DESIGNING PV INCENTIVE PROGRAMS TO PROMOTE SYSTEM PERFORMANCE: A REVIEW OF CURRENT PRACTICE

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ABSTRACT

Increasing levels of financial support for customer-sited photovoltaic (PV) systems, provided through publicly-funded incentive programs, has heightened concerns about the long-term performance of these systems. Given the barriers that customers face to ensuring that their PV systems perform well, and the responsibility that PV incentive programs bear to ensure that public funds are prudently spent, these programs should, and often do, play a critical role in ensuring that PV systems receiving incentives perform well. To provide a point of reference for assessing the current state of the art, and to inform program design efforts going forward, we examine the approaches to encouraging PV system performance used by 32 prominent PV incentive programs in the U.S. We identify eight general strategies or groups of related strategies that these programs have used to address performance issues, and highlight important differences in the implementation of these strategies among programs.

1. INTRODUCTION

Recent growth in the installed capacity of customer-sited photovoltaic (PV) systems in the U.S. has been fueled by an array of incentive programs offered by utilities, state agencies, and other organizations. The financial incentives provided through these programs, which are typically funded by taxpayers or utility ratepayers, are often in the form of an up-front rebate paid to the customer, supplementing the utility bill savings received by the customer.

With the increasing level of public funding has come greater interest in the performance of customer-sited PV systems. Although PV system owners have an inherent incentive to ensure that their systems perform well, many homeowners and building operators lack the necessary information and expertise to carry out this task effectively. Given this barrier, and the responsibility of PV incentive programs to ensure that public funds are prudently spent, these programs should, and often do, play a critical role in promoting PV system performance. Performance-based incentives (PBIs), which are based on the actual energy production of the PV system over time, are often suggested as one possible strategy. Somewhat less recognized are the many other program design options available, each with its particular advantages and disadvantages.

To provide a point of reference for informing program design efforts going forward, we survey the set of approaches to encouraging PV system performance – including, but not limited to, PBIs – used by 32 prominent PV incentive programs in the U.S. The information presented in this paper is drawn from a recent report by Lawrence Berkeley National Laboratory (1) and is based largely on publicly-available sources as well as a limited number of personal communications with program staff.

2. TAXONOMY OF PROGRAM DESIGN OPTIONS

The amount of electrical energy generated by a PV system over its lifetime is a function of three fundamental parameters: the amount of solar energy incident on the array, the efficiency of the entire system in converting that solar energy into AC electrical power, and the duration of time that the system is in operation. These three fundamental parameters, in turn, are affected by a wide variety of specific issues related to geographical location, system design, equipment quality, installation workmanship, and maintenance.

Based on our survey of PV incentive programs in the U.S., we identify eight general program strategies or groups of related strategies to promote PV system performance, each of which is best suited to addressing some set of the factors that affect system performance (see Table 1). In the remainder of this paper, we discuss each of these eight strategies in greater depth and highlight important differences in the implementation of these strategies among programs.

TABLE 1: PV INCENTIVE PROGRAM STRATEGIES FOR PROMOTING PERFORMANCE

Program Design Option	**Performance Factors Potentially Addressed**				
	Geographical Location	System Design	Equipment Quality	Installation Workmanship	Maintenance
1. Equipment and installation standards			✓	✓	
2. Warranty requirements			✓	✓	✓
3. Installer requirements, assessment, and voluntary training		✓		✓	
4. Design standards and administrative design review		✓			
5. Incentive-based approaches					
Performance-based incentive	✓	✓	✓	✓	✓
Expected performance-based buydown	✓	✓			
Incentive hold-backs				✓	
Improved rating conventions		✓	✓	✓	
6. Post-installation inspections and acceptance testing				✓	
7. Performance monitoring and assessment					
Performance monitoring by program administrator					✓
Meter display requirements and other information/diagnostic tools					✓
Customer education and training (re. system monitoring and assessment)					✓
8. Maintenance requirements and services					✓

2.1 Equipment and installation standards

Various organizations in the U.S. and internationally have developed standards for PV equipment and systems, and certification programs have been established to verify compliance with these standards. In general, certification of compliance with particular standards becomes binding when required by funding organizations for systems funded through their programs, by utilities for interconnection or net metering, or by lawmakers and permitting authorities for systems installed within their jurisdiction.

