STATE CLEAN ENERGY PROGRAM GUIDE

A REVIEW OF EMERGING STATE FINANCE TOOLS TO ADVANCE SOLAR GENERATION

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INTRODUCTION

The U.S. is rapidly becoming one of the world's leading markets for solar photovoltaic (PV) projects. Installed costs of PV systems are falling, and the extension of the 30% federal Investment Tax Credit is helping to improve project economics, attracting homeowners, commercial building owners, governments, and institutional investors. This solar success story has occurred, in large part, because states throughout the U.S. have established policies, programs, and incentives to support solar deployment. Despite this success, solar markets in the U.S. are still small relative to their potential. In particular, small- to medium-scale solar PV projects (<10 megawatts (MW)) are not well served by existing state renewable energy programs and policies, which tend to support lower-cost, larger-scale renewable energy technologies and projects.

Today, states are supporting solar electricity for a number of reasons: solar PV is an emission-free distributed generation (DG) resource that cost-effectively reduces peak demand, can be scaled down to the individual homeowner or scaled up to multi-megawatt projects, lends itself to quick project development timelines, and is a locally available resource in states that may have limited alternative in-state renewable energy resources.

Rebates and upfront incentives have historically been the primary form of state support for solar technology installations. Today, more than 25 states offer rebates for solar projects, either through state- or utility-run programs. These rebate programs have had a significant effect on the growth of residential and commercial solar PV. However, because of increased demand for these rebates, many states have simply run out of available funding. Insufficient funding and program cutbacks have caused market disruptions and boom-and-bust cycles.

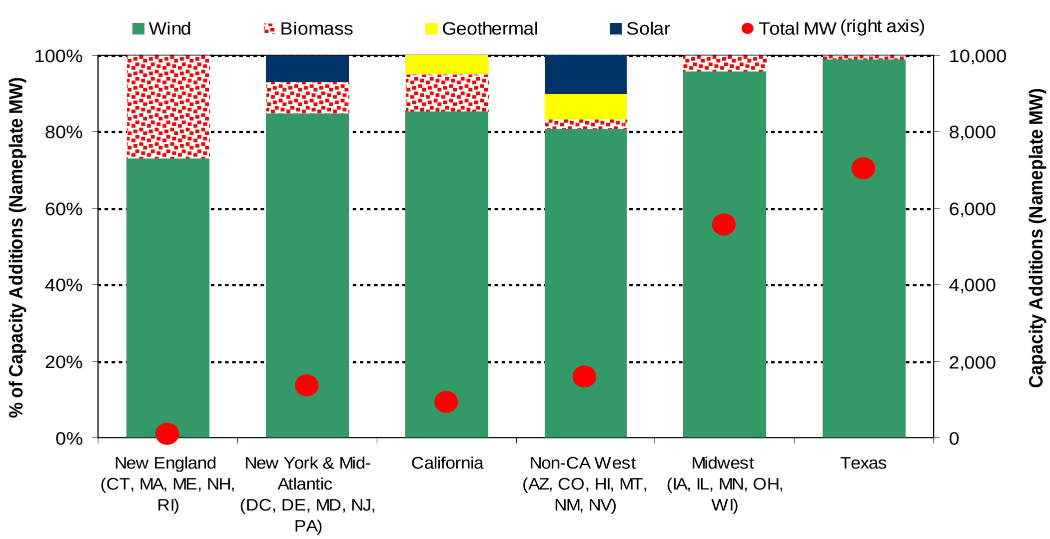
To address this funding challenge and ensure the sustainable growth of the solar industry, states are increasingly turning to alternative financing approaches in association with their Renewable Portfolio Standard (RPS) programs. This guide explores several of the most promising financing mechanisms that can be integrated into RPS programs: solar-specific provisions, feed-in tariffs, and market-based auctions. These mechanisms, if designed smartly, can allow states to build sustainable solar markets with programs that are economically efficient, reward solar system performance, drive cost reductions, allow for program continuity, advance market transformation, and avoid rebate dependency.

