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Supporting Solar Power in Renewables Portfolio Standards: Experience from the United States

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October 2010

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Abstract

Among the available options for encouraging the increased deployment of renewable electricity, renewables portfolio standards (RPS) have become increasingly popular. The RPS is a relatively new policy mechanism, however, and experience with its use is only beginning to emerge. One key concern that has been voiced is whether RPS policies will offer adequate support to a wide range of renewable energy technologies and applications or whether, alternatively, RPS programs will favor a small number of the currently least-cost forms of renewable energy. This report documents the design of and early experience with state-level RPS programs in the United States that have been *specifically* tailored to encourage a wider diversity of renewable energy technologies, and solar energy in particular. As shown here, state-level RPS programs specifically designed to support solar have already proven to be an important, albeit somewhat modest, driver for solar energy deployment, and those impacts are projected to continue to build in the coming years. State experience in supporting solar energy with RPS programs is mixed, however, and full compliance with existing requirements has not been achieved. The comparative experiences described herein highlight the opportunities and challenges of applying an RPS to specifically support solar energy, as well as the importance of policy design details to ensuring that program goals are achieved.

Executive Summary

Among the available options for encouraging the increased deployment of renewable electricity, renewables portfolio standards (RPS) have become increasingly popular. By design, most RPS policies were originally developed to be largely technology-neutral, stimulating competition among various renewable energy technologies and allowing the most economically attractive technologies to win out. One concern that has been voiced, however, is whether RPS policies of this design will offer "adequate" support to a wide range of renewable energy technologies and applications or whether, alternatively, such RPS programs will favor a small number of the currently least-cost forms of renewable energy. This report documents the design of and early experience with state-level RPS programs in the United States that have been *specifically* tailored to encourage a wider diversity of renewable energy technologies, and solar energy in particular. Key findings from this analysis are as follows:

State RPS programs have not yielded a significant diversity of renewable resources thus far, though there are signs that this may be changing in some regions. As of the end of September 2010, 29 states and the District of Columbia had established binding RPS policies. Wind power has been the primary resource installed as a result of these policies, representing an estimated 94% of all RPS-driven renewable energy capacity additions in the U.S. from 1998-2009. Going forward, however, a more diverse set of renewable energy technologies may play a larger role in meeting RPS compliance obligations. In part, this is a consequence of the growing prevalence of RPS policy designs aimed specifically at encouraging greater resource diversity. At the same time, the trend towards greater renewable resource diversity is also being driven by the improved economics of solar relative to wind power, particularly in California and the desert southwest, where a sizeable pipeline of utility-scale solar projects has been announced. Though most of these projects are not yet in operation, these announcements, along with the growing use of RPS designs specifically tailored to increase resource diversity, portend a very real prospect for increased renewable resource diversity within state RPS programs, particularly in regions that contain high-quality solar resources and/or limitations in the supply of other forms of renewable energy.

Many states have adopted RPS policy designs explicitly aimed at supporting greater renewable resource diversity, and solar energy in particular. In addition to the suite of policies that might be used *in addition to* an RPS to support greater renewable resource diversity, at least two RPS design options exist that can be and are being used to encourage or even require greater resource diversity *within* RPS programs. First, RPS policies can incorporate **set-asides** consisting of different targets for different renewable technologies or applications, often with varying penalty levels to further encourage compliance. Alternatively, or in addition, preferred technologies or applications can be supported through **credit multipliers** of various designs that give preferred resources additional credit towards meeting a supplier's RPS compliance obligation. Of the 30 U.S. jurisdictions with RPS programs, the vast majority – 26 in total – have developed RPS programs with set-asides and/or credit multipliers, and in many cases these provisions have been adopted relatively recently. Most common are set-asides for solar energy (14 states) or distributed generation (4 states). However, set-asides for other renewable energy technologies (or broader technology bands) and for "community" renewable energy projects have also been established in a number of states. Credit multipliers of various magnitudes and durations are currently employed for solar energy (5 states), wind energy (3 states), and other sources. The greater popularity of set-asides suggests that state policymakers in the U.S. have tended to judge the advantages of set-asides to be greater than those of multipliers.

The design of solar and distributed generation (DG) set-asides varies widely across states. Design variations reflect the differing objectives of state policymakers, state-specific political exigencies, and electricity market designs and regulatory frameworks. As a result, a patchwork of solar support policies exists, demonstrating both a range of design choices available to policymakers, and how those design choices can impact policy outcomes. Key design issues highlighted and discussed in this report include: solar and DG targets and timeframes, eligibility rules and the use of multipliers to target particular preferred types of solar technologies or applications, contracting requirements and incentive mechanisms to overcome financing barriers, protocols for the measurement and tracking of solar RECs (SRECs), and cost containment and compliance enforcement.

Solar and DG set-asides have played a significant role in the recent growth of the U.S. solar market. Solar capacity in the U.S. has expanded rapidly over the past several years, albeit from a relatively small base. This growth has been driven by a number of factors, including – though not limited to – state RPS programs with solar or DG set-asides. As one relatively simple indicator of the impact of these polices, in each year from 2005-2009, 65-81% of the annual grid-connected PV capacity additions in the U.S. outside of California occurred in states with active or impending solar/DG set-aside obligations.[1] In aggregate, from 2000 through 2009, more than 250 MW_{ac} of PV capacity is estimated to have been brought on-line to meet state-level solar or DG set-asides. The fact that solar capacity growth outside of California has centered, by and large, in states with solar or DG set-asides, suggests that these policies have played a key role in accelerating solar deployment in the U.S. These impacts have been most apparent in New Jersey (101 MW_{ac} through 2009), Colorado (46 MW_{ac}), Arizona (36 MW_{ac}), New York (22 MW_{ac}), and Nevada (19 MW_{ac}); these states were also the largest PV markets in the U.S., after California, from 2007-2009. The impact of solar set-asides is also evident in the budding resurgence of the concentrating solar power (CSP) market in the U.S. After initial growth in the late 1980's, construction of CSP capacity in the U.S. largely ceased. This has begun to change in recent years, with two new CSP projects constructed to meet solar set-aside requirements: the 1 MW Saguaro project installed in Arizona in 2006 and the 64 MW Solar One facility installed in Nevada in 2007. Although experience with credit multipliers is limited, the available evidence suggests that, unlike set-asides, they have not yet resulted in a significant increase in solar generation.

Compliance with solar/DG set-aside targets has been mixed, highlighting the importance of careful policy design. Across the nine states with active solar/DG set-aside obligations in 2008 (the most recent year for which comprehensive set-aside compliance data are available), 68% of the aggregate solar/DG set-aside compliance obligation was achieved through the purchase of qualifying renewable energy and/or RECs. Though the targets in a number of these states amounted to only several megawatts of solar capacity, only three states (Colorado, Nevada, and

[1] California, which is by far the largest state PV market in the U.S., does not have a solar set-aside as part of its RPS and has, instead, driven growth in solar capacity through other policy support mechanisms: principally, through incentive payments for distributed PV, but more recently though larger-scale solar installations that compete with other forms of renewable energy within the state's RPS or that receive feed-in tariff payments.

Pennsylvania) fully achieved their solar/DG targets in 2008; the other six states (Arizona, Delaware, Maryland, New Jersey, New York, and Washington D.C.) met between 0% and 84% of their solar/DG set-aside obligations through the purchase of eligible forms of renewable energy and/or RECs. Though electricity suppliers in these states may not have been technically out of compliance with the solar/DG set-asides (due to alternative compliance payment mechanisms, funding limits, and force majeure provisions), these results demonstrate the challenges of meeting solar/DG set asides and the need for careful policy design.

The estimated retail rate impacts of solar/DG set-asides have thus far been relatively modest, though compliance costs have reached or are approaching 1% in some states. The retail rate impacts of solar/DG set-asides in 2009 have been estimated for seven U.S. states where data on average SREC prices or actual/budgeted expenditures are available.[2] For five of these states (Delaware, Maryland, New York, Ohio, and Pennsylvania), the estimated retail rate impacts are estimated at 0.01-0.04% of average retail electricity costs, reflecting the correspondingly low solar targets in those states, which ranged from 0.01-0.1% of retail sales in 2009. In New Jersey and Arizona, which had higher solar/DG set-aside targets of 0.2% and 0.3% of retail sales, respectively, estimated compliance costs reached 0.96% and 1.15% of total retail electricity costs.

State RPS programs, including both those with and without solar/DG set-asides, are poised to drive significant growth in the U.S. solar market. Solar capacity additions required to meet solar/DG set-aside targets will continue to grow as a greater number of existing set-asides take effect and as targets increase over time. By 2025, an estimated 9,500 MW_{ac} of solar generation capacity would be needed to fully meet the existing state set-aside requirements. Fully achieving set-aside targets during intervening years would require average annual capacity additions on the order of 400 MW_{ac} per year from 2010-2014 and approximately 600 MW_{ac} per year from 2015-2025. In comparison, in 2009, approximately 107 MW_{ac} of solar capacity was added in order to meet solar and DG set-asides, a figure that would have been higher had full compliance with existing targets been achieved. At the same time, recent announcements for utility-scale solar projects suggest that future growth in solar capacity will, by no means, be limited to meeting solar or DG set-aside obligations. Much of this announced capacity, which totals more than 22,000 MW_{ac}, is planned for California or parts of the desert southwest and, if constructed, would largely serve to meet general RPS compliance obligations in the region. This latter trend suggests that, in the future, solar/DG set-asides may be especially important in states with poorer solar resources or for distributed and customer-sited solar applications.

A variety of emerging issues will affect the impact of RPS policies on solar growth. Meeting the long-term solar/DG set-aside targets, as identified in the preceding paragraph, will require a scale-up in the solar delivery infrastructure in many states. In addition to this challenge, a number of policy design issues may constrain the market's growth. In particular, many states have developed cost containment mechanisms that may ultimately become binding. Arizona and

[2] Data on spot market SREC prices can be used to roughly estimate the cost of complying with solar set-aside requirements in those states *if* one assumes: (a) that SREC prices represent the total incremental above-market cost of solar resources, (b) that the average price of short-term SRECs is representative of the price of all SRECs used for compliance, and (c) that the full compliance obligation was achieved solely through retirement of SRECs, without the need for solar alternative compliance payments (SACPs), or that SREC and SACP prices are similar.

New York, for example, both missed their set-aside targets in 2008 as a result of funding limits, and Ohio utilities were granted a force majeure exemption in 2009, thereby curtailing achievement of that state's solar targets. Furthermore, some states, especially those with competitive retail electricity markets, continue to struggle with how to encourage long-term contracting for solar generation. In response, utilities and regulators in a number of states have sought to reduce SREC price risk and facilitate project financing through a variety of policy designs and other strategies, including: adopting long-term contracting requirements, offering financial incentives or financing programs, conducting centralized procurement of RECs, and developing other novel procurement models, including direct utility ownership of distributed PV assets. Further experimentation with such mechanisms may be needed to help ensure that solar set-aside targets are fully achieved in a least-cost fashion, especially in states open to retail electricity competition.

1. Introduction

Renewables portfolio standards (RPS) have, within the last decade, emerged as among the most popular forms of policy for supporting the deployment of renewable energy technologies. Though its design can and does vary, at its heart, an RPS simply requires that electricity suppliers (or, alternatively, electricity generators or consumers) purchase a growing quantity of renewable energy over time; most jurisdictions allow trade in renewable energy certificates to increase compliance flexibility and facilitate compliance verification. RPS programs – also known as quota systems, renewables obligations, renewable energy standards, or tradable green certificate programs – are widely used at the state level in the United States, and have been implemented in Australia, Belgium, Canada, China, India, Italy, Japan, Poland, Sweden, and the United Kingdom. Notwithstanding its breadth of adoption, the RPS is still a relatively new policy with limited experience.

Despite its popularity, the RPS policy has its detractors. Though successfully employed in a number of instances, in some cases, RPS programs have done little to support growth in renewable energy supplies, and in others that growth has come at a high cost (see, e.g., IEA 2008; van der Linden et al. 2005). More generally, concerns have been expressed about the ability of RPS programs to support the long-term contracts that renewable energy generators require, the willingness of policymakers to enforce renewable energy purchase obligations, the complexity of crafting a well-designed program, the challenges of minimizing windfall profits for some generators, the need to enact supporting policies beyond the RPS, and whether alternative policies may deliver comparable social benefits at lower cost (see, e.g., Agnolucci 2007; Bergek and Jacobsson 2010; Butler and Neuhoff 2008; Chupka 2003; Cory and Swezey 2007; Finon and Perez 2007; Hvelplund 2001; Kildegaard 2008; Lauber 2004; Lipp 2007; Menanteau et al. 2003; Meyer 2003; Midttum and Gautesen 2007; Michaels 2008; Mitchell et al. 2006; Palmer and Burtraw 2005; Ringel 2006; Wiser et al. 2005a; Wiser et al. 2005b).

By design, most RPS policies were originally developed to be largely technology-neutral, stimulating competition among various renewable energy technologies and allowing the most economically attractive technologies to win out. Consequently, a key concern sometimes voiced in academic and policy circles has been that an RPS of this design may not support the diversity of renewable energy technologies and applications that may ultimately be necessary in the long term if even-higher levels of renewable energy deployment are to be attained. Meyer and Koefoed (2003), Lauber (2004), and Ringel (2006), among others, discuss this concern in general, while Voogt and Uyterlinde (2006) show empirically that an EU-wide renewable energy target with uniform renewable energy certificate pricing is unlikely to provide much support for solar photovoltaic technologies in particular; similarly, analyses of Federal RPS proposals in the United States have typically found that wind and biomass are likely to dominate compliance, with lesser quantities of solar and geothermal energy (e.g., Kydes 2007; Nogee et al. 2007). Bergek and Jacobsson (2010) note the concern when evaluating Sweden's RPS, while Falconnett and Nagasaka (2010) conclude, as a result, that feed-in tariffs are superior in supporting less-mature technologies. van der Linden et al. (2005), meanwhile, note that small renewable energy producers may face barriers under an RPS due to the significant transaction costs and risks involved in participating in the resulting renewable energy market.

What is sometimes missing from this literature, however, is a clear recognition that RPS programs can be specifically designed to encourage renewable resource diversity. At least two specific policy design approaches are feasible: developing technology- or application-specific set-asides (also called "bands" or "carve-outs"), or providing credit multipliers that offer preferred technologies or applications additional compliance credit towards the RPS.[3] A growing number of U.S. states have designed their RPS policies to apply one or both of these mechanisms to support a broader set of renewable energy technologies and applications; other countries have also, at times, employed similar mechanisms. Alternatively, RPS policies can be paired with other types of policies that provide targeted support to solar or other renewable technologies that may not fare well under traditional RPS designs.

