wide energy productivity defers the need for construction of new power plants or upgrades to transmission and distribution infrastructure.

Where to Look? Wisconsin



Wisconsin has implemented energy efficiency programs in the power sector since the 1980s, though it lacked a formal EERS until 2011.

Most of the state's efficiency efforts are contained within its comprehensive "Focus on Energy" program, which since 2001 has been funded through a utility rate surcharge. The charge is about 1.2 percent of investor-owned utility revenues plus participation from publicly owned utilities and cooperatives. The program is authorized by state legislation with implementing regulations and oversight provided by the state's Public Service

Commission (PSC). The PSC is required to review the program's goals, priorities, and targets every four years. Focus on Energy implements a number of subprograms including ten for residential end-users alone that involve, for example, consumer rebates on energy efficient appliances and home retrofits. In the commercial and industrial area, the subprograms include, for example, energy assessments, technical support, financial incentives, and energy-saving products. A 2011 third-party evaluation found that most of the program's electricity and natural gas savings came from nonresidential sectors.

RECOMMENDATION

States should adopt an Energy Efficiency Resource Standard (EERS) to help improve energy efficiency and cut energy bills. An EERS should allow for flexibility in the types of efficiency measures covered, and it should address cost-effectiveness, total incremental costs, and cost shifting among customers.

Wisconsin's approach has recently seen a number of important changes:

First, as a result of the PSC's periodic program evaluations, it was decided in 2010 to transition from a spending-based target (i.e., a set 1.2 percent of utility revenues) to an annual energy reduction-based target, which is the conventional approach taken by other state EERS programs. When the authorized total program budget was later limited through legislation, the PSC revised annual energy savings levels but retained the overall reduction-based, rather than spending-based, approach.

Second, the program's funding utilities decided to select a new third-party for-profit program administrator following a round of competitive bidding. There was also competition for the individual efficiency sub-programs. While the decision to shift administrators was not unanimously supported, it reflected a view that program targets could be met more cost-effectively, especially given limited ratepayer funding. One

change involved cutting funding for customer-sited photovoltaics (a measure not generally eligible in other state EERS programs) in favor of energy efficiency efforts with shorter-term return on ratepayer-funded investment, such as appliance recycling, lighting discounts, and energy auditing. A 2013 independent evaluation found that these changes resulted in higher program participation levels and greater total electricity savings across the state, improving the program's "total resource cost" benefit-cost ratio.

Wisconsin's experience shows both how an EERS can help stimulate existing state-run energy efficiency efforts and how broadly an "EERS" can be defined in order to best suit individual state goals and conditions. It also demonstrates the benefits of undertaking—and responding to—program evaluation.

Policy Benefits

For states that already have energy efficiency programs in place, establishing an EERS can help to organize and benchmark those existing efforts. For states without such programs, an EERS can help establish a strong energy efficiency portfolio.

Energy efficiency measures are among the cheapest resources available to states to reduce power sector emissions and meet growing demand for new energy services. When implemented well, EERS programs and policies can serve as powerful drivers for energy savings, using market forces to take advantage of the most cost-effective measures first. EERS policies generally limit compliance eligibility to cost-effective efficiency technologies or programs, helping to ensure that the policy results in real economic value to the state.

The energy savings achieved under EERS policies can benefit participating customers, nonparticipating customers, utilities, and third-party suppliers of efficient products.

Customers will generally fund EERS program costs through their utility bills, either in the rate itself or as an added tariff. However, those customers who in turn take advantage of end-use efficiency programs enjoy lower energy bills by cutting their energy use. Over time, utility customers on average also benefit from smaller bill increases, as accumulated energy savings defer the need for construction of new power plants or upgrades to transmission and distribution infrastructure. This result was demonstrated through modeling performed by Lawrence Berkeley National Laboratory (LBNL) on Massachusetts's energy efficiency programs in 2010.

Because an EERS requires the use of new energy efficient goods and services, it can help develop a robust energy efficiency market. This includes both the manufacturers of energy efficient products and the workforce to install them, although gains here may come at the expense of incumbent suppliers of electric power. However, for utilities, a well-designed EERS can offer investment, customer service, and revenue

Right now, 85 percent of our load growth is being met through conservation. That's a lot. A lot of power plants won't have to be built as a result of this effort.

—David Danner, chair, Washington State Utilities and Transportation Commission

opportunities beyond conventional generation and grid infrastructure. This is especially the case in states where alternative utility regulatory models, such as “decoupling,” have been adopted allowing utilities to better ensure reasonable revenue levels even as sales decline due to customer efficiency improvements.

DESIGN CONSIDERATIONS

Well-designed EERS policies can provide flexibility—in terms of technology choice, implementation strategy, and program management—for utilities or competitively selected third-party administrators. In general, a more broadly defined EERS will encourage more cost-effective efficiency investments. However, an EERS is not cost-free. In order to design and implement it effectively, policymakers will need to consider a number of issues. The response to these issues has varied widely across states:

- **What types of efficiency technologies and programs will be included?** Programs to meet EERS goals may authorize spending on efficiency measures involving both electricity and natural gas technologies, for example, heating, cooling, and lighting. Actions can range from upgrading specific equipment to comprehensive building retrofits. They may also include combined heat and power projects. Some programs also include fuel switching as an option, for example, from fuel oil to natural gas for home heating. Some programs also give implementers partial credit for savings from building codes and equipment efficiency standards, subject to certain conditions.
- **How will performance targets be set?** Efficiency targets are typically tied to projected load growth or the previous year's energy sales. Policymakers should base targets on independent third-party assessments of possible energy savings in the state and/or actual accomplishments in similar states. The targets should ramp up to gradually provide stakeholders with time to adjust to and plan for growing efficiency demand. Nominal incremental annual savings targets in states with EERS today range from about 0.15 percent in Texas, to 0.75 percent in Arkansas, and 2 percent in Illinois and Indiana. Many other states—including Arizona, New York, and others—have adopted cumulative or quantity-based targets, which generally fall within a similar range.
- **How will performance targets be distributed across customer classes?** Cross-subsidies could arise if utility efficiency programs are targeted at one customer class and all customers are required to cover the cost. Segmenting performance targets for each customer class can help to prevent cross-subsidy and encourage regulated entities to develop a well-rounded portfolio of efficiency programs.
- **How will the cost-effectiveness of eligible efficiency measures be defined?** “Cost-effectiveness” is a good principle to use when setting limits on the measures that can be undertaken in meeting an EERS, and there is a range of definitions used to determine it. Costs can be measured in terms of impacts on customer rates, the impact on customer bills, or simply the aggregate benefits of avoided energy-supply investment versus the costs of implementing the EERS program. Most states, including Pennsylvania, Florida, and New York, use this final measure, which is known as the “total resource cost test.” A few states, including Arizona, Iowa, and Oregon, go further to include a “societal impact” test, which is similar to the total resource cost test, but also includes any externality impacts from an efficiency measure such as reduced pollutant emissions or the avoided costs of having to replace inefficient lightbulbs more frequently. In addition, many states, including California, choose to measure and report cost-effectiveness measures using multiple definitions but designate one or two as primary.

- **Will utilities or a third-party administrator be responsible for meeting the EERS targets and implementing the portfolio programs?**

Some states require utilities to be the implementing entity under an EERS. This can reduce political opposition to an EERS, and in many states utilities have extensive experience implementing energy efficiency programs, but it may not be the most cost-effective option. Other states have placed responsibility for meeting EERS targets in a third-party administrator, which, unlike many conventionally regulated utilities, does not face the mixed incentives of profit through increased energy sales and compliance with efficiency mandates that reduce sales. Independent administrators have proven highly capable in some states, for example, Vermont, for both their competence and cost-effectiveness.

- **How will savings be measured and verified?**

Savings measurement is key to successful compliance with an EERS. Accurately gauging the impact of EERS efforts over baseline actions given natural economic and other variability is perhaps the major challenge of the EERS approach. Evaluation models include bottom-up accounting models (used by most states) that extrapolate the savings of individual efforts (e.g., light bulb replacement) across the total number of actions, or more experimental meter-based statistical end-user analyses. The key questions are whether cost-effective efficiency upgrades would have been undertaken without the EERS investment, and whether the upgrades that have been made are working. For example, independent program evaluators often report lower actual levels of energy savings than program administrators. To improve consistency, many states are now moving toward standardized regional measurement and verification protocols.

- **Will customers be able to get credit against EERS-related rate surcharges by undertaking self-directed efficiency actions?** Ideally, utilities and program administrators should aim to provide complete portfolios of programs, targeting all customer classes. In some states, however, large electricity customers in the industrial or commercial sectors have sought to undertake

their own energy efficiency improvements instead of participating in utility- or administrator-run programs and, in turn, pursued exclusion from EERS-related rate surcharges. The rationale for this includes sensitivity to electricity rates or a belief that tailored efforts undertaken individually will be more effective than standard third-party efficiency interventions. It can be difficult, however, to determine the “additionality” and fairness of such self-directed efficiency investments. Colorado, Michigan, and Washington have EERS programs that include some self-direct provisions, while Illinois, Indiana, and New York do not.

- **How will the EERS be enforced?** Many states with EERS programs adopt positive incentives to meet or exceed performance goals. Penalties for noncompliance do exist but have been rarely used. More important is that administrators and other stakeholders are involved from the beginning of EERS implementation so that potential compliance issues can be addressed up front in program design rather than through after-the-fact enforcement. For states without noncompliance penalties, such as Texas, the EERS serves more as an overall framework under which the success of other more specific complementary energy efficiency measures can be gauged. Another advantage of EERS programs is that they offer a quantitative and consistent framework through which to measure energy efficiency savings that can be useful not only in the implementation of EERS subprograms but also for other efficiency efforts in the state, such as building energy codes. Hawaii uses this approach.

- **How long will the EERS be in effect?** The longer an EERS is in place, the more certainty the targets will provide to stakeholders and the more likely the policy will result in developing markets for efficiency. To take advantage of these market-signaling benefits, an EERS should ideally be in effect for a minimum of five to ten years, with periodic reviews.

Additional Resources

For EERS implementation maps and updated state policy details, see the Database of State Incentives for Renewables and Efficiency (DSIRE), maintained by the North Carolina Solar Center and the Interstate Renewable Energy Council (IREC) at <http://dsireusa.org>.

The American Council for an Energy Efficient Economy (ACEEE) also tracks state EERS policies: <http://database.aceee.org>.

Other resources include:

1. Sandy Glatt and Beth Schwentker for the US Department of Energy. "State Energy Efficiency Resource Standards Analysis." July 2010.
www1.eere.energy.gov/manufacturing/states/pdfs/eers_web_final.pdf
2. ACEEE. "State Energy Efficiency Resource Standards Policy Brief." July 2013.
<http://aceee.org/files/pdf/policy-brief/eers-07-2013.pdf>
3. ACEEE. "The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs." March 2014.
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4. Karen Palmer, Samuel Grausz, Blair Beasley, and Tim Brennan for Resources for the Future. "Putting A Floor on Energy Efficiency Savings: Comparing State Energy Efficiency Resource Standards." February 2012.
www.rff.org/RFF/Documents/RFF-DP-12-11.pdf
5. The Cadmus Group for the Public Service Commission of Wisconsin. "Focus on Energy Calendar Year 2011 Evaluation Report." October 2012.
http://cleanwisconsin.org/index.php?module=cms&folder=127&cmd=cmsproxy&filename=files/Evaluation_Report_2011.pdf
6. The Cadmus Group for the Public Service Commission of Wisconsin. "Focus on Energy Calendar Year 2012 Evaluation Report." April 2013.
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Energy Efficient Building Codes

ENERGY EFFICIENT BUILDING CODES typically require that new buildings be constructed with improved building envelopes and other efficiency features to reduce heating, cooling, and lighting costs, and provide better indoor air quality. Modern codes are one of the most cost-effective policies to cut wasted energy in individual buildings and in the aggregate.

Building energy codes are often set in state law or regulation by reference to third-party standards, including the International Energy Conservation Code (IECC) and the American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE) Standard 90.1. Both the IECC and ASHRAE 90.1 are developed in a public process by industry and other stakeholders, with the support of the US Department of Energy (DOE). In many states, building codes and standards are implemented and enforced by local rather than state governments, reflecting different building practices, geographic variation, and economic conditions.

Where to look? Mississippi



Mississippi has undertaken a multiyear strategy to both develop new energy supplies and reduce energy waste in order to support statewide economic growth. The Mississippi legislature adopted HB 1281, which established new statewide *commercial* building energy standards to match the ASHRAE 90.1 2010 revision. This is notable not only because it is an advanced standard for the region, but also because it replaces a previous commercial standard set nearly forty years ago—the ASHRAE 90 1975 revision—and widely regarded as obsolete. Given the magnitude of this revision, the legislation provided flexibility measures such as leaving code enforcement in the hands of local rather than state authorities. Mississippi’s *residential* building code remains voluntary and was not updated as part of this measure.

In addition, the Mississippi legislature enacted HB

1266, which strengthened the energy efficiency standards for state-owned buildings that exceed a certain size. A key rationale was that government buildings are funded by state tax dollars and therefore strong yet cost-effective efficiency standards will conserve public funds.

The adoption of these codes followed analysis by the DOE’s Building Energy Codes Program, the Building Codes Assistance Project, the Southeast Energy Efficiency Alliance, and others that concluded that Mississippi could expect broad cost savings and short payback periods from new code adoption, particularly in the commercial sector. Since passage of the legislation, the state has also: (1) formed an advisory group to meet quarterly on implementation issues and (2) scheduled a series of statewide training sessions. Since code enforcement is left to local authorities, effective training programs are particularly important.

RECOMMENDATION

States should adopt or update energy efficient building codes following an independent analysis of cost-effectiveness, distributional impacts, and other factors. Building energy codes are a relatively straightforward and transparent energy efficiency strategy. Updating codes is likely to be most worthwhile in states with the oldest existing codes.

Mississippi's efforts to improve its overall energy competitiveness have received strong support from the governor's office. Updating building

energy codes represents a prudent, cost-conscious first step in improving the state's building energy performance.

Building efficiency is a big problem. We replace 1 percent of our building stock per year. So between now and 2050, we're going to replace 40 percent of all the buildings in the United States. If you think about that, if you replace them with much more energy efficient buildings, you're going to make a big gain in efficiency and a big decrease in emissions.

—Burton Richter, director emeritus, Stanford Linear Accelerator

Policy Benefits

Buildings are typically built for decades of use. Once operational, reducing a building's energy consumption through retrofitting can be expensive. Ensuring a building is initially constructed for efficient operation may increase up-front costs but has a variety of longer-term benefits. Gillingham and Palmer (2013) note that empirical studies estimate enactment of a building energy code to reduce statewide per capita electricity use by approximately 3 to 5 percent, with some time lag in the impact due to the slow turnover of overall building stock.

