DEED

APPA American Public Power Association

An Introduction to Community Shared Solar Programs for Public Power Utilities

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A Report to:

Sacramento Municipal Utility District and the American Public Power Association Demonstration of Energy & Efficiency Developments (DEED) Program

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1. Introduction and Summary

Community solar broadly refers to any solar project that has multiple participants—co-owners, lease-holders, subscribers, or donors—where each carries a relatively small portion of the total project cost and shares proportionally in the project's benefits. Recently, solar advocates have begun to substitute the term *shared solar* for community solar, as the benefits from many of these projects flow primarily to the participants and less to the community at large.[i] In fact, some iterations of this business model are not limited to participants within any one community. For example, Mosaic, a company described later in this report, uses online crowd-funding to develop solar projects. Yet a review of the market today suggests that most shared solar projects still fit the narrower definition of community solar, which stipulates that project participants and the project itself both reside in the community.

Shared solar advocates say the driving force behind these developments is the overwhelming popularity of solar energy across a wide spectrum of people, coupled with the barriers to on-site solar development. Generally, rooftop solar requires site ownership, a long-term commitment (beyond the term of typical homeowner or business occupation), high first costs, uncommonly good solar exposure, and other attributes. According to Vote Solar, only 25 to 30 percent of all homeowners have a suitable site for PV. That figure seems about right, based on information from leading public power solar programs, where an estimated one-third of customers who have inquired about solar rebates reportedly do not have an adequate site.[ii] Arguably, shared solar could address rooftop solar barriers and greatly increase investment in solar nationwide. Shared solar is a solution that could evolve quickly, especially due to the solar industry's push for business models that work for customers, when current incentives decline or disappear. Federal solar tax credits are slated to disappear after 2016, and states like Arizona and California are nearing the end of their long-standing incentive programs. Whether declining solar industry costs can outpace declining or disappearing incentives is an unknown that makes a lot of solar advocates and utility planners uneasy.

From the public power perspective, shared solar could represent a threat or an opportunity. Without careful oversight, a non-utility shared solar enterprise could open the door to a range of schemes that use the public grid for private gain, undermining the whole idea of a community-owned, equitably managed public power utility. Concerns about consumer protection arise, too. Will the shared solar project owner be there for 20 years or more to cover operations and maintenance and other responsibilities? What is the utility's role, if the private enterprise fails?

While these concerns are real, utilities that look beyond them might see a strong opportunity in shared solar. Utilities that take or share leadership may realize benefits, without so many risks or costs. The majority of successful shared solar projects today are the result of such collaboration. And the majority of them involve public power or cooperatively owned utilities. These utilities have discovered that their innovations represent a community-based win-win proposition, which satisfies utility, participant, and non-participant interests, and which preempts worst-case scenarios.

In summary, some of the top utility benefits that community solar may deliver are listed below:

1. Accelerates work toward utility solar and sustainable development goals
2. May revive or expand older green power programs
3. Responds to customer interest, addressing siting, affordability, and other issues
4. May support innovation, public service or educational goals
5. Eases solar interconnection and operational requirements
6. Potential for strategic siting and operation
7. May generate solar credits for compliance or sale
8. May maximize project economics, depending upon financing structure
9. Potentially negligible impact on non-participants; ripe for pricing innovations

10. Other benefits depending on program design

Later, this paper will discuss utility benefits and accompanying risks, with regard to specific community solar program designs. That includes asking how community solar might affect a public power utility today and how a well-designed program might anticipate new utility concerns, which are quickly emerging. This is a perspective that is lacking in much of the literature.

The Sacramento Municipal Utility District (SMUD) in California is leading this study, based on its longstanding interest in community solar. SMUD pioneered this model, based partly upon its successful experience with a voluntary green power program that sold utility wind power. In 2008, SMUD introduced the largest solar-based green power program in the country. Called Solar Shares, the program sold the output of a 1-MW PV project, which was owned by a third-party developer (enXco) on a site leased from the utility. Each share, which was equivalent to the output of 1 kW of PV in Sacramento, was priced to include the appropriate buy-down, reflecting the value of incentives for each customer class, in response to the California Solar Initiative (CSI) program. For example, in 2009, a small residential customer paid a fixed fee of $21.50 per month for a 1-kW equivalent Solar Share and received an average monthly (virtual net metering) credit of about $7, making for an average monthly premium of about $14 to participate in the program. Although SMUD has a 20-year agreement with enXco, customers have been able to come and go from the program without penalty (a design element that has pros and cons). SMUD's virtual net metering credits have been based on retail rates and vary with the seasonally varying kilowatt-hour output of the PV array. The Solar Shares program was instantly popular; today it has about 600 participants at any one time. This has been a good program for SMUD and, as modified, has potential for success at other utilities nationwide. Now, looking forward, SMUD wants to review the range of shared solar possibilities and to adapt its program to a changing, growing market.

In that interest, this paper references other pioneering projects from public power cities, including Ashland, Oregon; Ellensburg, Washington; St. George, Utah; Orlando, Florida; etc. Outside of the public power world, it is also worth noting some community solar innovations from electric cooperatives and investor-owned utilities. And a few non-utility models are described, explaining their potential impacts, for better or worse. Yet this paper focuses on the *utility* experience with community solar, because—as SMUD has found—utilities already play a central role in serving community energy needs. If they can collaborate with innovators, they are uniquely capable of designing solar solutions that offer choice and that promise to serve the community well into the future.

Looking ahead, SMUD planners see that solar will be accepted as a growing part of most utilities' resource portfolios. Solar costs and benefits no longer will be merely a topic for speculation; they must be better understood and better reflected in utility rate structures—whether for rooftop solar customers, community solar customers, or as needed to support major utility solar resource acquisitions. Utilities will be more mindful of covering their fixed costs of service, as customers are likely to use solar plus a range of energy efficiency measures to reduce monthly kilowatt-hour use to a minimum.[iii] At the same time, public incentives will subside, including federal tax credits (and even sooner, the performance-based rebates associated with California's SB1 Program for public power utilities). With future energy policies and technology innovations both in flux, utilities and solar advocates will have to work together to steer changes toward those that are most equitable and beneficial to the whole community.

Specifically, SMUD has requested this report in order to examine questions, such as

- What are the dominant models for utility-related community solar today, and what are the widely recognized strengths and weaknesses of each?
- Looking first at community solar project financing issues, what are the leading options that are suited to public power utilities today, and how might this change if federal tax credits end after 2016?

- For public power utilities with interests similar to SMUD's, what elements from different community solar programs of all kinds might be considered as valuable components?
- Like many utilities, SMUD is reassessing solar policies for coming years, and is interested to know how new proposed rate structures will impact traditional rooftop solar customers and community solar customers. Analytic research, which will be summarized in a later phase of this APPA DEED-funded project, will offer include quantitative findings, based on proposed future SMUD rates. The assignment is not to provide answers, but to anticipate the question, how might the overall customer economics of traditional rooftop solar, leased solar systems, and community solar compare?
- For other utilities that are just beginning to consider community solar, a summary of recommendations on how to proceed is provided. These recommendations are developed specifically for this project and also draw on research for the Solar Electric Power Association (SEPA), which has contributed to this APPA DEED-funded effort.

This report is structured to address these questions—and other public power utilities' questions—through a review of best and emerging practices for community solar program design and public-power focused finance. It then looks more closely at the Sacramento program. Section 4 directly addresses SMUD concerns, introducing a revised Solar Shares model and testing it according, especially in terms of its anticipated impacts on customer economics and utility risk-management concerns. For other utilities, that section is a close-up case study. It offers specific program-design ideas, but broadly applicable lessons.

SMUD's proposed new Solar Shares program, as modeled, is very promising. The program design (summarized in Figure 1.1) allows customers to take advantage of optimal project scale, solar siting, design, and financing. Purchase power agreement costs—especially in California—have fallen to levels that nearly balance falling state incentives. As the discussion below details, SMUD still has choices for financing and presenting the project, but, even as modeled—a basic long-term wholesale purchase power agreement—the numbers work. The use of a cost-based rate for participants who subscribe to a solar share has many benefits over other approaches, such as keying the rate to a rapidly changing incentive structure.

From the customer perspective, program design has an additional benefit, because it applies virtual net metering—a very popular and fairly simple way of compensating solar customers for the generation (in this case all of their share's generation) that goes to the grid. That strategy works, in part, because SMUD has applied community solar modeling to a new, anticipated rate structure. The rate, and its relationship to the community solar plan, is explained in detail in Section 4. The bottom line is a win-win for both the utility and for the participant—especially for participants in the residential sector.

Residential customers can anticipate much stronger economics for participating in the community solar program than they would see from investing in a comparably sized solar project through either a home-equity loan-financed system or through a leased system. For example, a multi-year subscription to the community solar program would be cash-flow positive, reaching payback in less than three years. What's more, community solar participants would not have to participate at the same scale as a typical (4.5-kW) rooftop solar plant; they could sign up for a share equivalent to 1 kW or less. Notably, all three customer solar options modeled (rooftop financed, rooftop leased, and community solar) could save money for participants under the new rate structure. But it is notable that the community solar program results are far and away the strongest.

Section 4 also discusses a participation scenario for large-commercial customers. Large customers in California can take advantage of third-party PPAs. One main difference for them between a customer-driven rooftop system and participation in community solar is that the community solar PPA still offers

technical and operational advantages. The participant economics are close for either offer, though neither is as compelling as the offer for residential participants. Section 4 discusses the marketing appeals that may still tip the balance in favor of participation in the proposed Solar Shares option.

Community solar is not just an economic proposition. The marketing appeals are important—as are the marketing appeals for customer-financed or leased systems. This report focuses on understanding customer economics, plus the range of appeals for each option. Following on encouraging research results, it addresses utility risk management as it pertains to community solar, so utilities can be comfortable taking the lead on this emerging and highly promising public power program opportunity.

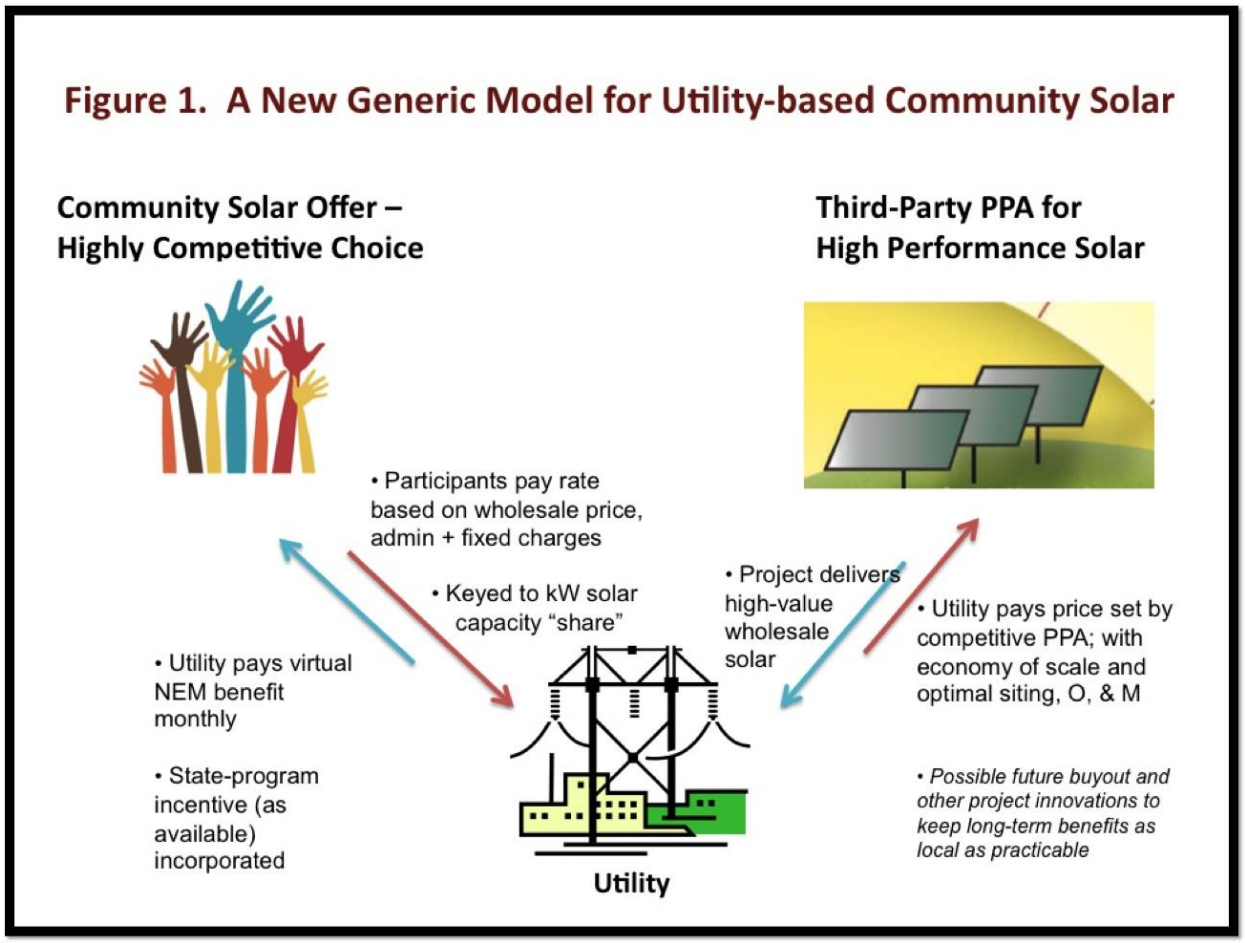

Figure 1.1 Diagram of SMUD Proposed Revision for the Solar Shares Community Solar Program.

2. Overview of Community Shared Solar Options

Considering the broad field of shared solar—and particularly community solar—programs, it is possible to make some basic distinctions among popular business models. Four distinct categories among these include.

1. Finance and solar aggregation models with minimal utility involvement
2. Developer-driven shared solar with some utility involvement/support (e.g., metering/billing)
3. Utility-driven shared solar, with capacity-based pricing
4. Utility-driven shared solar, with energy-based pricing

The trend nationwide has been toward the finance- or developer-driven models. This is due in part to the ease of implementation from the utility's perspective and a perceived risk-management benefit. This also may be due in part to a lack of understanding of the opportunities presented by other models or innovations.