RENEWABLE PORTFOLIO STANDARD PROGRAMS AND RELATED MECHANISMS THAT SUPPORT SOLAR

Twenty-nine states and the District of Columbia have established electricity Renewable Portfolio Standards (RPS). RPS's are state-based requirements that utilities (or load-serving entities) must supply a certain percentage of their electricity supply from renewable energy sources by a certain date. The enabling legislation and/or regulations generally allow utilities to procure their renewable portfolio requirements by purchasing renewable energy certificates (RECs) from "least-cost" resources. RECs represent the "environmental attributes" of one megawatt-hour (MWh) of renewable electricity generation from an eligible facility. In most states, these RPS requirements are primarily met with wind, legacy hydropower, and landfill gas generation (see Figure 1).

RPS-driven projects tend to be large, require several years to develop, are often located in remote areas far from load centers, and are sometimes located out of state. Higher-cost and smaller-scale renewable energy technologies such as solar PV – a locally available resource that can be developed in all states – are generally disadvantaged by a standard-design state RPS.[1]

Figure 1: Cumulative Distribution of RPS Compliance by Technology, 2008



Source: Wiser and Barbose, Lawrence Berkeley Laboratory, 2009

[1] In certain markets, notably California, large solar PV projects can and do economically compete in RPS compliance markets today against other forms of renewable generation without a solar-specific set-aside or multiplier. These projects also may be able to compete against non-renewable resources as well. A strong solar resource, high cost of developing other renewable generation, and high power costs combine to make large-scale solar projects competitive there.

To correct this imbalance, an increasing number of states are either designing new or modifying existing RPS policies to provide specific, differential support and procurement targets for solar power. The most popular approach used by states is the establishment of solar "carve-outs" or "set-asides," in which a growing share of the RPS obligation must be met with solar or other distributed generation resources. Sixteen states now have RPS set-asides for solar or distributed generation. See Table 1.

Table 1: Summary of State RPS and Solar/DG Requirements for States with Set-Asides

State	Overall RPS Requirement	Solar (or DG) requirement
Arizona	15% by 2025	4.5% customer-sited DG by 2025
Colorado	20% by 2020	0.8% solar electric by 2020 (1/2 from customer-sited projects; 1.25x multiplier for in-state projects
DC	20% by 2020	0.4% solar electric by 2020
Delaware	20% by 2019	2.005% solar electric by 2019; 3x multiplier for solar installed before 2015
Illinois	25% by 2025	1.5% solar PV by 2015
Maryland	20% by 2022	2% solar electric by 2022
Massachusetts	11.1% by 2009 + 1%/year	400 MW
Michigan	10% by 2015	3x multiplier for solar PV
Missouri	15% by 2021	0.3% solar electric by 2022
Nevada	25% by 2025	1.5% solar by 2025; 2.4x multiplier
New Hampshire	23.8% by 2025	0.3% solar electric by 2014
New Jersey	22.5% by 2021	2.12% solar by 2021
New Mexico	20% by 2020	4% solar electric by 2020
New York	24% by 2013	0.1542% customer-sited DG by 2013
North Carolina	12.5% by 2021	0.2% solar by 2016
Ohio	12.5% by 2024	0.5% solar by 2024
Oregon	25% by 2025	20MW solar PV by 2020; 2x multiplier for projects installed before 2016
Pennsylvania	8.5% by 2020	0.5% solar PV by 2020
Texas	5,880 MW by 2015	2x multiplier for all non-wind projects

Source: Wiser and Barbose, Lawrence Berkeley Laboratory, 2009

Berkeley Labs reports that the effect of the state RPS set-asides on installed solar PV markets has already been substantial. Excluding California, 67% of PV additions from 2000 through 2006 occurred in states with active RPS solar targets. Further, the future impact of these existing state RPS solar set-asides will be sizable: 400 MW by 2010 and 2,000 MW by 2015, assuming full compliance. New Jersey's requirement alone represents 2,300 MW of solar PV capacity by 2021.

The key to making these set-asides meaningful and effective is to establish binding regulatory requirements (by public utility commissions and/or legislation) that ensure the solar targets are enforced, ideally through creation of separate compliance and market-support mechanisms (e.g., solar compliance fees and utility solar REC contracting requirements). Among all of the states that have established solar set-asides, very few states have created the design or enforcement mechanisms to make them binding.