The existing standards most directly related to performance are those that specify how manufacturers of PV modules and inverters are to establish the *nameplate ratings* for individual product lines. The only U.S. standard governing the rated output of PV modules is Underwriters Laboratories standard UL-1703, which relates primarily to product safety, but also requires that the lower end of the tolerance band for module power output be at least 90% of the nameplate rating. Virtually all of the 32 PV incentive programs in our sample require modules to be UL-listed and thus meet this minimum rating standard. In addition, for its new program, the California Energy Commission (CEC) adopted a tighter standard, requiring that the lower end of the tolerance band be at least 95% of the rated power output.

Although no national standards have been adopted for inverter efficiency ratings, the CEC has adopted its own standard, requiring that the rated efficiency of inverters be based on the weighted average efficiency measured at six specific load levels. The measurements are to be conducted according to a specific test protocol jointly developed for the CEC by Sandia National Laboratory and several other organizations. A number of other programs in California use the CEC's inverter ratings, and thus implicitly require the same standard.

Other equipment and installation standards pertain primarily to *safety*, which may be relevant to performance insofar as safety issues also lead to pre-mature equipment failure or degradation. As mentioned previously, UL-1703 is the national product safety standard for PV modules, and UL-1741 is the analogous standard for inverters and other interconnection equipment. The Institute of Electrical and Electronics Engineers (IEEE) has developed a set of safety-related standards for utility-interconnected systems (IEEE-929 and its successor, IEEE-1527). Finally, the National Electrical Code (NEC) contains numerous standards related to the wiring and electrical connections for PV systems, including Article 690, which specifically addresses PV installations. Among the PV incentive programs surveyed for this paper, most require that inverters be UL-listed, and over one-third also require compliance with IEEE-929. Some programs also require that installations meet NEC standards, though it is more common, perhaps, that these standards are incorporated into state or local building codes.

2.2 <u>Warranty requirements</u>

PV equipment manufacturers and installers may offer various types of warranties, which can be distinguished according to: the *duration* of coverage, the *items* covered (modules, inverters, the installation service, etc.), the *conditions* covered (performance degradation or simply failure/breakage), and the *costs* covered (parts or labor). PV incentive programs may specify minimum warranty requirements and thereby promote performance by imparting an incentive to manufacturers and installers to design and install reliable products, and by reducing the costs customers would otherwise bear to repair malfunctioning systems.

Almost all of the programs reviewed in this paper incorporate some type of minimum warranty requirement. The most common is a requirement that the PV contractor warrantee the entire system for a five-year period. California's recently enacted solar legislation (SB1) requires a more aggressive 10-year system warranty for the state's new incentive programs. As an alternative to a whole-system warranty (or perhaps in addition to it), some programs have component-specific warranty requirements for modules (typically 10-20 years) and/or inverters (2-5 years). Finally, three programs require that installers provide distinct warranties (one or two years) for the installation service, specifically.

With respect to the conditions covered by the warranty, all program requirements specify that the warranty provide protection against breakage or failure. Ten programs also require that the warranty include a performance guarantee that output does not degrade by more than a specified percentage (usually 10-20%) over the warranty period. Such performance guarantees are most often required as part of a system warranty, although the Connecticut Clean Energy Fund (CCEF) and the Rhode Island Renewable Energy Fund (RIREF) both also require that PV modules come with a separate performance guarantee of less than 20% degradation over 20 years.

Regarding the costs covered by the warranty, program guidelines typically require a full warranty covering parts and labor. As an exception, rather than requiring a full, five-year system warranty, the Pennsylvania Sustainable Development Fund (SDF) and CCEF require a full warranty only for the first two years of operation and a limited (parts-only) warranty for an additional three years.

2.3 <u>Installer requirements, assessments, and voluntary training</u>

The performance of PV systems depends, to a large degree, on the expertise of the professionals involved in their design and installation. PV program administrators have sought to ensure the proficiency of installers through a number of distinct approaches, including (a) imposing installer eligibility requirements, (b) disqualifying installers that have performed poorly, and (c) directly sponsoring or otherwise supporting voluntary training activities.