For owners and tenants, more efficient buildings mean lower energy costs—and potentially greater comfort levels. Simple payback periods for updating energy standards are often estimated to be under ten years for residential buildings and under five years in commercial properties. Specific figures, however, vary by technology, climate, and how the added up-front costs are financed. In any case, payback periods should be carefully weighed against the opportunity cost or uncertainty of making that investment. When the tenant is responsible for energy costs, the existence of a reasonable energy efficient building code helps level the playing field in the rental market.

For builders, suppliers, and utilities, making energy efficient buildings the norm helps provide stable, long-term market signals for energy efficient products, services, and construction. And lower building energy demand also defers the need for investment in new power infrastructure and reduces power sector emissions.

For some states, adoption of a new code at the state level automatically applies to all local jurisdictions. Other states have “home rule,” which allows local jurisdictions to adopt and enforce their preferred versions of energy codes (which may be more or less stringent than the state code). In a home rule context, states or municipalities may choose to set aspirational energy efficiency codes and implementation strategies as a model to others.

In Hawaii, the PUC is just finishing up our potential study. We found that with just a few modifications in our building codes, Hawaii can easily meet or even exceed its 2030 efficiency target of 4,300 gigawatt hours. So that was pretty revealing.

—Hermina Morita, chair, Public Utilities Commission of Hawaii

DESIGN CONSIDERATIONS

There are some key issues that should be addressed in adopting a well-designed building code policy:

- **Which specific code provisions should be selected?** The most up-to-date version of both the International Energy Conservation Code (IECC, revised every few years) and American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE) 90.1 standard are typically the most energy efficient codes. Some states—Iowa, for example—adopt these codes by reference, while others, including Oregon, tailor them to local characteristics. Another option is to set a standard in state law that is always up to date by requiring compliance with the latest version of a code. This will ensure that a state’s building codes take advantage of all cost-effective efficiency technologies. Maryland and Illinois have taken this approach.
- **What will it cost to comply with code provisions?** States should explicitly evaluate the costs, benefits, and distributional aspects of potential building energy code revisions for various building sectors and stakeholders. Though many of the requirements in energy efficient building codes are designed to save money over the medium and long term, it is important for states to understand and account for their cumulative impacts on up-front costs and design flexibility. Model codes attempt to account for this, and DOE has published energy code cost-effectiveness studies for various IECC versions to help states with this effort.
- **What provision should be made for training and compliance?** Building energy codes can be complex and adequate funding must be available for their enforcement. Local architects, builders, and building inspectors should be trained to ensure that codes are effectively understood and implemented. In some cases, doing so may require a state to simplify certain elements of the code. The DOE Building Energy Code Program has developed software tools that states may use for builders to demonstrate and report on compliance with a code.
- **What steps should be taken to assess actual building performance?** Meeting or exceeding even well-defined design standards is important but ultimately insufficient to ensure that a building *actually* cuts energy use in a significant fashion. Design-based standards, for example, do not ensure that a building is operated properly following construction. Accurate measurement of real-world energy performance is important to assess the true costs and benefits of new standards and to help ensure that energy savings are achieved in the field. German building codes address this issue by placing energy code compliance and performance liability on builders and architects themselves, who self-certify to the building owner. In addition, there should be mechanisms for removal of new code elements that do not deliver promised savings.

Louisiana [following hurricane Katrina] had to wake up from having no effective efficiency codes, to, ‘gosh, we’ve got to rebuild this whole place, we’d better do it smart.’ So change can happen in an instant, too often in reaction to some unfortunate event or power brownouts or some crisis.

—Andy Karsner, executive chairman, Manifest Energy

- **How will existing building stock be affected?**

Because the rate of turnover in building stock is generally quite slow, some states require that existing buildings that are undergoing extensive renovations also comply with some aspects of building energy codes that apply to new construction. The anticipated benefits of this may be substantial in some cases and should be carefully weighed against the potential disincentive it may create to undertaking otherwise useful renovations.

- **Are there ways to encourage builders to exceed codes?**

Some states with more in-depth energy efficiency policies, for example, California and Massachusetts, offer voluntary “stretch” codes that local jurisdictions can adopt that go beyond the statewide standards. In addition, some utilities provide incentives to builders to exceed the state or local code, frequently tied to EPA’s Energy Star criteria for super-efficient homes.

Additional Resources

The DOE's Building Energy Codes Program website (www.energycodes.gov) has excellent information for state policymakers seeking assistance in the implementation of energy efficient building code policies, including links to multiple pieces of model legislation.

For updated details on state building energy code implementation, see the Database of State Incentives for Renewables and Efficiency (DSIRE), maintained by the North Carolina Solar Center and the Interstate Renewable Energy Council (IREC) at <http://dsireusa.org>.

The American Council for an Energy Efficient Economy (ACEEE) also tracks state building energy codes: <http://database.aceee.org>.

Other resources include:

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Building Energy Benchmarking and Disclosure

ENERGY BENCHMARKING AND DISCLOSURE of existing building stock is a market-based policy tool to overcome informational barriers to energy efficiency. Benchmarking is a simple, low-cost practice used by many building operators to evaluate the energy efficiency of their buildings and target investments to improve energy performance. Disclosing that benchmarking information for commercial buildings helps tenants, investors, and banks to identify and compare the energy performance of buildings, unlocking the market's ability to drive demand and competition for energy efficient space with lower utility costs.

The scale of applicability is large: nearly half of all energy consumed in the United States is used in buildings. Moreover, older buildings represent the vast proportion of the US building stock, with approximately 75 percent of US commercial buildings, for example, more than twenty years old. Businesses and investors in many states do not have reliable energy performance information regarding buildings before they lease or buy space, or only see energy information late in the buying process. Benchmarking and disclosure policies are meant to mirror transparency rules in other market sectors, such as nutritional labels on food and fuel economy ratings on vehicles.

Two states (California and Washington), nine cities (New York, Washington, D.C., Chicago, San Francisco, Boston, Philadelphia, Seattle, Minneapolis, and Austin), and Montgomery County Maryland have adopted benchmarking and disclosure requirements. Together, these policies cover more than 50,000 buildings totaling more than 6 billion square feet of floor space.

Where to look? California and Washington State



CALIFORNIA. In 2007, California adopted a benchmarking and disclosure policy for municipal and privately owned buildings through AB 1103. The policy requires benchmarking and disclosure of

the previous year's energy consumption data to prospective buyers, lessees, or lenders prior to the close of real estate transaction for nonresidential buildings greater than 5,000 square feet. The requirement does not apply to partial transactions,

such as a new lease to a single tenant within a multitenant building. Building owners must also file a "statement of energy performance" with the state's energy commission, and may elect to have their servicing utility automatically upload building energy performance onto a standardized software platform provided by the US Environmental Protection Agency (EPA). Following initial technical and implementation delays, the state's requirements were phased in over a yearlong period, starting with larger buildings.

RECOMMENDATION

States should adopt a policy requiring benchmarking and relevant disclosure of energy performance information for larger nonresidential and residential buildings.



WASHINGTON STATE. The state of Washington adopted a benchmarking and disclosure policy for public agency and privately owned commercial buildings in 2009 through SB 5854, the “Efficiency First Act.” As in California, the law requires benchmarking and disclosure at the time of a real estate transaction for nonresidential buildings greater than 10,000 square feet. Disclosure for privately owned buildings is limited to parties to the transaction, while more stringent public disclosure is required for government-owned buildings.

Under the Washington law, public buildings are subject to additional energy efficiency requirements, including a minimal performance rating for lease of new building space within a privately held commercial building.

In addition to these two states, major municipalities have also adopted their own building energy benchmarking and public disclosure policies within the last five years. These requirements tend to target larger buildings (20,000–50,000 square feet), with annual rather than point-of-transaction disclosure.

In San Francisco and New York City, there’s a required evaluation of commercial buildings over a certain size, and then some publication of information around that. ...This lets developers and private [energy efficiency providers] know who they’re going to talk to: “Look, your building is three times worse than the one next to you.” It’s all public information. Your tenants see this.

—Cisco DeVries, president and CEO, Renewable Funding

Policy Benefits

Building energy benchmarking and disclosure requirements can benefit local economies, property markets, and the public more generally. For policymakers and utilities, energy disclosure helps improve data-driven decisions about energy policy, including how to effectively deploy taxpayer or ratepayer-funded energy efficiency programs. For example, New York City’s analyses of benchmarking data for more than 10,000 buildings yielded practical information on building energy trends that the city is now using to inform its policy decisions.

According to recent analysis, building energy benchmarking is correlated with energy efficiency improvements and reduced building energy costs. For example, a recent study by the EPA of more than 35,000 benchmarked buildings across the nation found that those buildings reduced energy consumption by an average of 7 percent over a three-year time span. A 2012 report commissioned by the California Public Utilities Commission found that benchmarking was highly correlated with building energy improvements and management actions. And a 2011 industry survey of hundreds of building managers found that 70 percent of respondents used benchmarking information to “guide energy efficiency upgrade plans,” and 67 percent used it to “help justify an energy efficiency project.” For building owners, a number of studies have shown that the market is already rewarding energy efficient buildings with higher occupancy and faster lease-up. At the same time, there needs to be more empirical research on the direct causal effects of benchmarking requirements as well as the relative effects of voluntary versus mandatory disclosure.

More broadly, improving information availability around building energy performance likely helps to drive demand for energy efficient buildings. This, in turn, supports development of the broader market for energy efficient products and related skilled workers—without relying on tax breaks or subsidies. Such requirements do typically incur modest costs for building owners—on the order of \$20,000 for a large commercial building over five years, given annual updates. These costs may be offset by potential cost-effective efficiency upgrades they identify.

DESIGN CONSIDERATIONS

The key decisions in program design that states should consider include:

- **What are the types and sizes of buildings that the policy should cover?** Applying the policy to large nonresidential and residential buildings—those over 25,000 square feet—will make the policy administratively manageable and increase public support while capturing a majority of the floor space in a state.
- **How is benchmarking conducted?** All current US benchmarking and disclosure laws reference use of the EPA’s Energy Star Portfolio Manager, a free energy-assessment tool that is already widely used by the commercial real estate industry. With the access to utility meter data and analytics, more sophisticated tools are being developed that allow for greater insight into building use and rapid benchmarking across thousands of buildings. Benchmarking is typically conducted either by existing facilities staff or technical consultants.
- **How often should benchmarking be required?** Several existing municipal policies—for example, Boston, Chicago, and Minneapolis—require annual benchmarking, whereas state-level policies require it at the time of transaction. More frequent benchmarking may improve accuracy of information available to the market, but increases compliance costs.
- **Who should have access to benchmarking information?** In general, broader disclosure of benchmarking information increases the impact of the benchmarking and disclosure tool. Interested parties include local policymakers, utilities, tenants, investors, and members of the real estate industry. This, however, should be balanced against reasonable privacy or competitiveness considerations. Whereas Philadelphia and New York City require public disclosure for nonresidential buildings greater than 50,000 square feet, Seattle limits disclosure of the benchmarking results to the parties to a transaction. Washington State established greater levels of disclosure for government-owned versus privately owned buildings.
- **How do such policies affect property values?** Experience to date suggests that lease rates and property values improve for more efficient buildings. Moreover, early evaluations in New York City and Minneapolis of their benchmarking and disclosure policies have found that building energy performance is not strongly coordinated with building age. Additionally, efficiency advocates note that any potential devaluation of real estate assets caused by disclosure policies may be offset by cost-effective energy efficiency upgrades identified, as the most inefficient buildings also typically have efficiency upgrades with the shortest payback periods. San Francisco and Chicago’s municipal ordinances do not require public disclosure for the first year following initial benchmarking in order to allow building owners to upgrade their buildings.
- **How is the program enforced?** Most benchmarking and disclosure policies are mandatory for affected building stock to ensure full market participation, though noncompliance penalties vary.
- **What role do utilities play?** Utilities can help building owners and operators conduct benchmarking by providing convenient access to energy consumption for individual buildings. Many building owners/operators have difficulty accessing this information because each tenant is typically the sole holder of energy information for their particular leased space.

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Utility and Customer Market Incentives

TODAY, WITH GROWING ENVIRONMENTAL AND SECURITY GOALS, alongside an array of new supply and demand-side energy technologies, utility regulatory and customer incentive models are coming under increasing scrutiny. While regulatory mandates and subsidies can help meet policy goals, day-to-day market signals faced by both utilities and customers do not always encourage them to operate in ways that make efficient and smart use of energy and grid infrastructure.

For utilities, the cost-of-service revenue framework is designed to encourage them to develop sufficient infrastructure to meet demand and plan for other grid security and reliability needs. But it tends not to provide incentives for utilities to encourage energy efficiency, demand response, or customer-sited distributed generation because these activities may reduce utility energy sales or rate-based investments and, correspondingly, utility earnings and shareholder returns.

Customers also face mixed incentives to pursue energy efficiency, demand response, or distributed generation under many conventional rate structures. For example, the most expensive and polluting electric supply comes on line periodically to meet peak demand but customers are often not incentivized to cut their use during these challenging periods.

To date, most states have taken at least some steps to adjust the utility revenue model. One well-known step is full revenue “decoupling” and seventeen states have taken this approach for at least one major utility. Under decoupling, a utility’s ability to recover costs and provide returns to investors is divorced from electricity sales. In a common approach, the regulator approves a revenue target, and then adjusts rates to keep revenues in line with that target. For example, if the utility revenue per customer is below the target in a certain period, rates adjust upward to make up the difference. This approach is often pursued in markets where electricity demand is no longer growing rapidly.

And increasingly, some jurisdictions are experimenting with complementary customer-side reforms, such as rate structures that more precisely reflect the marginal costs of energy supply. This may include, for example, instituting time-variant “time-of-use” or “dynamic” pricing, which can help improve energy efficiency or reduce peak demand. Another strategy has been to disaggregate customer pricing for the fixed (e.g., distribution and transmission) versus variable (e.g., energy) costs of electricity supply through monthly fixed charges or other rate reforms. This can help optimize customer-sited distributed generation investment decisions.

While either utility- or customer-oriented market incentives can be undertaken on their own, they are linked by a number of shared goals such as energy efficiency, grid security, and distributed generation.

RECOMMENDATION

States should adopt some combination of both alternative utility revenue and customer rate models—for example, decoupling and time-variant pricing—if doing so would advance policy goals, such as increasing energy efficiency, grid security, and distributed generation cost effectively.