The following is a more in-depth design description of these RPS-related policy mechanisms being used by states to support solar PV.

Credit Multipliers

Under a credit multiplier, utilities earn "extra credit" towards their RPS compliance obligations when they acquire RECs from solar PV generation in contrast to other non-solar generation (e.g., 3 RECs per 1 MWh of solar electricity generated). The solar credit multiplier concept is also included in the proposed federal Renewable Energy Standard legislation in the House and Senate, as a 3:1 multiplier. While these credit multipliers are too new to be fully evaluated for their effectiveness in driving solar deployment, Lawrence Berkeley National Laboratory analysis has found that multipliers are *not* an effective way to support solar PV, because there is no mandate for utilities to actually procure solar RECs. As long as non-technology-specific RECs are low cost and readily available, the multiplier is not likely to be a sufficient incentive by itself to encourage solar PV growth. In addition, to the extent that utilities do in fact acquire solar RECs, the multiplier reduces the overall state RPS capacity targets.

Solar Set-Asides and SRECs

Under a state solar set-aside, a utility must comply with the solar RPS requirement by acquiring solar-specific renewable energy certificates (SRECs) or, in several states, otherwise make a solar-specific alternative compliance payment (SACP). SRECs work similarly to RECs, as tradable certificates in the clean energy markets. Each SREC represents the attributes of 1 MWh of solar power. SRECs provide a revenue stream to solar system owners that can replace the need for other direct incentives that make solar financially attractive to owners and investors. The SACP is an essential component of an effective solar set-aside program as an enforcement mechanism and as a backstop to protect both utilities and ratepayers from unexpected cost impacts of the solar set-aside. The SACP sets an upper limit for the cost of RPS solar compliance, removes the risk of unknown financial penalties for any procurement shortfalls, and gives utilities flexibility in complying with RPS solar requirements.

Solar set-asides create a market-based financial support mechanism for solar installations as an alternative to rebates or other performance-incentive programs. Solar system owners can sell their SRECs to a broker, aggregator, or obligated utility that must buy SRECs to meet state RPS obligations. The price of a SREC is determined primarily through bilateral, long-term contracts with an obligated utility and, in the spot market, by the supply of and demand for SRECs at a given point in time (the price of SRECs tends to rise as a compliance period ends). The SACP establishes the ceiling price for an SREC. It is critical that SACP prices are set by a regulatory board to be above the expected SREC market price so that utilities have an incentive to purchase SRECs and advance solar generation, instead of paying SACPs. States can dedicate any SACPs collected towards direct support for solar PV projects within a state.

In 2008, New Jersey transitioned from a solar rebate system to a program that primarily uses SRECs to grow its solar industry. New Jersey's rebate program was aggressive; as a result, the program periodically ran out of funds. This caused boom-and-bust cycles for the solar industry within the state. New Jersey regulators concluded that a system based on SRECs would alleviate this problem and lead to far lower long-term ratepayer impacts than continuation of its rebate program. New Jersey intends to phase out its rebate program gradually to a SREC-only approach by 2012. To ensure financing is available for initial solar project installations, New Jersey encourages its utilities to sign long-term contracts (15 years) to purchase SRECs from solar generators to provide a predictable revenue stream. (See NJ SREC program details below.)

Maryland, like New Jersey, has decided to transition from a rebate program to an SREC approach. Maryland has established a special RPS set-aside for solar that starts small and increases each year, from 0.005% energy from solar in 2008 up to 2% by 2022. Utilities recover their costs through a generation charge on all customers, with a rate-increase cap overall. To help homeowners and small generators address the high initial cost of solar PV systems, Maryland requires utilities to sign 15-year contracts for RECs and to pay the entire contract price up front.

Massachusetts recently adopted a different version of a SREC financing model, again as a more cost-effective mechanism than rebates for meeting the state's aggressive solar targets. Under the Massachusetts program, qualified solar facilities will have the right (although not the obligation) to deposit SRECs produced annually into an auction account within the New England Generation Attribute System. At the end of each RPS compliance period, retail electric suppliers will be able to purchase these SRECs at a fixed price (with an initial price of $300 per SREC). Any unsold SRECs will be banked for future compliance periods.