In this section, each category of models is examined for its potential relevance to public power. More current models are examined in greater detail, in terms of:

- Definition, appeals, examples
- The utility role (whether direct, via power contract or other support)
- The customer/participant role (rate, purchase, lease) and return
- Risks and risk management
- Observations from the public power utility perspective

Comparative tables are included in the next section of this report, as well as links to shared solar program examples. As noted above, this report is focused on best opportunities for public power utilities, and particularly, with the experience and interests of SMUD in mind.

2.1 Finance-Driven and Aggregation Models With Little Utility Involvement

Reports on solar business models usually begin with a description of the most practical options, then expand toward the edge of the figurative envelope. Here, we begin with business models that are considered highly innovative, promising, and—from the utility perspective—challenging. By taking this approach, the reader can develop an understanding of the models that excite the business community and solar advocates today and then consider ways to capture some of that excitement, while maintaining practical, forward-looking utility interests.

2.1.1 Crowd-Funding and Mass-Market Investment Vehicles

Crowd-based funding for shared solar is a financing strategy that attracts many small investors through social networking (usually a website) to fund a large solar project. Crowd-funding has been used successfully by nonprofits and innovators through sites such as Kickstarter.com. The Berkeley-based startup, Mosaic (joinmosaic.com), has used this method to initiate community solar development, though it differentiates itself from typical crowd-sourced ventures because it promises a return on investment. As of spring 2013, more than 1,200 investors had signed up to help finance more than a dozen large solar

projects, in California, New Jersey and Arizona. Mosaic focuses on lending funds to the special-purpose entity that would be formed to develop a specific purchase power agreement-supported solar project. The return to investors so far is between 4.5 and 6 percent—relatively good for small investments today. Mosaic reportedly takes about 1 percent. However, the regulatory oversight that makes Mosaic so attractive has also slowed business growth; small investors must reside in California or New York to participate, or they must work with an accredited investment advisor. Mosaic also received a $2 million grant from the U.S. Department of Energy's SunShot Initiative and raised additional funds to develop a fully functional online user platform.

CleanEdge, the clean tech think tank, named Mosaic a top solar trendsetter for 2013, announcing, "Distributed solar financing comes of age," and concluding that the potential of this and similar companies is enormous.[iv] Other solar industry pundits acknowledge Mosaic, but say new West Coast solar finance and development strategies will be surpassed by two Wall Street favorites. The first is the REIT, short for Real Estate Investment Trusts. These are tax-sheltered investment vehicles, made up of individual contributions totaling $640 billion nationwide, that are typically used to finance real estate development. The U.S. Internal Revenue Service recently issued a letter ruling allowing one investment firm to use REITs for solar financing. [v] That ruling is not public, but investment bankers take it as a sign that REITs will soon be attracting a whole new market of solar investors.

The other strategy is the Master Limited Partnership (MLP). For 30 years, MLPs, which have the tax advantages of partnerships but are traded like corporate stock, have driven oil and gas exploration and pipeline developments. Renewable energy projects are not eligible, but bipartisan federal legislation called the Renewable Investment Parity Act, introduced in April 2013, could change that.[vi]

Solar energy is very popular across the political spectrum—an April Gallup poll found that 75 percent of all Americans rank solar development as their top pick among US energy development choices. Crowd-funding, REITs, and MLPs could tap into that support. And some of their strategies already use *community-based* solar projects to attract more investor support. Mosaic, for example, has favored solar developments on affordable housing. And given the choice, Mosaic investors tend to direct their investments to projects in their own states—if not in their own communities.

From the utility perspective, solar projects using this type of financing would look no different from other large solar projects. The difference is they are capable of leveraging a new boom in solar projects—both on customer sites and as independent power producers. Public power utilities might also consider implications of where the investor funding is coming from—and what that means to the local economy. It is beneficial to attract investment to the community—but conversely, too much outside investment may raise concerns about local control.

2.1.2 Non-Utility Aggregators and Implications for Public Power

Legislation to allow various kinds of community solar projects is in effect in Colorado, Delaware, Massachusetts, Maine, Rhode Island, Minnesota, Vermont, and Washington state. California recently expanded its limited allowance for multi-family housing. Along with Washington, D.C., California is considering community solar legislation. In most of cases, this legislation was initiated to encourage non-utility projects, i.e., to require utilities that might not favor shared solar to interconnect and offer net metering.

After the 2008 passage of a state law allowing solar aggregation in Massachusetts, one solar installer, My Generation Energy, Inc., began to work with community leaders in Brewster, on Cape Cod, to develop a community solar cooperative. The result was a 350-kW project located at the town water plant. Investors, who are the co-op members, receive net-metering bill credits from National Grid (the utility) for their share of the project. Although the cooperative claims to have coined the now-popular term, "solar garden," this model has not been widely replicated. Reasons include the relatively high cost of

participation, the need for a reliable lead business partner (such as My Generation Energy), and legal complexities, which make it hard to be sure this type of project complies with U.S. Securities and Exchange Commission regulations.

The sale of solar energy from an aggregator to retail customers is more readily feasible in deregulated states, when a competitive retail energy services provider might choose to offer solar energy from a particular project. Thus far, competing suppliers, like Green Mountain Power, have offered solar-derived energy to choice customers. However, the literature does not indicate any choice offers of solar energy from specific community-based projects. This is probably because the net metering arrangements would be complex. However, that model is theoretically possible, and likely to emerge.

A related model that has gained traction involved Community Choice Aggregation (CCA). CCA programs are bulk electricity purchasing arrangements available to cities and counties in many states with deregulated electricity markets. Under CCA, local governments (usually authorized by referendum) that do not have public power utilities can negotiate with power suppliers on behalf of local customers. They may choose among wholesale power suppliers based on cost of service and other factors—including green power availability. Marin County and San Francisco, California, already have CCA and offer a green power option. Cities in New Jersey, Ohio, Illinois and other states require up to 100 percent renewable-generated power in their CCA power supplies. Some cities are negotiating with power suppliers to sponsor local solar projects, in a variation of the community solar model.[vii]

While these models are not directly relevant to public power utilities, they indicate a national trend toward combining customer choice and shared solar projects. Customers are increasingly impatient with the idea that the resident utility should be the aggregator of energy services for the entire community. Public power utilities might consider how a well-run utility-driven community solar program might satisfy this understandable urge to "choose" local solar and pre-empt riskier and costlier program options.

Barriers to the Simplest Shared Solar Solution

The community solar buying club model could be a straightforward approach to shared solar—except for one or more significant barriers. Imagine a solar project that is centrally located, with a lead organizer responsible for the project infrastructure. Different, remote participants could buy their own panels within the project, while benefiting from the system economy of scale.

In many states, the obvious barrier to this model is that customer-distributed generation must be located at the metered customer site in order to receive net metering or related utility benefits. However, some states do allow remote, so-called virtual net metering benefits, with state-specific stipulations. For example, Maine, Massachusetts and Vermont allow all customers to net meter virtually. Connecticut, Rhode Island and Maryland offer net metering primarily for local government solar projects, whereas California allows it only for participants in multi-family housing. Colorado offers widespread virtual net metering through utility-related "solar garden" programs.

Even if the utility in a given state is willing to provide virtual net metering, the Internal Revenue Service (IRS) may thwart this kind of shared solar plan. The federal 30 percent residential solar tax credit applies only to equipment sited on the customer's residential premises and metered for that customer's solar benefit. (Initially, the IRS guidelines seemed to disallow ground-mounted systems on the customer's property, but the agency has taken a broader view, so long as the project is tied to one residential metered bill.) US Senator Mark Udall, D-Colo., introduced the SUN Act in 2011 to change tax-credit eligibility and allow aggregated solar projects nationwide. The bill attracted some support early on, but progress has stalled. The tax credits sunset in December 2016.

Because tax benefits are key to solar financing, this limitation has become a major stumbling block to shared solar. There are a few examples of community solar projects where the participant buys a panel

and simply foregoes the tax credit, but this usually involves a donation to a project at a school or for a nonprofit agency. Such projects focus more on charitable aims than on shared solar benefits. Common solutions to the tax credit barrier include:

1) A modest approach that focuses on group-buying without the community-based installation aspect. Examples include a program sponsored by One Block Off the Grid (1bog.org)

2) A true shared solar approach, working with a third-party solar developer (and sometimes to do this in partnership with the public power utility). The project is structured so it can take business solar tax credits and other benefits, which more than make up for added administrative costs. That approach is a focus of this report.

3) Investor-owned utilities can use tax credits directly, acting as the project owner/aggregator. In most cases, a tax rule called normalization requires them to return the tax benefits to their ratepayers. This reduces the benefit from the utility perspective, though a number of IOUs still pursue the strategy for other long-term economic and strategic reasons.

2.2 Developer-Driven Projects With Some Utility Involvement

The discussion above introduced a number of models designed without much regard for utility support. The model discussed here evolved largely from that kind of thinking, to the practical realization that shared solar succeeds better *with* utility support. The best-known company in this class is the Clean Energy Collective (CEC). In 2010, CEC pioneered a project with Holy Cross Electric Cooperative in north-central Colorado. That utility preferred not to shoulder administration and financing of shared solar, so it approved CEC's proposal to be a third-party developer, which in turn would serve individual participants who would purchase the solar panels. In 2009, when the project began, a tax benefit called the Treasury Grant in Lieu of Investment Tax Credit was available, making it relatively easy for a small business like CEC, with little tax liability, to finance a small commercial-scale solar project. The start-up was one of the first to create a special-purpose entity (SPE) to take advantage of tax benefits and manage project risks, in accordance with U.S. Securities and Exchange Commission requirements.

The definition of a security is complex, relating to regulations that vary under federal and state law. In general, a security is any note, stock, bond, evidence of indebtedness, certificate of interest or participation in any profit-sharing agreement or investment contract. Not all shared solar projects are viewed as issuing securities. Those that are direct *utility* solar resource acquisitions, by definition, would limit participants' investment risks. But developer-driven shared solar projects often form as special project entities and then, to simplify compliance, amend their legal structures to qualify for exemption or simplification of the rules. For example, if a project raises investment from a limited number of investors, meeting particular criteria (e.g., some percentage of generally wealthier "accredited investors" versus "non-accredited" ones), it could be exempt from some regulations. Other aspects of the business structure, such as how the entity defines participant investments and returns, are also key.

Clean Energy Collective and a handful of other shared solar development companies (for example, Greenbelt Community Solar, in Maryland) have successfully negotiated this tax and regulatory maze.[viii] CEC has become a major developer of community solar projects that partner with local utilities. It has completed at least seven community solar projects in Colorado and New Mexico; representing 3.3 MW of distributed solar generation. It reportedly has additional projects underway, including new projects in Minnesota and Vermont, which will bring its total solar capacity to about 8 MW by the end of 2013.

The CEC model has pros and cons. (Table 3.1 summarizes the pros and cons of several shared solar models.) One strong selling point for CEC is its metering and billing software. Utilities that have initiated virtual net metering report that the billing can be challenging—especially if the goal is to apply "virtual" net metering to a variety of existing rate structures. (Virtual net metering generally refers to dividing the

benefits of generation from a shared solar project among the participants, so that multiple meters are not required, and so that underperformance of a particular panel will not affect a particular participant inequitably.) Other utilities say they are happy with their billing systems, and that they would insist on making any billing changes themselves.

Another selling point for some Clean Energy Collective projects has been its focus on panel ownership. The company aims to get as close to the simple shared solar model (described in sidebar on pages 8-9), while complying both with securities regulations and utility requirements. CEC keeps the overall solar project running, but individual participants own their panels and receive long-term benefits associated with their share of the project. Because participants must have local utility accounts, a CEC project is typically owned by people in the community. Local workers are also hired, if possible. However, the downside to the upfront-ownership model is that it is still costly for many customers. The enforcement of limitations on long-term owners, such as how they may or may not dissolve ownership in the future, also may be troubling for some utility sponsors.

Also, the CEC model usually features long-term non-utility ownership, representing years of economic returns that would not be shared across the community, in contrast to the very concept of public power. Some other, utility-driven models discussed below are structured to allow eventual or immediate utility ownership. The pros and cons of those models are discussed below. Some utilities simply do not want to take on debt for solar projects, and they want to keep their risks to the minimum. The special-project entity, developer-driven shared solar model allows them to do that.

2.3 Utility-Driven Projects With Capacity-Based Pricing

When the utility takes the lead in developing a community solar program, it still faces many choices, principally:

- Capacity-based models, with customer investment mirroring up-front, lump-sum panel cost, or
- Energy-based models, with customer investment mirroring solar-generated energy cost ($/kWh)

The utility-driven, capacity-based model is discussed here, with energy-based models discussed in Section 2.4, below.

The first question a utility program designer might ask is why choose a capacity-based model for community solar? Some of the reasons are the same as those discussed under the special-project entity models, which generally (though not exclusively) use the capacity-based pricing approach. This model offers utility customers a strong sense of buy-in. From the utility's perspective, the model has commitment requirements similar to a solar rebate or performance-based incentive program—i.e., the rooftop solar customer would have to buy the solar hardware before benefitting from the program. But utilities seldom offer actual panel *ownership* through this model. They usually prefer mechanisms that have the "feel" of panel ownership, without all the risks (to participants and to the utility).

Using this model, public power utilities may own or host a solar project and charge participants a lump sum to reserve long-term solar benefits or for a 20-year lease of an identifiable portion (kW capacity or panels) of a project. This is primarily to minimize the problem of customers who might otherwise believe they had the right to sell their panel/s or who might leave it as an unclaimed asset or otherwise misinterpret the limits of a shared solar project. Still, capacity-based program marketing usually builds upon the sense of participant commitment. Community solar and similar, solar charity programs have shown that customers respond strongly if they can actually see the panels. Seattle City Light in Washington used this model and put participant names on a plaque at its community solar project site.[ix] United Power, an electric cooperative in suburban Denver, initiated a "Founder's Club" for its early community solar program participants. These utilities honor participants for their community spirit and

the solar projects are usually highly visible. This strategy works for most kinds of shared solar project marketing (including for capacity-based and per-kWh, energy-based models).

From the utility perspective, capacity-based pricing is a fairly conservative model. Sometimes, a taxable third-party developer actually owns the solar project and provides a solar services agreement—SSA—supporting a lease with the utility. If the utility can pay off the SSA lease in a lump sum with upfront money collected from participants, then it might get a better deal, or at least be able to work with a larger pool of local solar contractors, rather than only those that bring long-term financing to the table. The situation is similar if the utility wishes to arrange a power purchase agreement (PPA) to buy energy from the project. In either deal, the utility can go back to negotiate a low-cost purchase of the project, taking place after the tax-related benefits have been taken. A utility involved in this kind of project typically presents the shared solar project under its own branding. The difference between this third-party approach and the one described as a developer-driven special-purpose entity is primarily in the degree of utility branding, its involvement in metering, billing and maintenance, and—in some cases—its willingness to eventually buy out the SSA or PPA.