Where to look? Washington State and Arizona



WASHINGTON STATE. The Washington State Utilities and Transportation Commission, major utilities, and other stakeholders recently concluded a process aimed at reforming the current utility regulatory model. A particular focus was how to deliver energy efficiency improvements more effectively, without unduly affecting customer and investor interests. As a result, in 2013, one major regulated utility sought and was approved for decoupling and other proceedings are underway.

Washington State and its utilities had experimented with alternative revenue models for a number of years, but discussions began in earnest following implementation of the state's 2007 "Energy Independence Act" that required electric utilities to pursue all cost-effective energy efficiency measures. Interest in energy efficiency and demand response in this hydropower-rich state grew following the 2001 West Coast electricity crisis. The utility commission contracted for studies to estimate the state's sector-by-sector energy efficiency potential. Yet concerns arose that the new energy efficiency requirement would affect utility fixed cost recovery and profits. A 2010 utility commission policy report analyzed market conditions, laying out a path for utilities to request consideration of decoupling as part of their existing rate case schedule. Any such proposal would include a required evaluation of risks to both ratepayers and investors under a decoupling mechanism.

In a 2011 rate case, energy efficiency advocates pushed for decoupling, but were rebuffed when utilities were not satisfied with the revenue model that was offered. Stakeholder negotiations continued in parallel with refinement of the decoupling proposal. A new proposal was made in 2012, and in its 2013 rate case, Puget Sound Energy proposed and the utility commission approved a decoupling mechanism. At the same time, the utility agreed to undertake related obligations, including increasing its energy efficiency resource acquisition targets. As a final check, the utility commission required a third-party evaluation of the decoupling mechanism as a condition of approval. A second

Washington utility, Avista, has since filed a rate case also seeking decoupling.

Although Washington State's path toward decoupling took a number of years, its analytically driven stakeholder approach provides a useful model for reaching a broadly supported solution compatible with local customer, utility, and regulator needs.



ARIZONA. Meanwhile, on the customer side, two Arizona utilities offer a simple form of "time-of-use" electricity rates to residential customers encouraging

them to shift their demand away from summer weekday afternoon peak periods. More active customer participation in the electricity market is intended to reduce the need to start up old, polluting, or expensive marginal generation assets to meet temporary demand and avoid the need to invest in new peaking generation units.

Arizona Public Service Company offers several voluntary incentive rate plans, including "Time Advantage" and "Time Advantage Super Peak." These alternate plans include both off-peak and on-peak electricity rates, which may differ by a factor of four to nine times. The idea is that many customers will be able to reduce their monthly bills by shifting the timing of their electricity demand. The plans were approved by Arizona's utility regulator and have been offered to customers for more than twenty years. About half of the utility's residential customers now choose to participate in them instead of conventional rate plans. Another Phoenix-area utility, Salt River Project, offers similar options, with about one-third uptake, and in 2011 reported peak-load reductions of about 1.5 kilowatts per customer and monthly bill savings of 6 percent. These participation rates are considered high for residential "opt-in" rate programs.

In Arizona's case, reducing the summertime peak load, and thereby cutting costs and pollution, was a major policy goal that went unmet with conventional rate structures. Other alternative time-variant rate plans, ranging from simpler "critical peak pricing" to more sophisticated "real

Retail markets and price exposure [are often-overlooked] means to get energy efficiency: for example, in Texas...[T]he old connection between load growth and economic growth has disappeared quite dramatically in ERCOT. [This is in part] because of the price exposure we have in the retail market, especially with the industrials and the large commercials making investments in their own energy efficiency. Why? Because it makes economic sense to do so. They have every incentive to actively manage their consumption. And yet I rarely hear that being discussed in programs about energy efficiency.

—Kenneth Anderson, commissioner, Public Utility Commission of Texas

time pricing,” have been piloted in various states to cut peak load and meet other policy objectives. In California, for example, AB 327, adopted in 2013, directs the state’s utility commission to explore

and implement adjusted rate structures, including residential time-variant pricing, over a five-year transitional period.

Policy Benefits

For utilities, decoupling can be attractive because it helps stabilize revenues, ensuring fixed-cost recovery year-to-year. Under a decoupling regime, utilities are assured a certain revenue level and rates are adjusted with more frequency than they would be under a typical rate case. It should be noted, however, that while energy efficiency programs that are adopted following decoupling can reduce the overall costs of energy services, customers may not see a corresponding drop in their bills in the near term because of the guarantee to utilities of a total revenue level.

Meanwhile, on the customer rate side, more closely tying the prices customers see to the actual costs faced by the utility in delivering electricity service—whether through some form of dynamic pricing or bill disaggregation—may cut system costs and with it individual bills. And this in turn can help optimize a utility’s approach to building new infrastructure or buying power from independent producers. However, experience with time-of-use pricing or disaggregated pricing models—and their effect on customer behavior—remains limited.

DESIGN CONSIDERATIONS

The design of a utility’s revenue model and customer incentives have broad implications, so it is important that adjustments by legislators or utility regulators are informed by significant input from all parties: customers, utilities, and other advocates. There are a number of key questions to be addressed:

- **What policy goals can be advanced through adoption of an alternative revenue or rate model?** Energy efficiency has been a major driver for decoupling. Meanwhile, encouraging deployment of distributed-power systems, demand response, and improving grid security have spurred discussions of bill disaggregation and other mechanisms. Time-variant pricing has focused on reducing costs associated with system-wide peak load. The implications of adjusting the

utility revenue model should be evaluated against a state’s other long-term policy goals given the broad impacts of such adjustments.

- **How will any adjustments be phased in?** It is not necessary that revenue model or rate adjustments be made simultaneously across the state. California, for example, established individual transitional windows around rate case schedules for individual investor-owned utilities.

I've always felt like decoupling was the holy grail of state regulators in taking that first step to where we create incentives for utilities to make more money by behaving more efficiently, as opposed to having us look over their shoulder.

—Mark Sievers, former chair, Kansas Corporation Commission

- **For decoupling, how often will rates be adjusted?** Under decoupling, many states choose to adjust consumer rates to match utility revenue requirements in periods ranging from quarters to years. More frequent rate adjustments help keep changes small and prevent rate instability. States often also use automatic rate adjustments for specific circumstances such as economic downturns, the addition of large industrial customers, or prolonged weather events. Doing so can insulate both utilities and customers from such changes.
- **For decoupling, will “rate banding” be applied as a safety mechanism?** A major concern when implementing decoupling is that rates will increase unacceptably due to large drops in sales, for example, due to an economic downturn. In order to remove this risk, regulators can create a “rate band”—for example, 10 percent above and below the target rate—within which adjustments would occur automatically. If a needed rate adjustment falls outside the rate band, then regulatory approval would be required for the adjustment.
- **For decoupling, are economic transfers allowed among or within customer classes?** If economic transfers are allowed among or within customer classes, decoupling could result in cross-subsidies. For example, if efficiency programs target only commercial customers, then any reduced sales to commercial customers might be covered largely by residential customers, who may lack access to the utility’s efficiency programs. Similarly, within a particular class, for example, industrial or residential, customers may have widely varying energy use characteristics. In Washington, this issue was negotiated as needed between the utility and certain specific industrial customers and approved by the utility commission.
- **For rate reform, how will new rate models be implemented?** While Arizona utilities have seen success with voluntary “opt-in” enrollment in their time-variant rate plans, this is atypical. California’s Pacific Gas and Electric, for example, has convinced less than half a percent of its customers to enroll in a critical peak pricing rate option after more than five years. Many experts believe that making alternate rate options “opt-out” (i.e., default but voluntary), instead of “opt-in,” strikes the best balance between system-wide cost-benefit and customer choice.

[Let’s talk about] the issue of dynamic pricing . . . [as a regulator considering rate changes] you might as well think about retail rates that are aligned with wholesale market costs. In general, the broader objective should be to get retail rates and pricing right, which should help improve the overall economic efficiency of the electricity market. And, if you have installed an Advanced Metering Infrastructure, consider putting in a time-of-use rate as your default service and consider offering customers a time-of-use tariff that has a critical peak-pricing overlay. If you do that, you will address some of the problems and potential barriers to efficiency—though not all of it.

—Charles Goldman, Energy Analysis and Environmental Impacts Department head,
Lawrence Berkeley National Laboratory

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Renewable Energy



Renewable Portfolio
Standards



Net Energy
Metering



Community
Renewables



Renewable Energy
Tariffs





Renewable Portfolio Standards

RENEWABLE PORTFOLIO STANDARD (RPS) policies have been a major driver of new, large-scale renewable energy deployment in the United States. An RPS mandates that electricity suppliers generate or procure electricity from a set of specific clean energy technologies, with some degree of compliance flexibility. Generally, a state legislature sets an overall percentage-based or absolute RPS target for power that must be purchased from clean energy sources, establishes a multiyear compliance timeframe, and defines eligible technologies. Regulators may then set additional details, such as the form in which new renewable projects will be developed and procured, how costs will be distributed, reporting metrics, market issues, grid capacity, and other technical considerations.

Twenty-nine states and Washington, D.C., currently have RPSs in place, with about half extending through 2020 and most of the rest through 2025. Five additional states have nonbinding renewable power deployment goals. RPS policies have taken different forms in light of the relative cost of renewable energy technologies and availability of resources.

Renewables can be an important part of a state's electrical generation portfolio. However, sometimes they are more expensive than conventional power generation. Nevertheless, experience to date suggests that any resulting rate increases from RPS implementation have been relatively modest compared to those attributed to other power system infrastructure costs. A 2014 Lawrence Berkeley National Laboratory (LBNL) analysis pegs the increase at approximately 1 percent of retail rates with significant state-to-state variation. Moreover, as free fuels, renewables can help hedge against natural gas-price volatility. Going forward, the cost of deploying additional renewable energy will depend on a number of factors, including the cost of renewable technology, development costs, grid transmission and integration costs, the cost of capital, and the availability of incentives.

Where to look? North Carolina and Minnesota



NORTH CAROLINA. North Carolina in 2007 became the first and remains the only state in the Southeast to adopt an RPS. As North Carolina's existing cost of electricity is relatively low, and like many other southern states it lacks a significant onshore wind resource, the state's RPS target is modest. The North Carolina standard, effective

as of 2010, requires that investor-owned utilities reach 12.5 percent of sales, while public and cooperative utilities must reach a 10 percent target. Importantly, North Carolina provided a very broad mix of eligible technologies—with some variation between investor-owned utilities and public/co-op utilities. The list of eligible technologies encompasses all renewable technologies including,

RECOMMENDATION

States seeking to increase renewable power generation significantly should consider adopting or expanding a Renewable Portfolio Standard (RPS). RPSs are well understood and have proven effective at increasing deployment of renewable power generation. The extra costs of an RPS should be reasonable and should be shared fairly and transparently across customers.

in the case of public/cooperative utilities, large hydropower facilities. One-quarter of the North Carolina requirement may be met by combined heat and power systems as well as utility-provided energy efficiency improvements. While bundling energy efficiency improvements with a renewables requirement was seen as a prudent way to reduce total program costs and achieve political support for the RPS, nationally there has been a trend away from this approach. Hawaii, for example, initially followed this path and is now separating its RPS and Energy Efficiency Resource Standard (EERS).

North Carolina's standard also included particular technology "carve-outs," that is, quotas for solar power and energy from swine and poultry waste. These carve-outs were important for gaining political support but they also demonstrate the problem of establishing narrow technology mandates. While solar photovoltaic deployment in North Carolina has recently accelerated, the swine and poultry targets have proved challenging technically and in terms of capital cost. Utilities in 2012 and again in 2014 were granted delayed compliance schedules for these requirements.

The costs of the North Carolina RPS are presented to customers through a separate rider on monthly utility bills. In order to limit compliance costs, the RPS established flat per-customer cost limits: annual limits are \$34 for residential, \$150 for commercial, and \$1,000 for industrial customers, from 2015 and after. Once a utility hits its cost-cap, it is considered in compliance with the standard.

Overall, North Carolina's RPS approach is modest, but it is tailored to the state's specific needs and politics and its very existence is groundbreaking within the South.



MINNESOTA. Like North Carolina, Minnesota's current electric load is served primarily by existing coal and nuclear power. But whereas

the addition of new generation capacity in North Carolina in recent years was dominated by natural gas-fired turbines, Minnesota's—along with other windy Midwest states—has consisted primarily of wind-generated electricity. The development of this renewable resource has been supported by the state's Renewable Energy Standard. The policy, first

set out as a voluntary goal in 2001, now consists of mandatory utility-specific targets adopted in 2007, ranging from about 25 percent by 2025 for public utilities to 32 percent by 2020 for the state's largest investor-owned utility.

Wind power is an important element of the state's RPS planning. In 2006, before the mandatory renewable standard was adopted, the state's utility commission and the state's second-largest utility both commissioned studies to determine the impact on reliability of operating the Minnesota grid with higher levels of wind power (approximately 20 percent). The studies found that doing so would be technically feasible given sufficient thermal power backup and if new transmission development kept up with new renewable deployment. By 2013 about 16 percent of the state's electricity was supplied by wind power. Xcel Energy, the state's largest utility, is the nation's largest wind-energy provider and is required to meet 25 percent of its electricity supply with wind by 2020 as part of the state's RPS. In part to address wind's dominance in the renewable portfolio, a 1.5 percent solar photovoltaic carve-out was added to the existing overall renewable standard in 2013, with 10 percent of that required to be customer-sited distributed generation. The RPS also allows hydroelectric power plants with capacities up to 100 megawatts, recognizing the surrounding regional grid's hydropower resources.

While Minnesota's renewable standard contains no explicit cost cap, the state's utility commission is specifically authorized—through "off-ramps"—to intervene and modify the RPS if it determines it to be in the public interest, that is, if it finds unacceptable cost or reliability impacts, or transmission bottlenecks. Although this clause is vague, it has a potential advantage over North Carolina's hard cost limit by preventing utilities from "racing to the cap" through development of expensive and potentially ineffective renewable projects. Legislation in 2011 required the state's utilities to report on how much the RPS was costing customers. While results have been mixed, the data has helped improve policymaker, regulator, utility, and customer understanding of this important policy.

Kansas views wind as an export, just like grain.

—Mark Sievers, former chair, Kansas Corporation Commission

Policy Benefits

RPS policies clearly are effective at increasing renewables generation: only five of twenty-nine states have fallen below 90 percent of expected annual progress toward RPS targets. The impacts of the policy are generally well understood, with ten states having a decade or more of RPS operational experience. Moreover, RPSs operate at significant scale and drive substantial new investment.