The merits of the SREC approach are that it should result in lower costs to ratepayers than a traditional rebate or performance-based incentive program. Although the SACP level sets the maximum cost of acquiring SRECs, the dynamics of solar REC demand and supply should cause a market price well below this SACP level. For example, analysis done for the New Jersey Board of Public Utilities estimated that, under a SREC program, the ratepayer cost of meeting the state's solar requirements would be just one-tenth that of continuing its solar rebate program.

Examples of State Solar REC and Set-Aside Programs

NEW JERSEY

New Jersey's Board of Public Utilities (NJBPU) administers the state's EE and RE public benefits fund. New Jersey has both an ambitious RPS and an aggressive solar target within the RPS (2,300 MW by 2021). The Board has historically provided generous rebates to encourage solar installations. This resulted in New Jersey becoming the second-largest solar PV market in the country and an area of focus for commercial solar developers. However, in 2008, the Board determined that a market-based SREC approach would reduce the ratepayer impact of fulfilling the RPS solar carve-out as compared to its current rebate-based system. If the rebate levels were to remain unchanged, achieving the state's 2.12% solar RPS requirement by 2021 would have required an estimated $10.9 billion in rebates, adding about 7.5% to electricity rates.

In response, starting in 2009, New Jersey began to phase out its "CORE" rebate program and raised the SACP level for solar RECS to $711 per MWh, thereafter declining by 3% per year. This SACP level represents the highest cost that utilities would have to pay to comply with the solar set aside (either by purchasing SRECs "on the margin" or by making SACPs). In practice, the average price of these SRECs during the past year has been about $500 per MWh and they have approached the SACP level only at compliance deadlines.

Recognizing the importance of long-term contracts to both project investors and retail electric suppliers, the NJBPU recently established an auction system in which eligible projects provide an "offer" price for the future stream of SRECs associated with a proposed project. These offers are ranked from least to highest cost, and load-serving entities contract for them until their required solar obligation is met. Projects cannot be speculative but rather must be contracted for and ready to be built contingent upon getting an acceptable offer for the SRECs. By providing long-term contracting, the retail electric supplier is in essence financially underwriting the project.

MASSACHUSETTS

Massachusetts established a solar set-aside within its Green Communities Act of 2008. The Massachusetts Division of Energy Resources (which manages the state RPS program) recognized the importance of long-term contracting for renewable energy project financing but did not have the legal authority to require the state's retail electric suppliers to participate in long-term contracting. As a result, after extensive agency review and public comment, it has recently implemented a different type of auction-based, SREC trading system. Under this program, qualified solar facilities will have the right (although not the obligation) to deposit SRECs produced for a pre-determined number of years (for example, the first ten years of a project's life) into an auction account within the New England Generation Attribute System. At the end of an RPS compliance period, retail electric suppliers will be able to purchase these SRECs at a fixed price (with an initial price of $300 per SREC). If the supply of SRECs exceeds demand, then the price will not fall below this fixed level; rather, the life of these SRECs will be extended so that utilities can then purchase them for compliance in future years. Any SRECs produced that are no longer eligible for the auction (i.e., SRECs from older projects) can be sold either in bilateral transactions or on the spot market; however, there is no minimum price guarantee for these SRECs. Note that qualified solar facilities and utilities can still establish bilateral long-term SREC contracts. This model represents a fallback system to ensure that solar PV facilities can find a market for their SRECs and utilities have a central source from which to procure them.

MARYLAND

Maryland's solar carve-out is currently 0.01% of electricity sales but rises to 2% by 2022. The current solar ACP level in Maryland is $400 and will decline by $50 every two years, reflecting what the Public Service Commission believes will be declining installed costs for solar PV and rising market prices of electricity. The system owner is unlikely to receive REC payments at the current ACP level, both because of fluctuations in the REC market price and the share of solar REC payments captured by broker/aggregators. Any ACP payments made by utilities will be used by the state's clean energy fund to support new solar installations. Note that Maryland has not eliminated its existing solar rebate program but rather has reduced the rebate level considerably to reflect both the enhanced federal tax incentives as well as the rising market value of solar RECs.