A number of electric cooperatives have opted for the capacity-based solar service agreement model already, including United Power and Duck River Electric Membership Corp. in Tennessee. Sometimes, however, a utility will finance the solar project directly, foregoing tax benefits to simplify the financing plan or to increase the local economic development impacts. For example, Seattle City Light owns its community solar arrays, which are mounted on picnic structures at a city park. Seattle has very little risk because it received grant funding and charges remaining costs to participants. (Since the Seattle project includes architecturally interesting picnic structures, the cost per kW is more than double the national average.)

The capacity-based model also lends itself to a "pay as you go" approach. Some utilities that sponsor these projects promise to expand their community solar projects as participation increases—either on a panel-by-panel basis or in stages. There is no easy way for participants to exit the program so the sponsoring utility would have less risk of losing participants over time. In May 2013, the municipal electric utility in Traverse City, Michigan, started an innovative solar program of this type, together with a nearby electric cooperative. For that project, participation literally drives solar development panel-by-panel on a project, which is located at the electric co-op's headquarters. Clearly, this approach minimizes utility risk.

Note that many project characteristics may be combined in different ways, beyond our approach to categorizing shared solar models according to their basic pricing structures.

Traverse City Light and Power Partners for Community Solar

Traverse City Light and Power (TCL&P) in Michigan initiated an innovative capacity-based community solar program. Working with nearby Cherryland Electric Cooperative, it introduced the Solar Up North (SUN) Alliance program. The SUN Alliance invites residential and business customers of both utilities to invest in solar panels through a shared solar project—the first of its kind in Michigan. The project is owned by a for-profit subsidiary of the electric cooperative, Spartan Renewable Energy. This allows a close relationship with the utility, yet qualifies for tax credit benefits.

Interested TCL&P customers can purchase a SUN share, equivalent to a panel, for a one-time investment of $470. A $75 utility rebate applies, so the net cost is $395. In return for this one-time investment, SUN shareholders receive monthly bill credits, which track solar production as if the project were on a modified feed-in tariff (FIT), but calculated at the wholesale power rate. The benefit is estimated to total $2 per month per panel, for the 25-year project term. While the payback is not very strong, the program

pays benefits that an ordinary green power program would not. The credit will vary from month-to-month based on seasonal solar resources and weather conditions. Though currently small, the project will be expanded as participants sign up. Ultimately, TCL&P anticipates building a second array that will be more accessible to its customers. Immediate response from customers of both utilities' customers has been strong.

Some public power utilities may view this program as conservative. The calculation of net benefits, based on the value of wholesale power, sidesteps the net metering issues that other utilities confront. Yet this project offers several important innovations:

1) The for-profit solar subsidiary is a local economic development benefit, and its relationship with the electric co-op is in keeping with a view of the utility as a natural aggregator of energy services for its customers or member-owners. This strategy is especially useful in more rural areas, where it may help to jump-start a local solar industry.

2) The cost of solar to customers includes a pass-through of the tax benefits, which would otherwise be out of reach for both the utility and for the individual participants

3) By leaving it to the utility to site the project, it is likely to be in a highly visible location, with additional benefits for the community. If the utility were to experiment with ideal project siting and design, this approach could add additional benefits and minimize solar integration costs.

Most of these projects are designed to be comparable with the utilities' rooftop solar programs. They pay benefits comparable to the net metering benefits paid to solar owners or to leaseholders in states where private leases (from SolarCity, SunRun, etc.) are allowed. Utilities across the United States are struggling with questions about whether net metering programs are a viable long-term approach for compensating distributed solar generators. Alternatively, a modified feed-in tariff (FIT) or Value of Solar Tariff (VOST) might be applied for shared solar project participants. Innovation is also underway, to find new ways of compensating distributed generation as fairly as possible. For example, SMUD is working on ways (whether through a capacity-based or energy-based shared solar model) to adapt shared solar pricing to work with a new rate structure that will place more fixed costs in a customer charge and less in volumetric rates. In general, a utility would not use one net metering structure for its rooftop solar and another for its shared solar participants. Since shared solar agreements typically last 12 to 20 years or more, utilities that are considering changing their rate structures and revising their net metering programs might be well-advised to settle on a new rate design before finalizing guidelines for a community solar program—unless they include careful contract language that allows modest changes in the long-term benefits structure.

Other challenges of working with a capacity-based shared solar model include educating customers about the differences between their participation in the program and an actual rooftop solar purchase. As noted above, customers typically lease panels or subscribe to get program benefits for up to 20 years, and possibly more. Customer education is important, as participants cannot take the residential solar tax credits. The cost to participants would reflect a pass-through of some of the third-party tax benefits (if applicable) and a pro-rated portion of any available incentives. When determining ongoing benefits, such as virtual net metering payments, utilities usually work out the benefits per share, based on the project as a whole. That way, if an individual solar panel goes out of service or needs to be replaced, no individual participant is penalized.

A final note in considering which shared solar model might be best for a given utility: Seattle City Light sponsored a customer survey during planning, and it found that a greater and more diverse number of customers probably would participate if it converted the up-front capacity cost into energy-based pricing,

with a cost per kWh. Seattle decided to stick with the up-front capacity payment for its first community solar offer. This was practical, given that the initial project is only 24 kW and has a relatively high unit cost.

2.4 Utility-Driven Projects With Energy-Based Pricing

The majority of utility-driven shared solar projects today use some form of energy-based pricing. This does not mean they are interchangeable with utility green power programs. Some utilities, such as SMUD, have sponsored both community solar projects and green power programs (dominated by wind power) at the same time. The main characteristics that differentiate shared solar from green power programs are: (1) shared solar supports a specific project, preferably local and (if utility-driven) planned, developed, and promoted through utility leadership or investment; and (2) participants get some benefit over time, such as net metering or a buyback rate, which is tied to the project's solar generation. There are two generic ways to set up an energy-based pricing model for shared solar:

1. Asking participants to subscribe to blocks of solar power that represent the output of a given unit of solar capacity.

2. Asking participants to participate in a solar rate for all or some percentage of their energy use. In effect, this adds a solar premium to the bill.

In either case, the utility would typically offer some kind of benefit in return for customer participation, just as it would in a capacity-based model. The rate and the benefit are typically locked in for a long period of time (12 to 20 years or a longer period deemed to be the life of the system). Some utilities might arrange to take solar renewable energy credits (RECs) or other compliance benefits, too. In most states, a utility-driven community solar program counts (at least in part) toward the utility REC requirement. Where this is not the case, it is often because customers are allowed to keep the RECs (in order to comply with Green E or other certification programs), or because regulators require the utility to seek RECs from other sources.

Most of these programs also offer some kind of virtual net metering or performance benefit, as well as exemption from fuel adjustment charges—a departure from standard green power programs.

The green power approach focuses on streamlining implementation to increase total program capacity. Often, the utility makes a commitment to develop a significant amount of solar (as project owner or via a PPA or SSA), and then offers part or all of the project for participant subscriptions. The utility shoulders the risk of carrying the project, if it is not fully subscribed. This concern is important because green-power-based programs usually allow participants to come and go, with few restrictions. This type of project might be fully subscribed at the outset, and then lose participants. Newer iterations of this model tie particular benefits to long-term participation, to minimize that risk. For example, many programs allow customers to lock in the solar rate for the life of the program, but if they leave the program and re-apply later, they would not necessarily get the same solar rate. The Tucson Electric Power *Bright Tucson* community solar program offered to "true up" its virtual net metering credits, paying customers if their solar share exceeded their actual energy use—but only on an annual basis. (Other programs limit participation to solar power blocks that add up to no more than 50 to 120 percent of the customer's historic energy use.)

A utility could require a set time commitment from participants (at SMUD, the minimum subscription is one year), but there are also benefits to allowing the utility to reshape the program over time. The authors have, in their consulting practice, advised utilities to adjust the program subscription cost for all energy-based community solar participants (existing and new subscribers), as the cost of solar declines. In that way, early adopters are rewarded for staying in the program, as their initial cost per solar kilowatt-hour is reduced. New participants would, in effect pick up the difference, paying slightly more than the latest cost

of solar (assuming solar costs continue to decline) for subscribing to a later phase. But they would be rewarded with relatively low-cost solar, due to the financing and economy-of-scale benefits of the continuously growing program. The sponsoring utility would benefit from greater continuity and lower risk of having to shoulder the full responsibility for aging solar projects. SMUD, among other utilities, is reviewing the benefits of this kind of portfolio pricing to create a blended subscription cost for all participants.

The original and most common way to price an energy-based shared solar program is through a subscription for blocks of solar energy. This is similar to the green power pricing model, from which these shared solar programs are derived. For example, Columbia Power and Light in Missouri, initiated one of the first public power community solar programs in 2008.[x] Called Solar One, it invited local businesses and departments of city government to participate in solar development. The initial plan was to work primarily with businesses, which could take the investment tax credit for putting solar on their roofs. Then the utility would buy the solar energy through a power purchase agreement. In turn, customers could voluntarily subsidize the solar PPA, through a community solar subscription that resembled a typical green power program subscription. A block of 100 kWh of community solar costs $3.35. This program does not pay virtual net metering benefits so it is, in effect, a contribution, meant to jumpstart the local solar market and to green the utility without imposing rate impacts on other customers. Commercial-scale projects in the program are now sited at Quaker Oats, Bright City Lights, and Columbia's West Ash Pumping Station. The program remains popular with some customers but, since its inception, the utility has seen more customer-sited solar and it has committed to adding more renewable energy outside of the customer-subsidized program to expand its renewable energy portfolio from 8 percent to 15 percent by 2023.

The Orlando Utilities Commission (OUC) took a similar tack by taking advantage of lower solar development and PPA costs in central Florida and accounting for some strategic solar benefits. According to a 2012 OUC program report, the utility calculated a customer contract price of 17.5 cents per kWh and bought it down by about 5 cents per kWh.[xi] (These costs have changed slightly, but the current net cost for participation in the program is about 13 cents per kWh. A $15 deposit, refundable after two years, helps to build customer commitment. OUC also has a virtual net metering plan; if a customer's share of solar generation produces more energy in a month than he or she can use, the utility issues a credit. The net cost for a typical residential customer would be like a 2 cents premium per kWh for energy in the blocks subscribed. Because the price is locked in, it may provide a net benefit over time.

Like the Columbia, Missouri, program, this one relies on solar development partners in the community. To date, however, the solar is generated at a utility facility. The program is designed to give the utility complete cost recovery and it will not be built until it is fully subscribed. OUC has shared some lessons learned, including the difficulty of getting some businesses to offer their sites for project development, due to liability concerns (and especially in Orlando, because many high-visibility businesses have large corporate owners). Also, OUC struggled to set up its virtual net metering and billing software. The effort paid off, but should not be under-estimated.

SMUD's original Solar Shares pricing was similarly provided in shares equal to the output of 1 kW of solar plant capacity. The utility then paid a benefit based on the value of the energy, calculated based on the PPA cost and incorporating the value of the applicable California Solar Initiative Incentive.

Bright Tucson Sets the Pace for New, Large-Scale Community Solar

The Tucson Electric Power (TEP) Bright Tucson community solar program, launched in 2011, was one of the first investor-owned utility programs to enter the field. Following a green power model, TEP geared program economics to sell power from a 1.6-MW array at a university technology park. Total capacity is more than 4 MW, at several sites with a mix of utility-owned solar and third-party PPA contracts.

Customers may subscribe for 150-kWh blocks, for a premium of 2 cents per kWh over their normal rate today, fixed for up to 20 years. For residential customers, the total cost (late 2012 data) is about 12 cents per kWh.[xii] Commercial and municipal-service customers may participate, again, at 2 cents per kWh over their normal rate/s. In addition, community solar blocks are exempt from the fuel adjustment charge and from a renewable energy fund (public benefits) charge. Customers may cancel their participation in the program at any time and can buy as many blocks as they want—up to their usage. Virtual net metering credits the participant's share of solar generation against monthly energy use. Solar generation above energy use is credited to the next month's bill, with an annual true-up.

Like SMUD, Tucson has another green power program that is strictly charitable. Called GreenWatts, the program raises money for PV arrays at local schools, parks and other public facilities. Those customers receive no virtual net metering benefits. The Bright Tucson Program, by contrast, allows customers to take ownership of the solar power they purchase through the program. The program costs offset traditional energy charges, as well as providing environmental benefits.

TEP uses program RECs to meet its RPS goals. Initially, TEP wished to run the program over 10 years, to minimize planning uncertainties, but regulators ruled that 20 years was more appropriate. Over the long term, the program will function as a hedge for participants and for the utility, against rising electricity costs. This pace-setting program is now joined by other large utility-based community solar programs, particularly in the West. In general, all these programs use the green-power model. The main trade-off is that these programs tend to focus more on customer benefits than on the community benefits that are the focus of programs that put greater emphasis on supporting distributed solar on public or charitable sites.

Cautious program designers might recognize the marketing appeal of this model, but examine a few lingering questions, such as:

- Should the program run for a specified time, to minimize the complexity of managing different customer contracts with different start-up and end dates and (unless addressed in program design) potentially different total subscription costs?

- Could this model be combined with a more community-oriented or charitable model? The selection of sites seems crucial to maintaining the *community* solar profile. In addition, one rural electric cooperative, United Power, offers customers a chance to lease panels on behalf of a school or nonprofit, which would receive the net-metering benefit.

- How does this program affect the local solar industry? In markets that are not well developed (such as Traverse City, Michigan), utility selection of a contractor for a community solar project could help jumpstart solar businesses. SMUD also noted that an early effort to work with several local contractors on a single large-scale community solar project proved impractical. However, it is important to assure the industry that the program would target customers who are not good candidates for rooftop solar, and to boost other non-community solar business models as a customer choice, where available.

- Is the utility clear on the demographics of its target audience? If that audience includes renters and moderate-income participants, then a production-based ($/kWh) block subscription or premium might be appropriate. The challenge with this market is to provide a viable exit strategy, for those who move.