Because they are generally long term and politically stable year-to-year, RPS have also helped to build markets for the supply of renewable generation technologies. RPSs are also one of the few explicit tools available to policymakers and regulators to improve diversity in the power-generation mix. This helps provide a hedge against overall electricity rate volatility, for example, from the impacts of changing natural gas prices. Such diversity could also help in the event of fuel supply disruption.

From an environmental standpoint, RPSs can help reduce local or regional pollutants and associated health impacts from a state's power sector. An RPS also reduces carbon dioxide emissions in cases where new renewable generation displaces more carbon-intensive incumbents throughout the regional grid. An RPS on its own should be seen as helpful to environmental goals but not a comprehensive strategy to meet power-sector carbon dioxide emission targets. It is one of several avenues, particularly under the Environmental Protection Agency's (EPA) proposed carbon emission standards.

I think that the answers to questions on the full costs of wind integration are knowable, and we can do portfolio planning of a combination of solar and wind and other mechanisms to improve integration.

—Snuller Price, partner, Energy and Environmental Economics, E3

DESIGN CONSIDERATIONS

There are a number of considerations in designing an effective, cost-efficient, and fair RPS:

- **Should an RPS allow energy efficiency improvements to count in meeting targets?** Some states have included energy efficiency as an RPS-eligible resource. While this can provide flexibility, it can also detract from the basic purpose of the RPS, that is, to encourage investment in and deployment of renewable generation and supporting infrastructure. In our view, the preferred approach is to encourage improvements in energy efficiency through other policies such as an EERS and adjust RPS targets accordingly.

- **What technologies should be eligible to meet RPS targets?** Recognizing that an RPS is essentially a technology mandate, we believe that the eligibility pool should be defined as broadly as reasonable. This helps ensure that already-deployed and suitable clean energy technologies remain in the mix and that emerging renewable technologies do not face barriers to deployment as they become commercially available. At the same time, if overall RPS eligibility is kept broad, then it may be useful to limit the level of a single technology so it does not dominate the RPS portfolio. Another issue is whether renewable generation on the customer side of the meter should count toward RPS targets.

We need to think carefully so that we don't end up with stranded transmission costs. There continues to be a strong linkage between transmission planning and renewables development.

—Dian Grueneich, former commissioner, California Public Utilities Commission

- **At what overall level should the RPS be set?** Because states may choose to include existing renewable energy or other low-carbon technologies in an RPS, and because compliance periods may vary, there is no correct or universally appropriate RPS target level. Current levels range from 8.5 percent in Pennsylvania, to 20 percent in Kansas, to 30 percent in Colorado, to 33% percent in California, to 40 percent in Hawaii. Importantly, experience to date suggests that grid-integration issues have not been major barriers to the deployment of renewable technologies. At the same time, research into cost and reliability issues at higher penetration levels of variable generation is needed, as a next generation of likely higher RPS levels is considered.
- **Should “carve-outs” be created to encourage diversity in deployed technology type, scale, form, or location?** LBNL estimates that 88 percent of RPS capacity additions from 1998–2012 came from one technology: wind power, the cost of which for many years has benefited from a relatively mature technology and federal tax benefits. Carve-outs can be used to specify a mix of renewable generation, for example, requiring a share of distributed generation or a modest level of an emerging technology. However, it is important to avoid being too detailed or prescriptive in establishing carve-outs that, as North Carolina has experienced, may not be attainable for reasons of technology, grid integration, or cost.
- **How will RPS costs be allocated among customers in utility cost recovery?** If utilities are allowed to pass on the increased costs of renewable power to customers, it is important to ensure that the existing rate design does this fairly across and within user classes. Evidence to date suggests that the cost of renewable deployment is manageable in the aggregate, but it is important that it does not become too concentrated and burdensome for any particular subset of customers.
- **What form will cost-containment measures take?** An RPS policy should be designed to limit costs in a reasonable way, for example, through a percentage cost cap or a utility “safety valve” whereby a ceiling is set on per-kilowatt-hour compliance obligations and alternative compliance payments are established. A regulator may also be able to improve RPS cost-effectiveness through the adoption of additional procurement rules and mechanisms. California, for example, has adopted a standard contract and least-cost competitive bidding procedures for utilities to use, with independent oversight. Because attributing electric system costs is not trivial, the RPS should designate responsibility and provide funding for independent monitoring and reporting on total cost impacts to consumers, including those related to transmission and capacity as well as avoided costs such as fuel or environmental compliance. This is important for ongoing policy support, especially given the existence of simultaneous, non-RPS power system cost drivers, such as generation replacement, grid investment, or new environmental compliance costs.
- **To what degree will out-of-state renewables count toward RPS targets?** All else equal, allowing cross-border trade of renewable power will generally reduce total costs by giving states with less renewable energy resource access to larger, and perhaps cheaper, supplies in other states. At the same time, the use of out-of-state generation can affect the overall diversity, reliability, and security of a state's electricity supply. For example, long-distance imports may

be more subject to point disruption, but can also help reduce overall weather-related intermittency by providing greater geographic diversity. Also, there are pending cases based on the Commerce Clause challenging the authority of states to limit RPS to in-state sources.

- **How will responsibility for and costs of supporting grid infrastructure be determined?**

Because RPSs mandate the development of new-generation infrastructure, this may require investment in new transmission, firming, or other supporting infrastructure. Protocol for this should be set out explicitly in an RPS, as the cost and

availability of new transmission, distribution, and firming can significantly affect the success of an RPS. Texas established a Competitive Renewable Energy Zone model, which socializes the cost of developing new transmission lines in advance across all customers. And in California, billions of dollars have been spent developing new transmission capacity, following a structured stakeholder initiative, to help bring rural renewable power resources to coastal demand centers. Much of those costs have likewise been socialized across the state's investor-owned utility transmission grid.

The costs? In Washington State utilities are serving about 8 percent of their load with new qualified renewables, but the impact on customer bills is about 1 percent.

—David Danner, chair, Washington State Utilities and Transportation Commission

Additional Resources

For RPS implementation maps and updated state policy details, see the Database of State Incentives for Renewables and Efficiency (DSIRE), maintained by the North Carolina Solar Center and the Interstate Renewable Energy Council (IREC) at <http://dsireusa.org>.

Other resources include:

1. LBNL. “Renewable Portfolio Standards Resources.” <http://emp.lbl.gov/rps>
“A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards.” May 2014. <http://emp.lbl.gov/publications/survey-state-level-cost-and-benefit-estimates-renewable-portfolio-standards>
2. Clean Energy States Alliance. “State-Federal RPS Collaborative.” www.cesa.org/projects/state-federal-rps-collaborative
3. Climate Policy Initiative. “Limiting the Costs of Renewables: Lessons for California.” June 2012. <http://climatepolicyinitiative.org/wp-content/uploads/2012/06/Limiting-the-Cost-of-Renewables-Lessons-for-California.pdf>
4. North Carolina Sustainable Energy Association. “North Carolina’s Renewable Energy and Energy Efficiency Portfolio Standard.” http://energync.org/resources/regulatory-landscape/state_policies



Net Energy Metering

NET ENERGY METERING (NEM) is a policy and tariff mechanism that requires utilities to compensate customers for feeding power into the grid from a small distributed-power system, typically solar, and usually located at the customer's home or business. NEM exists in many states and the specifics of its implementation vary both technically and in terms of its monetary impact on customers. Typically, any electricity the customer purchases from the utility is netted against the excess distributed-energy production that the customer delivers back to the grid each month, and the customer is credited for net energy production at the applicable NEM rate.

A notable characteristic of NEM is the compensation rate for energy delivered to the grid. Most often, utilities are required to compensate customers at the full retail electricity rate. This simplifies administration and communications, and it has made NEM an effective way to encourage the development of on-site distributed power. Customer-sited distributed generation has a number of benefits, from fuel diversification and carbon emissions reductions and in some cases increased grid efficiency and avoidance of electrical distribution system upgrades.

However, retail electricity rate structures have generally been designed for policy goals other than encouraging distributed generation—that is, primarily to fairly recover a utility's costs in delivering energy services. The use of full retail rate NEM raises issues in current rate design. For example, a customer whose monthly distributed-power production level equals his monthly energy demand may pay nothing under a per-kilowatt-hour electricity rate structure despite regularly using the utility's distribution system. Or, in a tiered rate system, NEM customers with high total electricity use may be credited more for their distributed-power production than customers with a distributed generation system using less energy. Both situations may create a cross-subsidy, though the level of this subsidy may be mitigated by the utility's avoided costs or the beneficial grid services that a distributed-power system can offer.

Some states have undertaken efforts to more accurately determine the costs and benefits of both on-site distributed-power generation and other grid services in order to better understand the effects of NEM under existing rate structures. Potential responses have included refining the NEM compensation rate, reforming the broader existing electricity rate structure, or both.

Where to look? Austin, Texas, and Vermont



AUSTIN, TEXAS. Austin, Texas, is notable for being one of the first places to explore refinements to NEM that may better account for the benefits and costs of distributed generation. While the jury is out on the long-term implications of Austin's effort, it provides a useful early example.

For about a decade Austin, through its municipal utility Austin Energy, offered a conventional “run-the-meter-backwards” retail-rate NEM tariff for small distributed-power systems. In 2012, however, Austin revisited its NEM policy for residential distributed solar photovoltaic systems, following a period of rapid uptake and amid questions

RECOMMENDATION

States should increase the power-generation choices available to utility retail customers, by adopting a Net Energy Metering (NEM) policy that compensates customers for offsetting their energy use through a small, on-site, clean power system. Compensation for the value of the on-site system and any excess generation should be provided in the form of a credit on the customer's utility bill under a rate mechanism that has been determined in a fair and transparent manner.

regarding cost-effectiveness. In doing so, Austin Energy became the first utility in the country to update its existing NEM framework with a so-called “Value of Solar Tariff (VOST).” This step followed extensive stakeholder discussions and relied upon a valuation tool commissioned by utility staff and developed by third-party consultants. That tool enabled utility staff to better understand the costs and benefits of distributed customer-owned generation and to regularly update the value of solar electricity to the City of Austin. Austin’s approach has encouraged similar efforts in other states, with varying results.

Austin’s approach to NEM credits customers for every unit of energy generation at the same value of solar rate, and also charges customers for gross consumption of energy in order to ensure utility recovery of distribution service costs. This approach is implemented based on readings from two separate electric meters—one for the solar system, and the standard one at the connection to the grid. In periodically updating the value of solar rate paid for on-site generation, Austin Energy uses a transparent tool that calculates a current “indifference rate” that represents the rate at which the utility is financially indifferent to whether the solar energy is generated by the customer or the utility. Components analyzed in the Austin Energy Value of Solar rate include:

- **Electric energy and capacity:** Distributed generation systems reduce the amount of electricity that must be generated or purchased by the utility to serve load.
- **Transmission and distribution:** Distributed generation systems avoid some grid use and capacity requirements.
- **Grid losses:** Since distributed generation systems serve load at or very near the customer premises, conversion and resistance losses are also avoided.
- **Fuel price hedge:** Solar power is free and has no fuel price uncertainty and therefore offers benefits equivalent to a thirty-year fixed-price contract for fuel that otherwise would have to be purchased at often volatile market prices.

- **Environmental benefits:** Emission-free solar power offers significant environmental improvements compared to the grid’s conventional fuel mix. In Austin, the value that customers place on this benefit is estimated through willingness to pay reflected in the prices of the utility’s existing retail green pricing program.

While the algorithms used to calculate the VOST rate are flexible enough to be revised as more accurate valuation mechanisms are developed, in the interim the exercise of valuing the benefits and costs of distributed solar to the local grid brings some transparency to the debate over the value of on-site solar generation in Austin. The value-of-service method and rate design may not be adaptable to every state or utility, but can serve as a guide for further innovation, be that either Austin’s “buy all, credit all” two-meter model or the single-meter net-energy approach used in many other states. Indeed, Minnesota recently enacted legislation that allows utilities to propose a value-of-service rate as an alternative to conventional full retail-rate NEM. Similar valuation exercises are underway in at least seven other states, including Arizona, California, Colorado, Georgia, Hawaii, Nevada, and North Carolina.



VERMONT. Whereas Austin’s VOST approach reimagines NEM from the ground up, Vermont’s recent experience offers an alternative to states aiming to adjust an existing NEM policy to support broader uptake. Amid rapid growth in rooftop solar, wind, and other on-site distributed-power systems, the Vermont Legislature in 2102, under Act 125, directed the state’s Public Service Department to evaluate the existing NEM policy, and specifically assess the costs and benefits of on-site generation, any customer cross-subsidies, and any impact on utilities’ fixed-cost recovery. In-house departmental analysis and meetings with affected parties resulted in the release of a simple spreadsheet model and summary report, which found overall costs or benefits averaged across utilities of about 1 to 2 cents per kilowatt-hour of NEM production. These findings were later used to inform legislative

adjustments to the NEM policy, including raising the utility enrollment cap; slightly reducing the state's existing solar production subsidy paid to solar systems on top of NEM rate offsets (to account for differences in existing tiered-rate structures); and increasing the size of systems eligible for NEM enrollment.

Other states that choose to follow Vermont's approach to NEM analysis and reform may

incorporate different variables and parameters or arrive at different state-specific results. And these results may change over time alongside electricity market and policy conditions. But establishing a framework and capacity for quantitative analysis—whether from a blank slate, as in Austin's case, or more incrementally, as in Vermont—certainly looks to be a useful and reasonable way to ensure NEM's continued effectiveness.

There's really only a handful of states where DG [distributed generation] has taken off. In our view, net metering continues to be a very successful tool in most of the country. In those states that are most advanced, the time is ripe to talk about how we can more equitably share the costs of grid services, while continuing robust renewables growth.

—Devra Wang, director of the California Energy Program, NRDC

Policy Benefits

More than forty states and hundreds of utilities already have a NEM policy in place. The policy was first implemented in the United States over thirty years ago, and the 2005 Energy Policy Act explicitly required state regulators to consider it.

For the customer-owner, NEM's bill-crediting mechanism is simple and understandable. Where NEM credits customers at the full retail rate, this provides a strong financial incentive and is often a key factor in making the economics of installing a distributed system attractive.

More broadly, the installation of more distributed-power systems can provide a variety of benefits, such as diversifying the fuel mix and reducing the carbon-emissions intensity of the local grid, avoiding energy losses from power transmitted from centralized plants over long distances, and postponing the need for utility distribution, transmission, and generation upgrades.

On the other hand, distributed-power systems also incur costs. The local grid may require some upgrades to deal with the two-way flow of power on the local distribution circuit or the intermittency of generation. Also, depending on existing rate structures, NEM may result in participants avoiding paying for utility equipment and services that they nonetheless use. This situation could result in rate increases that shift some of the cost of the utility equipment to customers without distributed-power systems.