This report summarizes the design, early experience, and lessons learned from U.S. state RPS policies that have been specifically targeted at encouraging renewable resource diversity.[4] Because such policies in the U.S. have tended to emphasize support for solar energy, we also follow this emphasis. RPS programs are not the only, or perhaps even the most significant, form of support for solar energy either in the U.S. or internationally; feed-in tariffs and financial incentives also play major roles in solar deployment, and it is not our purpose to make the case for one policy over another. Instead, we focus exclusively on RPS policies because the growing popularity of such programs calls for a careful tracking and evaluation of policy design and results. Our focus on U.S. experience is driven by the fact that the U.S. arguably has the longest running and most diverse set of experiences with a wide range of RPS designs.

The remainder of this report is structured as follows. We begin in the next section by providing background on state RPS programs, and on the early results of those programs in encouraging renewable energy generally, and renewable resource diversity specifically. We then turn to a general discussion of the RPS design approaches that can be used to encourage greater resource diversity broadly, and solar energy in particular. Following that, we (a) discuss in some detail the multiple ways in which solar-specific RPS provisions have been designed in the U.S., (b) summarize the early impacts of those policies on solar energy deployment and retail electricity rates, (c) document the level of compliance achieved to date with those policies, and (d) provide a forecast for how solar deployment may increase in the future under these policies if full compliance is achieved. We conclude the report by discussing major policy design considerations and summarizing our key findings.

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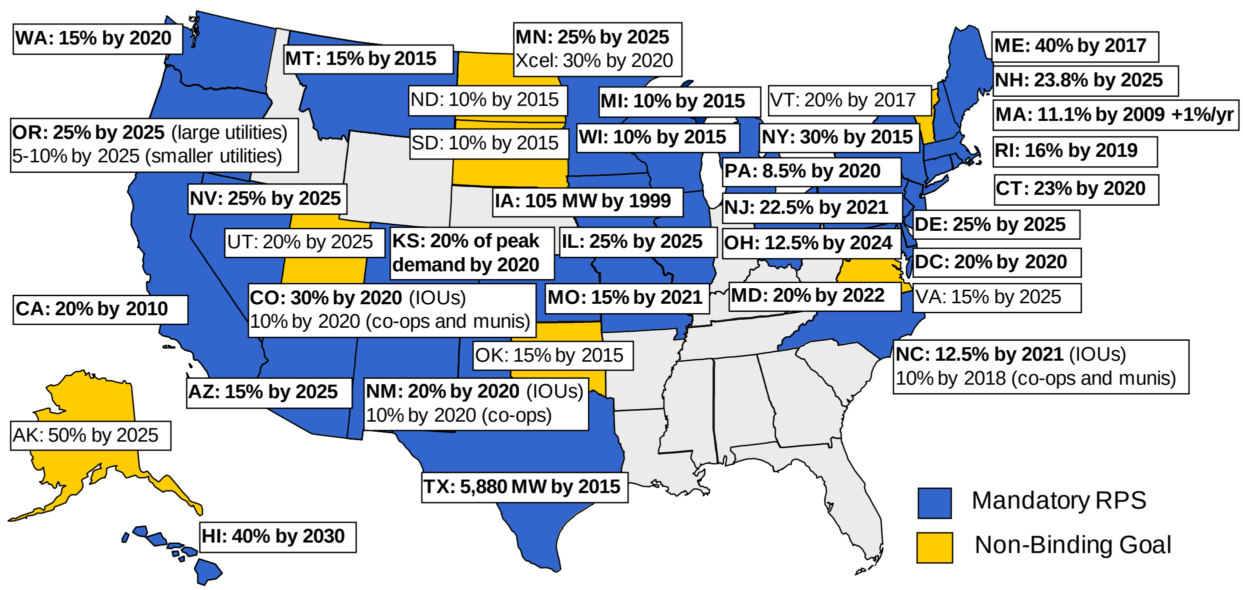
[3] Such mechanisms have been discussed in the literature for some time (see, e.g., Rader and Norgaard 1996; Haddad and Jefferiss 1999; and Verbruggen 2004), but few evaluations of their design and effectiveness have yet been published.

[4] For additional and more-general information on U.S. state RPS policies and experiences, not only those focused on solar resources, see: Rabe (2006), Exeter (2008), and Wiser and Barbose (2008).

2. State RPS Policy Background

2.1 Prevalence and Impact of State RPS Policies

Renewables portfolio standards have proliferated at the state level in the U.S. since the late 1990s. As of the end of September 2010, 29 states and the District of Columbia had established binding RPS targets which, when fully implemented, will cover 56% of total U.S. retail electricity sales, requiring that a certain percentage of those sales be met with renewable energy; an additional seven states have passed legislation establishing voluntary renewable energy goals.[5] Although the design and final compliance targets of these policies vary widely, Figure 1 shows that many of the RPS programs require that eligible forms of renewable energy contribute 15-25% of retail sales by 2030 or sooner.



Source: Berkeley Lab

Figure 1. Existing State RPS Policies and Non-Binding Renewable Energy Goals

State RPS requirements have emerged as one of the most important drivers of renewable energy additions in the U.S., especially when coupled with other complementary policies. Of the more than 37 GW of non-hydro renewable energy capacity added from 1998 through 2009 in the U.S., roughly 61% (23 GW) occurred in states with an active or impending RPS compliance obligation.[6] In total, existing state RPS policies will require roughly 73 GW of new renewable capacity by 2025, representing roughly 6% of total U.S. retail electricity sales in that year and 30% of projected load growth between 2000 and 2025. If these states increase their renewable energy targets, as many have done in the past, or if additional states were to adopt RPS policies, the collective set of state RPS policies would require an even greater quantity of new renewable energy additions.

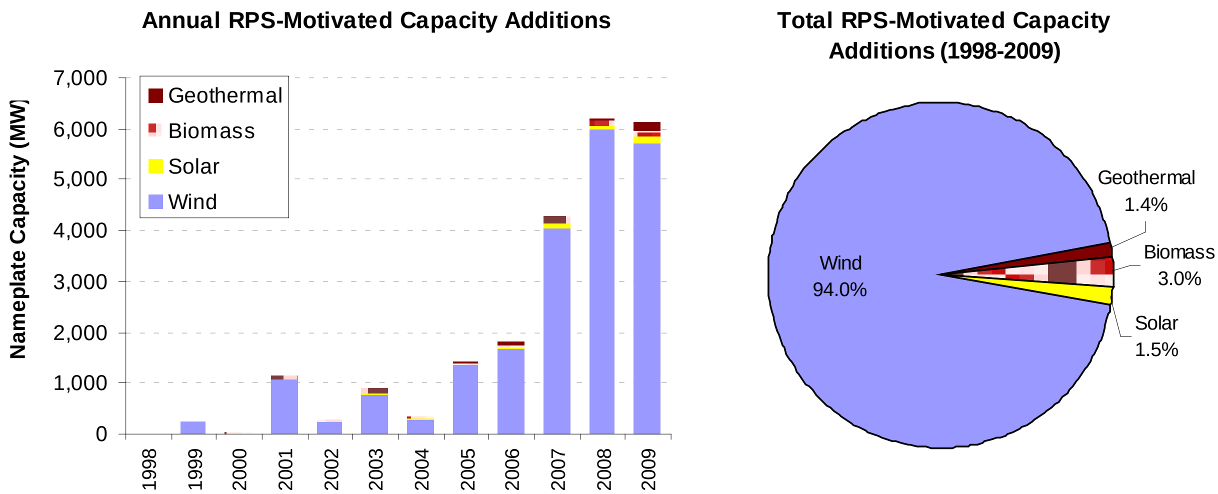
[5] At the Federal level, the U.S. House of Representatives and Senate have, at different times, each passed versions of a national RPS, although none has thus far been signed into law.
[6] Using a more sophisticated approach, Yin and Powers (2010) find that U.S. state RPS programs have had a statistically significant and positive impact on in-state renewable energy development.

2.2 Impact of State RPS Policies on Resource Diversity to Date

Wind power has been the primary resource installed as a result of state RPS policies thus far, representing an estimated 94% of all RPS-driven renewable energy capacity additions in the U.S. from 1998-2009; the remaining 6% consists of biomass, solar, and geothermal (Figure 2). Though some regions of the country with RPS policies have experienced somewhat greater diversity in new renewable energy additions, wind has thus far consistently been the dominant renewable technology deployed as a result of state RPS programs (Figure 3). This is because, as a 'market-driven' mechanism, a traditional RPS tends to stimulate investments in lower-cost and lower-risk technologies; higher cost technologies will generally not be chosen during the competitive process.

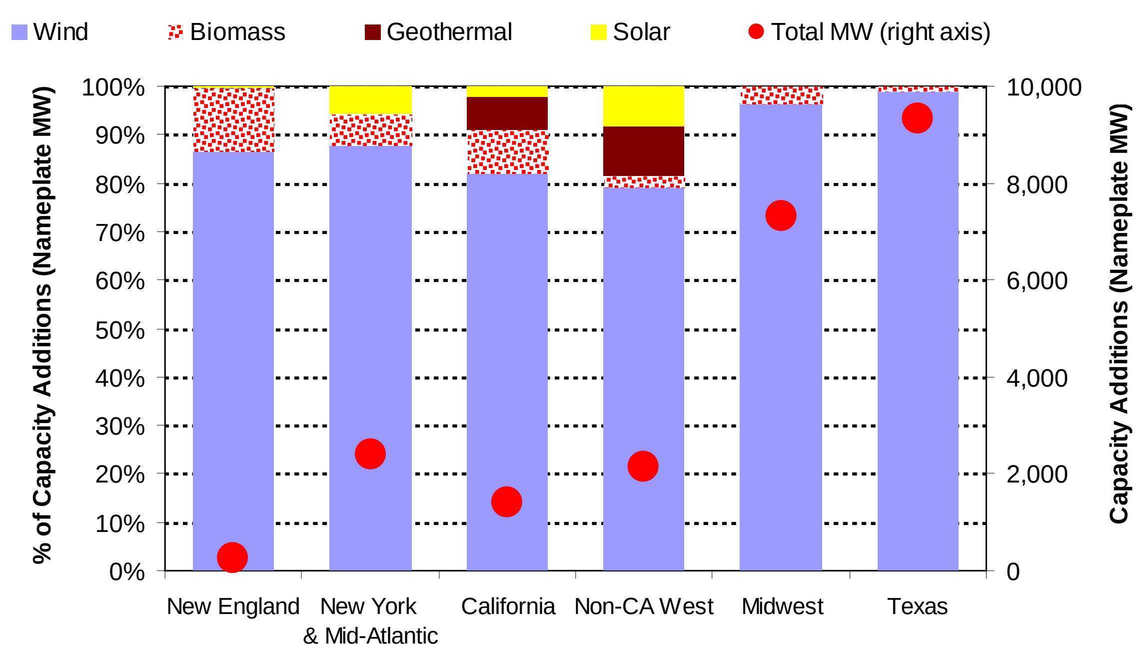
Solar has historically tended to be less economically attractive than wind energy in most regions of the U.S., and therefore (until recently) has not generally been selected through RPS procurement processes. In addition, some renewable energy technologies and applications – solar PV included – have historically been primarily deployed as smaller-sized systems (in the case of PV, located on the customer-side of the meter), and have therefore faced a variety of other solicitation-related barriers to participating in RPS markets. In particular, smaller solar projects are not always able to easily participate in the solicitations that have become common under many state RPS programs given the high transaction costs of such participation, explicit minimum project size thresholds that sometimes exist, and/or stringent metering requirements that can apply. Finally, solar projects have also sometimes faced policy-related barriers to participation in RPS programs, for example, uncertainty over renewable energy certificate (REC) ownership for PV projects that receive cash incentives or net metering.

Going forward, a more diverse set of renewable energy technologies may play a larger role in meeting RPS compliance obligations, even in cases where RPS policies are not explicitly designed to encourage that diversity. In California, for example, between 2002 and September 2010, the state's investor owned utilities (IOUs) and publicly owned utilities (POUs) collectively signed contracts for 21 GW of new renewable capacity. Roughly 41% of this capacity consists of large new solar photovoltaic (PV) and concentrating solar power (CSP) facilities, with geothermal and biomass each representing another 3%; 53% is wind (CPUC 2010, CEC 2010). In addition, announcements of prospective large, utility-scale solar plants have been made under the RPS policies in Arizona, New Mexico, and Colorado. This shift towards utility-scale solar energy is largely being driven by the improved economics of solar relative to wind power, particularly in the desert southwest. Though most of these projects are not yet in operation, the announcements signal a very real prospect for increased renewable resource diversity within state RPS programs in areas of the country that contain high-quality solar resources and/or limitations in the supply of other forms of renewable energy.



Notes: Renewable additions are counted as "RPS-motivated" if and only if they are located in a state with an RPS policy and commercial operation began no more than one year before the first calendar year with RPS compliance obligations. This approach ignores a number of complexities. First, most states allow out-of-state generation to count toward their RPS; thus, some renewable additions that, in fact, were motivated by RPS policies are excluded from the figure. Conversely, in some RPS states, renewable energy capacity has been added in recent years above and beyond the level necessary to meet those states' RPS targets, or has been added to serve voluntary green power markets; thus, some renewable additions included in the figure are not RPS-motivated.

Figure 2. Renewable Energy Additions in RPS States by Technology, 1998-2009



Notes: See Figure 2 notes for explanation of the methodology used to construct the figure.

Figure 3. RPS-Motivated Renewable Energy Additions by Technology and Region, 1998-2009

2.3 RPS Policy Designs for Supporting Renewable Resource Diversity

Notwithstanding the future prospect for increased renewable resource diversity resulting from the narrowing cost differences among various renewable energy technologies, the fact remains that – to date – U.S. state RPS programs have tended to largely support utility-scale wind power projects. Traditionally designed RPS policies have not yet yielded significant solar additions, with the exception of larger, utility-scale solar projects and project proposals in the sunny desert southwest. Smaller, customer-sited solar applications have – thus far – fared particularly poorly when required to compete with larger, utility-scale wind power projects.

In addition to the suite of policies that might be used *in addition to* an RPS to support greater resource diversity, however, at least two RPS design options exist that can be and are being used to encourage or even require greater resource diversity *within* RPS programs. First, RPS policies can incorporate **set-asides** (also called bands, tiers, or carve-outs) consisting of different targets for different renewable technologies or applications, often with varying penalty levels to further encourage compliance. Alternatively or in addition, preferred technologies or applications can be supported through **credit multipliers** of various designs that give preferred resources or applications additional credit towards meeting a supplier's RPS compliance obligation; in particular, generation from the designated technologies or applications, although issued one REC for each MWh, may be credited as more than one REC (depending on the multiplier) for RPS compliance purposes. In the former case, increased diversity is required through segmenting the overall RPS requirement into various sub-requirements, while in the latter case increased diversity is encouraged but not strictly obligatory.