- More conservative utility program designs, such as those that do not pay a net metering benefit or (as is the case with a standard green power model) that never "pay off," might become outdated, from the perspective of solar stakeholders. The utility industry is evolving quickly and if utility solar offers do not meet customer needs, customers may find other ways to meet those needs. Customers need compelling reasons to make a long-term commitment, even if they are generally interested. The solution is not to avoid community solar, but to design programs to be flexible and forward-looking.

2.5 Choosing the Right Path Forward

The market for community shared solar is still new, but there appears to be pent-up market demand. Ever since the first programs were initiated in the mid-2000s, the topic has drawn standing-room crowds at solar industry conferences and community development meetings, and it has drawn widespread media attention. Implementation has started up slower than proponents expected, in part because the early business models that called for little utility involvement proved impractical. Utility involvement is critical to program success. Moreover, utility involvement in shared solar gives the utility opportunities, including:

- Optimal siting and interconnection;
- Increasing the solar resource portfolio with little or no rate impact;
- Maintaining the utility role as the primary energy aggregator, with encompassing community benefits;
- Depending on the program design, making solar affordable and available to all customers; and
- Offering a choice to customers who may afford or be able to use rooftop options.

The program design that is right for a particular public power community depends on its market, power supply situation, and compliance needs. For example, the community shared solar program in Traverse City, Michigan, would be considered conservative (and unlikely to succeed) in a state like California, since participant cost is relatively high compared to the benefits (wholesale net metering) provided. But other aspects of the Traverse City program are innovative and program sponsors find it to be a good fit for that fledgling solar market. By contrast, SMUD is looking for ways to advance its pioneering Solar Shares effort, including new pricing that can stand the test of time as solar industry competition continues to build and utilities move to a "net zero energy" business paradigm. Every public power utility must find its place in the spectrum of possibilities.

Yet distributed solar is a disruptive technology and is, by that nature, unstoppable. New crowd-funding strategies and innovations in market-based investment funds will drive the solar market whether or not utilities want it. Policymakers of both parties support solar and solar investment innovations. Utilities that are not proactive will be forced into a reactive mode. Community shared solar is the nearest a solar model has come to utility-compatibility. A utility-driven program can compete well against rising rooftop leasing models (e.g., Solar City) as well as against non-utility shared solar, which will before long incorporate storage and/or micro-generators that could deeply disrupt the standard utility industry model. It may not be the last word in 21st century utility strategies, but, at minimum, utility-driven community solar keeps the utility squarely in the game.

This report does not discuss important program design and implementation issues. That information is available, but beyond this scope. Suffice it to say that community shared solar can be relatively simple through a green power program model, or it can be relatively complex, the closer it comes to mimicking rooftop solar ownership. Different departments of the utility will have to be involved, and pricing (metering and billing) can be especially challenging. A subsequent section of this report sheds light on the business model concerns and innovations by at least one pioneering utility, SMUD.

The following sections of this report include a summary of community shared solar model "pros and cons" and extensive references or links to case studies—many at public power utilities. Finally, it includes a good introduction to solar development finance. That section is included because a review of case studies has indicated a lack of confidence on the part of public power utilities regarding how they can maximize cost-effectiveness and long-term utility investment value, given their non-taxable status. Among the solutions discussed are opportunities for public power utilities to lead project development or even to take ownership in out years, after a third-party developer would have absorbed the tax benefits of a given project.

Figure 2. The Founder's Club, including board members at the United Power Electric Co-op solar garden in Colorado, was featured in coverage of community solar in *The Wall Street Journal*.

Table 2.1 Comparative Summary of Community Solar Models

	Developer Driven; Some Utility Support	Utility-Driven Capacity-Based Offer	Utility-Driven Energy-Based Offer
Examples	Clean Energy Collective	Traverse City L & P Florida Keys Electric Co-op Seattle City Light	SMUD Tucson Electric
Summary Characteristics	Developer-owned, usually focused on customer economics and emphasis on customer self-reliance. Usually a high up-front pricing or reservation payment. Utility risks/benefits related to overall program success. Turnkey, but utility may be involved in marketing, metering, billing, depending on the relationship.	Focused on tangible solar; usually smaller scale; mimics solar ownership. Located at utility, community, or business site. Customer shares risks. Usually a high up-front pricing or reservation payment. Sometimes hybridized with green power rate in order to lower minimal participant cost.	Focused on streamlining implementation and lowering monthly costs, to increase total program size. Most resembles a green power program, selling solar kWh or blocks of solar generation. Utility may take on risks, such as guaranteed minimum output or developing projects before they are fully subscribed. Yet resembles other large utility solar projects.
Asset Ownership	Usually a third-party special-purpose entity, providing development and O&M for investors and/or panel owners. Can take tax credits and modified accelerated cost recovery.	Utility-owned or via PPA, SSA, etc. for the overall system. Participants may lease panels or purchase "solar benefits," but do not own panels without restriction. At end of term, the panels may revert to the developer, become utility-owned, be offered to participants for another term.	Utility-owned or PPA, SSA, etc. for overall system. Current models do not apply monthly payments as being toward purchase; customer gets solar benefits for the term of participation.
Scale	Limited by net metering rules. Newer projects include MW-scale, ground-mounted systems.	Varies. Usually smaller scale than green-power based, due to pre-requisite buy-in from participants.	Usually large commercial to utility-scale. Typically >250 kW to MW+ scale.
Participant Exit	Difficult. Special project entity sets guidelines for transfer of panels or shares.	Difficult, except to transfer to new address in the territory. Transfer to another customer may be allowed.	Usually easy. Some benefits, such as a locked-in rate rely on long-term participation. Ability to exit increases participation and utility risk.
Utility Credit for Solar Generation	Usually net metering, pro-rated per participant panel/s or shares. Value reflects utility	Utility usually provides net metering of the system that is pro-rated per participant	As distinguished from standard green-power programs, these usually pay a VNM benefit,

	program rules. Clean Energy Collective and other special project entities may offer billing software to assist the utility. Share may also be exempt from fuel adjustment charge and reflect rebate or PBI.	panel/s or shares. Share may also be exempt from fuel adjustment charge. Approximate credit may avoid need for new rate. If participants also receive rebates and other incentives, they are often integrated to offset the cost or rate.	similar to the capacity-based model. However, usually limited to those who sign a contract or stay in the program for a year or more. Share may also be exempt from fuel adjustment charge. Usually rebates and other incentives integrated to offset the rate.
True-Up of Solar Generation	In keeping with the utility policy. Some utilities do not allow participation over typical annual consumption.	In keeping with utility policy, though benefits may be estimated. Typically, no participation over typical annual consumption. Feed-in tariff would eliminate virtual net metering.	Only if blocks or energy purchased is keyed to consumption, with virtual net metering. Feed-in tariff would eliminate virtual net metering.
Utility and Participant Risks	Participant risk mostly due to the contract terms with the special-project entity. Utility risk is limited but if the utility participates in billing, etc., it may be seen as a partner. If net metering is required, it may be difficult to change for the long term. Utility usually cannot access long-term benefits of ownership and strategic operation.	Depends on the financing used. "Pay as you go" projects have lower risk, but are typically small scale. If virtual net metering is required, it may be difficult to change for the long term. The long-term contract, difficult exit provisions, and (sometimes) high entry cost increases customer risk.	Larger PPA/SSA projects have unique risks and benefits. Minimal risk to customers, though shorter-term participation. If VNM is required, it may be difficult to change for the long term. Utility must plan to adjust program participation cost/rewards as the market changes to maintain interest in the project.

2.6 Searchable Reference List of Community Solar Programs

The following list of community solar programs is provided from the US DOE Green Power Network. The list is relatively complete through 2012. It includes all kinds of community solar programs, from utilities and non-utility solar developers. Many—though not all—are public power programs.

- Ashland, Oregon (2008 - 63.5 kW)
- Bainbridge Island, Washington (2009 - 5.1 kW)
- Berea Utilities, Kentucky (2011 - 14.1 kW)
- Boone Community Solar, North Carolina (2009 - 2.5 kW)
- Brewster Community Solar Garden Coop. Inc., Massachusetts (2012 - 345.6 kW)
- Colorado Springs, Colorado (2012 - 575 kW)
- Corvallis, Oregon (2011 - 15.5 kW)
- Delta-Montrose Electric Association, Colorado (2011- 20 kW)
- Edmonds, Washington (2011- 4.2 kW)
- Ellensburg, Washington (2006/2008 - 57 kW)
- Florida Keys Electric Coop, Florida (2008 - 117.6 kW)
- Holy Cross Energy/Clean Energy Collective, Colorado (2010/2011 - 938 kW)

- Okanogan Electric Cooperative, Washington (2010/2011 - 43.1 kW)
- Olympia, Washington (2012 - 75 kW)
- Poudre Valley/Clean Energy Collective, Colorado (2012 - 115 kW)
- Poulsbo Middle School Project, Washington (2011 - 75 kW)
- Sacramento Municipal Utility District (SMUD), California (2008 - 1000 kW)
- Salt River Project, Arizona (2011 - 9840 MW)
- San Miguel Power Association/Clean Energy Collective, Colorado (2012 - 1000 kW)
- Seattle City Light, Washington (2011 - 24 kW)
- St. George, Utah (2009 - 250 kW)
- Trico Electric, Arizona (2011 - 193 kW)
- Tucson Electric Power, Arizona (2011 - 1600 kW)
- UniSource Energy Services, Arizona (2012 - 1720 kW)
- United Power, Colorado (2009 - 10 kW)
- University Park Community Solar, Maryland (2010 - 22.8 kW)
- Whidbey Island, Washington (2011 - 25 kW)

3. Perspectives on Solar Financing

3.1 The Buy Vs. Build Decision

Public power views differ widely on the question of whether to buy or build solar generation and on exactly how to pursue either of these development paths. Some public power utilities have not owned solar PV to date because PV was an emerging technology—high priced and prone to operations and maintenance risks. Today, that has changed. Solar PV has become a widely accepted technology—not so different from any small generation project. However, utilities typically have other concerns, too. With regard to community solar, each utility must decide first on whether to develop it as an internal or outsourced program, and if internal, exactly how to finance the development. This section briefly defines particular utility solar development models, including:

- Internal financing for utility-owned solar, using low-interest debt;
- Acquisition through a power purchase agreement (PPA) or solar services agreement (SSA) with a taxable third-party;
- Use of the PPA or SSA, with an ownership flip or utility buyout; and
- Pre-payment models and hybrids.

Solar financing approaches have proliferated in the hands of savvy lawyers and solar developers and some of their innovations have been useful. At the same time, it is important to note that the declining tax appetites of many investors and the expected decline of federal and state tax incentives make it important to look beyond these approaches. The latest solar finance strategies include variations on crowd-funding (and soon, master limited partnerships), blended with more familiar PPAs and SSAs. To begin, however, newcomers should review the basic approaches and be prepared to consult legal and accounting expertise before moving ahead with any project.

Also, the utility should remember that financing alone does not define a solar business model. For example, a utility might lease customer roof space for community solar, but finance the system using internal self-financing or an SSA. Projects that look the same may, in actuality be quite different.

Note that examples discussed approximate an "apples to apples" comparison, but that is nearly impossible. For example, a Clean Renewable Energy Bond (CREBs) project would be financed for 15 years, while an SSA would typically run for 20 years or more. Interested utilities may use modeling software provided by expert consultants or the National Renewable Energy Laboratory's SAM (system advisor model).[xiii]

Useful Finance Terms

Public power utilities are familiar with project finance. Yet some terms have a particular meaning in the context of solar finance. For example:

Annual Cash Flow The net savings/revenues or payments resulting from an investment in a solar project. Annual cash flow is determined by subtracting the payments associated with the plant depending on the finance model (i.e., loan, PPA, lease) from the savings and revenues provided by the plant (i.e., energy and capacity savings)

Net Present Value (NPV) The present value of a time series of cash flows. NPV is a metric for measuring the time value of money and is calculated through a discounted cash flow analysis incorporating a discount rate applied to annual savings/revenues and payments associated with a solar plant over its expected life.

Levelized Cost of Energy (LCOE) The cost of energy generated from a solar plant over its expected life. LCOE is calculated by computing the present value of all the lifecycle costs associated with a solar plant divided by the present value of the expected energy generated over its life.

Internal Rate of Return (IRR) The percentage return on an investment in a solar plant over its expected life. IRR is a function of the net present value analysis and utilizes a discounted cash flow model to determine the yield of an investment based on the timing and amount of payments and the timing and amount of savings and revenues resulting from a solar project. Depending on the timing and magnitude of cash flows, similar projects can have differing IRRs and NPVs; one project can have a higher IRR than another one, yet have a lower NPV and vice versa.

3.2 Internal Financing Using Cash, Bonds and Low-Cost Loans

This is financing the traditional way and, as such, it has a natural appeal for some public power utilities. The question is, can this approach compare favorably to more innovative financing approaches?

Cash financing is primarily viable for relatively small solar projects. It is also a good choice for projects that ask participants for a one-time lease payment for solar benefits on a per-panel or per-kW capacity basis. That is because the utility would recover its investment as soon as the project sells out. (Or in the case of a "pay as you go" project, cost recovery would be almost immediate.) The problem is, many utilities have other uses for their cash and they typically do not have a lot of it.

Using municipal bonds or other sources of low-cost public finance could result in a high IRR, but a low net present value (NPV). Typically this type of project achieves a positive cash flow much earlier than other financing alternatives, but the payments continue for 10 to 15 years longer than other alternatives, such as the PPA with a buyout. It may surprise some utilities to find that this type of financing has advantages over third-party financing that taps tax credit value, in part because municipal utilities can access financing with very favorable rates and terms. Tax-incentive finance passes along benefits, but it also passes along costs associated with finding tax partners and working through complex legal agreements. Another benefit of internally financed projects (cash or municipal bond or loan) is that the utility can keep close control of the project, including plugging economic-development leaks that often occur when working with an out-of-town third-party solar developer.

A variation in coming years might be greater public-private partnerships. One example is called the pre-paid solar PPA or pre-paid SSA. This is also known as the "Morris Model," after Morris County, New Jersey, where it was successfully applied. This financing approach is relatively new to community solar, but it has recently gained considerable attention.[xiv] By this approach, the city or county issues a solicitation for a developer to finance, own, and operate renewable generation on its own (or another non-profit entity's) site. While the solicitation is moving forward, the local government entity sells government bonds at a low interest rate to finance the project. This entity is then able to transfer low-cost capital to the renewable energy developer. In exchange for this low-cost capital, the winning developer (which is able to use tax credits) can offer a lower price in the PPA or SSA. This model is discussed again with PPA and SSA financing, below. Details are also available on the NREL financing portal, cited above.