The grid itself has an inherent value in terms of providing reliability, in terms of providing access to as much energy as you want, whenever you want.

—Snuller Price, partner, Energy and Environmental Economics, E3

DESIGN CONSIDERATIONS

States considering enacting new NEM policies, or revising existing NEM policies to meet an evolving market, should consider the following key design questions:

- **What is the rate at which distributed-power system owners will be compensated for offsetting generation or excess electricity delivered to the grid? How will it be set?** Using the retail electricity rate to compensate customers is an easy way to encourage the development of distributed-power systems. However, this approach sometimes may not reflect the true benefits or costs of an on-site grid-connected distributed-power system or the supporting transmission and distribution services that the utility continues to provide. As our ability improves to accurately assess both aspects, states may decide to adopt a regulatory model that periodically updates the value of solar and other distributed technologies to a utility and its customers. This will likely require that states undertake empirical studies in order to generate the data to support appropriate legislation or regulation.
 - **Which distributed-power technologies should be eligible?** Broad eligibility of renewable or other clean power technologies (such as fuel cells) is more likely to encourage innovation and competition. One way to ensure flexibility may be a performance standard rather than a technology whitelist.
 - **Should there be a total program capacity cap?** Many states have instituted program enrollment caps to ensure that regulators and utilities can observe and respond to any issues that may arise from increasing distributed-power system penetration. Such a cap should be considered a temporary measure until a determination can be made about the design of the NEM policy and related benefits and costs.
 - **What is the eligibility cap on the size of each individual system?** As a general principle, eligible system size should be commensurate with typical on-site historic electricity use. Some states further limit the maximum eligible system size, though doing so may preclude commercial customers.
- Any such limits should be based on locally appropriate technical or rate-related grounds rather than an arbitrary capacity designation, for example, 1 megawatt.
- **Should meter aggregation or “virtual net metering” be allowed?** This describes the practice of installing a single distributed-power system on a single electric circuit but applying its NEM production credits to multiple customer meters within a contiguous property. For example, residents of a multifamily housing unit would be able to “share” a single on-site system. This practice should generally be permitted.
 - **How should net excess generation be dealt with?** Most current NEM policies allow bill credits for excess on-site generation to carry forward month to month. Some states require utilities to compensate customers on an annual basis for net excess generation over the course of a year, though this is more controversial.
 - **Who owns the renewable energy credits (RECs) generated by the distributed-power system?** REC ownership should be made clear in the implementing legislation or regulation. While many states require utilities to meet some portion of their RPS mandates through distributed-power systems, REC ownership should by default remain with the distributed-power system owner or the utility should compensate the distributed-power system owner to acquire any on-site RECs, just as the utility is required to do in purely wholesale transactions.
 - **Energy storage or microgrid ability?** Combining distributed-power systems with on-site storage capacity or ancillary grid services can enhance grid resiliency and other benefits of the system. NEM, by itself, does not provide a strong incentive for customers to undertake this potentially significant additional investment. Additional policy measures may be needed to help increase investment in this area, with significant resulting benefits.

- **Does a sustainable NEM policy require broader rate reform?** On-site grid-connected customer power generation is a fundamental change in the way that customers relate to their utility. Policies and tariff structures such as NEM that help enable this new relationship have sparked larger

discussions regarding the design of electricity rates and related issues. As Austin, Texas, has shown, this is a useful conversation in the context of NEM, along with other important goals for the grid.

I think one of the really interesting dynamics in this whole conversation is the change in the political economy of rate making. We have a new set of stakeholders entering the rate-making context. And it's very interesting to hear the concerns from owners of distributed generation who are worried about stranded costs—homeowners worried about stranded costs. And I think about that as a nuclear power plant issue.

—Michael Wara, associate professor of law, Stanford University

Additional Resources

For NEM implementation maps and updated state policy details, see the Database of State Incentives for Renewables and Efficiency (DSIRE), maintained by the North Carolina Solar Center and the Interstate Renewable Energy Council (IREC) at <http://dsireusa.org>.

Other resources include:

1. Interstate Renewable Energy Council (IREC). “Net Metering Model Rules, 2009 Edition.” October 2009. http://irecusa.org/fileadmin/user_upload/ConnectDocs/IREC_NM_Model_October_2009-1.pdf
“A Regulator’s Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation.” October 2013. www.irecusa.org/wp-content/uploads/2013/10/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG.pdf
2. Energy and Environmental Economics, E3. “California Net Energy Metering Ratepayer Impacts Evaluation.” October 2013 www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm
3. Rocky Mountain Institute Electricity Innovation Lab. “A Review of Solar PV Cost and Benefit Studies.” September 2013. www.rmi.org/cms/Download.aspx?id=10793&file=eLab_DERBenefitCostDeck_2nd_Edition&title=A+Review+of+Solar+PV+Benefit+and+Cost+Studies
4. Solar Electric Power Association. “Ratemaking, Solar Value and Solar Net Energy Metering—A Primer.” July 2013. www.solarelectricpower.org/media/51299/sepa-nem-report-0713-print.pdf
5. Karl Rabago. “The Value of Solar Tariff: Net Metering 2.0.” The ICER Chronicle. December 20, 2013. www.icer-regulators.net/portal/page/portal/ICER_HOME/publications_press/ICER_Chronicle/Art_10
6. Clean Power Research. “Minnesota Value of Solar: Methodology.” November 2013. <https://mn.gov/commerce/energy/images/DRAFT-MN-VOS-Methodology-111913.pdf>



Community Renewables


SEVERAL STATES HAVE SUPPORTED more use of renewable energy, or other sources of clean distributed power, by enabling such projects to be underwritten by numerous “subscribers” who then receive benefits on their utility bills for the energy the project provides to the grid. In a recent publication the Interstate Renewable Energy Council (IREC) describes this opportunity as “programs that enable multiple customers to share the economic benefits of one renewable energy system via their individual utility bills.” These programs are referred to by several names: “community renewables,” “community solar,” “shared renewables,” and “community solar gardens.” The most popular efforts to date use solar photovoltaics, although some programs cover energy produced from other sources.

The “community renewables” model can be considered an off-site, grid-side-of-the-meter analogue to the on-site model now used for smaller solar systems or other clean distributed-power systems at people’s homes. One key difference is that because of the larger scale and off-site nature of distributed community projects—which therefore require additional management and reliance on grid infrastructure—community renewables typically involve closer regulatory oversight.

RECOMMENDATION

States should enact legislation to permit distributed “community renewables” projects that enable multiple customers to share in the economies of scale and other benefits of an off-site renewable energy system via their individual utility bills.

Where to look? Colorado, California, and Minnesota



COLORADO. Colorado has had success in expanding access to community renewables (specifically solar photovoltaics) by encouraging the construction of solar projects of 2 megawatts or less to offset the power needs of neighborhoods and small communities. The Community Solar Gardens Act (HB 10-1342) allows the power generated by “solar gardens” to be credited against the utility bills of the individuals who “subscribe” to the project, and in so doing underwrite the cost of project construction. The act was adopted in 2010 and implementing regulations were issued in 2012. Since the effective dates of the Colorado law and regulations, twenty-two projects totaling 13.5 megawatts peak capacity have been installed.



CALIFORNIA. Following Colorado’s early experience, in 2013 California enacted the Green Tariff Shared Renewables Program (SB 43). The legislation directs the state’s public utility commission to adopt regulations to implement the law for 600 megawatts of initial capacity. That process is ongoing, with participating utilities submitting proposed programs for anticipated customer availability in 2015.



MINNESOTA. Minnesota also enacted legislation (216B.1641) in 2013, as part of a broader update to its statewide renewables policies, authorizing a “community solar gardens” program. The legislation specifies that individual projects must

use the state’s yet-undetermined “value of solar” tariff, be up to 1 megawatt in capacity, and be located in counties adjacent to the customer. Also, the number of projects will not be limited. In early

2014, Minnesota’s public utility commission was reviewing a proposed program filed by its major utility, Xcel, in response to the legislation.

In Colorado, we put in place what we called solar gardens...[I]t...was incredibly successful...what we saw was a very fast uptake. It was a capped program. But they had I think something like ten or fifteen times the capacity in applications than they actually could meet within the cap. And it did offer a variety of different benefits, some of which were associated with cost...People can just sign up easily. It’s another tool in the toolbox.

—Tom Plant, vice president for state policy, Advanced Energy Economy

Policy Benefits

There are significant benefits from community-distributed renewables for consumers, utilities, and investors.

For consumers, the programs offer the chance to participate in the deployment of solar or other renewable generation even if they do not own property where it can be sited. Also, the cost to the consumer of becoming a “subscriber” can be significantly less than often required to install a solar or other distributed-power facility at the consumer’s residence.

For utilities, these programs could offer an opportunity to ensure that projects are located and constructed in ways that efficiently access both the renewable resource and the grid, though this benefit would depend on program design choices.

And for potential third-party owners and financiers of community distributed power, the relatively larger size of these projects compared to separate installations at individual residences helps reduce the per-kilowatt-hour “soft costs”—including customer acquisition, cost of interconnects, permitting, labor, and maintenance costs.

DESIGN CONSIDERATIONS

There are numerous ways community renewables programs like this can be designed. Many of the key design considerations are similar to those for an on-site third-party ownership policy:

- **What sizes and types of facilities should be eligible?** Much of the activity around community renewables has focused on mid-sized solar photovoltaic projects. To the extent that alternative distributed technologies—wind, biomass, fuel cells, etc.—do not have significant environmental impacts, they should be permitted to enable flexibility.
- **Who is eligible to be a developer and owner and what obligations do they have?** In principle, both third parties (for profit, and not for profit) and incumbent utilities should be eligible. Standards of competence for third parties are an appropriate safeguard but should not be used as an undue barrier to participation. Incumbent utilities and competitive providers should be subject to comparable rules to ensure fair competition.

There's such a limited number of folks who can actually host solar on their roof, and those folks are homeowners with enough room space that's oriented to the right way without trees. But are there also more cost-effective ways to deploy solar? Can you do midsize or some other larger-scale systems that people buy into, that neighborhoods or communities have purchased into? Does that give people the same sense of ownership?

—Cisco DeVries, president and CEO, Renewable Funding

- **Who is eligible to be a subscriber?** Subscription should generally be limited to customers within a certain geographic proximity to the generation system itself—the surrounding “community”—though this need not be a fixed arbitrary radius. Subscribers should be able to participate in a share representing an approximation of their existing electricity demand. In Colorado, for example, consumers may generally subscribe within their county at up to 120 percent of average annual electricity consumption.
- **How is the energy produced by the community facility valued and credited to subscriber bills? Is there a limit or prohibition on cross-subsidy from nonparticipating ratepayers?** Due to the scale and grid-reliant nature of community power, it is important that such projects do not become vehicles for cross-subsidy. The regulator should establish—or system developers and distribution grid owners should negotiate—subscriber tariffs that attempt to reflect the true economic costs and benefits of such systems, including the costs of the utility's distribution system in a fair and efficient manner. California's community solar policy design, for example, explicitly stipulates that the tariffs set for participation in community power projects cannot transfer costs onto nonparticipants.
- **Should there be a cap on the amount of community renewables that utilities are required to accommodate?** Colorado limited the initial size of its program to 6 megawatts, per utility, for the first three years of the program. California has authorized a 600-megawatt program, for which regulations are still being developed.
- **Who owns the renewable energy credits (RECs) resulting from the project?** States should determine whether to specify that the utility that purchases the power from the project also owns the RECs, or whether those remain the property of the project developer or subscribers. In California, for example, RECs associated with electricity generated and utilized as part of the program are expected to be retired by the utility on behalf of the customer and may be used toward Renewable Portfolio Standard requirements.

We are looking at the soft costs [of installing distributed-energy technologies], because a given state can't really have an effect on hardware cost reductions... If you think of the communities that have adopted community solar, they have reduced soft costs of customer acquisition and installation through group buying and peer effects.

—Richard Kauffman, chair, energy and finance, State of New York

Additional Resources

For updated details on state community renewables programs, see the Database of State Incentives for Renewables and Efficiency (DSIRE), maintained by the North Carolina Solar Center and the Interstate Renewable Energy Council (IREC) at <http://dsireusa.org>.

Other resources include:

1. IREC. "Model Rules for Shared Renewable Energy Programs." June 2013.
www.irecusa.org/2013/06/irec-releases-revised-model-rules-for-shared-renewable-energy-programs
2. National Renewable Energy Laboratory (NREL). "A Guide to Community Shared Solar: Utility, Private, and Nonprofit Project Development." May 2012.
www.nrel.gov/docs/fy12osti/54570.pdf
3. Michael Borchardt. "The Colorado Community Solar Gardens Act and Implications for Minnesota Solar Gardens." May 2013.
www.mnrenewables.org/sites/mnrenewables.org/files/Community%20Solar%20Gardens%20Law%20Student%20Report.pdf



Renewable Energy Tariffs

MANY LARGE CONSUMERS OF ELECTRICITY, often reflecting corporate social responsibility targets, seek to procure some or all of their electricity from renewable sources. For consumers with large centralized electricity loads, such as data centers or industrial facilities, on-site generation options such as rooftop solar are often not feasible. For this reason, large consumers may prefer to purchase renewable electricity from their incumbent utility. However, they may also want to ensure that, just as with self-generation, this energy is from renewable generation that is additional to what the utility is otherwise required to provide by the state.

To accomplish this result, some states now allow large electricity consumers to work through their utility to solicit new energy generation projects to provide the requested renewable power. In these states, large energy consumers are able to meet corporate social responsibility targets without burdening the utility customer base with any cost premium that may exist.

Where to look? North Carolina and Virginia



NORTH CAROLINA. North Carolina has seen large growth in energy demand recently as more data centers have been located in the state. These data centers have added to the variety of large commercial and industrial consumers of electricity in the state.

Responding to a demand for additional renewable energy from these customers, Duke Energy filed a “Green Source Rider” pilot program with the North Carolina Utilities Commission that was approved in December 2013. Under this tariff, nonresidential customers who have added more than 1 megawatt in demand to the grid since June 2012 are eligible to participate.

Participating customers request an annual amount of energy and renewable energy credits (RECs) through the program’s application process, and

agree to participate in the program for a contract term of three to fifteen years. Duke then enters into a power purchase agreement (PPA) with a third party on the customer’s behalf or matches the customer’s demand with renewable generation from a Duke Energy facility with unclaimed capacity. The customer continues to pay typical demand charges and fees under Duke’s industrial tariff, but is also charged for all extra costs related to the procurement and delivery of the additional renewable energy and retirement of RECs. This eliminates any potential for cross-subsidy by other customer groups. Finally, the customer receives a bill credit for the avoided energy/capacity expense arising from participation in the program, which is calculated in accordance with Duke’s regulator-approved avoided cost model.