Set-asides and credit multipliers each offer their respective sets of corresponding advantages and disadvantages, whether applied to solar or to other preferred technologies or applications. Focusing on solar (see Table 1), chief among the advantages of set-asides is that they provide a degree of certainty that the RPS will result in the development of a specific amount of solar resources: a key ingredient to financing large-scale solar projects. Credit multipliers, in contrast, provide no such certainty, and to the extent that they do stimulate solar development, they do so at the expense of reducing the effective RPS percentage.[7] In addition, set-asides can provide policymakers with a greater ability to create a tailored form of support for solar to address solicitation-related barriers – for example, by establishing solar-specific procurement mechanisms and REC tracking protocols. A prime disadvantage of set-asides, on the other hand, is the risk that they will put upward pressure on RPS compliance costs, if solar is more expensive than other sources of renewable generation. Credit multipliers do not entail this risk, as solar resources would be used to meet the RPS target only to the extent that doing so is lower cost than the alternate renewable options available. Credit multipliers also have the advantage of providing a means by which states can directly indicate the degree to which they value particular types of renewable resources over others. It is perhaps in recognition of the unique advantages offered by both set-asides and multipliers that several states have adopted policies combining

[7] Because each unit of renewable energy on which a multiplier applies counts as more than a single MWh towards RPS compliance, higher multipliers will (absent a chance in the underling renewable energy target) naturally lead to lower levels of renewable energy deployment.

both mechanisms, though the greater popularity of set-asides suggests that state policymakers in the U.S. have tended to judge the advantages of set-asides to be greater than those of multipliers.

Table 1. Advantages and Disadvantages of Solar Set-Asides and Solar Credit Multipliers

Set-Asides	Credit Multipliers
Advantages • Recognizes unique benefits of solar • Greater certainty in the amount of solar deployment • Targets cost and solicitation barriers • Does not reduce effective RPS percentage • Less risk of over-subsidization of solar • May enable larger market for solar than multiplier depending on details	**Advantages** • Recognizes unique benefits of solar • Lower risk of higher/uncertain cost impact • Allows policymakers to clearly signal the degree to which solar is valued relative to other resources • Does not "pick winners" as directly as set-asides • May enable larger market for solar than set-aside depending on details
Disadvantages • Greater risk of higher/uncertain cost impact • May cause overall RPS cost cap to be reached, if a separate cost cap for set-aside is not established • Picks winners more directly than multiplier • Establishing level of set-aside is challenging • Set-aside often rigidly set without easy ability to alter given changes in market conditions	**Disadvantages** • Does not ensure certain amount of solar deployment • Does not directly target solicitation barriers for smaller solar projects • Reduces effective RPS percentage • Establishing multiplier value at "correct" level over time is challenging: requires supervision • If multiplier is not reduced as costs decline, could lead to over-subsidization

Of the 30 U.S. jurisdictions with RPS programs, the vast majority – 26 in total – have designed their RPS programs with technology and/or application diversity in mind, and both set-asides and credit multipliers have been common.[8] As shown in Table 2, these policies take many forms, suggesting that policy interests and preferred resources are far from uniform across states. Most common are set-asides for solar energy (14 states) or distributed forms of renewable generation more broadly (4 states). However, a number of states have adopted set-asides for wind and other renewable energy technologies, or for "community" renewable project ownership. Other states have developed broader technology bands that separate renewable energy sources into "Class I" and "Class II" technologies, where Class I technologies typically represent the newer, more costly, and/or more-preferred sources. Finally, a number of states have developed credit multipliers of various magnitudes and durations for solar energy (5 states), wind energy (3 states), and other resources.

[8] In addition to being used to support resource diversity, set-asides and multipliers have also been used within RPS programs to, among other things, support the development of in-state renewable resources.

Table 2. Application of Set-Asides and Multipliers in State RPS Programs

Set-Asides			Credit Multipliers
General Technology	**Specific Technology**	**Specific Application**	
• Class I vs. II: CT, DC, MA, MD, ME, NJ	• Solar Energy*: DC, DE, IL, MA, MD, MO, NC, NH, NJ, NM, NV, OH, OR, PA • Wind Energy: IL, ME (goal), MN, NJ (offshore), NM • Existing Biomass/Methane: NH • Existing Hydropower: NH • Geothermal or Biomass: NM • Swine Waste: NC • Poultry Waste: NC • Non-Wind: TX (goal)	• Distributed Generation: AZ, CO, NM, NY • Community Ownership: MN (goal), MT (wind), OR (goal, community and small scale)	• Solar Energy: CO (POUs), DE (general RPS), MI, NV (PV), OR • Wind Energy: DC, MD, DE (offshore) • Methane: DC, MD • Distributed Generation: NV (PV), WA • Community Ownership: CO, ME • Fuel Cells: DE • Waste Tires: NV • Non-Wind: TX

* *Rhode Island passed legislation in 2009 requiring the state's electric distribution companies to sign long-term renewable energy contracts totaling 90 MW by 2014, of which 3 MW must be solar energy. The long-term contracting requirement is not technically part of the state's RPS, and we therefore do not include Rhode Island in our tally of states with RPS solar set-asides.*

3. Supporting Solar in an RPS: Set-Aside Design Variations

3.1 Prevalence of Solar-Specific RPS Designs

Though the approaches used are varied, solar energy has been the most common target of RPS policy designs aimed at promoting renewable resource diversity. As of the end of September 2010, 14 of the 30 RPS policies contained solar-specific set asides, while four states had developed distributed generation (DG) set-asides that will likely serve, in large measure, to support solar (Figure 4). In addition, five states had adopted solar multipliers, either in lieu of or in combination with set-asides, and two additional states had multipliers for DG.

Many of these policies have been enacted recently, demonstrating a growing concern among many states about the tendency of traditionally designed RPS programs to provide little support for certain solar applications; 10 of the 17 jurisdictions with solar or DG set asides, for example, have developed those policies just since the beginning of 2007. Also of note is a general trend away from multipliers over time; based on limited historical experience, multipliers have not proven particularly effective at stimulating solar adoption, and states have increasingly sought the greater certainty of solar deployment associated with obligatory set-asides. For this reason, the remainder of this section exclusively covers those states with solar or DG set-aside policies.

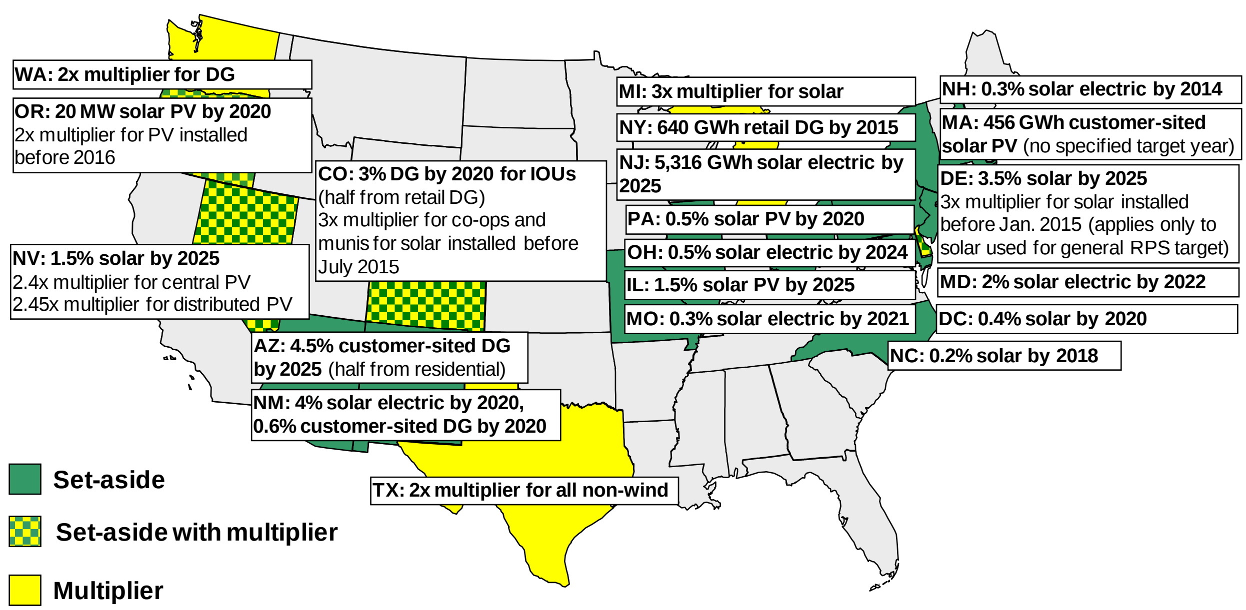


Figure 4. Set-Asides and Multipliers for Solar Energy and Distributed Generation in State RPS Policies

As implied by Figure 4, the design of state solar and DG set-asides varies substantially; uniformity in design has neither been sought, nor achieved. Design variations reflect the differing objectives of state policymakers, state-specific political exigencies, and electricity market designs and regulatory frameworks. As a result, a patchwork of solar support policies exists, demonstrating both a range of design choices available to policymakers, and how those design choices can impact policy outcomes. Key design issues are discussed further below and include: solar targets and timeframes, eligibility rules and the use of multipliers to target particular preferred types of solar technologies or applications, contracting requirements and incentive mechanisms to overcome financing barriers, protocols for the measurement and tracking of solar RECs (SRECs), and cost containment and compliance enforcement.

3.2 Solar Targets and Timeframes

Among the multitude of design variations, perhaps the most significant is that the ultimate percentage targets under solar and DG set-asides varies widely, with some states eventually requiring solar or DG generation of 1-6% of the retail electricity sales on which the RPS applies, while others have targets that rise to only a fraction of a percent.[9] The ultimate targets are listed in Figure 4, while Figure 5 presents data on how the targets increase over time; the latter shows that growth trajectories vary, as does the frequency of upward ratchets over time.[10] Although a number of states with relatively aggressive percentage targets are located in the Southwestern U.S. (Arizona, New Mexico, Colorado, and Nevada), with its robust solar resource, this is by no means exclusively the case. In fact, the highest percentage solar target (6%) belongs to New Jersey, and a number of other Mid-Atlantic or Mid-Western states (Delaware, Maryland, and Illinois) have adopted solar targets that ultimately reach 1.5-3.5% of retail electricity sales by 2025 or sooner.

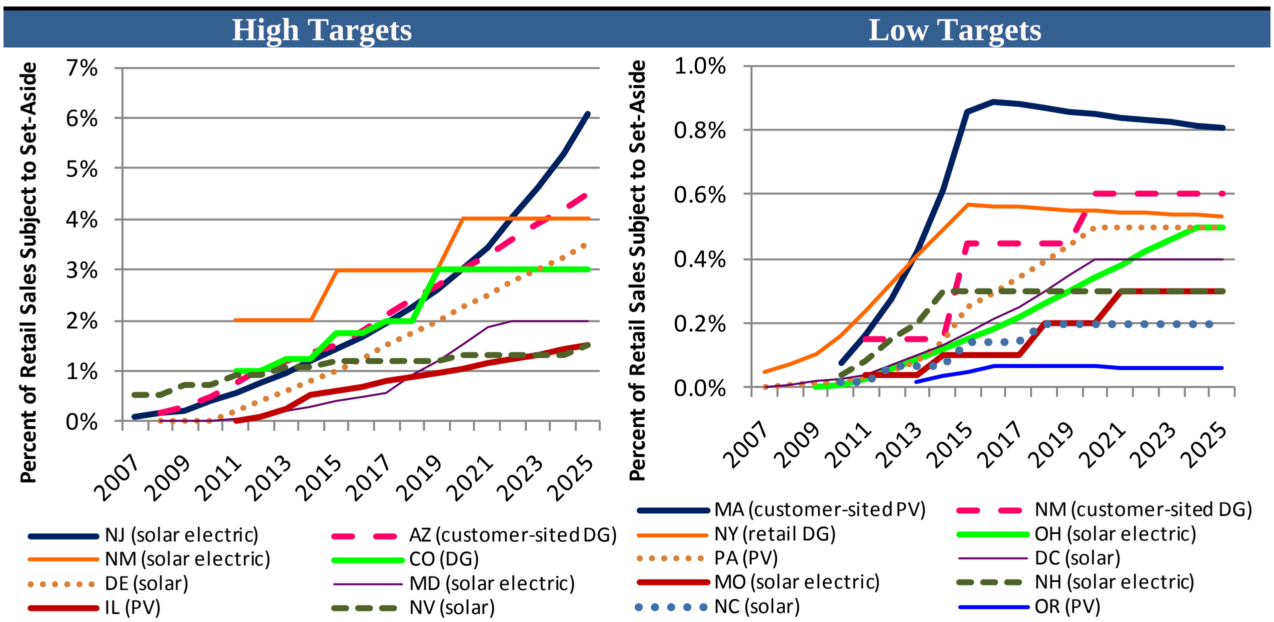


Figure 5. State RPS Set-Aside Targets for Solar and Distributed Generation

3.3 Eligibility Rules and Multipliers

The aggressiveness of the set-aside obligations must also be viewed within the context of differences in resource eligibility. Here, there are many design options to consider: whether to focus on solar or to be more inclusive; what types of solar technologies and applications are eligible; whether to limit eligibility to customer-sited solar or to include utility-scale solar; and

[9] Because of various exemptions offered to certain electricity suppliers or customers, RPS obligations do not always apply to all retail sales in a state (Wiser and Barbose 2008),

[10] The percentage targets shown in Figure 5 are translated into solar capacity additions (MW) later, in Figure 10.

whether to place geographic limitations on solar eligibility. As with most elements of program design, the answers depend on a clear understanding of policy goals.

As shown in Table 3, states have taken very different approaches to defining eligible technologies and applications for their set-asides. Specifically, solar electric technologies (just PV, or PV and CSP) are generally the focus of solar set-asides, though solar heating and/or cooling (SHC) technologies, which may include solar hot water, are also eligible for solar/DG set-asides in six states.[11] Four states have broader distributed generation set-asides in which solar is one of several eligible technologies, while other states have solar set-asides that specify that a certain proportion of the target must come from specific applications, e.g., customer-sited distributed solar or residential solar.