3.3 Power Purchase Agreements

A power purchase agreement (PPA) is a common financing instrument for utility renewable energy projects today. The advantage for wind and solar power is that the third-party developer can take advantage of all available tax credits, accelerated depreciation, and any other available incentives and pass some of these through to a utility that is non-taxable or (as with many IOUs) subject to normalization. A buyout is a popular modification, allowing the utility to buy the solar plant after the tax credits have been fully utilized. By IRS rule, it must pay "fair market value," which is, in out years, a fraction of the installed cost.

Utilities think of the PPA as a utility resource acquisition tool, but in almost half of all states, PPAs also are allowed to finance third party projects for customers. They would buy renewable energy from the PPA provider, using it on-site as needed and taking advantage of utility net-metering to track credits for any power not used immediately. Five states forbid such PPAs and some other state laws and regulations are vague on the matter. For example, Iowa's regulations regarding PPAs are vague, but an April 2013 state court ruling provided the clarity that many observers believe will open that state's markets for more customers to use third-party PPAs for net-metered projects.

In states where non-utility entities are clearly forbidden from entering into PPAs, such as Florida, the utility's ability to do so and to provide community solar options can be a great service. The community solar program sponsored by the Orlando Utilities Commission (OUC) is one example. It offers large customers the chance to work with the utility and its PPA provider. The Columbia Water and Light Solar One program in Missouri is structured similarly.

The solar service agreement (SSA) or service contract offers an alternative to the PPA, which is especially useful in drawing a bright line between the taxable party and the non-taxable solar off-taker. The SSA also appeals to some public power utilities, because it offers more turnkey benefits, which lowers risks. Particular qualifications, under Section 7701(e) of the Internal Revenue Code include:

- The service recipient (e.g., municipal utility) cannot operate the system for the term of the agreement;
- The service recipient cannot be asked to pay for electricity that it did not receive, nor can it benefit from unanticipated operating cost savings;
- If the service recipient desires a purchase option, the price must be set at fair market value at the time of the sale.

Public power utilities may find this type of financing attractive for community solar projects because it clearly allows the solar developer to take the investment tax credit and accelerated depreciation, adding 40 percent or more to the potential benefit of a solar deal. Not all of that benefit would be passed through to the service recipient, but it would be reflected in a lower SSA price. This approach is relatively low-risk. The solar developer usually works with a bank (or large investor) and forms a project-specific limited-liability corporation. But the developer remains the single point of contact for the term of the agreement. In summary, benefits include:

- Low or zero up-front cost;
- Turnkey design/build services, which may be tailored to maximize utility strategic benefits;
- No operations and maintenance costs or risks;
- Predictable solar energy costs for the selected term (typically 15 to 25 years), though some deals include a price escalator;
- Relatively low per-kWh cost, as the developer passes through a portion of the tax benefit; and
- Usually favorable terms to acquire the project after the tax benefits are wrung out of it.

A municipal utility that uses either the power purchase agreement or solar service agreement must negotiate certain details. For example, a solar developer might take ownership of the renewable energy credits (RECs) in a customer deal. If the utility needs RECs for environmental compliance (now or in the near future), then it would want to retain them. If the utility takes the RECs for compliance, it may be the utility's policy to inform customers that their community solar program participation does not technically entitle them to say that they are receiving solar power. This is a difficult, small-print distinction, but only one entity may hold the solar RECs.

Most of the business models discussed in this report center on utility ownership or control and do not involve net metering. This includes projects where the utility might choose to lease a highly visible or relevant site. These projects typically use "virtual net metering" to give participants a benefit that mimics net metering in some ways, which does not involve metering individual participant shares. The general design of this rate for SMUD's community solar expansion is one focus of this DEED research report. If the utility plans to site the project on its own property and take the generation, it should verify that the terms of the PPA or SSA would not conflict with any other power supply contracts, especially in the case of a joint action agency "all requirements" contract.

Note that there are projects by non-utility community solar developers that may use net metering for the overall project, in a more conventional way. One example might be a project that serves residents in co-housing. This is a relatively rare (and potentially complicated) arrangement, but some solar proponents would like to see it used more.

A major potential benefit of using either the PPA or SSA is that either is compatible with a separate option to purchase the solar project in an out year, for a fraction of the original installed cost. Such a buy-out allows the utility to obtain the energy generation benefits for the plant's remaining life—likely 20 years or more. Many PV projects that were built in the 1980s still perform well today, and newer solar technologies often carry up to 30-year warranties. When the utility acquires a community solar project as a distributed generation asset, it assures all customers that the long-term benefits of that project will stay in the community.

The SSA structure also lends itself to a pre-paid agreement, which is briefly described below.

Participant Offers As Distinct From Utility Solar Acquisition

If the public power utility buys a solar project, it may structure participation in its own community solar program in a number of ways. It may lease solar capacity (by panel or by kW); it may sell capacity-based blocks of solar green power, or it may sell solar green power on a per-unit ($/kWh) basis).

If the public power utility has a PPA or SSA with a solar developer, then it is buying either the energy (kWh) or energy plus other (typically O&M) services. In that case, it could not offer solar shares that perfectly mimic panel ownership. Some projects using the SSA form nevertheless lease solar energy services to their participants. The simpler approach would be to simply offer either blocks of solar green power (e.g., 100 kWh for a set price) or offer solar generation on a per-kWh basis. Often utility-based community solar programs will recommend a block of power that actually represents the output of a kW of solar capacity or of a particular solar PV panel. The goal there, would be to make an intangible solar power benefit easier for customers to comprehend. There are a number of compatible choices for community solar participants under one wholesale financing agreement or another.

Utilities should carefully advise community solar program participants about the fact that, regardless of the project's financial structure, they are generally not able to take solar tax credits for their participant shares. The reasons have to do with 1) the siting of the solar generation as remote from the participant/customer's facilities and 2) that only one entity may take tax incentives on a project or part thereof.

3.3.1 Pre-Paid PPA or SSA

Some community solar models use a pre-paid PPA or pre-paid SSA. To date, projects using this kind of financing have been on a relatively small scale, so the non-taxable utility could use cash instead of tax-exempt bonds or loans to complete the deal.

On a larger scale, this approach can combine the benefits of tax-exempt financing with the tax benefits of a PPA-like solar services agreement. In broad strokes, it is the same as the "Morris Model," briefly described above. The utility would pre-pay for a portion of the energy output of a solar project, using tax-exempt bonds or other sources (for example in partnership with a local government or public power district). In return, the project developer could use that money for project construction. However, it would account for it as income earned month-by-month, in payment for actual power generation. In this way, the developer could take full advantage of tax credits and modified accelerated cost recovery (MACRS) when financing the project. Typically, the utility would make a partial prepayment, and it would still have some charges that it would pay monthly, over the length of the contract.

Sometimes this structure is considered a prepaid lease. The structure may be the same, but it is important not to confuse this lease with a typical capital lease, as that could affect eligibility of the project to pass through the tax benefits, and it might be treated differently on the utility's balance sheet.

The bottom line benefits for a well-structured pre-paid project are strong. In addition, the utility could still purchase the project in a future year. Pricing would be set at fair market value at the time of the sale.

A notable case study for the prepaid service contract is the White Creek Wind Project in Washington state. The Last Mile Electric Cooperative, made up of rural electric cooperatives and public utility districts specifically to finance renewable energy projects, initiated the project. Last Mile used a pre-paid service contract to leverage a 205-MW wind project—the largest public-power wind project in the United States at the time. Subsequently, the model was applied by the California Statewide Communities Development Authority for financing a program called Grow Solar.[xv]

Expert legal advice well beyond what is offered here is crucial in negotiating and structuring any of these solar development deals. The more complex deals also require larger-scale projects, as there are transaction costs, which only larger projects can offset. However, the models presented are widely considered acceptable. They are based on regulations from the Treasury Department and the Internal Revenue Service, which specify the types of prepayments for property or services that are eligible for tax-exempt financing.[xvi] Under a revised final regulation, Treasury determined that the categories of prepayments eligible for tax-exempt financing include not only certain prepayments for natural gas, but also certain prepayments for electricity. These new provisions were intended to assist non-taxable utilities in securing long-term supplies of natural gas and electricity at reasonable prices from energy markets.

3.3.2 Lease-Related Models Distinct From PPA-Related Models

Another relatively common financing structure is called the sale-leaseback. As it is a fairly complex arrangement, this report will not explain it in detail. In short, it would allow a developer that cannot use the tax benefits of a large solar project to take ownership of the project and then sell the project back to the investors and continue to lease it for the term of the agreement. One problem that has arisen since all these financing models were first developed is that the recession of the last decade eliminated many potential investors with a strong, long-term tax appetite. Investors have tended to sell solar projects and regardless of practical impact on the local utility, it can be discomforting (and potentially politically risky) when a local community solar project is sold to investors far away.

Note that the lease*back* is different from a lease to the public power utility. There are two types of leases: the capital lease assumes a lease leading to a purchase, and the operating lease assumes the lease is primarily for use of the equipment over a specified term, with a possible buyout to be determined later.

Utilities are familiar with operating leases, as they apply to distribution-system equipment, including backup generators. Under this approach, the lessor is not selling renewable kWh, but merely leasing the equipment, a distinction that may be attractive to some utilities. For example, the utility would treat lease payments as an operating expense—leading to the common definition of an operating lease as "off balance sheet financing." However, the tax-credit and accelerated depreciation implications of leases are complicated. Benefits were available for a few years under the "Grant in Lieu of Tax Credit" program, but that program has expired. Also, the lessee must take the risks associated with the solar output of the leased equipment. If for any reason the solar project fails to produce, whether due to mechanical failure or weather events, the lessor (usually a bank) still expects to be paid. Insurance and warranties cover most of this risk, but the idea of facing a "hell or high water" lease payment may be daunting.

More and more, the solar industry is looking to innovative ways—beyond tax-credit financing—to support solar development. Some of these ultimately lend themselves to PPAs, SSAs, and other familiar agreements. For example, the crowd-funding and market-fund sources described in Section 2 of this report (including up and coming Master Limited Partnerships—MLPs) hold promise as a source of community solar funding. Individual customer investments, managed through a utility-ownership structure or through an SPE structure, are another type of crowd-funding that works on a relatively smaller scale.

Table 3.1. Comparison of Major Community Solar Financing Approaches*

Parameter	Bond- or Municipal-Lending Agency Financed	Externally Financed Power Purchase Agreement	Externally Financed Solar Services Agreement
Availability	CREBS, QECBs, and other tax-credit bonds are difficult/costly to place. Other public power financing offers various low-cost options. Internal financing offers high IRR, but low NPV.	Readily available to utilities; some states limit retail customer access. Requires a taxable partner—usually via investment banks or firms.	Readily available to utilities. May need to differentiate from a capital lease, in order to access tax benefits with the taxable develop/partner.
System Owner	Utility	Investor	Investor/service provider
Term	Typically 15 to 17 years; other non-taxable financing may run up to 30 years	20 years or as negotiated	20 years or as negotiated
Accounting	On balance sheet	Off balance sheet	Off balance sheet
Pricing	Fixed term for bonds, or as agreed per specific financing arrangement	Utility contracts for energy. Contracts have different risk tolerance, from a guaranteed output, at a per-kWh price, to an agreement keyed to the actual output of the system.	Utility typically contracts for the output of the system, often with O&M included. The technology warranties limit risk, but additional insurance may be desirable.
Payments	Monthly, quarterly, or annually	Usually monthly. Alternatively, the contract may be pre-paid	Monthly, quarterly, or annually. Alternatively, the contract may be prepaid.
Federal energy tax credit (ITC)	N/A	Investor's account; savings leads to lower PPA cost	Investor's account (services not applicable); savings translates to lower SSA cost
Federal depreciation	Straight-line, as applicable	MACRS (5-year accelerated)	MACRS (5-year accelerated)
Renewable Energy Credits**	Utility, unless marketed or sold to participants.	Owner's account unless negotiated	Owner's account unless negotiated.

Insurance Liability	Utility/owner's account (after warranty)	Owner's account or per insurance contract	Owner's account or per insurance contract
O&M Expenses	Utility/owner's account or per O&M contract	Owner's account	Per O&M contract
Purchase Option	N/A	Fair market value; return may also be negotiated	Fair market value; return may also be negotiated

* A solar lawyer should be engaged to review this or any proposed solar development contract.

** In all cases if the participant does not get the RECs, it is appropriate to inform them that they do not own the green attributes of the system, but are technically facilitating rather than owning solar benefits.

3.4 Additional Incentives

Some solar projects use additional federal and state incentives, which are too numerous and too frequently changing to be included in this report. For example, some solar projects recently tapped the federal New Market Tax Credit (NMTC) program, an economic development program designed to channel investment into low-income community census tracts. It has been used extensively over the years to develop a wide variety of real estate, low-income housing projects, and similar investments. The credit provided to the investor totals 39 percent of the cost of the investment and is claimed over a seven-year credit allowance period. Transaction costs may lower this number somewhat, but the NMTC may be combined with the 30-percent solar ITC, in deals with taxable partners. See http://www.cdfifund.gov/what_we_do/programs_id.asp?programID=5.

A complete summary of incentives is available at the Database of State Incentives for Renewable Energy (dsireusa.org). Consult your state-level economic development authority information for details. Because state-level incentives are so variable, we do not attempt to include them in our calculations of solar project economics.

Public power utilities also may check into state and voluntary markets for renewable energy credits. Solar REC auction prices are listed online at sources such as, srectrade.com. (A REC represents the renewable energy attributes of a MWh of generation.) In some states, SREC value is still relatively high, but in other states, it has fallen to negligible. The anticipated rise of carbon markets in some regions could alter this financial picture.

4. A Community Solar Program Revision for SMUD

Looking ahead, the Sacramento Municipal Utility District (SMUD) anticipates continuing growth of the solar industry, but foresees some bumps in the road, associated with the decline of solar incentives, the innovation process within the solar industry, and the increasing need for utilities to adapt to high-penetration customer-solar integration. In recent years, SMUD planners recognized that the pricing strategy for their current Solar Shares program, which incorporated the high-value state incentives of the mid-2000s, and the benefit of net metering on the existing rate structure could not endure. They suggested that a new community solar business model with new pricing could address current solar industry and utility realities. Specifically, they were mindful of:

- Reduction or elimination of state solar incentives, as the California Solar Initiative (CSI) program is near reaching its goals;
- Expiration of the current federal residential solar tax credit and business investment tax credit (ITC) with accelerated depreciation, with little certainty about a subsequent incentive policies;
- Anticipated changes in the utility rate structure, which would replace a tiered rate system with a time-of-use (TOU) rate and would more accurately update the customer charge;
- Anticipated continued cost reductions and innovations from the solar industry; and
- Utility interest in expanding customer choices for solar, to include a community solar option that would compare favorably to rooftop home-financed or leased solar systems.