This pilot program has an overall annual cap of 1 million megawatt-hours.

RECOMMENDATION

States should permit contracting between utilities and large commercial and industrial energy consumers to procure additional renewable power at the request of, and paid for by, the relevant consumer. Steps should be taken to avoid cost shifting to nonparticipants and to ensure that new generation would not have been developed otherwise.



VIRGINIA. Meanwhile, in Virginia, Dominion Power in April 2014 began offering a similar green tariff, called “Rate Schedule RG,” to nonresidential customers whose power demand exceeds 500 kilowatts. Under this program, the customer can request the type or even particular project source of its desired qualified renewable generation from outside Dominion service territory, as long as the source is within the broader PJM regional transmission market. Eligible customers sign a contract for Dominion to purchase additional amounts of

renewable energy as determined by the customer. The renewable energy supplier signs a power purchase agreement with Dominion equal to the amount of renewable energy to be purchased under the customer’s contract. This approach allows larger commercial and industrial customers to identify renewable projects that meet their specific needs, creates competition, and potentially facilitates lower prices for renewables. Program participation is currently capped at a hundred customers.

In Texas’s competitive retail market, there are retailers who aren’t exclusively renewable, but they offer renewable product. There’s a market for that. There are people who are willing to pay more in order to feel good about it.

—Ken Anderson, commissioner, Public Utility Commission of Texas

Policy Benefits

For the large energy consumer, a green tariff provides a way to meet its corporate social responsibility goals without having to install and own its own renewable generation capacity. For the utility, this option ensures that a large customer continues to purchase its electricity from the utility instead of developing its own generation.

DESIGN CONSIDERATIONS

In addition to ensuring that the electricity under a green tariff is additional to electricity a utility is otherwise required to procure, for example, under an RPS requirement, policymakers have several choices to make when designing a green tariff.

- **At what level will rates be set?** Rates should be set at a level that allows the utility to recover the full cost of providing the renewable power, that is, ensuring there is no cross-subsidy from non-green tariff customers.
- **Will there be a minimum size for the contract?** In order to reduce transaction and administration costs, regulators may wish to set a minimum contract size.
- **Should the utility be required to obtain a certificate of convenience and necessity in order to construct facilities under a green tariff?** Standard rules for project approval, interconnection, and construction should be followed by the utility or by the project developer.
- **Will the RECs that result from the renewable generation be bundled with the power sold to the consumer?** RECs should be bundled and sold to the customer. To avoid the use of RECs for state-mandated compliance purposes, it is best to establish RECs in the name of the customer who is paying for them on its monthly bill. In this way, the RECs can be retired and attributed to the customer’s targets.

Additional Resources

1. Duke Energy. “Duke Energy Carolina’s Petition for Approval of Green Source Rider Pilot.” November 2013.
www.duke-energy.com/pdfs/2013111501-addendum.pdf
2. Dominion Virginia Power. “Schedule RG.” April 2014.
www.dom.com/dominion-virginia-power/customer-service/energy-conservation/schedule-rg.jsp



Financing



Energy Savings
Performance Contracts



Third-Party Ownership of
Distributed-Power Systems



Property-Assessed
Clean Energy



On-Bill Repayment

Account Summary

is Bill
t - Thank You
Delivery Charges

Delivery Svcs Balance

Cost of Electricity

Category	Rate	Quantity	Total
Delivery Services			
Customer Charge			
Distribution			
Transmission *			
Transmission	.04825	X	
Local Energy	.01458	X	659
Losses	.00482	X	659



Energy Savings Performance Contracts

AN ENERGY SAVINGS PERFORMANCE CONTRACT (ESPC) is a contract between an entity such as a school, university, prison, hospital, or other government office and a qualified energy service company (ESCO) for evaluating, recommending, and implementing cost-savings measures related to energy or water use. ESPC savings most commonly result from building efficiency improvements. Under a typical ESPC, an ESCO designs, installs, verifies, and guarantees that the measures and strategies will achieve a specified level of energy (or, if specified, cost) savings over an extended contract term. Customers, most commonly public entities, typically finance projects using tax-exempt bond financing arranged by the ESCO through a commercial lender. This debt remains on the customer's balance sheet and is repaid over the life of the ESPC out of the energy savings achieved by the project. In effect the ESPC is a financial mechanism to pay for today's facility upgrades with the savings realized in energy or water use over the term of the contract.

This chapter focuses on policy that expands utilization of ESPC's by public entities—which are estimated to represent about 75–85 percent of the total ESCO market today—as the private sector does not require authorizing legislation to enter into these contracts.

Where to look? Pennsylvania



Between 2000 and 2010, Pennsylvania's ESPC program accomplished over \$590 million in energy efficiency retrofits in state buildings alone, all at no up-front cost. While the state's program is no longer as robust as it once was, its achievements during the past decade still stand as the best example of what a well-designed ESPC program can accomplish.

Pennsylvania's success was due a variety of factors. During the initial design and implementation of the program, the state designated an agency champion—the Department of General Services—to oversee the program

and help state facilities take advantage of it. Additionally, Pennsylvania's legislation provided funding for outside technical resources and support to train Department of General Services staff and ensure the program would be well designed and run.

Another hallmark of Pennsylvania's program was the level of cooperation the program designers were able to achieve among all state agencies and staff involved, including the attorney general's office and the Treasury office. The speed of implementation of the ESPC program was facilitated by the comfort all state government stakeholders had with the process.

RECOMMENDATION

States should adopt legislation authorizing Energy Savings Performance Contracts (ESPCs). States with existing authority should ensure that the benefits available through this financing mechanism are being effectively realized.

The first underpinning of success is performance-contract-enabling legislation. The second is an energy agency that administers the program and a state that actually wants it to work, a champion.

—Charles Goldman, Energy Analysis and Environmental Impacts Department head,
Lawrence Berkeley National Laboratory

Pennsylvania’s ESPC program was also distinguished by the consistency of its rules over a decade and through different state administrations. With standard project documents and state ESPC contracts, all stakeholders—ESCOs, state agencies with administrative oversight, and state facility “clients”—became comfortable with the process. Eventually, the Department of General Services was able to batch-process projects and run multiple

requests for proposals (RFPs) at once, which sped up the process even further. An initial loan term of fifteen years (later extended to twenty years) increased the amount and extent of projects that were financeable under the program.

Finally, Governor Rendell (in office 2003 to 2011) made state-facility use of ESPCs an administration priority, which increased demand for ESPC services.

Policy Benefits

ESPCs allow public entities to implement equipment and facility upgrades to achieve energy and water savings with little or no up-front investment. By using ESPCs, public entities can begin benefiting from technology advances that improve energy and water conservation without waiting for the appropriation of public funds. ESPCs typically guarantee that the public entity will realize cost savings over the life of the contract and stabilize its energy and water costs.

Both state and local governments across the country have authorized their agencies and other public entities to use ESPCs, as has the federal government since 1986. Lawrence Berkeley National Lab (LBNL) estimates total public-sector ESCO market activity of about \$1.4 billion per year over the past two decades, with consistent growth. In 2008, state and local projects alone totaled nearly \$3 billion. Annual average net public-sector “customer” benefits from such projects are further estimated to have averaged just under \$1 billion per year, with typical project cost-benefit ratios of about 1.4, or about \$0.89 per square foot. More qualitatively, at the national level, the National Association of Manufacturers issued a report in 2013 declaring a recent federal ESPC funding initiative to be “an unqualified success” in spurring investment and “creating jobs across the manufacturing supply chain.”

DESIGN CONSIDERATIONS

Most states have enacted legislation to authorize energy savings performance contracting; however, the laws in many states unnecessarily limit the use of the authority. Key design features include the following:

- **Should contracting authority be applicable to savings from reduced water usage as well as reduced energy consumption?** Although the generally used name “energy savings performance contracts” suggests that this approach applies to only energy savings, in fact many building renovations also include savings resulting from reduced water usage. The legislation authorizing ESPCs should encompass both energy and water savings.
- **What technology, equipment, and facility upgrades are eligible under the ESPC program?** A key issue regarding ESPCs is whether the public entity can realize the necessary level of savings in the cost of energy and water as a result of the work performed under the contract. States should avoid restricting the use of this authority to the installation of particular technologies or particular types of measures to improve efficiency in order to meet the overarching motivation for the program.

- **What types of entities are eligible to participate?** The ability to enter into an ESPC should apply to the full range of public entities: state agencies, local governments (including counties, cities, villages), local school districts, higher-education institutions, other state-supported institutions, and joint action agencies composed of political subdivisions. States should also ensure that in the implementation of the law, particular types of public entities are not dissuaded from participating because of budgeting requirements imposed on those entities. This has occurred in New Mexico, where school districts do not take advantage of the program because the law requires that the school district take on all the performance risk, rather than the ESCO.
- **What length of term should be allowed for performance contracts?** States should authorize an allowable ESPC term of at least fifteen years (many executed contracts will in fact be shorter than this allowable term). Authorizing even longer allowable terms of twenty years or more may offer useful flexibility in cases where the risk of changing energy efficiency technology is less of a concern.
- **Will there be a designated state office responsible for program implementation?** There are numerous challenges to achieving substantial implementation of ESPC authority. As in Pennsylvania, one office at the state level needs to be the champion for the program, and that office must have the implementation of the program as its primary (if not its exclusive) mission. It must take the lead in developing a prequalified list of ESCOs, approving standardized contracts and templates to be used in the state, ensuring proper tracking and monitoring of projects, and performing education and outreach activities to promote use of the program.
- **How will state ESPC programs be funded?** States must ensure that adequate funding is available to launch and operate an effective ESPC program. This will require a commitment from the governor and legislators. Increasingly, state agencies are electing to charge fees for the administration of specific ESPC projects, which are then incorporated into the financial structuring and cash flows of that project.

A lot of this comes down to program administration. You can design the greatest system in the world, but if it's not administered in such a way that people know about it and that it's easy, I think that it's doomed to fail.

—Tom Plant, vice president for state policy, Advanced Energy Economy

Additional Resources

For updated details on state ESPC policy implementation, see the Database of State Incentives for Renewables and Efficiency (DSIRE), maintained by the North Carolina Solar Center and the Interstate Renewable Energy Council (IREC) at <http://dsireusa.org>.

The American Council for an Energy Efficient Economy (ACEEE) also tracks state ESPC policies: <http://database.aceee.org>.

In reviewing and implementing improvements to state ESPC legislation, help is also available from the following organizations and resources:

1. Department of Energy (DOE) Office of Weatherization and Intergovernmental Programs, OWIP.
www1.eere.energy.gov/wip/solution_center/performance_contracting.html
2. National Association of State Energy Officials, NASEO.
www.naseo.org
3. National Association of Energy Service Companies, NAESCO.
www.naesco.org
4. Energy Services Coalition.
www.energyservicescoalition.org/legislation
5. LBNL. “Performance Contracting and Energy Efficiency in the State Government Market.” November 2008.
<http://emp.lbl.gov/sites/all/files/lbnl-1202e.pdf>
6. “Evolution of the US Energy Service Company Industry: Market size and Project Performance from 1990–2008.” July 2012.
<http://emp.lbl.gov/sites/all/files/lbnl-5447e.pdf>



Third-Party Ownership of Distributed-Power Systems

THIRD-PARTY OWNERSHIP of on-site distributed-power systems is a way for consumers to reconcile the relatively high up-front costs of installing rooftop solar and other distributed-power systems with their generally low operating costs. An increasingly common approach in some states is for the consumer to contract with a private company to finance, install, maintain, and manage the operation of the system while the consumer provides a project site and agrees to pay for the output of the system over a set term. This can be done through a lease by the consumer of the infrastructure itself or through a ten- to twenty-year term power-purchase agreement (PPA).

In cases where existing subsidies such as federal or state tax credits, tradable renewable energy credits (RECs), or net energy metering (NEM) already make the consumer economics of on-site distributed generation favorable, third-party ownership allows the user to pay little or nothing up front while entering a contract with payback rates often below the displaced cost of utility-provided electricity, even after the added cost of financing.

In and of itself, third-party ownership is simply a mechanism to enable private contracting between a consumer and a private firm; it is not a subsidy. Where permitted, however, it does improve a customer's ability to benefit from the various subsidies available to distributed generation generally.

Twenty-three states explicitly allow some sort of third-party ownership either through leases or PPAs. Elsewhere, the legal status of third-party ownership of on-site distributed-power systems is uncertain, disallowed under monopoly utility regulation regimes, or existing law suggests that such providers would be regulated as either a utility or competitive generator. In many of the states where it is expressly allowed, the majority of new residential rooftop solar installations are now owned by third parties, just a few years after providers entered the market. Similar ownership models apply in the commercial sector where month-to-month energy budgets may not otherwise allow self-ownership.

Where to look? New Mexico



With over three hundred days of sunshine per year, New Mexico is ideally suited to solar-power production.

And state regulatory mandates and subsidies have reflected this, with a solar and distributed-

power carve-out in the state's renewable portfolio standard and a residential tax credit for rooftop panel installation. New Mexico has also helped encourage rooftop distributed-power development through no-cost legislation that gives consumers

RECOMMENDATION

Third-party financing and ownership of on-site and, where applicable, community-based distributed-power systems has proven effective at broadening the availability of such infrastructure. States should authorize this form of financing and, as necessary, clarify that providers of this financing option are not classified as regulated utilities.

and installers the ability to enter into private contracts for the financing and installation of rooftop solar systems.

Specifically, in 2010 New Mexico enacted HB 181, which clarified that third parties could finance the deployment of rooftop-style solar photovoltaic or other distributed-power systems through payback agreements with the property owner. By explicitly stating that such third parties would not be subject to “jurisdiction, control or regulation of the commission and the provisions of the Public Utility Act,” the state established that such firms could offer their distributed-power financial and service products in the state with certainty that they would not be considered regulated utilities.

Terms of the legislation, which revised the state’s Public Utility Act, were straightforward, just a few pages in length, and reproducible elsewhere: the exclusion from “utility” status applies only to on-site production (for the system’s “host,”

its tenants, or employees), requires a common point of connection with the existing local utility distribution grid, and cannot be sized to exceed 120 percent of annual on-site power consumption. The legislation also restricts eligibility to only “renewable” distributed-power systems, whereas other states may choose to broaden applicability, depending on particular power system goals.

New Mexico’s legislation may seem like a minor matter, but it signals an important reality. Many state laws and regulations for the power system do not reflect a new technological reality in which even residential power users can now often economically meet their electricity needs through clean, on-site generation. While allowing third-party ownership is not a comprehensive strategy for encouraging the deployment of distributed-power systems, clarifying the issue has nonetheless removed a major regulatory roadblock to new market development at no direct cost to taxpayers or ratepayers.