Regarding the first of these three approaches, most of the 32 programs surveyed require that installers meet some set of minimum qualifications related to proficiency. The most common requirement, adopted by almost half of the programs, is that installers have a general contractors' license, an electricians' license, or (in California) a solar contractors' license. A separate type of requirement, adopted by more than a third of the programs, is that installers have some minimum level of training and/or experience with PV, specifically. Four of these programs require that installers be certified by the North American Board of Certified Energy Professionals (NABCEP). Other programs specify requirements in terms of some minimum number of installations (ranging from three to ten) and/or completion of training course(s) sponsored by the program administrator or another approved organization.
Given the nascent state of the installer infrastructure in many regions, some program administrators have taken a flexible approach to their training and experience

requirements. For example, those programs requiring NABCEP certification typically phase in the requirement over a one- to two-year transitional period, during which time installers can participate provided that are in the process of obtaining certification. Similarly, the New York State Energy Research and Development Authority (NYSERDA), which generally requires installers to have completed at least three installations and 24 hours of nationally-accredited training, may allow installers that do not meet these standards to participate in its program on a provisional basis; NYSERDA works closely with these installers on each project, conducting detailed design reviews and site inspections.

The second general type of approach to ensuring installer proficiency is to assess the quality of workmanship of participating installers and, if necessary, disqualify or place on probation those whose workmanship is found to be unacceptable. In the new California Solar Initiative (CSI), for example, installers that fail three inspections are disqualified from the program for one year. NYSERDA, which also assesses the workmanship of installers participating in its program, has uncovered a limited number of installation problems through its regular inspection process and, as a result, has kicked one installer out of its program and demoted several others to provisional status (2).

A third approach to ensuring installer proficiency, which a number of programs have pursued, is to provide funding or other forms of support for voluntary installer training. The Los Angeles Department of Water and Power (LADWP), Sierra Pacific, and Nevada Power have sponsored workshops for installers. Wisconsin Focus on Energy (WFE) has supported voluntary training by offering a higher incentive rate for PV systems installed by NABCEP-certified installers (150% of the rate for non-certified installers) as well as "business scholarships" for tuition or exam fees associated with training activities. Last but not least, NYSERDA has taken a particularly aggressive approach to promoting installer training and certification, providing various forms of financial support both to installers and to training and certification institutions.

2.4 Design standards and administrative design review

The performance of PV systems is critically affected by decisions made during the design phase, and PV incentive programs have sought to ensure acceptable system design by incorporating minimum design standards and/or administrative design reviews.

Minimum design standards come in two basic varieties. Ten programs have adopted standards that are specified in terms of *measurable design parameters* related to panel orientation and/or shading. Panel orientation standards generally require that panels be facing in a southerly direction (i.e., between ± 90 degrees of true/due south), and sometimes also require that the tilt angle fall within a designated range. Shading standards are specified in different ways depending on the program – either requiring no shading during certain hours of the day, a maximum percentage of hours of shading, or no physical obstructions within a given space relative to panels.

The second variation of design standards are those that are specified in terms of *estimated annual energy production*, expressed either on an absolute basis (e.g., minimum kWh per installed kW) or on a relative basis, by comparing the expected output of the system to that of an "ideal" reference system. One important feature of the latter approach is that the ideal reference system may be defined to include or exclude any of the myriad design parameters that affect performance (geographical orientation, panel orientation, shading, equipment selection and sizing, etc.). Most programs define the ideal system based on the same equipment and location as the actual system, but with no shading and oriented to maximize annual energy production.

Although some programs may not have explicit minimum design standards, the program administrator (or a technical consultant) may conduct some form of design review, prior to reserving funding for a project. As could be expected, these administrative reviews vary widely in terms of the specific process utilized and the depth of the design review. Many programs simply request information about panel orientation in the project application form (although it is not always apparent from the program literature whether poor orientation would actually cause a project to be rejected). A number of programs require more detailed information (e.g., site drawing or photographs) or more rigorous analysis by the applicant (e.g., a shading analysis or simulation of annual energy production). Finally, as part of the design review, some utilities also conduct pre-installation site inspections.

2.5 Incentive-based approaches

Historically, PV incentive programs in the U.S. have provided rebates for PV systems based on module nameplate capacity, disbursed prior to or immediately following installation. While simple to administer, this incentive structure, sometimes referred to as a *capacity-based buydown* (CBB), does not account for factors that affect system performance. To address this shortcoming, a growing number of programs have adopted alternative incentive structures or modifications to the same basic incentive structure, which differentiate among projects based on either their actual performance or factors that are likely to affect performance.

2.5.1. Performance-Based Incentives

Foremost among these alternative incentive structures, in terms of the breadth of performance issues accounted for, are performance-based incentives (PBI), whereby the incentive payment is calculated based on the measured output of the system over some performance period. Of the 32 programs surveyed, five offer incentives in the form of a PBI.

The PBIs offered by these five programs can be distinguished according to a number of design parameters.