The research team developed a timely, responsive, community solar program model and to test its performance, especially from the perspective of potential residential and large commercial participants in Sacramento. This section summarizes that research. In turn, these lessons can assist public power utilities nationwide that are considering community solar. There are opportunities for a well-planned program to benefit the utility—particularly in easing the abrupt impacts of a booming rooftop solar market and increasing utility confidence that solar can be a high-performing and valuable addition to the resource portfolio. Also, from the customer perspective, a well-planned community solar program can be an strongly economical and convenient option.

4.1 Methodology and the Research Process

In 2008, SMUD pioneered utility-based community solar, when it introduced the largest solar-based green power program in the country. Called Solar Shares, the program sold the output of a 1-MW PV project, which was owned by a third-party developer (enXco) on a site leased from the utility. Each share, which was equivalent to the output of 1 kW of PV in Sacramento, was priced to include the appropriate buy-down, reflecting the value of incentives for each customer class, in response to the California Solar Initiative (CSI) program. For example, in 2009, a small residential customer paid a fixed fee of $21.50 per month for a 1-kW equivalent Solar Share and received an average monthly (virtual net metering) credit of about $7, making for an average monthly premium of about $14 to participate in the program. The program's virtual net metering credits have been based on retail rates, and they vary with the seasonally varying kWh output of the PV array. Further, customers have been able to come and go from the program without penalty, as SMUD accepts all of the project's output whether it is subscribed or not. Solar Shares was instantly popular and, currently, it has about 600 participants. The utility wished to carefully consider its choices before redesigning the program, which it plans to grow and maintain for the long term.

The program-design investigation has taken the following steps:

- Benchmark a "straw man" community solar business model with best practices in community solar nationwide. Adjust the model and create a likely program scenario.
- Establish necessary assumptions for an economic analysis for the residential sector and the large commercial sector. In the residential sector, choices include rooftop solar financed via a typical home-equity loan, rooftop solar acquired via solar leasing (popularly characterized by SolarCity, SunRun, etc.), and community solar. In the commercial sector, choices include rooftop (fixed-tilt) solar via a third-party PPA, compared to community solar, which uses ground-mounted single-axis tracking technology.
- Adjust assumptions for the analysis to account for practical limitations. This includes *consistently* using assumptions based on current (2013) data, along with applying anticipated changes for the rates and community solar program pricing.
- Utilize the NREL solar System Advisor Model (SAM) to run the analysis for each rate customer choice, for each rate class.
- Analyze results and report on the extent to which the community solar might compete with existing customer solar options.
- Provide qualitative observations regarding the likely outcomes and remaining questions to resolve before full implementation.

4.2 Starting Point: A Straw Man Model

The two fundamental aspects of the original Solar Shares Program were: (1) to acquire solar output from a relatively large third-party solar project (PPA) that captures economies of scale, and (2) to market participation via "shares" (initially set as a percentage of the participant's energy use). The first decision for SMUD was whether to retain this fundamental structure.

Early in the redesign process, staff considered what might happen under a proposed state law, which would significantly change the program structure. It would have allowed private solar developers to establish relationships with customers who subscribe to a shared solar project. The utility's role would be limited. It would track each participant's share and provide a payment or credit for each share of energy delivered to the grid. This model also would require a PPA agreement between the utility and the developer, because the utility would contract for the full output of the project, whether or not all the shares were subscribed by participants. It would be similar to the community solar model initially popularized in Colorado, which is developer-driven, with some utility support, discussed in Section 2, above. The lack of hands-on involvement in program marketing and implementation could be one significant utility risk. (For example, if the developer has a purchase power agreement with the utility for the full output of the project, additional contract-measures might be needed to ensure robust marketing to end-use participants.) Getting the right pricing for the PPA from a limited pool of qualified bidders could be another. In fact, the model had many risks and benefits, depending on the utility's perspective.

When the proposed legislation did not move forward, the utility turned to a more familiar and ultimately preferable option. That was to retain much of the original Solar Shares model, but to adjust specific parts, taking in lessons from other best-practice programs. These top programs included the Bright Tucson energy-based program with virtual net metering, and a program that was researched but not implemented for another large public power utility, refining the use of cost-based pricing, which would most likely enhance benefits over time. Figure 4.1 shows a diagram of the new community solar program design.

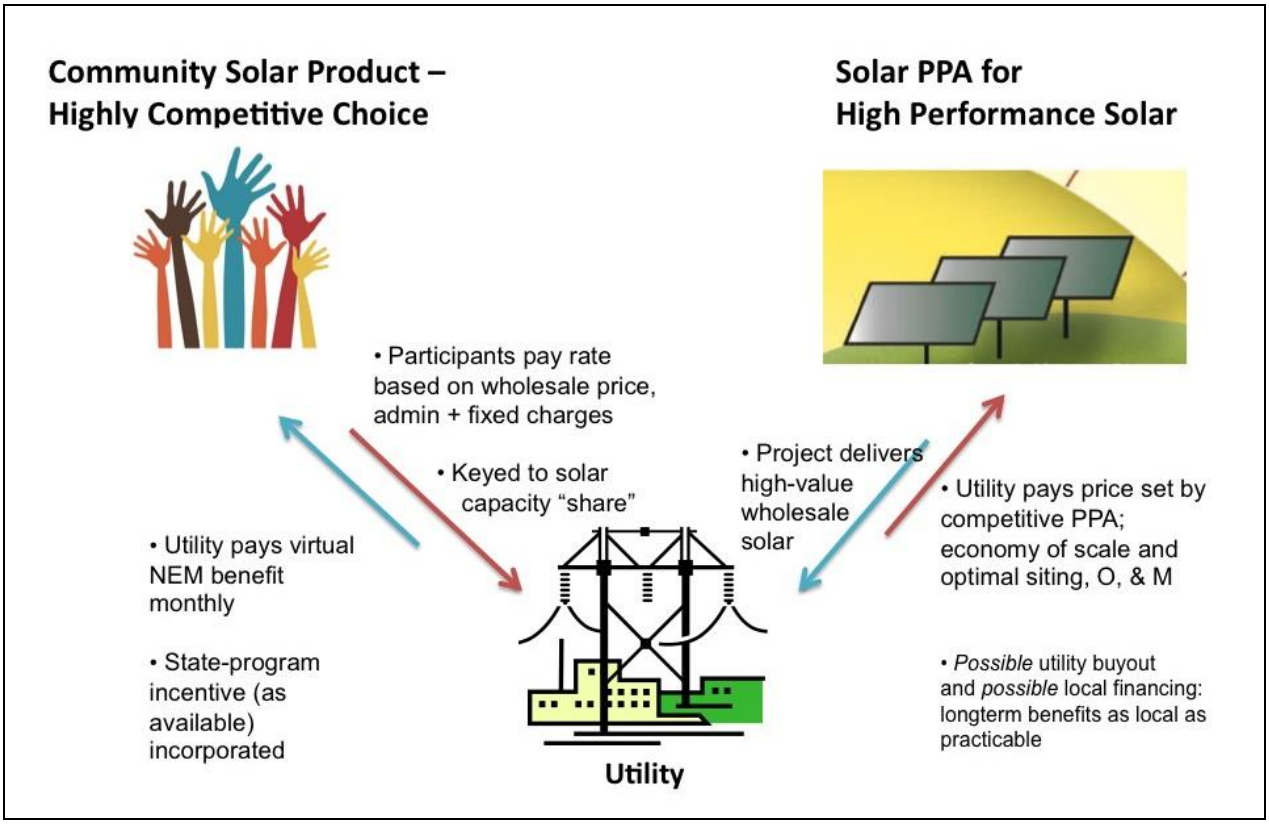

Figure 4.1 SMUD Proposed Revised Solar Shares Program Model.

Participants would subscribe for a solar share (keyed, say, to 0.5 or 1.0 kW of capacity). But they would pay no upfront cost; only a per-kWh price for related generation. The Solar Shares rate would be based on the price of the wholesale solar PPA, plus a share of program administrative and fixed charges. Then, the utility would track overall system performance, and each participant would receive a monthly virtual net energy metering (NEM) credit to their bill at the applicable retail rate. The utility would have a few choices in exactly how to manage the NEM. For example, it might credit customers at a blended rate reflecting their time of energy use, or it might credit them based on a rate reflecting the time of solar energy production. State performance-based incentives, as available, also would be incorporated in the NEM rate.

Because the fuel-free, long-term cost of solar is predictable, the Solar Shares rate could be locked in for new participants, so long as they do not leave the program. Over a number of years, the anticipated rise in rates for utility customers across the board would not affect the locked-in Solar Shares rate. A slight premium over standard rates in Year 1 becomes a significant savings in later years. The utility must decide how long the program would stay in effect, but that term could be up to 30 years.

One obvious question arises: Won't the cost of new solar be much lower in 20 or 30 years? The answer is, most likely, yes. That is a risk that rooftop solar customers take. But the proposed Solar Shares program could adjust the rate for all participants, as it grows the community solar fleet. (There is a small chance that solar costs could hold steady or even go up for a short time, due to misalignment of solar industry factors and solar incentives.) Fleet-based pricing is a mutually beneficial hedge against any large, abrupt changes in the rate. This also would reward early adopters that stick with the program, and keep the program attractive to new participants for the long term.

Another highlight of the proposed updated Solar Shares program is how it works with SMUD's anticipated new utility rate structure. The tiered rates that SMUD and other California utilities have used in recent years proved complex, and left some issues related to declining revenues from declining sales unresolved. Thus, SMUD will phase in a new rate structure for all customers, beginning in 2014. It moves toward a time-of-use rate, with a more accurate, increased fixed customer charge. The new rate structure insures that energy-conserving and solar customers pay a share of utility costs, without introducing complicated riders or otherwise setting these customers apart.

But what might the bottom-line impacts on solar customers be? The easiest way to answer that question is to examine modeled economic results of the different customer solar options. The next section describes the design of that modeling for SMUD. Other public power utilities might learn from this discussion, imagining adjustments to inputs and assumptions, based on their own utilities and markets.

4.3 Modeling Assumptions

This research used the National Renewable Energy Laboratory solar System Advisor Model (SAM) to create a comparative analysis of customer economics for different solar options, once the anticipated TOU rate is in effect.[xvii] Table 4.1 summarizes the cases modeled.

Cases for Economic Impact Modeling	
Residential Customer Perspective	**Large Commercial (includes Government) Customer Perspective**
Rooftop System Lease (apx. 4.5 kW, per historic data for installation and performance)	Private PPA for 250-kW rooftop, fixed tilt system
Rooftop Customer-financed (apx. 4.5 kW, using a home equity line of credit, per historic data for installation and performance)	
Solar Shares Community Solar (apx. 4.5 kW equivalent share, modeled as part of 1-MW single axis tracking, crystalline system)	Solar Shares Community Solar (apx. 250-kW equivalent share, modeled as part of 1-MW single-axis tracking, crystalline system)

Table 4.1. Cases for Economic Impact Modeling from the Customer's Perspective.

The community solar case is based on the output of a 1-MW, ground-mounted, single-axis tracking solar project, using crystalline technology. Single-axis tracking systems use controlled motors to follow the sun from east to west, and deliver 15 to 25 percent more solar energy than do fixed-tilt systems, depending on location and other design factors. This technology is well-tested and low-maintenance, but it is not well-suited to smaller, rooftop projects. Therefore, the customer rooftop options tested assumed fixed-tilt systems. In fact, the analysis utilized actual data for solar performance, available through the PowerClerk® reporting system. SMUD uses that system to help administer its performance-based solar incentive program.[xviii] It showed that systems installed on customer rooftops provide, on-average, less than the ideal, modeled output. That is because customer rooftops sometimes are not perfectly oriented or tilted or clear of shade. Figure 4.2 shows the annual performance of a residential rooftop solar option and a comparably sized "solar share" in a properly sited, single-axis tracking system.

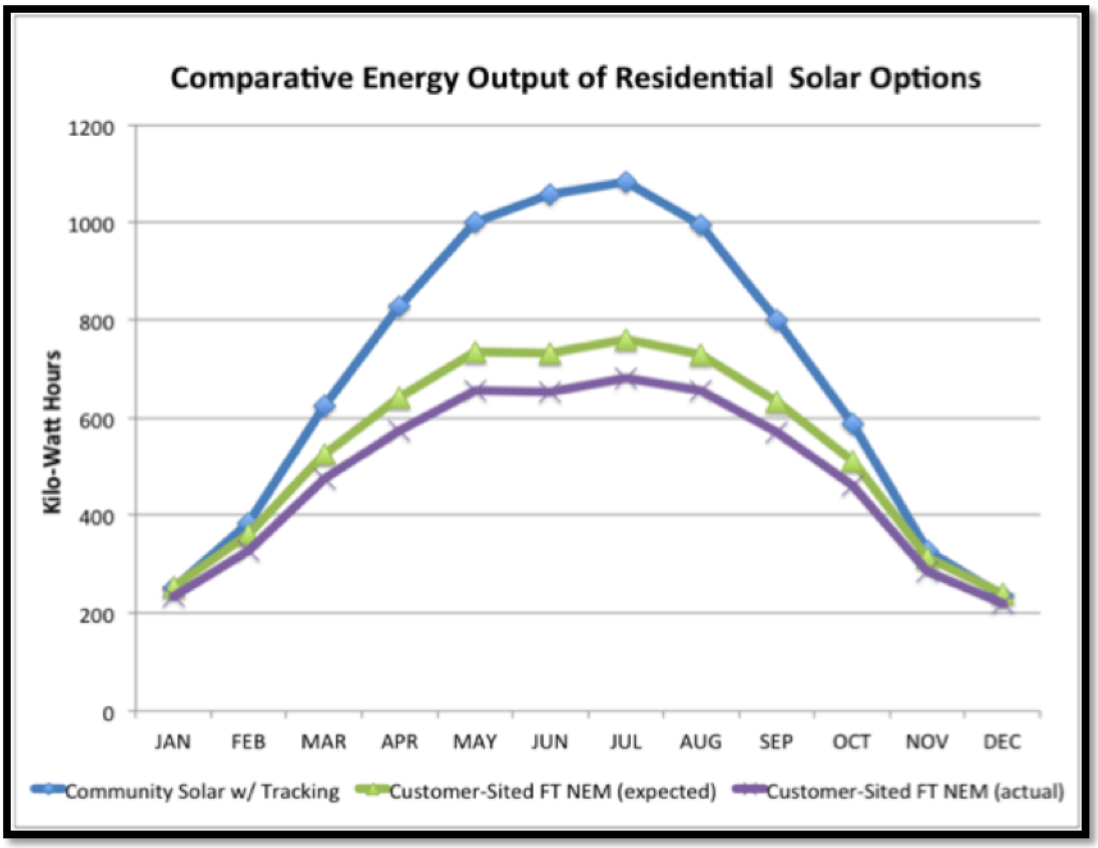

Figure 4.2. Comparative Energy Output of Residential Solar Options for Sacramento. The overall production of installed and modeled systems would differ for each location, but the greater seasonal production for single-axis tracking technology is widely characteristic. The actual performance of customer-sited residential systems is, on average, below that of modeled systems, because of real-world variations in system orientation, tilt, shading, etc.