A number of the policies require that projects eligible under the relevant set-aside be located in-state, especially customer-sited DG. In some states, this requirement is effectuated by requiring that eligible projects be connected to the distribution system of an electric utility serving customers in the state. Other states allow out-of-state solar facilities to qualify, but that allowance sometimes comes with limitations aimed at encouraging in-state development. In Maryland, for example, retail electricity suppliers are allowed to purchase SRECs from out-of-state solar projects only until 2012, and only if sufficient in-state SRECs are not available. At the same time, customer-sited solar facilities located in Maryland that wish to sell their SRECs are first obliged to offer those SRECs for sale to electricity suppliers with compliance obligations under the state's RPS. Ultimately, decisions on the treatment of out-of-state facilities requires a balance between the desire of policymakers to promote in-state economic development, on the one hand, and the need to not violate the interstate commerce clause of the U.S. Constitution prohibiting states from erecting barriers to interstate trade, on the other.[12]

Finally, some states have established credit multipliers, in concert with set-asides, to try to direct investments towards certain preferred solar technologies, applications, or project locations. Oregon currently employs a time-limited multiplier for solar to motivate accelerated deployment. Nevada, on the other hand, provides multipliers that seek to motivate PV applications over CSP applications, whereas Colorado and Missouri offer multipliers for in-state facilities (applicable only to the wholesale DG portion of the Colorado's DG set-aside).[13] Several other states currently employ multipliers for solar energy (or that apply to solar energy) without an

[11] Solar heating and cooling applications may offset the onsite use of natural gas or oil rather than electricity, which would offer greater scope for the reduction of greenhouse gas emissions; however, inclusion of SHC within an RPS may be problematic if the state's legal authority over the RPS stems from electricity regulation. Perhaps as a result, a number of states that allow SHC limit eligible applications to those that displace electricity use.

[12] This very issue was recently brought to the fore through a lawsuit filed by TransCanada Power Marketing in U.S. District Court against the state of Massachusetts. The lawsuit challenged the in-state provisions of two separate state renewable energy programs: the RPS solar set-aside and a separate program mandating that the state's distribution utilities solicit long-term contracts with renewable generators located either in-state or in adjacent Federal waters. Under the settlement reached by the parties, Massachusetts retained the in-state requirement under its RPS solar set-aside, but eliminated this requirement under the long-term contracting program. For more on the interstate commerce clause and its implications for the legality of state renewable energy policies, see Ferrey (2006) and Endrud (2008).

[13] Though no longer in existence for new facilities, Arizona's RPS once contained an extensive and varied list of multipliers, and Washington D.C. employed a time-limited multiplier for new solar that has since expired.

associated set-aside (Michigan, Texas, Washington, Colorado[14]); similarly, Delaware offers a time-limited multiplier for in-state solar (and fuel cells) that applies to solar resources that used to meet the general RPS target, but not the solar set-aside.

[14] Colorado's multiplier for solar energy applies for a limited time to the state's POUs, which are not obligated to meet the DG set-aside that applies to the state's IOUs.

Table 3. Technology and Application Eligibility for Solar and DG Set-Asides

State	PV	CSP	SHC	Non-Solar DG	Eligible Applications	Geographic Restrictions
AZ	✔	✔	✔	✔	Customer-sited; 90% retail DG (installed behind customer-meter); ½ residential; SHC must displace electricity	Effectively in-state[(a)]
CO	✔	✔		✔	≤ 30 MWdc per project, ½ retail DG	In-state required for retail DG; in-state multiplier for all other RPS resources, including wholesale DG
DC	✔	✔	✔		All	Out-of-District solar accepted only if insufficient in-District[(b)]
DE	✔	✔	✔		SHC must displace electricity	Delivery required to region
IL	✔				All	Preference for in-state (IOUs only)
MA	✔				Customer-sited and ≤ 6 MWdc	In-state
MD	✔	✔			All	Out-of-state accepted until 2012 only if insufficient in-state
MO	✔	✔			All	In-state multiplier for all RPS resources, including solar; delivery requirements under development
NC	✔	✔	✔		All	Unbundled RECs allowed with limits; otherwise delivered to state
NH	✔	✔			All	Delivery required to region
NJ	✔	✔			All	Effectively in-state[(c)]
NM	✔	✔		✔	DG set-aside: Customer-sited Solar set-aside: All	DG set-aside: Effectively in-state[(d)] Solar set-aside: Delivery required to state and preference for resources located in-state
NV	✔	✔	✔		All	Delivery required to state
NY	✔		✔	✔	Retail DG; SHC must displace electricity	In-state
OH	✔	✔			All	Delivery required to state; ½ of all RPS resources must be in-state
OR	✔				500 kW to 5 MW per project	In-state
PA	✔				All	In-region

(a) *Arizona's RPS rules require that distributed solar energy resources are sited at a customer facility and serve on-site customer load or provide wholesale capacity and energy to the local utility distribution company.*

(b) *Washington D.C.'s RPS rules require that solar resources are connected to the distribution system serving the District, unless insufficient in-District solar is available.*

(c) *New Jersey's RPS rules require that solar resources are connected to the in-state distribution system.*

(d) *New Mexico's RPS rules require that DG resources serve on-site customer load or serve customers in contiguous distribution substation areas.*

3.4 Policy Design Options for Facilitating Project Financing

RPS policies are, in theory, intended to motivate the private sector to meet renewable energy purchase obligations at least cost and with a minimum of ongoing regulatory oversight. In practice, however, state policymakers have often guided the process of resource selection and procurement due to concerns that electricity suppliers either may not pursue least-cost compliance paths, or may otherwise not seek to procure certain preferred solar resources or applications. In the former case, the concern is typically that electricity suppliers may be unwilling or unable to enter into the longer-term contracts that renewable generators require for financing and that may lead to lower overall compliance costs than shorter-term purchases. This is especially true in restructured electricity markets open to retail competition where retail suppliers do not have certainty over their future load obligations, and therefore also lack certainty on the size of their future renewable energy purchase mandate. In the latter instance, the concern is often one of seeking to support a wide range of solar applications, including residential and commercial solar installations that might not otherwise compete with central station solar projects, or that may have a tendency to need up-front payment mechanisms.

Minimum contract duration requirements are one approach that states have taken to improving certainty in REC revenue for renewable energy projects and facilitating project financing. Among states with solar or DG set-asides, Colorado, Maryland, and Nevada have established minimum contract duration requirements for all solar energy contracts of 20, 15, and 10 years, respectively. In addition, although North Carolina does not have a fixed contract duration requirement, the state does require that contracts with solar energy facilities "be of sufficient length to stimulate development of solar energy." In practice, contracting requirements are often simpler to implement in markets still characterized by regulated, vertically integrated utilities because (a) regulators have a history of strong oversight of energy procurement decisions in these contexts; (b) these utilities can be relatively certain about their future retail loads and RPS obligations because they are not subject to competition from other suppliers; and (c) with traditional cost-based regulation, cost-recovery can be assured.

Contracting requirements are more difficult to apply in restructured electricity markets in which retail competition is allowed, because electricity suppliers face greater uncertainty about their future load and RPS obligations, and because the state may lack the legal authority or desire to impose contracting requirements on competitive retail suppliers. As such, only one restructured state (Maryland) requires long-term contracting for SRECs by competitive suppliers, and this requirement is imposed only if the retail electricity supplier purchases SRECs directly from the solar generator (not through a broker or other intermediary). Other restructured states have, instead, turned to a variety of alternate models to facilitate revenue certainty for solar (and other renewable) projects required under their RPS programs. New York and Illinois have both adopted a central procurement model, whereby a state agency issues solicitations for RECs on behalf of obligated electricity suppliers (see Text Box 1). In Delaware, legislation was passed that suspends the three-year lifetime of RECs that are held by state's Sustainable Energy Utility (SEU), which serves as a REC aggregator; this provision was intended to allow the SEU to hold RECs off the market during periods of oversupply and thereby support greater price stability. New Jersey and Massachusetts have each developed alternative approaches aimed at supporting the financing of solar energy projects specifically. In New Jersey, the state's regulated electric distribution utilities effectively act as SREC wholesalers by purchasing SRECs under long-term contract and then re-selling them to competitive retail electricity suppliers; in Massachusetts, the state plans to conduct annual SREC auctions to provide a backstop SREC market for projects that do not arrange bilateral SREC contracts (see Text Box 2 for further details).

In addition to or instead of the approaches described above, many states or utilities have developed standard offer SREC purchase programs and/or incentive programs (under which SRECs may or may not be transferred to the utility or state). Like long-term contracting requirements, incentive and standard offer programs of this type – whether the payment is made up-front in the form of a rebate or over time based on project performance – mitigate revenue uncertainty for the solar project owner, but such programs can also advance other objectives, such as providing differentially higher support for certain types of solar applications (e.g., customer-sited or residential systems). In a number of jurisdictions (Colorado, Missouri, Nevada, New York, and the District of Columbia), these contracting and incentive programs were created specifically as a mechanism for meeting solar or DG set-aside requirements.[15] However, standard offer SREC purchase programs or incentive programs have been developed voluntarily in most other states, independent of any explicit requirement included with the state's RPS legislation. In general, these programs target customer-sited PV projects, and in some instances include SHC technologies as well. Often, eligible applications are limited to projects less than a designated size (or are limited to net-metered systems, where net metering rules place restrictions on system size) and/or the total per-system payment amount is capped. Depending on the program and project size, payment may be provided up-front or over time, based on measured solar energy production. If SRECs are transferred from the system owner to the utility or state in exchange for payment, the SREC transfer may extend for a designated period of time (e.g., 3 years in the case of New York's PV incentive program or 20 years in the case of Xcel Energy's Solar Rewards Program), or it may continue indefinitely (e.g., in Arizona Public Service Company's Renewable Energy Incentive Program and Nevada Energy's SolarGenerations Program).

Finally, utilities and state regulators have also addressed the challenges associated with solar project financing though direct utility ownership of solar assets – focusing particularly on distributed PV applications (see Text Box 3 for examples). This trend – which exists both in states with solar or DG set-asides and in states with no such policies – reflects a variety of

[15] In Colorado, the utility regulator requires that IOUs offer a standard rebate of $2/W for customer-sited PV systems; in addition to the standard rebate, Xcel Energy offers a separate payment for the SRECs produced by such systems over a 20-year period. The Missouri RPS legislation obligates electric utilities to offer a rebate of $2/watt for customer-sited solar systems up to 100 kW, but the rebate is to be paid for only up to 25 kW. Subsequent regulations adopted by the Missouri Public Service Commission require the utilities to also develop standard-offer contracts that provide either an up-front or annual payments for solar RECs produced over 10 years, with terms that vary depending on project size. Similarly, Nevada requires that each utility in that state offer up-front, declining rebates to certain solar systems, with total payment based on the lesser of the actual capacity of the system or 5 kW for residential systems, 30 kW for public buildings and small business systems, and 50 kW for school systems. By accepting the rebate, a program participant is required to transfer the SRECs to the utility. Alternatively, a participant may opt to enter into an agreement with the utility to transfer the SRECs over time for a minimum term of ten years. In New York, as part of its RPS, a state entity (the New York State Energy Research and Development Authority, NYSERDA) offers rebates to solar installations based on system size, differentiated by sector. Finally, as part of a law that increased its RPS in 2008, Washington, D.C. also adopted a renewable energy incentive program that includes up-front rebates for small solar PV and SHC projects.

objectives, in addition to facilitating project financing. At the broadest level, the challenges of meeting aggressive RPS targets and the desire to diversify RPS compliance risk have prompted utilities to pursue a multitude of procurement strategies. Solar asset ownership gives utilities greater control over meeting their RPS targets, and procurement models focusing on distributed solar, specifically, allow utilities to side-step the transmission- and permitting-related barriers that can slow the development of central-station generation. Moreover, direct ownership of solar assets offers utilities the opportunity to rate-base capital costs and thereby earn a return on solar asset ownership – an opportunity made more financially attractive by changes to federal tax law in 2008 allowing utilities to claim the Section 48 business solar investment tax credit. From the customer perspective, hosting a PV facility that is owned by the utility obviates the need for the customer to raise the funds needed to cover the high capital cost of a solar facility, and lowers the customers' transaction costs of evaluating, selecting, and dealing with private contractors. A disadvantage of greater direct utility involvement in the solar market may be the natural tendency of utilities, based on economies of scale, to focus on larger commercial and industrial solar applications to the detriment of residential and small commercial customers. There may also be concerns about utilities competing with private sector solar services, although utilities can still work with solar industry trade allies to identify, develop, install, and service the installations under contractual arrangements. Allowing or requiring that the utility acquire a portion of the solar capacity through competitive procurement from independent power producers is one option to address this latter concern.

Text Box 1: Central Procurement of RPS Resources

One way to address issues caused by uncertain RPS obligations for retail electricity suppliers in restructured markets is to appoint a central procurement agent, thereby relieving the competitive suppliers of direct compliance obligations. Two states – New York and Illinois – have thus far adopted a central RPS procurement model, applicable both to overall RPS compliance obligations and to the solar or DG set-aside obligations.

New York: Investor-owned distribution utilities in New York collect a surcharge on retail sales for RPS implementation. The New York State Energy Research and Development Authority (NYSERDA) manages this RPS fund and uses it both to purchase RECs from new qualifying renewable energy generators through a competitive process and also to provide financial incentives for customer-sited distributed renewable resources, including solar. Under the rules for receiving the latter incentives, customers with DG systems agree to relinquish the first three years of RECs associated with their systems to NYSERDA, and the aggregate generation from such DG facilities is counted towards the state's DG RPS set-aside.

Illinois: The Illinois Power Agency (IPA) was created to develop electricity procurement plans for the state's large IOUs. For the purposes of RPS compliance, the IPA plans and administers elements of the competitive procurement processes for renewable energy; the IPA also prepares a compliance plan for meeting RPS requirements. Though the IPA manages the competitive solicitations for renewable energy on behalf of the state's large IOUs, unlike in New York, it is up to the individual utilities to contract with the winning bidders of the IPA-managed solicitations. Until recently, all of the IPA RPS procurements have been for unbundled RECs, and just for one-year periods. Starting in 2010, however, the IPA will conduct a 20-year procurement for RECs bundled with an energy swap. The RECs under the 2010 solicitation are required to come from specified facilities, with energy delivered to a utility delivery point. As yet, procurement plans have not differentiated solar from other RPS resources, because the solar requirement does not begin for the state's IOUs until 2011-2012. The IPA also manages a portion of the RPS procurement for the state's competitive retail suppliers, which are required to meet at least 50% of their annual RPS procurement obligation by providing funds (termed Alternative Compliance Payments, though similar to a systems benefit charge) to the IPA, which uses those funds to purchase RECs. Solar set-aside obligations as applied to the competitive suppliers do not begin until 2015, however, so as with the IOUs, the IPA has not yet issued a solar-specific solicitation.