BEST PRACTICES FOR SOLAR SET-ASIDES AND SREC MARKETS

The following are emerging best practices to implement a solar REC program:

1. **Specify Eligible Technologies and Project Sizes:** The set-aside should clearly specify whether all forms of solar technology are eligible or whether solar thermal technologies or projects over (or under) a certain size should be excluded, based on state policy goals.

2. **Set Aggressive but Realistic Growth Targets:** State set-aside targets should be aggressive but achievable without significant adverse rate impact. State solar RPS requirements should grow at a level that sustains market demand without overwhelming market capabilities to meet these requirements. The overall solar market is growing at 30-50% per year. State RPS solar ramp-up requirements certainly should not exceed this and should ultimately target a level that is achievable, given the available solar resources in the state, anticipated cost reductions, and reasonable ratepayer impact.

3. **Maintain Program Continuity:** RPS program elements should be designed to enhance the certainty of future revenue streams and ensure market stability to enhance investor confidence. The regulatory or legislative commitment to the program must be sufficiently long in duration and strict in enforcement to create market confidence. Long-term RPS programs, with limited revisions and clear eligibility criteria, are critical to building robust markets. This will benefit ratepayers through reductions in compliance costs, attract capital to the marketplace, facilitate longer-term contracting, and reduce financing costs. Conversely, frequent alterations in RPS programs lead to lack of market confidence and increased financing risks.

4. **Set Effective SACP Levels:** The market-driving mechanism of solar-specific RECs and ACPs will increase the likelihood of achieving solar set-aside targets. To be effective, the noncompliance penalty for meeting the solar RPS target should be set significantly higher than that for the RPS program overall and at a level that provides an adequate incentive for solar PV installations (reflecting all available state and federal incentives). The non-compliance fee should be approximately 25% above the expected market price for SRECs.

5. **Set Declining SACP Schedule:** SACP rates should be established according to a schedule that declines over time to reflect anticipated reductions in the installed costs of solar PV and to put downward pressure on SREC prices and solar installation costs.

6. **Impose Appropriate Rate Impact Caps:** Reasonable rate caps will assure that the development of solar PV does not unduly expose ratepayers to significant rate increases. For example, Maryland allows utilities to apply a one-year delay in meeting RPS requirements if the cost of SRECs exceeds one percent of annual utility revenues.

7. **Encourage Long-Term Contracts**: States should encourage or require long term (e.g., 15 years) SREC contracts in order to create investor confidence and advance financing options. Utilities may be reluctant to enter into long-term contracts with solar project developers because of expectations of future SREC prices trending downward, or concerns about an inconsistent or changing regulatory landscape. Additionally, since the RPS obligation is directly associated with serving retail load, any utility uncertainty surrounding future

customer load deters long-term SREC commitments. A utility's tendency to purchase SRECs on a short-term basis impedes the ability of solar developers to obtain project financing. Absent long-term contracts, project investors will heavily discount future REC revenue streams. This risk premium will tend to inflate SREC prices in the immediate term, with the additional costs borne by ratepayers.

8. **Continue to Provide Rebates for Small Systems:** States should consider continuing existing solar rebate programs for small system owners for whom SREC transaction costs are high and whose need for upfront capital support is greater. These small PV projects, however, should not also be eligible to contribute towards the solar RPS requirements.

FEED-IN TARIFFS

A feed-in tariff (FIT) is a standard offering from a utility for a fixed-price contract for electricity produced from a renewable energy generator for a specified term length. States can use FITs as a complementary policy to their RPS' to encourage the development of in-state solar PV or other specific renewable energy technologies.[2]

Under a feed-in tariff, obligated utilities are required to purchase electricity from renewable electricity system owners at long-term fixed rates established by utilities and/or regulatory commissions. These rates can be limited to certain technologies, and can vary by system size and project location.

Feed-in tariffs are the dominant policy mechanism for supporting all forms of renewable energy in Europe, currently used in 18 of 25 European Union countries. In the U.S., FITs have generated considerable discussion and recently have been adopted by a few states and utilities (Gainesville, FL, Vermont, California,[3] and the Sacramento Municipal Utility District).