Assumptions for the customer economic analysis are listed with comments in Table 4.2. Specific numbers are seldom provided in this report, in part because of utility confidentiality concerns, but more so because these numbers differ over time and for different utilities. The relative impact of different assumptions is discussed in the Results section, below. It is important for key assumptions, such as the energy cost escalation rate and discount rate, to be applied consistently for all cases modeled.

Assumptions Required for Customer Solar Economic Analysis	
Metric	**Comments**
Average solar system size and price	For SMUD residential customers, actual data from PowerClerk® was used. Average residential system size of about 4.5 kW was matched with the same sized "share" from a 1-MW solar project. For large commercial customers, a 250-kW system was used, compared the same-sized "share" of the 1-MW project. Current local pricing data was applied.
Applicable financing rates or terms	For the residential customer-financed option, five-year home equity line of credit financing (HELOC) was used; for leased systems, typical local lease rates and terms were applied. For the large-commercial customer system, a PPA at a representative current price was used.
Customer energy use	Applied average customer energy use (kWh/year) and TOU patterns for each customer class.
Customer rate information	Used residential rates that would be in effect after the phase-in of SMUD's new rates (2018 for residential and 2015 for large commercial).
Incentives	Used state incentives currently in effect per customer class (for example, a five-year PBI for residential at 6 cents per kWh or a 10-year PBI at 3 cents, according to the SB1 schedule). Also applied current federal incentives.
Net metering policy	SMUD's net energy metering policy is anticipated to apply under the new rate structure. A higher customer charge, which more accurately reflects utility fixed costs, assures that all solar customers will pay a share of those costs.
Applicable taxes	Applied as stated on a typical bill.
Discount rate	A discount rate was set at the current yield on a 30-year Treasury bond. At the time of the analysis, this was 3.65 percent. Note that solar dealers and some utilities use widely differing discount rates. Here, one rate was used.
Electricity cost escalation rate	The analysis used a rate of 3% per year. Note that solar dealers and some utilities use widely differing, usually higher, rates. Here, one rate was applied.
Life of system for the analysis	30 years. While a given lease or PPA might have a differing project life, this metric provided a long-term view, consistent with solar benefits.

Table 4.2. Assumptions Required for Customer Solar Economic Analysis.

The reader might notice that all the metrics are current (or, in the case of solar performance, historic), except for those pertaining to the new SMUD rate structure. Solar incentives, system costs, etc. will undoubtedly change, but it would be impossible to guess how. For example, will the federal tax credits be renewed or replaced by some other incentive? Will system costs continue to fall at the current pace or faster—or slower? The team opted for the use of realistic, *current* assumptions and knowable future utility rates. That way, the analysis would not likely get caught up in a debate about assumptions. Results focus primarily on how each solar option compares to the others under the new rate structure.

Note that the utility must be comfortable with the community solar program, too, in terms of how the Solar Shares rate and virtual net metering would play out. A utility might tweak the rate, based on getting a better PPA price or reassessing the program budget and costs. However, the Solar Shares rate is attractive partly because it is cost-based. For this research, the utility completed an internal economic assessment and provided results to the research team. Modeling used a representative Solar Shares rate of 12 cents per kWh.

4.4 Modeling Results

This summary of the customer economics for different solar options in SMUD's service territory is divided into two parts: first, modeling the results for residential customer options, and then modeling the results for large commercial customer options.

The residential solar options include: (1) leased rooftop system, (2) customer-financed (HELOC) rooftop system, and (3) Solar Shares consistent with an approximately 4.5-kW (average-sized) system. Modeling (as described above) provided the detailed customer economic results summarized in Table 4.3.

Economic Metric	Customer-Owned	Customer-Leased	Community Solar
Value of Lifecycle Cash Flow ($2013)	$9,200	$9,300	$15,750
NPV of Lifecycle Cash Flow	-$770	$3,300	$7,500
Average Annual Cash Flow ($2013)	$310	$310	$525
Levelized Cost Of Energy ($/kWh)	$0.28	$0.15	$0.13
Benefit-Cost Ratio ($2013)	1.29	1.41	1.54
Benefit-Cost Ratio (NPV-basis)	.97	1.23	1.43
Years to Positive Cash Flow	24	15	3

Table 4.3 Representative Residential-Customer Economic Results for Three Solar Options.

The community solar option offers by far the best customer economics. The proposed Solar Shares program applies technical and business advantages to deliver savings, beginning as soon as the participant subscribes, and locking in those savings for the long term. A multi-year subscription would be cash-flow positive, reaching "payback" in less than three years. Note that long-term benefits are calculated on a 30-year project life. If the program culminates in less than 30 years, or if a participant withdraws after only a

few years, the net benefits would be proportionally less. Figure 4.3 shows the cumulative cash flows expected from each of the three cases, carried through the full 30-year term.

One notable modification to the community solar model tested would allow the utility to "buy out" the third-party PPA and take ownership of the project after the tax credit value is realized (say, in Year 7). At that time the fair market price for the project would be a fraction of the original price. The utility could then share the benefit, either to improve participant economics even further, or to finance more innovative new projects in the community solar fleet. The opportunity to apply voluntary participant funds to more innovative or complex projects could enhance program marketing in future years. Community solar economics already are potentially at or near "parity" with typical retail California energy costs. For that reason, SMUD may limit participation to a percentage of the participant's total electricity needs.

It is also striking that customer-owned and customer-leased rooftop systems modeled require a relatively long time to reach cash-flow positive (payback), and that overall results do not look stronger. There are several reasons why:

1) The expected electricity cost escalation rate is an important economic driver, and local solar dealers and leasing companies commonly use an expected electricity cost escalation rate of 5 percent per year or more. This modeling used an expected electricity cost escalation rate of 3 percent per year.

2) Local solar dealers also may use differing assumptions for the discount rate, and some do not include all applicable taxes. It is important to recognize that this analysis applies assumptions consistently for all three cases.

3) Installed-solar costs have declined, but the California SB1 solar incentives have declined relatively quicker. For this analysis, the applicable residential incentive was at Step 8, providing a performance-based incentive (buydown) of 6 cents per kWh (five-year) or 3 cents per kWh (10-year). A few years ago, at Step 6, the buydown was about three times as much.

4) The proposed SMUD time-of-use rate provides solar net metering, but the benefits are focused on a relatively small window of time, compared to possible solar benefits on the previous tiered rate structure. SMUD plans to send a strong signal to conserve during super-peak hours, which occur in summer from 2 pm to 8 pm. Only a portion of solar generation occurs during that window, and net metering credits reflect that. Note that almost identical net metering parameters apply to the Solar Shares case, but the proposed community solar plant would use tracking technology, which picks up more super-peak hours.

Other differences between the cases pertain to the timing of customer economic benefits. The customer-financed option requires full repayment of the system within the first five years of operation, which affects the net present value of the economic cash flow. Note that average annual savings differ by only $70 per year between the customer-financed and customer-leased option, but those savings actually accrue very differently.

Each option reflects some advantages from the federal tax credits. The customer-financed option utilizes only the 30 percent residential tax credit, while the customer-leased and the community solar options pass through richer benefits from the commercial solar investment tax credit and accelerated depreciation. (Details pertaining to a typical leasing model were difficult to obtain.) However, it is clear that all cases would suffer from a loss of federal incentives, and that may occur in 2017.

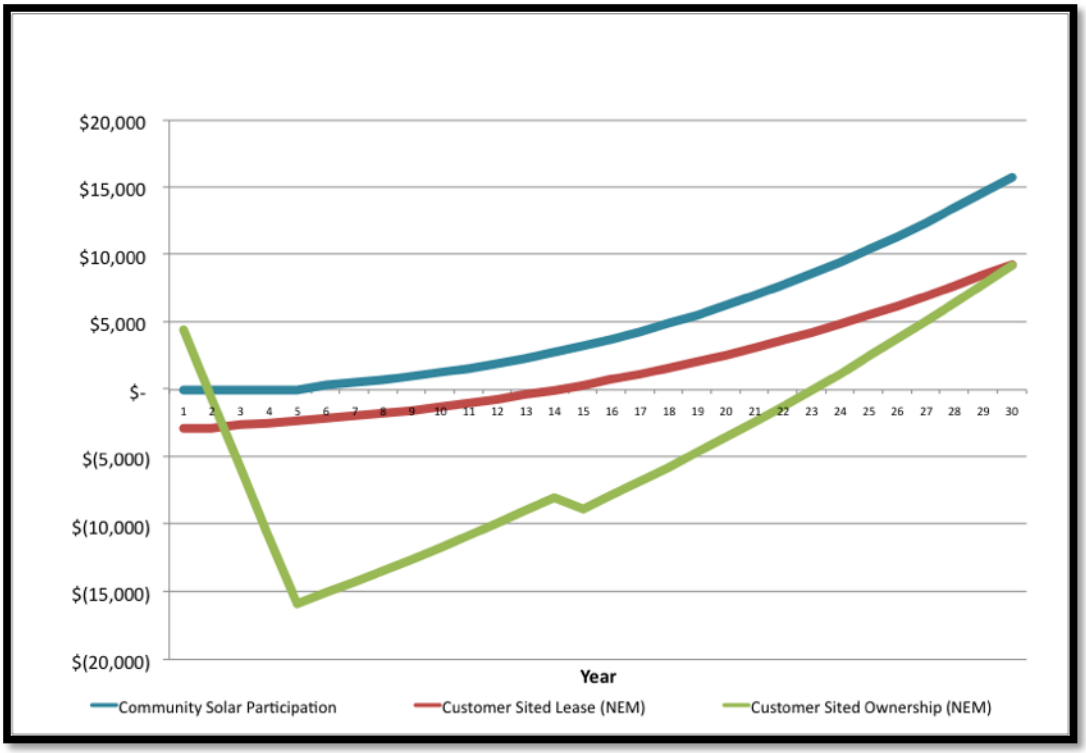

Figure 4.3 Comparison of Cumulative Cash Flows from Residential Solar Options.
The customer-financed case requires the customer to replace the PV inverter in Year 15. For other cases, that expense is integrated into the overall lease or rate.

A discussion of program design and marketing implications of these results is included in Section 4.5.

Research for this project also included an economic analysis of two solar options for large commercial customers: 1) a private, third-party purchase power agreement to finance a customer-rooftop system 2) equivalent participation in the proposed Solar Shares program. Modeling (using assumptions and data described above) provided the customer economic results summarized in Table 4.4.

Economic Metric	Customer-Sited PPA	Community Solar
Value of Lifecycle Cash Flow ($2013)	$337,000	$417,000
NPV of Lifecycle Cash Flow	$130,600	$162,200
Average Annual Cash Flow ($2013)	$11,200	$13,900
Levelized Cost Of Energy ($/kWh)	$0.13	$0.13
Benefit-Cost Ratio ($2013)	1.26	1.26
Benefit-Cost Ratio (NPV)	1.17	1.27
Years to Cash Flow Positive	16	16

Table 4.4 Representative Large-Commercial Economic Results for Two Solar Options.

The large-commercial sector includes a variety of large facilities, some owned by tenant companies and some leased. In Sacramento, many state government facilities are also included. For this sector, however, the community solar option is not the hands-down favorite. The economic results are almost evenly matched. They are favorable (with NPV benefit-cost ratios of 1.2−1.3), but a long term to cash-flow positive (payback time) and other metrics suggest that for these customers, the decision to "go solar" would not be made on economics alone.

The driving difference between the two cases lies in the choice of solar technology. The customer case assumes a fixed-tilt rooftop 250-kW solar project, and the community solar case assumes an equivalent sized capacity (250-kW) share from a single-axis tracking system. The output of the tracker is greater, so the scale of the cash flows (and total lifetime savings) is greater. But the incentive structure for both cases are the same (passing through some benefits of the commercial solar ITC and accelerated depreciation), and both cases are subject to the same anticipated TOU rates for net metering.

The anticipated TOU rate for large-commercial customers is set lower per kWh in each TOU window, as the per-unit cost of service is lower for this sector. Thus, the solar savings opportunity is going to be less compelling, no matter what solar option the customer chooses. Note that the Solar Shares rate tested was the same cost-based rate applied to residential customers.

Most commercial customers require a short return on investment and would not look patiently on the chance to lock in lower electricity costs as, year by year, standard electricity rates rise. However, those with "patient money" would be rewarded. (Figure 4.4 shows cumulative cash flows from the commercial solar options.) The target market for the community solar rate tested might include some government customers, who are sure to be around in 16 years or more. Their interest might be further piqued if they need to meet sustainability goals or (for private businesses), if they wish to add a commitment to green power as a sign of their social commitment, and particularly if they lease their facility.