Text Box 2. Supporting Solar Project Financing in New Jersey and Massachusetts

New Jersey and Massachusetts have each developed innovative, but distinctly different, approaches to addressing the financing challenges for solar energy projects in restructured electricity markets.

New Jersey: As part of the state's transition to a market-based model for solar project development, the New Jersey Board of Public Utilities (BPU) ordered the state's four regulated electric distribution companies (EDCs) to develop solar financing programs as a means of allowing customers to "securitize" SREC payments. Out of this order, two different program models emerged. Public Service Electric and Gas (PSE&G) modified its pre-existing Solar Loan Program through which the utility loans customers a portion of the up-front cost of a PV system, and the customer repays the loan either in cash or in the form of SRECs generated by their PV system over a 10-15 year term. For purposes of loan repayment, SREC prices are equal to the greater of the prevailing market price for SRECs or a pre-established floor price that varies by customer segment and by loan origination date. PSE&G's current Solar Loan II Program is approved for a two-year period, with a cap of 51 MW. The state's other three EDCs do not directly finance solar projects, but instead, offer 10- to 15-year contracts for the purchase of SRECs, with projects

Text Box 2. Supporting Solar Project Financing in New Jersey and Massachusetts (continued)

selected through periodic competitive solicitations. In 2009, the BPU approved the contracting programs of these three EDCs for a three-year period, with a cap of 65 MW. The programs offered by all four EDCs are open only to net-metered residential and non-residential systems up to 500 kW.

Importantly, the EDCs are not retail electricity suppliers and therefore do not have RPS compliance obligations. Consequently, the EDCs are allowed to sell the SRECs that they procure to retail electricity suppliers that do have RPS compliance obligation or to other interested parties through an auction process, and use the revenue from such sales to offset the costs of their programs. Effectively, the BPU has used the regulated EDCs to facilitate solar financing through these programs, and therefore to also facilitate compliance with the state's solar set-aside by the state's competitive electricity suppliers.

In addition to these loan and SREC contracting programs, New Jersey has also sought to mitigate SREC price risk and encourage project financing through a variety of other measures. These include: establishing a rolling 15-year solar alternative compliance payment (SACP) schedule and a legislative prohibition on reducing any SACP level that has previously been established in order to provide a measure of certainty to market participants (see Section 3.5 for more on SACPs); and establishing a mechanism for automatically increasing the solar set-aside targets in the event of an SREC surplus and declining SREC prices in three consecutive years, also with the intent of increasing revenue certainty for solar project developers and investors.

Massachusetts: In early 2010, Massachusetts developed emergency regulations for its solar set-aside; as of September 2010, a revision to these rules was under review. Under the emergency rules, owners of eligible solar generators would have the option to participate in an annual *Solar Credit Clearinghouse* auction overseen by the Massachusetts Department of Energy Resources (DOER). A 5% auction fee would be levied on solar system owners, which is intended to encourage project owners to contract bilaterally rather than sell their SRECs through the auction. If project owners do choose to participate in the auction, they must deposit their SRECs into a special auction account. Regular SRECs must generally be sold or retired in the year in which they are generated, but SRECs deposited into the auction account will be retired and re-minted with a two-year life. DOER or its agent will then conduct an auction of the re-minted SRECs. The sale of these special SRECs will be at a fixed price of $300/MWh (equal to half of the solar alternative compliance payment of $600/MWh). Bids will be denominated in terms of the *volume* of re-minted SRECs that bidders are willing to buy at the fixed auction price. If an auction does not clear, then the shelf-life of the SRECs is extended to three years, and the auction is repeated. If the auction again does not clear, then the solar set-aside obligation for the following year is increased and the auction is repeated. In effect, these auctions provide a backstop SREC market – and pricing – for projects that do not arrange bilateral SREC contracts, thereby providing a measure of revenue certainty to solar project developers and investors.

In addition to the auction mechanism, Massachusetts has also sought to encourage SREC price certainty through its approach to setting annual solar set-aside targets. Each year, the solar target is calculated based on a formula that takes into account the targets in the prior two compliance years, as well as the number of SACPs used, the auction volume, and the number of SRECs banked two compliance years prior. The net effect is that a surplus of SRECs will tend to increase the solar target in subsequent years, while a shortage of SRECs will tend to reduce the target in subsequent years (with the constraint that the target can never be less than in the prior compliance year). This method for calculating annual solar targets is intended to reduce the likelihood of prolonged periods of depressed or inflated SREC prices, thereby creating greater certainty in SREC prices.

Text Box 3. Emerging Utility Procurement Models for Distributed Solar

Utilities have traditionally sought to add solar energy to their generation mix by offering rebates or other cash incentives for customer-sited PV systems, by purchasing SRECs through short-term over-the-counter markets, or by signing power purchase agreements or long-term REC contracts with utility-scale solar projects. Increasingly, however, solar/DG set-aside requirements and RPS obligations, more generally, have prompted utilities to develop alternative procurement models – in many cases focusing on distributed solar and often involving utility-ownership of distributed PV assets. The following examples illustrate the diversity of approaches to utility ownership of distributed PV assets that have emerged in recent years:

Public Service Electric & Gas (PSE&G) Solar 4 All Program: This program, launched in 2009, includes two elements, each intended to yield 40 MW of solar capacity by 2013. The first component consists of installing small (approximately 200 watt) PV systems on 200,000 utility poles throughout PSE&G's service territory in New Jersey. The second component consists of large (>500 kW) rooftop systems and "solar gardens" owned by PSE&G and installed at a combination of PSE&G sites (25 MW), other private property (10 MW), and sites in Urban Enterprise Zones (5 MW).

Arizona Public Service (APS) AZ Sun Program and Community Solar Pilot: APS received regulatory approval in 2010 for two new programs involving utility ownership of distributed PV. Under the AZ Sun Program, APS plans to install 100 MW of utility-owned, ground-mounted PV within its service territory. Projects will be selected through competitive solicitations and may be located on customer premises, thereby qualifying as distributed energy for compliance with Arizona's RPS DG set-aside. Under the Community Power Project, a pilot program in Flagstaff, APS plans to install 1.5 MW of distributed renewable generation within a single distribution feeder. As part of the program, APS will own, operate, and maintain PV systems installed on residential and commercial customer rooftops, connected on the customer-side of the meter, and will sell the power to the host-customers under long-term power sales agreements.

Duke Energy North Carolina Solar PV Distributed Generation Program: Duke Energy plans to install 10 MW of ground-mounted and rooftop PV systems by 2011 at both residential and non-residential customer sites. The utility will own the systems, which will be interconnected on the utility-side of the meter, and will provide a monthly lease payment to the customer for the use of their property.

Massachusetts Utility-Owned Solar: The Green Communities Act of 2008 allows the state's regulated Electric Distribution Companies to construct, own, and operate up to 50 MW of solar generation each. To date, two utilities have initiated plans to construct PV systems under the provisions of this law. National Grid has received pre-approved cost recovery for the construction of 5 MW of PV systems located on company-owned property; later phases of the program will include utility-owned PV projects sited on customer properties as well as financial offerings to customers that want to own a PV system. Western Massachusetts Electric Company (WMECO) has also received approval for the initial phase of its solar program, in which the utility will develop 6 MW of PV projects at sites that may include both utility properties as well as private and public facilities.

California IOU Programs Targeting Large Distributed PV Projects: Although not subject to a solar set-aside, California's three IOUs – Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) – have received approval for a set of solar PV programs under which the utilities will both own and enter into power purchase agreements (PPAs) for large distributed PV projects. The programs extend over five years, and the three utilities are authorized to procure a total of 1,100 MW of distributed PV (500 MW for PG&E, 500 MW for SCE, and 100 MW for SDG&E).

Text Box 3. Emerging Utility Procurement Models for Distributed Solar (continued)

PG&E's program will target 1-20 MW projects, and the utility-owned projects are expected to be ground-mounted and sited at or near utility substations, while SCE's program will target 1-2 MW projects installed on commercial rooftops, and SDG&E's program will target 1-5 MW, primarily ground-mounted projects. Under PG&E's and SCE's programs, the authorized program capacity is evenly split between utility-owned systems and PPAs, while SDG&E's program is more heavily weighted towards PPAs, representing 74% of the authorized program capacity. These programs are intended to support market segments for solar not adequately supported by other existing programs – namely, the California Solar Initiative, which provides cash incentives for up to 1 MW of capacity, and the general RPS procurement process, in which the transaction costs may effectively exclude participation by smaller distributed PV projects.

3.5 Protocols for SREC Metering, Measurement, Tracking, and Trading

Rules for SREC metering, measurement, tracking, and trading must also be developed in the course of establishing a solar/DG set-aside. A number of states with solar set-asides (Delaware, Maryland, New Mexico, Ohio) rely exclusively on their regional REC tracking systems for these purposes, in which case the same protocols related to REC measurement and tracking apply to solar resources as to other types of renewable generation. Other states, however, have recognized that these protocols may not fit well for small, customer-sited solar facilities and have developed separate rules and procedures, with varying degrees of specificity.

One issue facing RPS administrators is whether to require measurement of the output from small solar electric systems (e.g., residential PV) whose size might not otherwise warrant the expense of high-quality metering hardware.[16] A number of jurisdictions (Colorado, Missouri, Nevada, New Jersey, North Carolina, Pennsylvania, and Washington D.C.) have therefore adopted metering and measurement requirements for solar projects that vary by system size, and that provide RECs to systems smaller than a specified size threshold (typically 10-15 kW) based on engineering calculations of system output rather than on metered electricity generation. Beyond these states, others with solar or DG set-asides generally require all solar electric systems, regardless of size, to have a dedicated meter for the purpose of determining REC production.[17] In many cases, this latter requirement is implicit, as the RPS rules defer to the measurement procedures developed and applied by the relevant regional REC tracking system, which, in turn, typically require measurement of electricity generation using a revenue-quality meter.[18]

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[16] Most small systems are net-metered, requiring only one bi-directional meter and resulting in the measurement of the net excess generation (beyond any solar used onsite), if any, fed from the customer's system into the distribution grid. This limited measurement does not record the entire generation produced by the system, most of which is consumed onsite, so cannot be used as a means of issuing RECs to the owner of the system.

[17] Where separate metering of solar energy systems is required in order to assign RECs, this raises the issue of which party (the customer or the utility) will bear the cost of the metering equipment. Colorado and North Carolina both assign that cost to the utility. Other states generally are not clear about who pays for the meter, although many states' net metering rules prohibit a utility from compelling a customer to pay for a second meter.

[18] The regional REC tracking systems for New England, the Mid-Atlantic, the West and the Upper Midwest all require, by default, measurement with a revenue-quality meter. However, the tracking system in the Mid-Atlantic region allows generation from small solar systems to be estimated using the "PVWatts" software developed by the National Renewable Energy Laboratory, if permitted by state regulations.

Similarly, states that allow SHC systems to qualify for a solar or DG set-aside must decide what type of metering standards to require for measuring heating and cooling output. A number of jurisdictions (Nevada, North Carolina, and Washington D.C.), under certain circumstances, allow solar thermal output to be estimated, rather than measured directly with a thermal energy meter. Other states require a thermal energy meter for all systems. States that allow SHC systems to qualify for a solar or DG set-aside must also decide how to convert thermal output into electricity (MWh) units. Two such states have specified the conversion within their RPS rules (Arizona and North Carolina specify conversions of 3,415 Btu/kWh and 3,412 Btu/kWh, respectively); other states appear silent on the issue.

Reporting and verification of generation data presents another issue that is addressed by some states. Whereas large generation facilities may be expected to install telemetry to communicate measured output directly to the independent system operator (ISO), utility, or tracking system, this option may be viewed as too costly for smaller systems. States have therefore adopted varying rules related to the reporting of generation data for small systems – including whether meter readings can be self-reported by the system owner or must be conducted by an independent third-party, and how frequently meter data must be reported.[19] Alternatively, states may rely on the protocols established by the regional REC tracking system.[20]

Separate from the issue of how the creation of SRECs is measured and reported, RPS administrators must also establish rules related to the trading and tracking of SRECs. By and large, states with solar or DG set-asides apply the same rules and procedures for tracking and trading SRECs as they do for all other types of RECs.[21] For example, a number of states explicitly allow REC trading (both solar and non-solar), and largely rely upon regional REC tracking systems to ensure that trading in SRECs is appropriately verified; these states include Delaware, Ohio, Pennsylvania, Maryland, New Hampshire, New Mexico, New Jersey, and Washington D.C. New Jersey, however, allows solar projects to qualify for SRECs only for 15 years, after which the projects qualify only for standard New Jersey Class I RECs. Other states have taken somewhat different approaches to developing systems for SREC tracking and trading. In Colorado, for example, utilities may create their own auditable REC tracking database or may request regulatory approval to use a central third-party database. In North Carolina, attestations, contracts, and compliance reports may be used to track REC transactions until regulators have adopted an online tracking platform, expected in 2010, while in Nevada the regulator has developed its own REC tracking database. Similarly, New York bases its SREC tracking on contracts. In New Hampshire, the regional REC tracking system performs most of the tracking

[19] For example, New York allows generation data from all solar energy systems to be self-reported, while New Hampshire requires that it be performed by an independent third-party, and North Carolina allows self-reported data for systems under 1 MW. In New York, meters must be read at least every six months and reported to NYSERDA at least twice a year for three years. For systems 25 kW and larger, meter readings must be taken monthly and submitted to NYSERDA every six months. New Hampshire requires a meter reading no less frequently than 13 months (the first within 30 days of the beginning of the calendar year and the second within 30 days of the end of the year); the District of Columbia requires a meter read at least once each calendar year.
[20] Most regional REC tracking systems allow meter readings from small generators to be reported by the owner of the generation unit on either a quarterly or annual basis.
[21] See Holt and Wiser (2007) for a more comprehensive summary of state RPS rules related to REC trading and tracking.

functions, but the regulatory body may issue RECs to customer-sited, metered systems located in the state that are otherwise ineligible to participate in that tracking system. In Maryland, the regional REC tracking system also performs most of the tracking functions, however, alternative approaches are allowed for facilities located outside the region.