Policy Benefits

For customers, third-party ownership tends to be popular for the low up-front cost, low-risk, low-effort option it provides. It offers a readily available turnkey product for those who would like to install and have maintained for them a rooftop solar system on their home or business for environmental reasons or where rooftop solar is already competitive with utility rates. And where existing subsidies make the total cost of ownership more attractive, third-party ownership is a way for a broader group of customers to benefit from these policies.

Third-party ownership particularly helps lower-income property owners to afford distributed-power systems and take advantage of related subsidies. First, it reduces or eliminates the need for up-front payment. Second, it helps such consumers maximize the value of tax benefits. This includes federal tax benefits from accelerated depreciation and the current 30 percent investment tax credit available to buyers of solar photovoltaic systems. For example, those with annual incomes below about \$75,000 might not otherwise have a federal tax burden high enough to use a large tax credit—on the order of \$10,000 for a typical residential rooftop system—while a third-party contracting firm is able to monetize that savings and reflect it in a lower monthly payment obligation. Overall, this helps mitigate the regressive nature of many existing rooftop solar subsidies. The ability to capture tax benefits through a third party can similarly benefit public tax-exempt entities that wish to install distributed power.

Finally, a multiyear fixed PPA or system lease rate can also help consumers offload the price risk of buying utility-provided power, though some third-party contracts may reserve the right to renegotiate payment terms given major utility rate adjustments.

Third-party ownership agreements are not the only way for homeowners to finance on-site generation. Federal Housing Authority-backed Title 1 home improvement and, specifically, “PowerSaver” loans offer a potentially lower-cost, if less comprehensive, option for residential solar photovoltaic installations. We believe, however, that it is worthwhile for states to enable the more popular privately contracted third-party ownership option as well.

It strikes me that what's going on right now is really the first instance of platform competition for regulated utilities, where they're competing against a really different platform to supply the service that they're used to selling in a monopoly context. And they're coming at DG [distributed generation] from all different directions, because they're afraid that their business model is being undermined.... We don't want PG&E getting a major bond rating downgrade, because DG is undermining their economics and their rate recovery. But we also don't want SolarCity having problems deploying panels on customers' rooftops, because we want that, too. We want both things.

—Michael Wara, associate professor of law, Stanford University

DESIGN CONSIDERATIONS

- **How will third-party owners be classified?**

Classification as a utility may prevent third parties from operating in a state due to the resulting regulatory requirements. States with the most active third-party providers—including Arizona, California, New Jersey, Ohio, Texas, and others—have generally designated such firms as nonutility, nontraditional power generators that do not provide ancillary services and therefore should not be required to operate as utilities.

- **What distributed-power technologies will be eligible for third-party ownership?**

Today, the most established third-party ownership providers focus on solar photovoltaics, but eligibility for such private contracting should be extended to other on-site distributed-power systems as well, potentially including small on-site wind and geothermal systems, solar water heaters, heat pumps, cleaner fossil such as gas-fired microturbines or microCHP, as well as fuel cells, storage, and other microgrid equipment. For these technologies, project scale should generally be based on maximum on-site demand of the residential or commercial end-user rather than an arbitrary kilowatt capacity limit.

- **Will third-party-owned systems be eligible for NEM programs?**

Because some NEM programs may act as subsidies from the utility to the consumer, or across consumers, some states with third-party ownership restrict the simultaneous use of NEM (or other generally available distributed-power subsidies). This may

be a reasonable short-term measure in some circumstances, but ideally any problems due to NEM or other distributed-power subsidies should be addressed through changes in the design of the NEM policy, rate structure, or subsidy itself rather than through artificial limits on private contracting.

- **Who will own any RECs produced by the distributed-power system?**

States vary with respect to ownership rights of RECs produced by distributed-power systems owned by third parties, variously assigning them to the third-party provider, the customer or system owner, or elsewhere. For many commercial consumers, ownership of the credit is an important part of the overall value of the system as it may affect their ability to advertise their use of such a system.

- **Will both leases and power-purchase agreements be allowed?**

“Full” third-party ownership regimes generally allow the provider to enter into equipment leases or PPAs with consumers. Some states today restrict the use of PPAs, which particularly affects the ability to use the third-party ownership model for government-owned buildings. In general the additional flexibility of PPAs should be allowed, as doing so does not materially affect the role of the third-party provider. The scale of such agreements is quite small—the power consumption of just an individual consumer—and so these PPAs should be considered financial instruments rather than a form of utility power supply service.

- **Will municipal utilities be allowed to restrict third-party ownership of distributed systems?**

In some states municipal or co-op utility service areas may choose to limit third-party ownership, or state-level legislation may otherwise restrict municipal utilities from allowing it. We do not see a convincing argument to justify such restrictions.

- **Will utilities be allowed to act as third-party owners?**

In some states, including Ohio, Florida, Georgia, and California, utilities themselves have sought to act as third-party providers, either directly or through unregulated affiliates and as investors in other third-party ownership firms. This should be encouraged, though utilities should be restricted from leveraging their monopoly status to create a financial privilege or barrier to entry for competitive third-party providers.

Additional Resources

For third-party ownership implementation maps and updated state policy details, see the Database of State Incentives for Renewables and Efficiency (DSIRE), maintained by the North Carolina Solar Center and the Interstate Renewable Energy Council (IREC) at <http://dsireusa.org>.

Other resources include:

1. NREL. “Solar PV Project Financing: Regulatory and Legislative Challenges for Third-Party PPA System Owners.” February 2010.
www.nrel.gov/docs/fy10osti/46723.pdf
“Solar Leasing for Residential Photovoltaic Systems.” April 2009.
www.nrel.gov/docs/fy09osti/43572.pdf
“Residential Solar Photovoltaics: Comparison of Financing Benefits, Innovations, and Options.”
www.nrel.gov/docs/fy13osti/51644.pdf
2. Rarus Institute. “The Customer’s Guide to Solar Power Purchase Agreements.” October 2008.
ww2.cityofpasadena.net/waterandpower/solar/CustomerGuidetoSolarPPAs.pdf
3. US DOE Energy Information Administration. “Most New Residential Solar PV Projects in California Program Are Not Owned by Homeowners.” September 2013.
www.eia.gov/todayinenergy/detail.cfm?id=12991#



Property-Assessed Clean Energy

PROPERTY-ASSESSED CLEAN ENERGY (PACE) programs allow the up-front cost of energy efficiency and distributed generation to be financed through private or public capital and then repaid through a special assessment on the property tax bill of the improved property. A property owner borrows funds that cover all or part of the cost of the energy improvements. A PACE lien is then placed on the property, and an assessment is added to the property tax bill. The PACE assessment has priority over other obligations and is repaid over an extended period, usually fifteen or twenty years. At the end of the period, the special assessment is retired and the lien is extinguished.

Current PACE programs mostly target commercial projects, due to regulatory hurdles facing residential PACE. In 2010, the Federal Housing Finance Agency (FHFA) determined that PACE programs with first liens are contrary to the Fannie Mae-Freddie Mac Uniform Security Instrument. Efforts to resolve this issue are continuing, particularly through state-level funding, but uncertainty remains about the future of residential PACE programs.

PACE-enabling legislation exists in thirty-one states and the District of Columbia. Some states have programs currently in operation at the local government level. Others are on hold or under development, with some already passed into law but currently unfunded.

Where to look? Connecticut



In early 2013, Connecticut launched the first statewide commercial PACE (C-PACE) program. Commercial, industrial, and multifamily (defined as five or more dwelling units) properties are eligible. As of January 2014, seventy-seven towns had opted into the Clean Energy Finance and Investment Authority's C-PACE program, providing over 80 percent of the commercial and industrial properties in the state access to C-PACE financing. Since launching in 2013, over \$20 million in loans have been approved.

Several legislative criteria define the Connecticut program: 1) the energy savings-to-investment

ratio must also be greater than one, over the assessment term; 2) the mortgage lender on the applying property must consent to the C-PACE assessment; and 3) any interested municipality (the taxing entity in Connecticut) must opt into the statewide program, administered by the Connecticut's green bank, the Clean Energy Finance and Investment Authority (CEFIA). CEFIA is funded by a variety of sources, including federal funds and grants, surcharges on residential and commercial electric bills, and auction allowance proceeds from the Regional Greenhouse Gas Initiative, as well as private capital. Unlike programs in some other states, Connecticut C-PACE was created

RECOMMENDATION

States should authorize Property-Assessed Clean Energy (PACE) programs allowing property owners to access third-party finance for energy improvements, with repayment through an assessment on their property taxes.

with the support of the banking community. The Connecticut Bankers Association endorsed the final legislation.

Through Connecticut C-PACE, commercial property owners can finance energy efficiency and renewable energy improvements through a loan repaid by a voluntary tax lien, or “benefit assessment,” on their property tax bill. The benefit assessment is placed on the improved property as security for the loan. Private lenders provide capital to building owners,

either directly or through CEFIA as an originating intermediary.

Eighteen lenders currently participate in Connecticut’s C-PACE program. The program uses a “lending tree” model to ensure highly competitive bids from their prequalified lenders. CEFIA has originated deals directly and sold down pools of assessments to its Qualified Capital Provider list, which includes a mix of local and global financial institutions.

What we did with PACE was simply amend a 100-year-old assessment district law to say that in addition to sewers, and seismic retrofits, and fire sprinklers, and other things you can pay for as a property tax assessment, you can also do solar and energy efficiency.

—Cisco DeVries, president and CEO, Renewable Funding

Policy Benefits

From the perspective of property owners, PACE enables energy efficiency and clean energy improvements to be financed over an extended period of time with loan repayments added to the property tax bill. The assessment term is set to match the useful life of the energy improvement projects. The policy also allows for transferability of the financing obligation at resale, because the debt is structured to stay with the property.

From the perspective of investors and financial institutions, PACE benefits from the public taxing infrastructure to provide security of repayment. The PACE assessment is applied equally and without preference versus all other property taxes, and is supported by a senior lien on the subject property. In addition, the property tax bill has a strong, predictable payment history and exhibits low incidence of default.

Finally, from the perspective of the local taxing authorities, PACE can provide sources of private capital for clean energy improvements in their jurisdiction. More broadly, PACE financing enables the environmental and electric grid benefits of distributed clean power systems and a more energy efficient building stock.

DESIGN CONSIDERATIONS

Key design features that states should consider when implementing PACE include the capital source, target sector, eligible projects, repayment mechanism, and opportunities for economies of scale.

- **What is the capital source?** PACE capital funding options include public funding (e.g., local government-issued bonds backed by the pledge of property-assessment revenues), government-designated single-sourced private lenders, and “open” pools of competitive private lenders. As PACE offers investors an attractive risk-return profile and has the ability to attract significant

private capital for funding projects, the “open” private capital model has been preferred, although public funding can be useful to kick-start the local lending market. In cases where public funding and resources are used to cover program design and implementation costs, costs should be reimbursed under PACE repayment terms.

We don't think we always need to be in the subsidy business because we see that there are segments in the market where the problem is not that the projects are not economic. They're just not financeable. So we're making a distinction between those things that are economic and those that are not financeable.

—Richard Kauffman, chair, energy and finance, State of New York

- **What sectors should be targeted?** Most PACE programs currently focus on the commercial sector. Funding residential projects has not been as successful because Fannie Mae and Freddie Mac have resisted the first position lien on property. Many commercial PACE programs now require mortgage lender consent or notification. Cumulative default rates for PACE and other energy efficiency finance instruments have generally ranged from 0 to 3 percent, according to a 2011 American Council for an Energy Efficient Economy (ACEEE) study. Ongoing state-level efforts to reopen PACE to residential properties have generally focused on the development of pooled loan-loss reserves equal to about 2 to 5 percent of assessed PACE loans.
- **What technologies should be eligible for financing?** Projects eligible for financing from PACE vary across states, but most include a broad list of both energy efficiency improvements and on-site distributed-power systems.
- **How should the program be scaled?** Once a state legislature enacts PACE-enabling legislation, local government entities may authorize the use of the program and then adopt a special tax-assessment authority. A successful PACE program will benefit from economies of scale. When PACE financing becomes available to a large group of borrowers and lenders, the program can reduce overhead and transaction costs.

Additional Resources

For PACE implementation maps and updated state policy details, see the Database of State Incentives for Renewables and Efficiency (DSIRE), maintained by the North Carolina Solar Center and the Interstate Renewable Energy Council (IREC) at <http://dsireusa.org>.

OTHER RESOURCES INCLUDE:

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On-Bill Repayment

ON-BILL REPAYMENT (OBR) is a finance tool that enables property owners to finance energy efficiency and distributed power through third-party investments repaid as part of the owner's monthly utility bill. By securing repayment through a utility bill, an OBR program can make clean energy more attractive to private investors. Once qualifying cost-effective projects are identified, OBR allows property owners to have them installed at little or no up-front cost. A related approach, often referred to as on-bill financing (OBF), instead uses utility capital, and may involve the utility itself implementing improvements.

Through OBR, property owners select energy saving projects where the cost savings exceed the customer's monthly OBR payment. Since improvements are funded with private capital, and lenders can charge fees to cover program overhead, the program can be implemented without ratepayer or taxpayer funding. In this way, OBR is similar to Property-Assessed Clean Energy (PACE) financing mechanisms, except that the repayment is through a customer's utility bill rather than property taxes.

OBR is a promising financing concept due to its reliance on private investment, the additional choice it provides property owners pursuing efficiency upgrades, and its potential to scale significantly. While OBR may be used by both commercial and residential customers, it may be particularly useful in the residential sector, where the use of PACE financing has been limited due to legal constraints.

Where to look? Hawaii and New York



HAWAII. Hawaii is expected to implement the first "open-source" OBR program, in which market participants can compete

to provide lending capital for a building owner's energy improvements. Lenders and investors will be able to work with contractors and project developers to offer property owners customized upgrades. The program is expected to initially launch with residential and small commercial properties and then expand to large commercial properties. The Hawaii Public Utilities Commission expects a wide variety of projects such as energy

efficiency, solar PV, and solar hot water, as well as financing vehicles such as loans, leases, power-purchase agreements (PPAs), and energy services agreements (ESAs).



NEW YORK. While Hawaii is developing an "open-source" model for investors to compete for customers, a program in place in New York since 2012 uses a single source of capital.