A feed-in tariff can be used in combination with an RPS solar set-aside. The RPS set-aside would set the program capacity target and timeline while the FIT creates the market-based incentive to meet that capacity target. Like a SREC program, stable FIT programs increase project revenue certainty and investor confidence and lower financing costs and a project's required rate of return (by reducing the "risk premium"). A FIT, in essence, guarantees a price, a long-term revenue stream, and a grid interconnection. This reduces project financial risk and encourages financing and rapid growth of solar capacity.

The fundamental rate-making principle used in establishing FITs is to set tariff levels that reflect the current cost of a technology while providing an adequate and predictable rate of return for project investors. FITs need to be high enough to attract the desired amount of renewable energy capacity without providing excessive economic windfall to projects.

FITs have several merits. First, FITs are performance-based incentives that reward actual generated energy rather than installed capacity. Second, FITs, if set properly, are high enough

[2] This guide is not designed to provide a comprehensive assessment of feed-in tariff policies and practices but rather to give a high-level overview of FITs in the context of how they can be used within a state RPS to support solar.

[3] California's current feed-in tariff is closer to an "avoided cost" rate, as it is based on the projected marginal cost of natural gas generation rather an above-market price.

to allow solar PV developers to earn a competitive rate of return on investment. Third, FITs facilitate financing and investment in solar technologies by ensuring predictability and stability in the solar market. Finally, funding is not linked to state budget cycles and raids but instead is supported by ratepayers through cost recovery in utility ratemaking.

However, FITs also have several major disadvantages. Most notably, the total cost of FITs to ratepayers is difficult to determine, because it is unclear how much project development will occur and at what pace. Because utilities must buy this solar generation at a premium, total costs to ratepayers can increase rapidly. This can be controlled by capping total capacity quantities eligible for the FIT.

In addition, setting the right price is a significant challenge. If the price is too low, the FIT will not produce sufficient incentive to drive solar development. If the price is too high, the market will become overheated and ratepayers will overpay. Making price corrections is difficult because of the length of FIT contracts. Critics have argued that the FITs in Europe (particularly in Spain and Germany) have been too generous, leading to a surge in projects and higher-than-anticipated ratepayer impact or cost to the government. The lessons learned from the European experience are to set tariffs at a rate that is adequate to support projects but not excessive, to establish program caps to ensure that the desired amount of capacity is not exceeded, and to maintain FIT program stability over an extended timeframe.

Despite increasing interest in FITs in the U.S., there is a key regulatory issue that may raise legitimate concerns about the use of FITs. There are concerns that the European-style FIT may violate both the Federal Power Act (FPA) and the Public Utilities Regulatory Policy Act (PURPA), both of which limit the ability of the states to establish wholesale power rates. While a detailed review of these legal issues is beyond the scope of this paper, the basic issue concerns whether states have the right to establish power purchase rates that are higher than a utility's avoided cost and that are technology-specific.[4]

While the regulatory issues surrounding FITs are not resolved, there are a number of "workarounds" or alternative mechanisms that regulators can use to design a FIT-type program without conflicting with the Federal Power Act or PURPA. Among these are 1) establishing an avoided cost that reflects the value of solar PV in displacing peak generation, 2) compensating system owners at FIT levels above avoided cost through firm REC prices, tax credits, or other incentives, and/or 3) requiring utilities to *offer to purchase* (as opposed to *must purchase*) wholesale power from eligible facilities. Another emerging approach is to establish a market-based reverse auction to procure solar generation, which specifically avoids implicating any FPA or PURPA preemption.

[4]Note that these limitations do not apply to municipal/public power entities, rural electric cooperatives, or public utilities within Hawaii, Alaska, or Texas, none of which are under the jurisdiction of the Federal Energy Regulatory Commission. A comprehensive review of this issue can be found in a recent report from the National Renewable Energy Laboratory, "Renewable Energy Prices in State-Level Feed-In Tariffs: Federal Law Constraints and Possible Solutions," January 2010, available at http://www.nrel.gov/docs/fy10osti/47408.pdf).