- *Pure PBI or hybrid incentive structure*. SDF's Solar Grant program and CCEF's Onsite Renewable DG Program have hybrid incentive structures that combine a PBI with an up-front incentive payment. In both programs, the bulk of the total incentive payment is provided in the form of a traditional CBB. The other programs offer a "pure PBI", where the entire incentive is in the form of a PBI.
- *Entity receiving the PBI payment*. SDF splits the PBI payment between the customer and installer, thereby providing both parties with a direct incentive to attend to system performance. The other programs provide the PBI payment to a single entity (the project applicant or the customer).
- *Class of projects subject to a PBI*. Most programs with a PBI offer the same incentive structure to all projects eligible for the program. One exception is the CSI, which requires a PBI only for large projects (currently defined as 100 kW, dropping to 30 kW in 2010). Smaller projects instead receive an up-front incentive but can opt for a PBI, which may be more lucrative for high-performance systems (e.g., concentrating solar and tracking systems). Another exception is CCEF, which offers a PBI only as a small supplemental incentive for projects installed in the congested Southwest Connecticut region.
- *Performance period*. From the perspective of affecting system performance, the duration of the performance period can be significant, as many performance issues arise only over time (e.g., inverter failures and tree growth). Of the five PBI programs, three have a performance period of less than three years, while the CSI has a five-year performance period, and the performance period in WA DOR's program extends until 2014, regardless of when the system is installed.
- *Frequency of incentive payments*. The frequency with which PBI payments are made determines how regularly the customer receives feedback on the performance of its system. Of the five PBI programs in our survey, only the CSI provides monthly PBI payments. The other programs all issue payments on either an annual, semi-annual, or quarterly basis.

2.5.2. Expected Performance-Based Buydowns

The fact that PBI payments are issued over time could potentially deter some customers (in particular, those with insufficient cash or access to attractive financing to cover the full, up-front cost of the system). Expected performance-based buydowns (EPBBs) are an alternative incentive structure, whereby the incentive payment is issued up-front, but unlike a traditional CBB, can accounts for factors that affect system performance.

Twelve of the programs surveyed offer incentives structured as an EPBB, which can be distinguished according to:

- The particular set of performance issues accounted for in the EPBB calculation;
- Whether the EPBB is calculated based directly on estimated energy production or on performance relative to an ideal reference system;
- The definition of the ideal reference system; and
- Whether a "dead-band" is used, whereby no adjustments to the incentive payment are made if the project meets some set of threshold design criteria.

In terms of the particular performance issues accounted for in the EPBB calculation, most of the twelve programs with an EPBB account for panel orientation and shading. Five programs also account for geographical location; and one program, the CEC's New Solar Home Partnership program, accounts for the impact of mounting structure on system performance (based on its relationship to cell operating temperature).

Which performance factors are accounted for, and how they are accounted for, depends in part on which of two different EPBB formulations are used. One approach is to use an EPBB formulated as an energy-based incentive rate ($/kWh) multiplied by the PV system's expected energy production over a specified duration. At a minimum, this form of EPBB accounts for geographical location and panel orientation, as these parameters typically must be specified in order to calculate expected annual energy production.

More commonly, programs use an EPBB formulated as the product of a capacity-based incentive rate ($/kW), the system's rated capacity, and some type of *design factor*. Programs with this form of EPBB typically use a design factor equal to the ratio of the estimated annual energy production of the actual system to that of an ideal *reference system*. The CEC has adopted a more sophisticated variation on this approach, whereby the estimated energy production in each hour is weighted to account for temporal and regional differences in marginal generation and transmission and distribution (T&D) costs throughout the state (i.e., a higher value is placed on PV energy production during summer peak periods and in areas with T&D

constraints). The weighted annual energy production of the actual system is then compared to that of the reference system, to determine the incentive payment.

The ideal reference system used in EPBB calculations can be defined in any number of ways to account for different performance factors or to account in different ways for particular performance factors. For example, most programs define the ideal system as being un-shaded and/or as having a specific orientation, but otherwise equivalent to the actual system. These EPBB designs effectively ignore geographical factors that affect the quality of the solar resource, such as latitude and variations in cloud/fog cover. In contrast, the Salt River Project (SRP), the CEC, and the CSI fix the geographical location of the ideal system at a common location for all projects, thereby providing higher incentives to systems located in regions with a more favorable solar resource.