New York's program, locally referred to as "on-bill recovery financing," allows consumers and small businesses to pay for energy efficiency

RECOMMENDATION

States should authorize On-Bill Repayment (OBR) programs to enable property owners to finance cost-effective energy efficiency and distributed-power upgrades through a third-party investment that is repaid through the owner's utility bill.

improvements through a repayment on their electric or gas utility bill. The New York State Energy Research and Development Authority (NYSERDA) administers the program and provides capital. NYSERDA obtains part of its funds from Qualified Energy Conservation Bonds, which are rated AAA by Standard & Poor's. The program offers homeowners loans of up to \$25,000 and maturities as long as fifteen years. One of the program requirements is that over the course of a year, a project must lower the customer's utility bill after accounting for the finance charges. This concept, often referred to as "bill neutrality," is considered by many to be an important customer protection.

To finance energy efficiency improvements through the New York OBR program, homeowners are required to first participate in the Home Performance with ENERGY STAR Program. Under this program, a Building Performance Institute

(BPI)-Accredited Home Performance contractor conducts a comprehensive home energy assessment. Energy improvements are then recommended and implemented by a participating Home Performance with ENERGY STAR contractor. OBR makes it convenient for consumers to pay for these improvements without paying cash up front. Once approved for a loan, the consumer has an interest rate that is fixed for the duration of the loan. As of February 2014, the interest rate for a residential OBR in New York is 3.49 percent for a five-, ten-, or fifteen-year term. In addition, the monthly OBR amount cannot exceed one-twelfth of the projected savings. A homeowner can finance up to \$25,000 if the payback period is fifteen years or less, and up to \$13,000 if the payback period is longer than fifteen years. The billing and collection of loan payments from homeowners is managed by qualified utilities.

[T]here are actually entities out there who are in the business of making loans and making investments. If we take the utility out of the banking business, and we allow banks, leasing companies, whoever, to compete for property owners' business, then we can expect to see financial innovation and, eventually, significant amounts of financial private capital invested in these projects.

—Brad Copithorne, financial policy director, Environmental Defense Fund

Policy Benefits

OBR addresses a number of barriers in implementing on-site energy upgrades. Many property owners lack access to capital for energy efficiency and renewable-generation projects. Homeowners may not have sufficient home equity or choose not to obtain a home-equity loan. Banks and their regulators are often reluctant to take a subordinated position on commercial properties that have first mortgages.

For the property owner, OBR is attractive because it can lower the monthly utility bill without up-front payment for clean energy improvements. In order to qualify for OBR, the expected utility bill with the OBR charge must be lower than it previously was without this charge. OBR also allows for a single monthly payment.

OBR is designed to be broadly available, voluntary, and self-directed; the property owner is not limited to participating in capped utility or government-run efficiency programs. OBR is relevant to both those who intend to stay in a property for only a few years and to long-term building owners. In both cases, the payback obligation is directly transferred to successive building occupants, and each can continue to benefit from the energy efficiency or distributed-power system upgrade. This provision is particularly relevant for otherwise hard-to-finance tenant-occupied commercial properties.

For the financier, OBR offers a relatively low-risk market in which to deploy capital. Specifically, it provides

a predictable, secure repayment stream through the owner’s monthly utility bill, which historically has high payment rates. The repayment method places OBR between the property tax-backed repayment stream of PACE financing and, at the other extreme, a home-equity or credit card loan. OBR also has the potential for long amortization.

Also, OBR, unlike many utility- or government-run energy efficiency programs, does not directly involve ratepayer or taxpayer funds, particularly if “open source.” And because the capital is provided by third parties, OBR has the potential to reach many consumers. Finally, by avoiding the need for investment in new grid infrastructure, on-site energy upgrades enabled through OBR can reduce both overall ratepayer costs and environmental impacts.

DESIGN CONSIDERATIONS

Policymakers looking to create an OBR program should consider the following questions when designing the underlying policy.

- **What is the source of capital?** In an “open-source” OBR program, capital may be provided by banks, credit unions, leasing companies, or project developers offering a PPA or ESA model. A related program model, often referred to as on-bill financing (OBF), instead uses utility capital and may involve the utility itself directing building improvements. The capital provided in either case is repaid through the building owner’s monthly utility bill. The addressable customer base with this latter model is likely smaller than with OBR due to limits on available utility capital and requirement of customer service from the utility.
- **How should projects be qualified?** A neutral third-party inspector should qualify projects that are eligible for the program. The third-party inspector should certify that expected energy savings will exceed debt service.
- **How will performance risks be shared?** Although building energy efficiency investments are relatively predictable in terms of their impact on monthly energy use, a risk remains that the upgrades may not perform as expected or savings deteriorate over time due to changes in building use or the loads of building occupants. Also, as a result of a phenomenon known as the “rebound effect,” the building occupant may increase energy use following an improvement in energy efficiency, offsetting expected total monthly bill savings. OBR programs should specify how parties—the consumer, the financier, and/or the installer—share these various performance risks.
- **How should utility bill payment be addressed?** A principal attraction of the OBR model for lenders is that repayment risk is aligned with strong historical data on customer utility bill repayments rather than other forms of consumer debt. As such, policy design for the OBR repayment stream may affect lender interest. Options include: fixed monthly payments, some set share of monthly utility bill savings, some proportional share of the overall utility bill, and various term lengths. Lenders may prefer that OBR charges be collected in an equivalent manner to energy charges. OBR’s repayment provisions should also specify rules for handling nonpayment in both

Something that’s low tech, which is solar hot water—works in every county in New York State—if someone wanted a solar hot water lease in just the same way that solar leases have revolutionized residential solar PV, it’s not available. You can either take out a loan on your house or take out a personal loan. And it’s ridiculous, because that’s really low-hanging fruit.

—Richard Kauffman, chair, energy and finance, State of New York

occupied and unoccupied buildings as well as utility bill seniority. For example, many states have rules to protect consumers from utility service disconnection in cases of nonpayment. The utility, in acting as payment processor for the third-party financier, may seek to be protected from bearing additional collection responsibility or revenue risks in cases of OBR.

• **Should the OBR obligation be automatically transferred to subsequent building tenants?**

Many of the potential benefits of the OBR model rely on the repayment stream being attached to the property rather than the tenant. However, automatic transfer of OBR obligations has not been universally adopted. California's planned OBR program, for example, focuses on nonresidential properties and does not include automatic transferability of the OBR obligation to the building's next owner. Because of this, the program is expected to only be effective for publicly owned properties that do not tend to frequently transfer ownership.

Additional Resources

For updated details on state OBR policy implementation, see the Database of State Incentives for Renewables and Efficiency (DSIRE), maintained by the North Carolina Solar Center and the Interstate Renewable Energy Council (IREC) at <http://dsireusa.org>.

Other resources include:

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Federal Action



Department of Energy
State Energy Program





Department of Energy State Energy Program

THE STATE ENERGY PROGRAM (SEP) enables the Department of Energy (DOE) to work with state government officials and policymakers to improve energy efficiency, renewable energy, and other clean energy policy. Congress provides funding to the states through SEP formula grants to support energy efficiency and renewable energy program and policy development activities. States provide a 20 percent match for these annual SEP formula funds. Because SEP allows each state to identify its unique energy opportunities and target funding to public-private partnerships and policy development, the program has spurred innovation and cost-effective results with major impacts.

In addition to the formula funds, DOE places a portion of the SEP funds into competitive grants that require states to compete for funding in particular policy areas designated by DOE. These DOE-selected policy areas vary from year to year depending upon the department’s priorities. Combined funding for the SEP under both grant programs has ranged from \$44 million to \$50 million in recent years.

The SEP has a thirty-year history and is authorized by: Title III, part D, of the Energy Policy and Conservation Act (42 USC 6321 et seq.), as modified by the State Energy Efficiency Programs Improvement Act of 1990; the Department of Energy Organization Act (42 USC. 7101 et seq.); and the Energy Independence and Security Act of 2007 (section 531).

Where to Look? Nebraska and Massachusetts

States use their formula funds for a variety of projects and programs and these activities can change year to year. States also take advantage of solicitations for competitive grants.



NEBRASKA. The Nebraska Energy Office, for example, has operated the “Dollar and Energy Saving Loan Program” for more than two decades. The program finances energy efficiency improvements in homes, farms, ranches,

businesses, industrial facilities, schools, and other buildings. Federal SEP funds are leveraged with utility and other funds. Between 1990 and 2011, 27,339 projects totaling more than \$258 million were financed with low-interest loans from the Nebraska Energy Office and the state’s

RECOMMENDATION

The administration and Congress should expand funding for the Department of Energy (DOE) State Energy Program (SEP), the key federal grant program supporting the states in advancing energy efficiency and renewable energy.

894 participating lender locations. Although the overwhelming majority of loans were for residential projects, in the summer of 2011 the first two public compressed natural gas stations in Omaha were financed with low-interest loans. Defaults of only \$106,000 on the \$258 million in loans has occurred since the program's inception.



MASSACHUSETTS. Massachusetts has won six competitive SEP awards since FY 2012. Formula funding of \$807,460 in FY 2013 allowed the state to focus on:

- Energy assurance/emergency planning;
- Implementation of its Renewable Portfolio Standard;
- Improvements in transportation-sector efficiency and bolstering alternative-fueled and electric vehicles; and

- Projects pursuing various energy analysis and economic assessment studies.

For example, the Massachusetts Department of Energy Resources is using SEP funds to implement a real-time energy management program, the Enterprise Energy Management System (EEMS), which will result in the installation of nearly 1,200 real-time energy meters across over 400 state buildings, totaling more than 17 million square feet. Real-time building-level energy data will help state facility, project management, and finance personnel to identify cost-effective opportunities to make energy improvements, directly reducing state taxpayer burden. This is one of the first comprehensive state building EEMS projects.

Benefits

The SEP is an important adjunct to state policymaking on clean energy. It provides support for both the implementation of current policy and a proving ground for new ideas in energy efficiency and renewable energy, some of which have been widely adopted. For example, the forerunner of today's multibillion-dollar energy savings performance contracting (ESPC) industry began with groups of states using SEP and state funding to partner with the private sector to improve the financing of energy efficiency upgrades of public buildings.

SEP *formula* grants help support core state activities, such as statewide energy planning, as well as facilitating a range of programs, depending upon a particular state's priorities. Projects have included: establishing financing mechanisms for energy efficiency retrofit programs; supporting energy savings performance contracting and private-sector residential energy efficiency programs; developing voluntary building energy use disclosure policies; and reducing barriers to renewable energy siting and production.

Under the SEP *competitive* grants, DOE develops between two and four "areas of interest" each year for states to submit innovative proposals for competitive funding. State projects are selected following a merit review. In 2013, DOE made SEP competitive awards in the following areas: industrial efficiency and combined heat and power; stimulating energy efficiency action; driving demand for public facility retrofits; and clean energy economic development roadmaps.

A 2005 evaluation of the SEP conducted by Oak Ridge National Laboratory (ORNL) found that that every \$1 of SEP federal funding leveraged nearly \$11 in state and private funds supporting, for example, energy audits of homes and businesses, building retrofits, alternative-fueled vehicles purchased, and energy related loans and grants.

DESIGN CONSIDERATIONS FOR THE SEP

- **How can the SEP be improved?** A few program modifications could potentially make SEP's spending more efficient and more effective:
 - 1) improve the funding opportunity announcement (FOA) process by streamlining the FOA requirements and maintaining consistency of those requirements from year to year; 2) simplify SEP data collection and reporting requirements that states must meet; and 3) strengthen state-federal coordination of clean energy deployment through better information sharing and peer learning.
- **Should the balance between formula and competitive grants be adjusted?** There are strong differences of opinion about whether the competitive grant portion of the SEP should be reduced, in favor of formula-based funding. On the one hand, some believe that, given the modest level of current SEP funding overall, support for competitive grants should be cut so that core state needs are better met through the formula grants. On the other hand, others believe that the competitive grants are an effective means to connect DOE research priorities to state clean energy deployment.
- **Are current SEP funding levels adequate and, if not, what are more realistic levels and trajectories for an increase?** The FY 2014 funding level of \$50 million for SEP provides a basic level of support for state efforts to conduct core energy planning and policy-development activities. Expanding program funding would open several important avenues that would deliver great benefits, including state policy and planning related to energy infrastructure modernization as well as energy security and emergencies. States, for example, struggle to maintain a critical planning and response function to respond to severe weather and related disasters.

Additional Resources

1. US DOE Office of Energy Efficiency and Renewable Energy. "State Energy Program." www1.eere.energy.gov/wip/sep.html
2. ORNL. "An Evaluation of State Energy Program Accomplishments: 2002 Program Year." June 2005. <http://web.ornl.gov/info/reports/2005/3445605812458.pdf>

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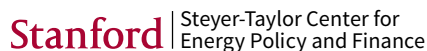


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George Pratt Shultz has had a distinguished career in government, in academia, and in the world of business. The Thomas W. and Susan B. Ford Distinguished Fellow at the Hoover Institution, he is one of two individuals who have held four different cabinet posts; has taught at three of this country's great universities; and for eight years was president of a major engineering and construction company. Shultz was sworn in on July 16, 1982, as the sixtieth US secretary of state and served until January 20, 1989. In addition to his work at Hoover, Shultz is honorary chairman of the Stanford Institute for Economic Policy Research, advisory council chair of the Precourt Institute for Energy at Stanford University, and chair of the MIT Energy Initiative External Advisory Board.

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Jeff Bingaman served in the US Senate 1982–2013 and was chairman of the Senate Energy and Natural Resources Committee from 2001–2002, and again from 2007 until the end of his term in the 112th Congress. In the 109th Congress, Bingaman played a major role in the passage of the Energy Policy Act of 2005, the first comprehensive energy bill to become law in thirteen years. He was the lead sponsor of the Energy Independence and Security Act of 2007, the most sweeping energy efficiency legislation ever to be put into law. Among numerous committee memberships, Bingaman served on the Senate Finance Committee and chaired the Subcommittee on Energy, Natural Resources and Infrastructure. Before being elected to the Senate, Bingaman was elected New Mexico attorney general. The former New Mexico senator has an undergraduate degree from Harvard University and law degree from Stanford.

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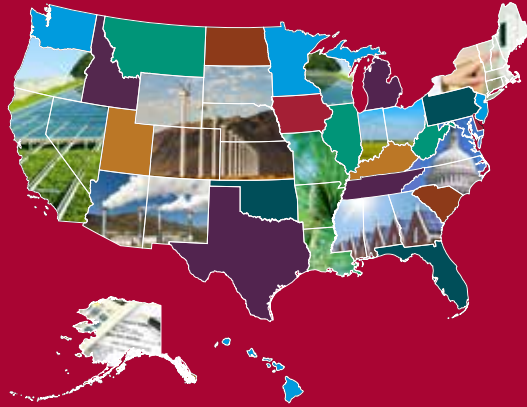
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