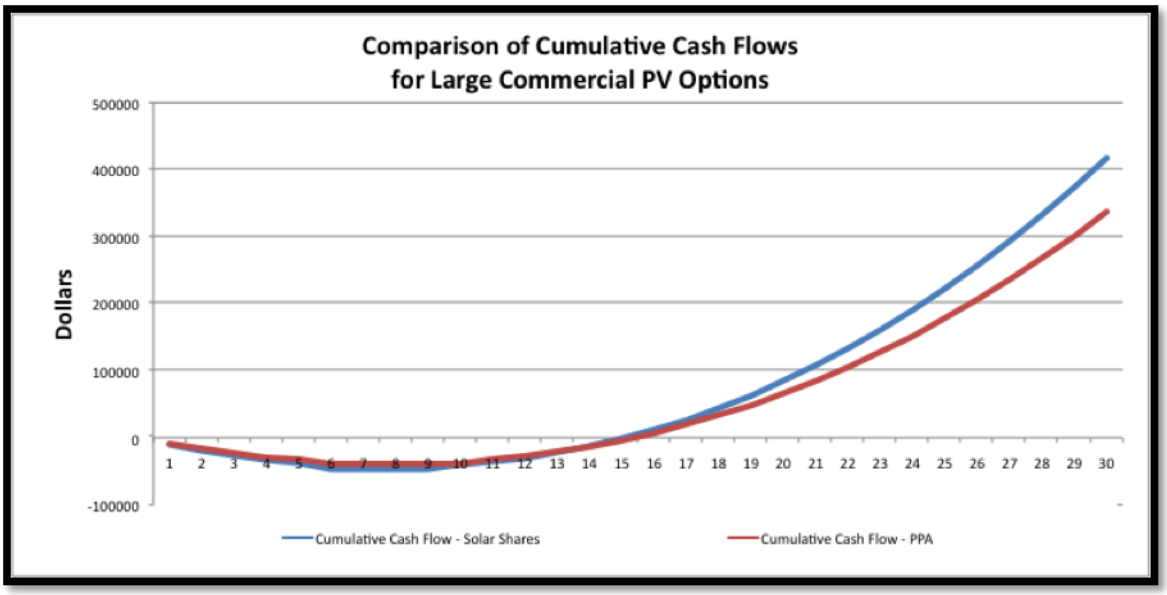

Figure 4.4 Comparison of Cumulative Cash Flows from Large-Commercial Solar Options.
The greater long-term cumulative cash flow from the community solar option is due to the greater output of the 1-MW single-axis tracking solar plant.

4.5 Discussion and Conclusions

The economic-impact modeling for SMUD customers' solar options under the anticipated new time-of-use rate suggests that SMUD's straw man program model for a revised Solar Shares is a highly attractive option for residential customers and a competitive option for large-commercial customers. This section will explore the strengths and vulnerabilities of the straw man model in more detail. It will suggest decision points for SMUD as it moves forward, and it will suggest lessons for other public power utilities nationwide.

It is important to note that the strong customer economics of the proposed community solar program are not merely in contrast to the economics of rooftop solar options. Modeling for two customer-sited options—customer-financed and leased systems—also show a positive lifetime benefit-cost ratio and average annual savings in the hundreds of dollars. It was a secondary aim of this research to see whether those options would work under the anticipated new rate structure; the modeling suggests the answer is *yes*. Some customers might prefer to own or lease and, over the long term, that could be a good decision for them.

However, the economics of the proposed Solar Shares program are more compelling. Participants would begin to save almost as soon as they subscribe. A multi-year subscription would be cash-flow positive on a cumulative basis, i.e., reaching payback, in less than three years. And if participants stay in for the long term, they would benefit from the long-term stability of the solar rate. The case modeled assumed an ~4.5-kW solar share, equivalent to the average-sized rooftop system, and total savings could surpass $15,000 over the 30-year life of the solar project. In reality, few customers would participate for that full term, even if the utility offered it. And not all participants would subscribe for a 4.5-kW share.

However, scaling down participant costs and benefits does not change their favorable nature. The average predicted residential participant net savings, based on a 30-year system life, would be more than $100 per year per *1-kW* equivalent solar share. An individual customer would not have to subscribe for anywhere near the full 30-year term to enjoy that savings, so long as the utility could maintain subscriptions for a viable community solar fleet. The marketing strategy might even allow for shares smaller than 1 kW of solar capacity, to serve a greater portion of the overall customer base. The research team recommends pricing on the basis of a per-kWh Solar Shares rate, which truly supports participation by all customers—especially because the per-kWh price proposed is very near parity with the blended (averaged out) new time-of-use rate.

Economic impact modeling for the large-commercial sector indicated similarly positive results for either a customer-sited, third-party-financed solar investment or a similarly sized subscription to the proposed Solar Shares program. The benefit-cost ratio for either, as modeled, is 1.3. The research did not model impacts at historic or current SMUD rates, so the research does not shed light on current large-customer economics. But it is likely that under either current or future rates for that class, there would still be a gap between the unit price of solar energy and the blended cost of conventional electricity. In other words, solar parity is farther off for large-commercial customers. Yet those that have patient money would benefit from investing in solar (community solar or a customer-sited PPA) now. Moreover, any large commercial customers who have renewable energy goals might find the Solar Shares program particularly attractive, for some of the following reasons:

- Solar Shares participation would not require rooftop siting, which is problematic for facilities that are not designed for heavy roof loads or have roofs with an expected life of 20 years or less, or have concerns with roof penetrations required by solar installations.
- Participation also appeals to those who lease their facilities, or whose facilities are otherwise unsuitable for rooftop solar (due to orientation, shading, or security concerns).
- Participation would not require a commitment for the full 30-year life of the system. As with the residential Solar Shares option, customers would pay a per-kWh community solar rate.
- Likewise participation would not require the equivalent of a full 250-kW average-sized commercial system investment. Large commercial customers could purchase the equivalent of a much smaller share (guidelines to be determined by the utility).
- The Community Solar option makes a public statement, with potential marketing value.

Effective utility planning is required for program success, and a full discussion of marketing plan development is beyond the scope of this research. A review of the earlier sections of this report, including best-practices, suggests some key marketing points.

With such a compelling economic proposition for residential customers (and a competitive solar option for large commercial customers), this proposed program is highly likely to be successful. From the utility perspective, the model addresses some key risks, relative to other community solar programs and relative to customer options at large. Table 4.5 summarizes some of these risk-management measures.

Utility Risk Management Considerations for Community Solar	
Consideration	**Response**
Program must work from the utility-economic perspective	Utility must perform internal analysis to set the proposed rate, based on estimated purchase power agreement cost and additional administrative and fixed costs. For SMUD, implementation of the new time-of-use rate with revised customer charge contributes to cost-effectiveness from the utility perspective. The Solar Shares program rate may be adjusted before implementation and periodically for new subscribers.
Program must be attractive, relative to other utility (wholesale) solar investments	Utility should seek competitive bids for the solar purchase power agreement. (Note that the rate used for this analysis is representative and not based on bids.) The financing structure allows pass-through of some tax-related solar-development benefits. The cost-effectiveness of the investment could be enhanced if the utility opts to buy out the solar project in Year 7 or later, when the project cost would be greatly depreciated, despite decades more of expected generation. Each utility should assess the benefits of solar ownership vs. a long-term PPA.
Program must be economical for customers to subscribe in the first place.	Each utility should model customer results. This research shows compelling economics for residential customers (savings almost immediately and payback of less than three years for given assumptions) and less compelling economics for large-commercial customers, although still on par with the typical rooftop option.
Full subscription of the project may require smaller, more affordably sized shares of the overall community solar project.	Participation may be based on smaller capacity, or simply on a per-kWh community solar rate. There are marketing benefits of relating to a capacity or panel size. Note that if the rate is highly attractive, the program may require a maximum limit (percent of total customer use).
Full subscription of the project may require a shorter-term option for participation, as well as other marketing features.	The marketing plan should include assessment of impacts on the utility of possible guidelines (such as ability go come and go from the program). As longer-term participation lowers utility risks, the program should include benefits for early and long-term participants—for example, a rate that adjusts for all participants as newer, more economical solar projects are added to the fleet.

The initial solar project may be viable for 30 years, but the utility must plan to keep participation attractive to future customers, who will have more solar choices.	In seeing community solar as a developing fleet, customers will be subscribing to the overall community resource. This may include more innovative or publicly beneficial projects in time. For example, ground-mounted SAT technology is preferable today, but perhaps a battery-based project would be a good future acquisition.
Customers like net metering, but the policy may be costly from a utility perspective.	In a utility-driven community solar program, the customer buys all electricity from the utility. Credits for solar generation are then applied monthly, based on the customer's share. Virtual net energy metering may be paid at a value equal to the blended cost of the customer's monthly consumption, or at the value of the share of solar generated (at the retail Solar Shares rate), at the time of generation. Utility billing preferences must be considered, but the end result of either option is about the same. Under SMUD's anticipated time-of-use rate, community solar minimizes net energy metering-related lost revenue.
The utility recognizes the implications of solar for community economic development, but wishes to manage related risks.	A community solar fleet that grows in increments offers opportunities for the utility to apply different financing strategies. Local companies may prepare competitive bids for future expansion, possibly testing largely local crowd-source financing, master-contractor energy performance contractor using local subcontractors, etc. Public power-based projects offer many opportunities or local economic benefits, relative to mainstream solar leasing.
The program may be affected by a loss of federal incentive funding or upheavals in the solar industry that affect today's competitive economic outlook.	Loss of federal incentives is a significant risk, if solar cost reductions do not continue to improve. Politically, support for solar incentives is advised. However, with a "grow as you go" incremental community solar strategy, future projects can be brought into the fleet at a revised Solar Shares rate, thus reducing utility risks.

Table 4.5 Community Solar Risks and Responses from the Utility Perspective.

This research confirmed that the proposed revised Solar Shares program is nearly ready for implementation in Sacramento. A few questions remain and the straw man model already described is still subject to adjustment. Some recommended final tasks include:

- Finalizing the virtual net metering/billing process. This includes modeling a few options and discussing outcomes with the billing department.
- Preparing the marketing proposition by modeling current customer economic impacts, as well as those under the new TOU rate. Also, consider different-sized shares and what the marketing implications would be (number of participants needed for a MW-scale plant, likely churn, impacts on utility economics, and specific appeals to build participation).

- Ways to reach and engage that segment of the large-commercial market, which would likely benefit from the community solar option. Consideration of ways to enhance the marketing appeal without significantly increasing utility program costs.
- Testing the community solar rate under changing conditions, exploring a range of "what-if" questions.

Utility program planning is always a balancing act between supporting decisions with data versus making a well-considered leap of faith. The successes of the original Solar Shares program underscores the benefit of a community solar option, which is priced so almost any customer can participate and brings the benefits of economies of scale and utility expertise into easy reach for the whole community. This modeling research leads naturally to supporting implementation.

For other public power utilities, this SMUD case demonstrates how utilities can offer a solar product that is not just different, but in many ways better than other choices available today. Especially for residential customers, the revised Solar Shares program model is compelling. It is not intended to replace customer-financed or leased rooftop options, but for many customers it could be the best choice. From the utility perspective, it offers many benefits—not the least of which is to maintain the public power utility's role as the first contact point for clean, affordable and equitable energy services.

The scale of the Sacramento program may be daunting to other utilities. Not all markets can deliver utility purchase power agreement bids that are as competitive as those anticipated in the Sacramento area. Yet this community solar business proposition is so strong that utilities in other regions could test it for themselves, to see how close they come to their own definition of a competitive offer.

There are possible pitfalls, of course. The SMUD case demonstrates that it would be wrong to assume that just because a solar rate works for one customer class, that it would work the same for every one. Higher rates across the board obviously improve the relative attraction of a solar program today. Yet, the consistent decline in solar costs year after year suggests that this technology is near a tipping point. The greatest risk for utilities might be that if they are not willing to help customers use solar power, the customers may find a way to go around the utility altogether. This is already beginning to happen, to some extent.[xix] It can have negative ramifications for any utility, but especially for public power utilities, whose mission is to benefit the whole community.

In some cases, any one community solar model described earlier in this report might suit a given public power utility. The research team recommends a thorough review of possibilities. The good news is that utilities and their customers have choices for new ways to work together to achieve immediate and lasting benefits.

Endnotes

[i] See http://www.sharedrenewables.org, a project of the Vote Solar Initiative. An even broader perspective encompasses all kinds of shared renewables, including wind, small hydro, landfill gas, etc.

[ii] Personal communication with Tim Harvey, Austin Energy and Stephen Frantz, SMUD.

[iii] California has established goals for achieving Zero Net Energy for all new residential buildings by 2020 and all new commercial buildings by 2030. Thus, California regulators and utilities have been industry thought-leaders in developing new business structures that do not rely disproportionately on kWh sales in order to cover utility costs of service.

[iv] Pernik, R., Wilder, C., and Trevor, W., Clean Edge Trends 2013, March 2013 p 10. See http://www.cleanedge.com.

[v] Konrad, T., A Clean Energy REIT: Hannon Armstrong Sustainable Infrastructure, Renewable Energy World, May 3, 2013. See http://www.renewableenergyworld.com

[vi] Reintroduction Of Master Limited Partnerships Parity Act On April 24, 2013, reported on http://www.Mondaq.com, May 1 2013. The Senate Bill, S 795, has a companion in the House of Representatives, HR 1696.

[vii] The Local Energy Aggregation Network, http://www.leanenergyus.org, is a DOE-funded program that tracks community aggregation efforts. See newsletters and factsheets for details.

[viii] US DOE tracks community solar projects and developers on its Green Power Network site, http://apps3.eere.energy.gov/greenpower/markets/community_re.shtml

[ix] The Seattle City Light program totals 23 kW, installed at a city park. See http://www.seattle.gov/light/solar/community.asp

[x] http://www.gocolumbiamo.com/WaterandLight/Electric/SolarOne.php

[xi] Szaro, J., Collaborating to Build Markets: A Utility Perspective, Presentation provided to J. Cliburn, July 2012. See also http://www.ouc.com/environment-community/solar/community-solar/community-solar-faq#calculate

[xii] See https://www.tep.com/renewable/reports/overview/

[xiii] NREL has sponsored a renewable energy finance portal, at https://financere.nrel.gov/finance/

[xiv] Wiedman, J. and Schroeder, E., "Community Renewables, Where Are We Now?" Proceedings of Solar 2012, American Solar Energy Society.

[xv] See www.scag.ca.gov/rep/ewg/documents/GoSolarPresentation3-14-2007.pdf

[xvi] See www.ustreas.gov/press/releases/js629.htm

[xvii] See https://sam.nrel.gov/ for a full description of the SAM model.

[xviii] See https://www.cleanpower.com for a full description of this widely-used utility software.

[xix] R. Smith and T. Sweet, "Companies Unplug from the Electric Grid, Delivering a Jolt to Utilities," *Wall Street Journal*, September 17, 2013. See https://www.online.wsj.com