Examples of State and Municipal Feed-In Tariff Programs

CALIFORNIA

California's recently-passed SB32 modifies a previously approved feed-in tariff program for renewable energy generators up to 3 MW in size. Under this California Public Utilities Commission (CPUC) program, investor-owned utilities are required to enter into long-term contracts (10- to 25-years) with generators and pay a "market-price referent" tariff for all power not consumed on-site. This price is based on the levelized cost of natural gas generation (currently between $0.085-0.10/kWh), adjusted by time of day (greater value for electricity generated during peak periods), and including the value of environmental compliance costs. The CPUC does not set the feed-in tariffs themselves, only the guidelines for establishing them. The program cap under this program is 750 MW across all qualifying technologies.

Complementing this program is a proposed market-based feed-in tariff program. This four-year pilot program would cover projects from 1-10 MW in size. Under this program, utilities would conduct two or more solicitations a year for long-term power purchase agreements. Renewable energy developers and/or project owners would respond to the solicitation and utilities would accept the lowest bids. There would be three categories of projects: baseload, peaking as-available, and intermittent as-available.

SACRAMENTO MUNICIPAL UTILITY DISTRICT (SMUD)

SMUD, one of the largest municipal utilities in the country, launched its new FIT program on January 1, 2010. The initial program cap is already fully reserved. SMUD's FIT rates are differentiated based on technology (CHP versus renewables), contract length, and time of day. For example, current rates under the renewables program range from $0.075/kWh for winter off-peak generation to $0.294 for summer "super peak" generation (2-8 p.m., Monday through Saturday). Its rates were based on both the energy value and the capacity value of the generation as well as projections of natural gas costs.

VERMONT

On May 27, 2009, the Vermont legislature passed a first-in-the-nation comprehensive pilot feed-in tariff program (H. 446). The program is capped at 50 MW of capacity with no eligible project larger than 2.2 MW. The program's final FIT rates (set January 2010, and generally lower than initial rates) are: wind systems ($0.118-$0.215/kWh depending on size), landfill gas ($0.09/kWh), biogas ($0.141/kWh), biomass ($0.125/kWh), hydropower ($0.123/kWh), and solar PV ($0.24/kWh). The solar PV and biomass programs were fully subscribed almost immediately. Note that Vermont does not have a state RPS.

BEST PRACTICES FOR IMPLEMENTING A FEED-IN TARIFF

1. **Program Stability:** As with all state-based renewable energy financing mechanisms, a stable policy is the key to a successful FIT program. To create a stable FIT, the program must be in place for an extended number of years to create project financing certainty. The term of a FIT should be linked to the life of a project and guaranteed at a minimum for the length of typical project debt (5-10 years).

2. **Size Limits & Program Caps:** The cost of a FIT program can be managed through program or project size limits, by technology eligibility, or through capacity block pricing. Program capacity levels can be limited on both an annual and a cumulative basis to prevent over-heated markets and boom-and-bust cycles while managing ratepayer impact.

3. **Appropriate Tariff Levels**: Tariff levels should be established based on the levelized generation costs of the technology plus a required rate of return to investors. Alternatively, FITs can include the estimated energy and environmental "value" of the renewable generation. A FIT can be structured as a level fixed payment for all output (¢/kWh), a premium payment above the current market price (wholesale or retail) of electricity, or a tiered payment (in which output beyond a certain level per unit of capacity receives a reduced price).

4. **Degression:** FITs should include a schedule of planned tariff-level reductions for future projects. Reducing tariffs for new projects over time creates an incentive which encourages rapid deployment and which reflects anticipated cost reductions.

MARKET-BASED AUCTION APPROACH FOR DISTRIBUTED SOLAR GENERATION

As noted, most RPS programs today are largely geared towards least-cost renewable energy projects. As a result, system-side solar distributed generation is rarely able to effectively bid into a traditional RPS program. In response, California is considering the establishment of an auction-based mechanism in association with its RPS program with a focus on wholesale solar PV projects (i.e., 1 - 10 MW scale projects). Under the program, developers would bid the lowest levelized prices per unit of electricity at which they are willing to develop a project, with the lowest-cost projects being accepted up to either the capacity or rate impact cap. The merits of this approach are that it allows the state to pay developers the price that is sufficient to bring projects online but does not provide surplus profits at ratepayers' expense. The key attribute of this mechanism is that it provides a long-term investment signal and can create a competitive market for distributed solar generation.