Definitions of the ideal system also vary in terms of how its orientation is specified. Most programs define the orientation of the ideal system as south-facing at a specific tilt angle. In contrast, SMUD treats any panel direction (azimuth) between south and southwest as ideal, and the CSI treats any azimuth between south and west as ideal. The rationale for this type of provision is to not penalize southwest- or west-facing systems, which have higher energy production during summer peak demand periods (when power is most valuable), but lower annual energy production. The CSI also incorporates a more nuanced approach to defining the ideal tilt angle, defining on a project-specific basis, as the angle that maximizes summer energy production for the particular ideal azimuth and latitude of the individual project.

The final differentiating feature among EPBB designs is whether a dead-band is incorporated. One rationale for such a feature is to avoid creating additional complexity and uncertainty for projects that are well-designed, even if not perfectly optimized. Four of the twelve programs with an EPBB have adopted explicit dead-bands specified in terms of an acceptable range in panel orientation, amount of shading, and/or expected energy production. Several other programs have features that are functionally similar to a dead-band. For example, allowing the azimuth of the ideal system to fall anywhere within a range of panel directions, as is done in SMUD's program and the CSI, is effectively a form of dead-band. Similarly, the CEC's program allows projects that meet a specified set of design standards (referred to as the "California flexible installation criteria") to receive an incentive based on a conservative estimate of the system's energy production, in lieu of a more elaborate calculation that accounts for the system's actual orientation and shading.

2.5.3. Incentive Hold-backs

Programs offering CBBs or EPBBs often disburse these payments only after systems have been installed and determined, through inspections or other means, to be operating properly. Several programs have gone one step further by holding back a portion of the rebate over a lengthier operational period and disbursing it only after acceptable performance has been demonstrated. Among the programs surveyed, only CCEF's Onsite Renewable DG Program currently takes this approach; in this program, the final 10% of the incentive payment is paid only after six months of operating data has been collected and the system has been shown to have produced at least 70% of its projected AC energy output. Several other programs also retain a portion of the incentive payment as collateral to ensure that participants submit annual energy production data (used for program evaluation purposes), but don't impose any specific performance requirement as a condition for receiving the final payment.

2.5.4. Improved Capacity Rating Conventions

A common issue relevant to both CBB and EPBB incentive structures is what capacity rating convention to use as the basis for the incentive payment. The simplest rating convention, but least indicative of actual performance, is the module manufacturer's rated DC power output under Standard Test Conditions (STC). Of the programs surveyed for this paper, about half use this measure of system capacity for calculating the incentive payment.

Naturally, any capacity rating is a poor proxy for the likely energy production of a system. However, there are several reasons why module manufacturers' ratings at STC may not even be a particularly reliable proxy for a system's actual capacity (i.e., its AC power output at peak sun conditions). The first reason is that actual cell temperatures under normal operating conditions are generally significantly higher than STC, which reduces a module's power output, and the size of this effect will vary depending on the climate as well as on the type of module and mounting structure used. Second, various losses are incurred in converting modules' DC power output to AC power, and the size of these losses will also vary between systems depending, for example, on the type of inverter used and how well-matched it is to the array. Third, module manufacturers' ratings have an associated tolerance band, and inevitably there is some variation in output at STC among individual modules within a product line.

One simple improvement upon using module nameplate ratings is to, instead, use modules' rated output at PVUSA Test Conditions (PTC), which better correspond to actual cell operating temperatures under full sun conditions in most climates. Eight of the surveyed programs use modules' rated output at PTC to calculate incentive payments. Another simple improvement is to multiply modules' rated output (at either PTC or STC) by the rated inverter efficiency to calculate an AC capacity rating for the system and thereby account for DC-to-AC losses in the inverter. Seven of the programs reviewed for this paper use an AC rating calculated in this manner; most use a particular variation, often referred to as the "CEC-AC" rating, which is equal to the modules' PTC rating multiplied by the inverter efficiency rating published by the CEC.

Although the CEC-AC rating is perhaps the most accurate and encompassing of the rating conventions described above, it cannot account for DC-to-AC losses outside of the inverter, nor can it account for inaccurate nameplate ratings. To account for these two factors, one must use an AC rating that is based on measurements of each individual system – what is sometimes referred to as a *verified AC rating*. Such an approach has the additional advantage of providing early detection of equipment or installation problems.