3.6 Enforcement and Cost Containment

Finally, states employ various approaches to ensure or encourage compliance with solar or DG set-aside targets, while also seeking to contain the absolute cost impact of those policies. As shown in Table 4, many states have established Alternative Compliance Payment (ACP) mechanisms. Though these policies vary in their design, generally electricity suppliers that have been unable to meet their RPS obligations through the purchase of renewable energy or RECs are allowed to make financial payments (ACPs) to meet those obligations. ACPs are distinct from financial penalties, as they are deemed to be legitimate forms of compliance, and suppliers are typically allowed to recover the cost of ACPs from ratepayers, as they would the cost of RECs. The funds collected through ACPs are often used by state agencies to support renewable energy in other ways, although New Jersey has, instead, recently opted to refund solar ACPs to ratepayers. States have typically established higher ACP rates for solar set-asides than for general (non-solar-specific) RPS obligations, reflecting the generally higher cost of solar electricity than other types of renewable energy. Among the six states with solar ACP (SACP) mechanisms in 2009, SACP rates ranged from $160/MWh to $711/MWh. Given an expectation that solar electricity costs will decline, however, several states plan to ratchet down SACP rates over time: Maryland and New Jersey have both adopted specified, declining SACP schedules, while Massachusetts' regulators have the discretion to reduce SACP rates by up to 10% per year. In contrast, SACP rates in other jurisdictions (Delaware, Washington D.C., and New Hampshire) either remain constant over time or rise with inflation.

States that have established ACP mechanisms in most cases avoid the need for explicit enforcement procedures in cases of non-compliance with the solar/DG set-aside: receipt of the financial payment fulfills the compliance obligation, and the primary instance of non-compliance would be if an electricity supplier refused to make its ACP. In other states, however, explicit enforcement procedures may be required. Some of these states (Missouri, Ohio, and Pennsylvania) have established financial penalties that are assessed automatically based on the level of non-compliance; in these cases, the penalty is structured similar to an ACP (and may even be called an ACP), except that the fee is not generally recoverable in rates. In other instances (Arizona, Colorado, and Nevada), regulatory commissions have the clear discretion to levy financial penalties (often with unspecified levels) as needed, after notice and hearing. In still other states (New Mexico and North Carolina), the RPS legislation directs the regulatory authority to enforce the targets, but specific rules or procedures have not yet been developed.

Table 4. Enforcement Provisions for Solar and DG Set-Asides

Alternative Compliance Payments	
DE	SACP for each supplier depends on how many years it has been used: $400/MWh in the first year a supplier uses the ACP; $450/MWh in the second year; $500/MWh in subsequent years
DC	$500/MWh
MA	$600/MWh; regulatory authority has discretion to reduce by up to 10% per Compliance Year
MD	$400/MWh (2009-10); declines by $50/MWh every two years until it reaches $50/MWh in 2023 and then remains at that level
NH	$160/MWh (2009), adjusted by inflation
NJ	$711/MWh (2008-09) declining to $594 (2015-16); 2010 legislation requires BPU to adopt a 15-year SACP schedule, and to review SACP annually, adding one additional year to the back end of the schedule
Financial Penalties	
MO	Utilities that do not meet their RPS obligations are subject to penalties of at least twice the market value of RECs for the compliance period
OH	Electricity suppliers are charged a pre-specified penalty for all shortfalls in meeting the solar set-aside ($450/MWh in 2009, declining to $50/MWh in 2024)
PA	Establishes solar compliance fee according to a formula that takes into account solar rebates that have been received; for 2008-2009 (the most recent year posted), that fee was $550.15/MWh
AZ, CO, NV	Financial penalties assessed at the discretion of the regulatory authority
NC, NM	Legislative authority to enforce compliance exists, but no rules have been established that indicate how this will occur

The level of the SACP can effectively cap the cost of the solar set-aside, because a supplier would presumably not pay more than the SACP to purchase an SREC.[22] The SACP level therefore sets the maximum price for SRECs, and also the maximum cost of compliance for the solar set-aside. Either in lieu of, or in addition to, an ACP, some states have also sought to contain RPS compliance costs by placing a cap on the retail rate increase or per-customer bill increase that is allowable under the RPS (see Table 5). In general, such cost caps are specified only for the entire RPS, in which case the cost of complying with the solar or DG set-aside is counted against the overall cost cap of the RPS policy. However, three states (Delaware, Maryland, and New Jersey) have established retail-rate-based cost caps that are specific to their solar set-asides and separate from the cost caps for their overall RPS. Similarly, New Mexico has specified the maximum price for solar resources allowable under its RPS, which also effectively serves to cap the cost of its solar set-aside. Only four states with a solar or DG set-aside (Arizona, Nevada, New York, and Pennsylvania) do not currently employ an explicit cost cap that has been established through legislation or administrative rules, although the earlier RPS rules in Arizona did contain a cap on the surcharge that utilities could levy on customer bills for recovering RPS compliance costs.

[22] Financial penalties, on the other hand, may or may not cap the cost of compliance, depending on whether the penalties are recoverable from customers. An obligated electricity supplier may prefer to comply with the RPS obligations, even if the cost of doing so exceeds the financial penalty, if compliance costs can be recovered from customers but financial penalties cannot. Such a situation is most likely to arise in still-regulated electricity markets not open to retail competition, in which case financial penalties are unlikely to cap the cost of the RPS. In markets with retail competition, on the other hand, financial penalties are more likely to be at least partially recoverable in rates, and therefore may be treated in the same fashion as SACPs by electricity suppliers, effectively capping the overall cost of the solar/DG set-aside.

Finally, in addition to cost caps established through legislation or administrative rules, cost containment can also occur through ongoing regulatory oversight of the RPS procurement activities by retail suppliers subject to cost-of-service regulation. Similarly, in New York, the public service commission establishes multi-year program budgets for RPS procurement activities conducted by NYSERDA (the central procurement agent), effectively capping the compliance costs under the state's RPS for the defined, multi-year period.

Table 5. Solar/DG Set-Aside Cost Containment Mechanisms Other than an ACP

Cap on Compliance Costs for *Solar or DG Set-Aside*	
DE	1% increase in retail rates
MD	1% increase in retail rates; allows for one year delay in meeting solar RPS
NJ	2% increase in retail rates
NM	Price of solar cannot exceed \$0.15/kWh (projects <10 kW) or \$0.10/kWh (projects >10 kW)
Cap on Compliance Costs for *Overall RPS*	
CO	2% increase in retail rates (investor-owned utilities) or 1% (cooperatives)
IL	IOUs: Cap on retail rate impact increases each year through 2011, after which it is equal to the greater of 2.015% of average retail rates in 2007 or the incremental RPS costs in 2011; Competitive retail electric suppliers: procurement costs capped based on alternative compliance mechanism[23]
MO	1% increase in retail rates
NC	Caps on annual cost per account for incremental RPS costs; varies by customer class and year
NM	1% increase in retail rates (2006) rising to 2% (2011); annual dollar caps established for large non-governmental customers (\$49,000 in 2006 rising to \$99,000 in 2011)
OH	3% increase in generation costs
OR	4% of utility's revenue requirement in the compliance year

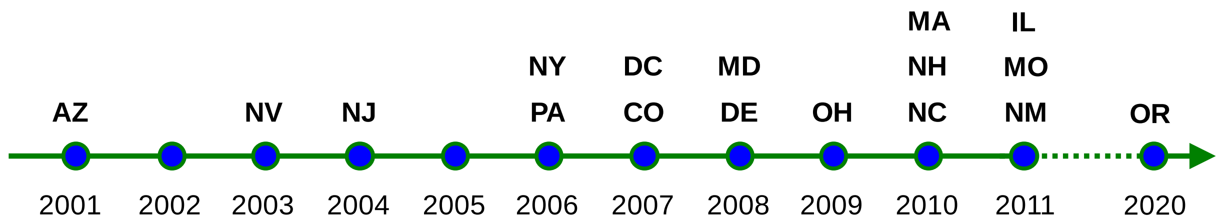
Note: This table identifies cost containment mechanisms established through legislation or administrative rule. In addition to the mechanisms identified here, cost containment in many states also occurs through ongoing regulatory oversight of RPS procurement activities and cost recovery, and in New York, cost containment occurs through regulatory approval of multi-year RPS program budgets for the state's central procurement agent (NYSERDA).

[23] Under Illinois' RPS rules, competitive retail electric suppliers are required to meet at least 50% of their annual compliance obligation with ACP payments; these funds are transferred to the Illinois Power Authority, which uses the funds to procure RECs. The remaining 50% of each supplier's obligations can be met through any combination of ACPs, renewable energy, or REC purchases. ACP rates are updated annually based on the average cost of RECs procured through the IPA's solicitations for the state's IOUs. For compliance year 2009, ACP rates were equal to either \$0.645 or \$0.764 per MWh of retail sales, depending on utility service territory (or approximately \$16 or \$19 per MWh of renewable energy required). Illinois' solar set-aside requirement for competitive suppliers does not begin until 2015 (the set aside for the state's utilities begins in 2011-12), and whether there will be a unique solar ACP is unclear.

4. Solar RPS Policies: Impacts and Expectations

4.1 Overview

Compliance obligations with state solar and DG set-asides have commenced relatively recently. Thus, actual operational experience – both with RPS policies, in general, as well as with RPS policy designs intended to support solar, in particular – still remains rather limited (see Figure 6).



Note: A number of states have RPS compliance years that begin in the middle of the calendar year. For the purpose of this figure, each state is assigned to the first calendar year in which compliance obligations begin.

Figure 6. First Calendar Year with Solar or DG Set-Aside Compliance Obligations

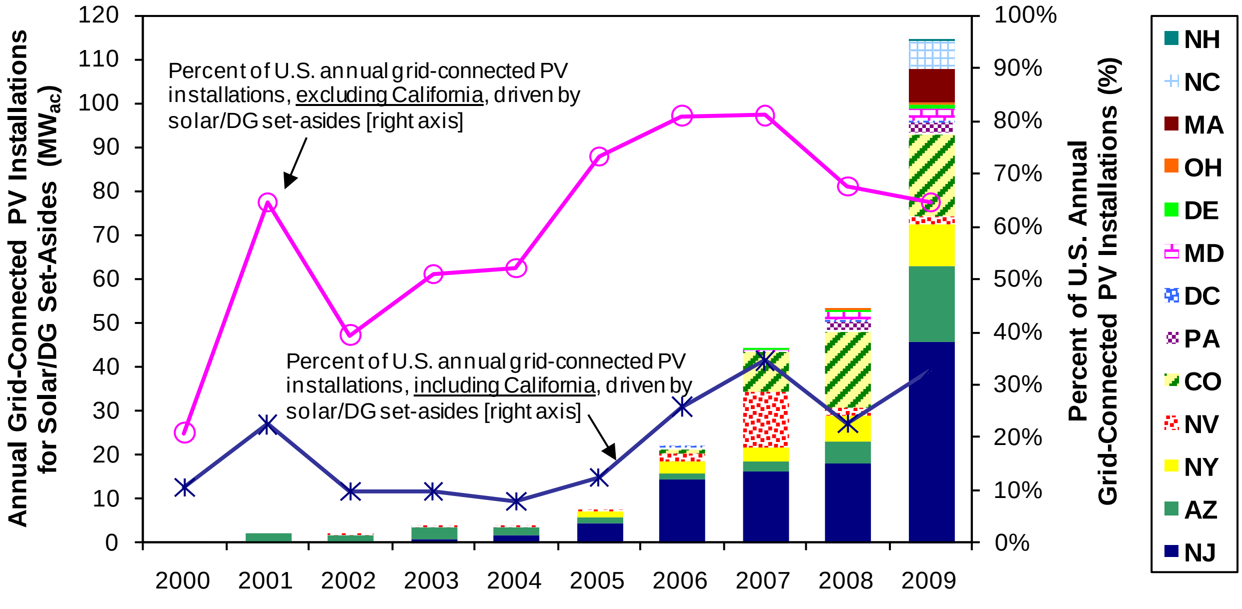
Nevertheless, early experiences do reveal a number of key trends. Specifically, as discussed at greater length in the pages that follow, while there is little evidence that credit multipliers have succeeded in spurring substantial solar installations, solar and DG set-asides have played a central role in driving growth of solar electric capacity in recent years, especially in certain states (though less so for solar heating and cooling technologies). To date, the retail rate impacts of solar/DG set-asides have been relatively modest, though, for a variety of reasons, set-aside targets have not been universally achieved. Meeting the longer-term solar and DG set-aside targets will require a significant amount of additional solar electric generation capacity in the U.S., signaling that these policies are likely to continue to be important drivers behind growth in the U.S. solar market. At the same time, a spate of recent announcements for utility-scale solar projects suggests that significant growth in solar generating capacity that is *not* associated with solar set-aside requirements may occur throughout the desert southwest and other regions with high quality solar resources. In the remainder of this section, we further explore each of the aforementioned trends.

4.2 RPS-Driven Solar Additions to Date

Solar capacity in the U.S. has expanded rapidly over the past several years, albeit from a relatively small base. This growth has been driven by a number of factors, including (though not limited to) Federal tax incentives, state renewable energy rebate and incentive programs, voluntary green power markets, and RPS programs both with and without solar-specific support mechanisms. Assigning attribution to each of these drivers is challenging.

As one relatively simple indicator of the impact of solar and DG set-asides, in each year from 2005-2009, 65-81% of total grid-connected PV capacity additions in the U.S., outside of California, occurred in states with active or impending solar/DG set-aside obligations (see Figure 7). California, which is by far the largest state PV market in the U.S., does not have a solar set-aside as part of its RPS and has, instead, driven growth in solar capacity through other policy support mechanisms (principally, incentive payments for distributed PV, but more recently though larger-scale solar installations that compete with other forms of renewable energy through the state's traditional RPS, or that receive feed-in tariff payments). In aggregate, from 2000 through 2009, more than 250 MW_{ac} of PV capacity is estimated to have been brought on-line to meet state-level solar or DG set-asides, compared to total U.S. solar capacity additions over that period of approximately of 370 MW_{ac} excluding California (or 970 MW_{ac} including California). The fact that solar capacity growth outside of California has centered, by and large, in states with solar or DG set-asides, suggests that these policies have played a key role in accelerating solar deployment in the U.S. These impacts have been most apparent in New Jersey (101 MW_{ac} through 2009), Colorado (46 MW_{ac}), Arizona (36 MW_{ac}), New York (22 MW_{ac}), and Nevada (19 MW_{ac}); these states were also the largest PV markets in the U.S., after California, from 2007-2009.

The impact of RPS solar set-asides is also evident in the budding resurgence of the CSP market in the U.S. After initial growth in the late 1980's, construction of CSP capacity in the U.S. largely ceased. This has begun to change in recent years, with two new CSP projects constructed to meet solar set-aside requirements: the 1 MW Saguaro project installed in Arizona in 2006 and the 64 MW Solar One facility installed in Nevada in 2007. More recent CSP activity (including three projects completed in 2009 and numerous projects under development) includes many projects that would serve to meet general RPS obligations, as well as solar set-asides.[24]



Notes: For the purpose of constructing this figure, solar capacity additions were identified as being driven by solar or DG set-asides if and only if they are located in a state with a set-aside and began operation no sooner than one-year before the start of compliance obligations under the state's set-aside. The only exception is the 10 MW_{ac} El Dorado PV project installed in Nevada in 2008; the electricity generated by this project is being sold into California, and therefore is not attributed to Nevada's solar set-aside.