This renewable energy reverse auction mechanism (RAM) as proposed by the staff of the California Public Utilities Commission[5] is designed to create a simple, standardized process for procuring system-side renewable DG. Key program elements that must be decided prior to the auction to ensure an effective result include standard contract terms and conditions, project viability requirements, locational preferences (if any), and revenue requirements. With these terms set, utilities then are able to rank DG projects on price alone, creating a competitive process that should be easy for developers to use and understand. Utilities then are required to sign all contracts that meet the pre-determined criteria up to state-authorized revenue requirement caps.

This approach provides pre-approved utility cost recovery, cost certainty for ratepayers, and regulatory certainty for the market. Other merits include:

1. Bidders receive the price they bid, which should reflect the price needed to get the project built.
2. A quick implementation timeframe that can take advantage of federal stimulus programs, the DOE loan guarantee program, and grants in lieu of tax credits.
3. The approach captures changing market prices in a timely manner.

[5] This is currently an open proceeding before the CPUC, Docket Number R 08-08-009.

4. Regulators and utilities can target renewable development in locationally-preferred zones.
5. Auction rules can easily be adjusted based on lessons learned from prior auctions.
6. Ratepayers receive cost-effective and viable projects.
7. Transaction costs are lowered for the developer, utility, and regulator.
8. The auction design minimizes underbidding since the price, once accepted, is not negotiable and bidders will lose their contract if the project is not online within 18 months.
9. Authorized revenue requirement caps provide cost containment/cost certainty for ratepayers.

The following program design elements are proposed for California's RAM initiative and may represent useful best practices:

1. Require a minimum of 2 auctions per year per utility.
2. Set standard FIT contract terms that are not negotiable.
3. Select projects based on the price that the developer bids into the auction; bid price is not negotiable.
4. Base program cap on a revenue requirement allocated yearly by the public utility commission.
5. The revenue requirement cap is determined by evaluation of how much renewable distributed generation each utility needs compared to their other renewable procurement strategies.
6. Projects must be online within 18 months of the effective date of the contract.
7. Require developers to submit a project development security deposit upon contract execution, refunded once the project is delivering; projects are allowed two 6-month extensions if the developer can demonstrate delay is caused by regulatory process.
8. Require developers to demonstrate previous project development experience.
9. Developer must demonstrate site control through ownership, lease, or option to lease or purchase.
10. Solar PV equipment must meet state standards.

CONCLUSION

State RPS policies have been one of the most significant drivers of renewable energy development in the U.S. Because of the nature of these policies, they have done little to advance the development of small- to mid-scale solar electricity projects. However, an RPS can be an important tool to support solar if it is designed or modified in a way that treats solar and other distributed generation as unique resources. Solar set-asides with solar-specific Renewable Energy Certificates, feed-in tariffs, and reverse auctions are all policy tools that states can use to advance solar without compromising the fundamental "least cost" principle of an RPS. This special treatment of solar is important for states if they are to build and maintain public support for their RPS programs, particularly in states where solar is the most widely accessible in-state renewable energy resource.

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ABOUT CLEAN ENERGY STATES ALLIANCE

Clean Energy Clean Energy States Alliance (CESA) is a national nonprofit coalition of state clean energy funds and programs working together to develop and promote clean energy technologies and markets. CESA provides information sharing, technical assistance services and a collaborative network for its members by coordinating multi-state efforts, leveraging funding for projects and research, and assisting members with program development and evaluation.

Many states across the U.S. have established public benefit funds to support the deployment and commercialization of clean energy technologies. Eighteen states make up the core base of CESA membership. Though these clean energy funds, states are investing hundreds of millions of public dollars each year to stimulate the technology innovation process, moving wind, solar, biomass, and hydrogen technologies out of the laboratory and toward wider use and application in business, residential, agricultural, community and industrial settings. State clean energy funds are pioneering new investment models and demonstrating leadership to create practical clean energy solutions for the 21st century.

Founded in 2003, CESA, managed by Clean Energy Group, is headquartered in Montpelier, Vermont, with staff based in Washington, D.C. and Chicago.

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