Figure 7. Grid-Connected PV Capacity Additions Driven by Solar and DG Set-Asides

[24] The resurgent interest in CSP is also partly driven by the ability to incorporate thermal energy storage, and thereby provide greater energy market value than wind and other solar technologies.

Unlike solar electric technologies, growth in solar heating and cooling capacity thus far has not been strongly influenced by the presence of state RPS programs, in general, or solar/DG set-asides, more specifically. This is, in part, a consequence of the fact that SHC technologies are eligible for only a sub-set of RPS set-asides (as shown previously in Table 3), and even in those cases, the types of eligible applications may be limited (e.g., to only applications that displace electricity consumption). The top three states in terms of SHC capacity additions – constituting 50-56% of SHC-related solar thermal collector shipments each year from 2006-2008 – are Hawaii, California, and Florida, none of which have a solar/DG set-aside (Sherwood 2010). Excluding SHC capacity additions in these states, still just 13% of the remaining solar thermal collector shipments in 2008 (or 6% of the U.S. total) occurred in states where SHC was eligible for a solar set-aside then in effect.

Although experience with *credit multipliers* targeting solar energy is extremely limited, the available evidence suggests that, at least to date, they have not resulted in a significant increase in solar generation. The Colorado RPS, for example, includes a solar credit multiplier for the state's rural electric cooperatives and municipal utilities, where each kWh of solar counts as three kWh for RPS compliance. Through 2008 (the most recent year for which RPS compliance data are available), Colorado's municipal utilities and cooperatives fully achieved their RPS compliance obligations with virtually no contribution from solar energy resources. In contrast, the state's investor-owned utilities are subject to a solar set-aside that has resulted in a significant growth in solar capacity. Three other states (Washington, Texas, and Michigan) currently have RPS policies that include only a credit multiplier for solar without an accompanying set-aside. RPS obligations have not yet begun in Washington and Michigan, thus it remains to be seen whether the solar credit multipliers in those states succeed in stimulating solar development. In Texas, the non-wind multiplier (and associated set-aside goal) may have had a limited impact on solar development to date, although Texas' final RPS compliance obligations were fully achieved in 2008, obviating the need for any further renewable additions (solar or otherwise) for meeting its RPS. In the past, both Maryland and Delaware offered RPS credit multipliers for solar energy without an accompanying set-aside. During the brief windows of time when compliance obligations existed in each state but only credit multipliers were in force, relatively small amounts of solar were installed (200-400 kW per year in Delaware, and <100 kW per year in Maryland). Finally, in Nevada, which currently has a multiplier for solar PV, along with a broader solar electric set-aside, the PV multiplier has had some effect in steering solar development towards PV and away from CSP (though both PV and CSP development have occurred under the state's RPS).

4.3 Compliance with RPS Solar Set-Asides

Notwithstanding the general success of solar/DG set-asides in expanding solar markets in the U.S., "compliance" with these requirements has been mixed. As of 2008 (the most recent year for which comprehensive solar set-aside compliance data is available), nine states had active solar or DG set-aside compliance obligations. Across these nine states, 68% of the aggregate solar/DG compliance obligation in 2008 was achieved through the purchase of solar energy, DG, and/or SRECs (see Table 6). Though the requirements in a number of these states amounted to only several MWs of solar capacity, only three states fully achieved their solar/DG requirements in 2008; the other six states met from 0% to 84% of the solar/DG set-aside obligations with the purchase of eligible forms of renewable energy. Though electricity suppliers in these states may not have been technically out of compliance with the solar/DG set-asides (due to SACP compliance options, funding limits, and force majeure provisions), these results demonstrate the challenges of meeting even early-year solar/DG set asides.

Table 6. 2008 Solar/DG Set-Aside Compliance Results

State	2008 Solar/DG Set-Aside Compliance Obligation		Percent of "Compliance" Obligation Achieved*
	% of Applicable Retail Sales	Equivalent Capacity @ 15% capacity factor (MW_{ac})	
Nevada	0.54%	104	100%
New Jersey	0.16%	99	58%
New York	0.07%	58	27%
Arizona	0.18%	52	40%
Colorado	0.20%	46	100%
Maryland	0.01%	2	7%
Washington D.C.	0.01%	1	0%
Pennsylvania	0.01%	1	100%
Delaware	0.01%	1	84%
		Weighted Average	***68%***

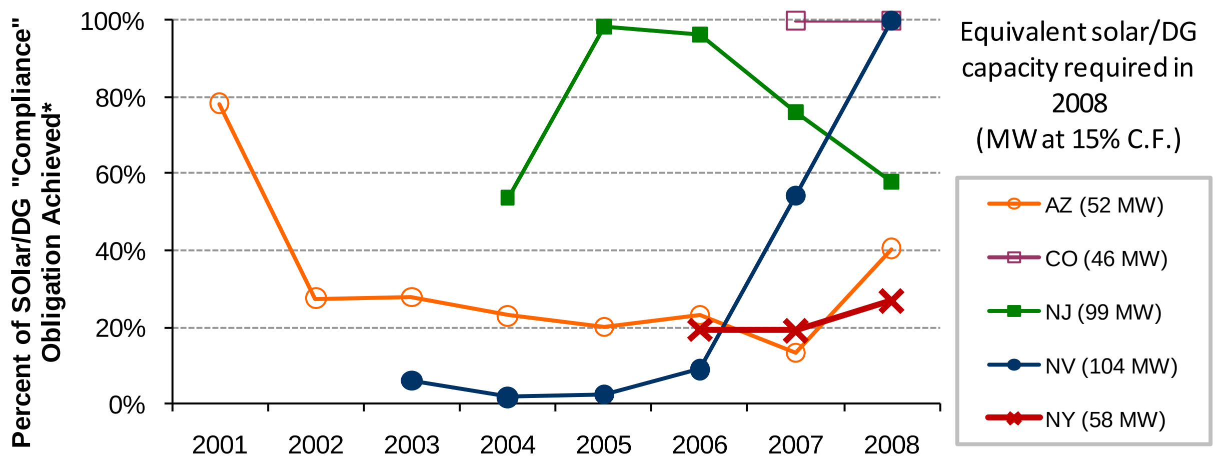
* *Percent of "Compliance" Obligation Achieved excludes ACPs but includes applicable credit multipliers. In cases where this figure is below 100%, suppliers may not have been technically out of compliance due to solar ACP compliance options, funding limits, and force majeure provisions.*

A time trend showing "compliance" results just for those states that had relatively sizable solar/DG requirements through 2008 is presented in Figure 8. In Arizona, the state with the longest history of compliance obligations under a solar or DG set-aside, compliance has remained below 40% since 2002, even after accounting for credit multipliers. This has largely been the result of RPS funding caps in place under the previous set of RPS rules, which were below the level necessary to meet the state's RPS targets.[25] In New Jersey, the solar set-aside targets were almost fully achieved in 2005 and 2006. Since that time, however, SREC supply has not kept pace with the annually increasing targets, resulting in a growing portion of the obligation being met through SACPs; in 2008, approximately 60% of the total set-aside obligation was met through retirement of SRECs, with the remaining portion met with SACPs. Despite various efforts to encourage solar project financing by the state's policymakers and lucrative SREC pricing, long-term SREC contracts are not widely available from competitive electricity suppliers in New Jersey, slowing solar development and thus far impeding full compliance absent heavy reliance on the SACP. Compliance with Nevada's solar set-aside, on the other hand, has steadily risen in recent years after two large solar projects – the 14 MW PV facility at Nellis Air Force Base and the 64 MW Nevada *Solar One* CSP plant – came online in 2007, providing the bulk of the solar generation required to meet the Nevada utilities' solar set-

[25] The apparent increase in compliance with Arizona's set-aside from 2007 to 2008 is largely an artifact of the state's transition from a solar set-aside to a DG set-aside, and the associated change in target levels and qualifying resources.

aside requirements for several years to come.[26] Colorado also fully met its solar requirements in 2008, relying primarily on SRECs purchased through its customer-sited PV incentive program, along with the 8 MW Alamosa PV project. New York, in contrast, has fallen well-short of the DG required under the Customer-Sited Tier of its RPS program, with eligible projects installed through 2008 representing just 27% of the target. Similar to Arizona, the funding levels established for meeting New York's DG requirements were insufficient for achieving its targets.

The remaining four states shown in Table 6 (Delaware, Maryland, Pennsylvania, and Washington D.C.) all had relatively small solar obligations through 2008, in terms of the absolute amount of solar generation required – in each case, requiring less than the equivalent of 2 MW of solar capacity. Of these four states, Maryland and Washington D.C. both missed their solar set-aside targets more or less in their entirety in 2008, reflecting the nascent state of the PV market in those jurisdictions as well as the challenges of encouraging long-term contracting and facilitating solar project financing in markets open to retail electricity competition. In contrast, the small solar targets in Pennsylvania and Delaware were fully or largely achieved.



Note: Percent of "Compliance" Obligation Achieved excludes ACPs but includes applicable credit multipliers. In cases where this figure is below 100%, suppliers may not have been technically out of compliance due to solar ACP compliance options, funding limits, and force majeure provisions.

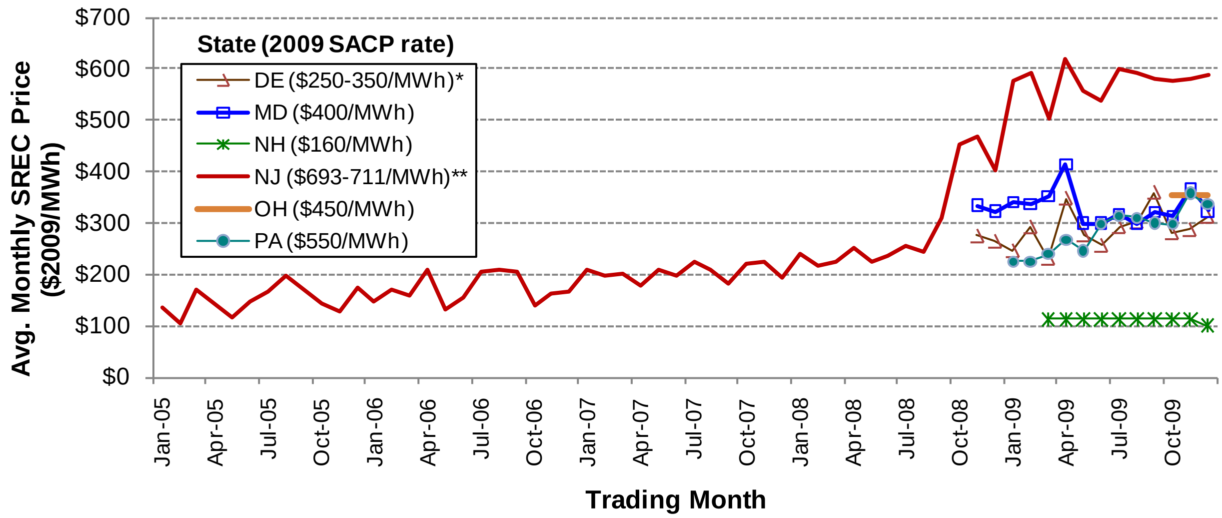
Figure 8. Compliance with Solar/DG Set-Aside Targets over Time

4.4 SREC Prices and Retail Rate Impacts

Most states with solar/DG set-asides allow unbundled SRECs to be used for compliance. In some cases, SRECs are transacted solely through long-term bilateral contracts, for which prices typically are not publicly available. In a number of states, however, SRECs are (also) traded through short-term spot markets, providing some visibility into both the value of potential investments in solar as well as the overall cost to electricity consumers (i.e., the retail rate impacts) of the solar/DG set-asides.

[26] The contribution of these solar resources to Nevada's set-aside is amplified by the application of credit multipliers for PV projects (2.4 for central-station PV and 2.45 for distributed PV).

As evident in Figure 9, SREC markets in the U.S. remained somewhat fragmented through 2009, reflecting differences in the underlying policies and the fact that some states prohibit or limit the use of SRECs sourced from out-of-state or out-of-region facilities.[27] In general, SREC prices were highest in those states with the highest SACPs (as identified in the legend of Figure 9), though average monthly SREC prices generally remained below SACP levels in each state. The similar SREC prices observed among Delaware, Maryland, Ohio, and Pennsylvania may partly reflect the similar SACP levels across those states, as well as the opportunity to trade SRECs among most of these states (as described previously in Table 3). The figure also illustrates the potential for significant fluctuations in SREC prices within an individual state. In particular, SREC prices in New Jersey rose substantially in 2008 and 2009, as the solar targets ratcheted up and SACP rates increased from $300/MWh to $711/MWh in mid-2008. In other states, all of which have a much shorter SREC price history, such fluctuations have not been observed.



Sources: New Jersey Clean Energy Program (NJ), Spectron (NH), PJM-GATS (all other states). Plotted values are the weighted average selling price, except NH, where they are the mid-point of the reported Bid and Offer prices for the current or nearest compliance year.

* *Delaware's SACP rate varies by supplier, depending on how many years the supplier has availed itself of the SACP option. Under the RPS rules in place in 2009, the SACP rate ranged from $250-350/MWh. New legislation passed in 2010 increased Delaware's SACP rates to the levels described in Table 4.*

** *New Jersey's SACP rate was $711/MWh during the first five months of 2009 and was $693/MWh for the latter seven months.*

Figure 9. Solar Renewable Energy Credit Spot Market Prices

The cost of complying with RPS solar/DG set-aside requirements has not been compiled in a comprehensive fashion, in part because of the early status of policy implementation and in part because of methodological complexities and data availability constraints. The SREC prices presented in Figure 9 can, however, be used to roughly estimate the cost of complying with solar set-aside requirements in those states *if* one assumes: (a) that SREC prices represent the total incremental above-market cost of solar resources, (b) that the short-term SREC prices presented in the figure are representative of all SRECs used for set-aside compliance, and (c) that the full

[27] Some caution is warranted in using these data, as they do not include bilateral trade in SRECs or longer-term contracts, and because liquidity is limited in many states. With the exception of the NJ SREC data, it is unknown how many transactions underlie each data point shown in the figure.

compliance obligation was achieved solely through retirement of SRECs, without the need for SACPs, or that SACP and SREC prices are similar.[28] Given these assumptions, the estimated average increase in retail electricity prices associated with meeting solar/DG set-aside requirements in 2009 is shown in Table 7, for the five states for which short-term SREC prices are available[29], along with Arizona and New York, where estimated retail rate impacts are based on actual or budgeted funding levels for DG incentive programs.[30] For five of these states (Delaware, Maryland, New York, Ohio, and Pennsylvania), the rate impacts are estimated at 0.04% or less, reflecting the correspondingly low solar targets. In New Jersey and Arizona, where the set-aside targets in 2009 were appreciably greater, estimated compliance costs reached 0.96% and 1.15% of total retail electricity costs, respectively.

Table 7. Estimated Retail Rate Impact of Solar/DG Set-Asides in 2009

<table>
<tr><th>State</th><th>Solar/DG Target
(% of retail sales)</th><th>Retail Rate Impact
(% of total retail costs)</th></tr>
<tr><td>Arizona</td><td>0.30%</td><td>1.15%*</td></tr>
<tr><td>Delaware</td><td>0.01%</td><td>0.03%</td></tr>
<tr><td>Maryland</td><td>0.01%</td><td>0.04%</td></tr>
<tr><td>New Jersey</td><td>0.20%</td><td>0.96%</td></tr>
<tr><td>New York</td><td>0.10%</td><td>0.01%*</td></tr>
<tr><td>Ohio</td><td>0.004%</td><td>0.04%</td></tr>
<tr><td>Pennsylvania</td><td>0.01%</td><td>0.04%</td></tr>
<tr><td>Washington D.C.</td><td>0.02%</td><td rowspan="3">Unknown
(data not available)</td></tr>
<tr><td>Colorado</td><td>0.20%</td></tr>
<tr><td>Nevada</td><td>0.72%</td></tr>
</table>

** The estimated retail rate impacts shown for Arizona and New York are based on actual/budged expenditures for DG incentive programs, which we take to be a proxy for the incremental cost of DG resources, though not strictly comparable to SREC prices.*

4.5 Projected Solar Capacity Required to Achieve Set-Aside Targets

The impacts of RPS solar/DG set-asides on solar development will continue to grow as a greater number of the existing set-asides take effect and as targets increase over time. By 2025, we estimate that approximately 9,500 MW_{ac} of solar generation capacity would be needed to fully meet the existing state set-aside requirements (see Figure 10).[31] Four states (New Jersey, Illinois, Arizona, and Maryland) represent the bulk of this total. Fully meeting RPS set-aside targets during intervening years would require average annual capacity additions on the order of 400 MW_{ac} per year from 2010-2014 and approximately 600 MW_{ac} per year from 2015-2025. In

[28] The SREC prices presented in Figure 9 do indicate that SREC prices have tended to be close to SACP levels, albeit somewhat lower. More generally, if SACPs are heavily used for compliance, then average SREC prices should tend approach the SACP.

[29] SREC pricing is also available for New Hampshire (see Figure 9), but compliance obligations for that state's solar set-aside do not begin until 2010, so retail rate impacts for 2009 are not included in Table 7.

[30] Specifically, retail rate impacts for Arizona are based on the DG set-aside expenditures reported by each applicable utility in its 2009 compliance filing, and retail rate impacts for New York are based on NYSERDA's 2009 budget for the RPS customer-sited tier. Neither of these states rely primarily on SRECs for compliance with its set-aside; thus, the cost impacts may not be directly comparable to the other states included in Table 7.

[31] This sum is in addition to California's policy goal of installing 3,000 MW of distributed PV by 2017. California's goal is not part of an RPS solar/DG set-aside, so is not included in Figure 10.

comparison, in 2009, approximately 107 MW_{ac} of solar capacity was added in order to meet solar and DG set-asides in the U.S., a figure that would have been higher had full compliance with existing targets been achieved.

Meeting solar set-aside targets in the future will therefore require a scale-up in the solar delivery infrastructure in many U.S. states. In addition to this challenge, a number of policy design issues may constrain the market's growth to levels below those noted above. In particular, as described earlier in Table 5, many states have developed cost containment mechanisms that may ultimately become binding, thereby limiting future solar capacity additions to levels below those estimated here. For example, Arizona and New York both missed their set-aside targets in 2008 as a result of funding limits, and Ohio utilities were granted a force majeure exemption in 2009, thereby curtailing achievement of that state's solar targets. Furthermore, some states, especially those with competitive retail electricity markets, continue to struggle with how to encourage long-term contracting for solar generation. In part as a result, compliance with solar set-aside targets to date has been well below 100%, in aggregate.

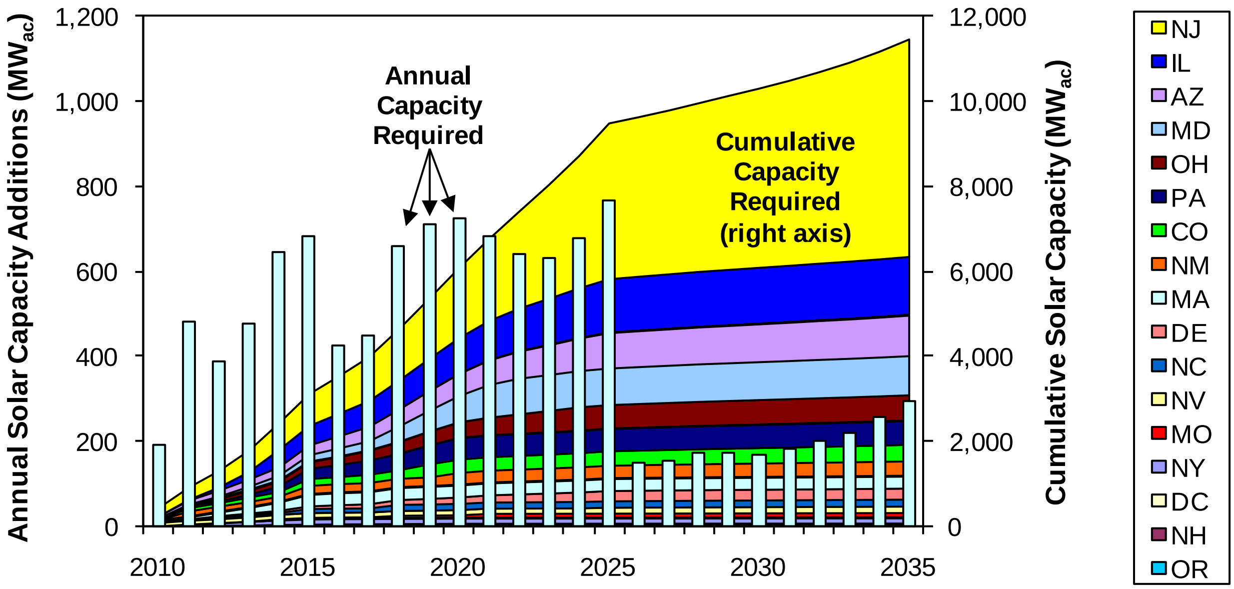


Figure 10. Required Solar Capacity Additions to Meet Solar/DG RPS Set-Aside Targets

Solar and DG set-asides, combined in many cases with additional financial incentives, have been the primary force behind solar electric capacity additions outside of California in recent years, and as shown in Figure 10 will continue to motivate capacity growth going forward. That said, recent announcements for utility-scale solar projects in the U.S. suggest that future growth in solar capacity will, by no means, be limited to meeting set-aside obligations (see Table 8). Among the approximately 23,000 MW of announced utility-scale solar projects in the U.S., more than 15,000 MW is planned for California, where (if constructed) these projects would presumably serve the state's general RPS obligations. Outside of California, most of the remaining announced capacity is planned for states in the desert southwest (Arizona, Nevada, and New Mexico). Some portion of that announced capacity would likely serve the solar set-aside obligations in those states. However, much of the solar capacity planned in Arizona consists of central-station projects, which are not eligible for that state's DG set-aside, and the planned solar capacity in Nevada and New Mexico significantly exceeds those states' solar set-aside requirements through 2020. Thus, much of the announced solar capacity in the desert southwest would, if built, likely end up serving general RPS obligations in the host states or other states in the region, rather than solar set-aside targets specifically. Outside of the southwest and California, utility-scale solar projects have been announced in states with solar set-asides (380 MW) as well as in states with only general RPS obligations (97 MW). In addition, a sizable amount of solar capacity has been announced in Texas (381 MW), where the RPS targets have already been fully met, and in Florida (208 MW), which does not have an RPS. Florida has already seen the addition of one utility-scale solar facility, the 25 MW_{ac} DeSoto plant, which was completed in 2009 and represented the largest PV plant in the U.S. at the time of commercial operation.

Collectively, these project announcements suggest that, at least in the desert southwest and other regions with relatively strong solar resources, utility-scale solar may be able to compete against other renewables within a general RPS framework. As a result, in the future, state solar/DG set-asides may be especially important in states with poorer solar resources or for solar applications that are not likely to fare well under a traditional RPS design (e.g., customer-sited, distributed solar).

Table 8. Summary of Announced Utility-Scale PV and CSP Projects

State	MW	RPS Drivers
CA	15,492	General RPS obligations
NV	3,367	Solar set-aside (~110 MW target in 2020) and general RPS obligations
AZ	2,225	General RPS obligations (primarily) and DG set-aside
NM	429	Solar set-aside (~300 MW target in 2020) and general RPS obligations
TX	381	Not RPS-driven
FL	208	Not RPS-driven
Other states with solar/DG set-asides (CO, DE, MA, MD, NC, NJ, NY, OR, PA)	380	Solar set-aside and/or general RPS obligations
Other RPS states without solar/DG set-aside (HI, MN, WA)	97	General RPS obligations
Other states without RPS (ID, GA, TN, VT)	38	Not RPS-driven
Total	**22,617**	

Source: LBNL analysis of data compiled by the Solar Energy Industries Association

5. Conclusions and Lessons Learned

By design, most RPS policies were originally developed to be largely technology-neutral, stimulating competition among various renewable energy technologies and allowing the most economically attractive technologies to win out. Not surprisingly then, experience has generally shown that traditional RPS programs in which all eligible renewable technologies compete have yielded rather modest levels of renewable resource diversity. This realization has led many U.S. states to design their RPS policies to provide targeted support for solar (and other preferred) renewable technologies. Although most of these RPS provisions have been in place for only a brief number of years, the breadth of experience and variation in policy design reveals a number of key findings.

RPS programs can spur the development of solar energy. Perhaps the most important conclusion is simply that RPS programs can, in some cases, lead to the development of solar energy and to renewable resource diversity, more generally. This fact is evident by the strong growth in solar electric capacity and the pipeline of solar projects under development in California, New Jersey, Nevada, Colorado, New York, Arizona, and other states. In most of these states, this market growth has been driven largely by RPS policies with provisions that specifically target solar or DG. However, the ability of RPS programs to successfully achieve resource diversity, and to do so at an acceptable cost, requires numerous tradeoffs in policy design, and careful attention to policy details.

Set-asides have been a more popular, and arguably more effective, RPS mechanism for solar support than credit multipliers. Of the two basic mechanisms for providing targeted support to solar technologies through an RPS – solar set-asides and solar credit multipliers – set-asides have clearly emerged as the more popular option. This preference is likely driven by a number of perceived advantages of solar set-asides, compared to credit multipliers. Most obvious, perhaps, is that set-asides provide greater certainty that a given amount of solar energy will be produced. This presumption has, in fact, been born out in experience, as solar set-asides have successfully initiated solar market growth in a number of states, while solar credit multipliers have yet to demonstrate any comparable success (though this may partly be due to a shortage of actual operating experience with solar credit multipliers).

Targeted forms and degrees of support may be warranted for different types of solar applications and project sizes. Solar is somewhat unique among renewable energy technologies in the extent to which the technology can serve a variety of distinct applications and relatively localized markets. RPS programs may therefore require tailored strategies focused on different solar market segments in order to achieve broad deployment among multiple applications and meet aggressive set-aside targets. For example, the recent spate of announcements for utility-scale solar projects throughout the southwest (including California) and Florida suggests that, at least in regions with strong solar resources, utility-scale solar projects may be competitive with wind power and other forms of renewable generation. Some states may therefore wish to consider whether solar set-asides continue to be appropriate for utility-scale solar projects, or whether such policies are best targeted to distributed generation applications. Furthermore, within the distributed PV market, project development in many regions has become increasingly oriented towards relatively large-scale distributed PV applications (e.g., >100 kW installations), due in part to economies of scale. State policymakers may therefore also wish to consider whether differentially greater support for small-scale distributed PV projects is warranted – e.g., a requirement that some portion of the solar set-aside be met with residential projects, as well as mechanisms to make it easier for small project owners to participate in SREC markets.

The success of RPS policies in fostering the development of solar energy hinges on whether financing-related barriers are adequately addressed. Experience with RPS policies has often revealed the challenges faced by renewable projects in securing financing, especially in restructured markets where RPS compliance has tended to be dominated by short-term REC transactions. For solar energy, these issues can be particularly acute, given the smaller project sizes, higher up-front costs, and – at least until recently – the less-mature state of commercial development of solar relative to certain other renewable technologies (e.g., wind power). As a prime illustration of their role as "laboratories of experimentation," several states have introduced innovative mechanisms for mitigating this revenue uncertainty. In New Jersey, regulated distribution utilities hold auctions for long-term SREC contracts and re-sell those SRECs to the competitive electricity suppliers that must meet the state's solar set-aside. In Massachusetts, the state plans to hold annual statewide auctions for SRECs, and has established a floor price that will remain in effect over the lifetime of the program. And in New York and Illinois, state agencies play an active role in procuring RECs required for RPS compliance. Further experimentation with such mechanisms may be needed to help ensure that solar set-aside targets are fully achieved in a least-cost fashion, especially in markets open to retail electricity competition.

Solar set-asides may complicate RPS cost containment. Although relatively few states have thus far reached their cap, costs caps are likely to increasingly become an issue as RPS compliance obligations rise over time. Already, funding limits in both Arizona and New York have been binding, resulting in underachievement of each state's solar or DG set-aside target. Solar set-asides may also put pressure on general RPS cost caps. Solar energy has historically been more expensive than those forms of renewable energy that have traditionally been used to meet RPS compliance obligations (principally wind power). To the extent that these historical trends persist, solar set-asides may raise RPS compliance costs. In states where RPS cost containment is achieved solely through ACP mechanisms, the higher cost of solar resources has been accommodated by establishing a separate and higher ACP rate for solar resources than for general RPS compliance. States with explicit cost or rate impact caps, however, have often established only overall RPS caps, without a separate cap for the solar set-aside. These states may find that their RPS cost cap is reached sooner than originally anticipated, resulting in less renewable energy development. States with cost or rate impact caps may therefore wish to consider either increasing the overall RPS cap or establishing separate caps for their solar and DG set-asides.

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