Two of the programs surveyed for this paper use a verified AC rating, although their approaches differ quite substantially. Salt River Project uses a verified AC rating (for systems >10 kW only), calculated by multiplying the system's stipulated CEC-AC rating by the ratio of the actual energy production measured over a 30-day period to the expected energy production over the same period. Expected energy production is calculated based on the system's stipulated CEC-AC rating, its orientation and shading, and actual weather data (satellite solar radiation and ambient temperature for Phoenix). If the ratio of actual to expected energy production is between 0.95 and 1.00, the initial stipulated rating is used to determine the incentive payment rather than the adjusted value. Tucson Electric Power also uses a verified AC rating method for Option 1 of its program. The utility measures each system's AC power output, solar insolation, and wind speed over a two-week period. The utility then develops a linear regression among these three measured variables and uses that statistical relationship to estimate the system's AC output at PTC, which is the basis for the incentive payment.

2.6 Post-installation site inspections and acceptance testing

Post-installation inspections are often conducted by different entities for different reasons: the building inspector assesses code compliance; the local utility ensures that the installation complies with its interconnection standards; and the PV program administrator or its representative verifies that the installation is consistent with the approved project application and, in some cases, verifies that it is functioning properly.

More than half of the 32 programs surveyed conduct routine post-installation site inspections, in most cases for all projects. As might be expected, the depth of the inspection process varies considerably among programs and, in many cases, serves solely to verify that the installed system is consistent with the approved application (e.g., by checking equipment ratings and module orientation). However, some programs do conduct more detailed inspections where the quality of the installation workmanship and system performance are directly verified. Most notably, in six programs, inspectors conduct "acceptance tests," which involve a set of on-site measurements to verify that the system is producing the expected amount of power, at the time of inspection. Four other programs require that installers conduct acceptance tests and submit satisfactory results prior to receiving the full incentive payment.

2.7 Performance monitoring and assessment

Many performance issues arise only over time, and to identify and remedy these issues, PV systems must be monitored and their performance routinely assessed. PV program administrators may conduct this performance monitoring and assessment directly. Alternatively, or in addition, they can facilitate performance monitoring and assessment by the system owner, by providing (or requiring that installers provide) customer training and/or enabling technologies.

Regardless of who conducts performance monitoring and assessment, metering equipment must be installed to measure and record system output. Most of the programs surveyed require some form of PV metering (separate from net metering of the facility's load). Program metering specifications differ in terms of the required accuracy: nine programs require "revenue-grade" meters while others allow less accurate meters, such as those internal to the inverter. Metering specifications also differ somewhat in terms of the required functionality. For example, several programs require that meters have communications capabilities, several require an "easy to read" display, and several require that the meter measure and display instantaneous power output in addition to cumulative energy production. Only the CSI requires interval metering (for systems >10 kW only).

Although most of the programs in our survey do collect or require that customers submit PV production data, a relatively small number of programs appear to conduct any routine analysis of this data for the purpose of identifying performance issues at individual sites. SMUD is one utility that does take a particularly active approach to performance monitoring and assessment (3). Every month, the utility collects energy production data and computes a performance index for each system, by comparing its actual energy production to the amount expected based on the system's specifications and monthly weather data. SMUD then uses these monthly performance indices to flag under-performing systems, which it then inspects. While SMUD is unique in providing this level of ongoing diagnostics, several other program administrators also conduct follow-up inspections to assess system performance, on either a one-time or ongoing basis.

Finally, PV programs can help customers become more adept at monitoring and assessing the performance of their PV system by providing, or requiring that installers provide, education and/or enabling technologies. At the most basic level, many programs require that installers provide customers with an estimate of their system's annual energy production as a benchmark for evaluating its actual performance. RIREF and MTC also require that installers provide system owners with some level of training on performance monitoring and assessment, and LADWP has directly sponsored PV training workshops for customers. In terms of enabling technologies, a number of programs require "customer-friendly" meter displays, and the Long Island Power Authority provides customers with a free, web-based diagnostic tool that can be used to estimate the amount of electricity their system should have produced over any range of dates, based on actual weather data.

2.8 Maintenance requirements and services

Several programs incorporate elements that serve to directly ensure that necessary maintenance is conducted. For example, a previous program offered by RIREF for C&I customers required that project contractors provide maintenance services and scheduled inspections for at least five years. Contractors were also required to provide training to host site personnel so that they would know how to implement routine maintenance and repair.

Tucson Electric Power and UniSource Power Supply have taken a different tack: rather than requiring that installers provide maintenance services, the utilities provide it themselves. Both utilities conduct ongoing, annual inspections of each system, and if, in the course of these inspections, the utility determines that a system requires repair, it will provide the maintenance labor for such repair at no cost to the customer.

3. CONCLUSIONS

Given the relatively high cost of incentives required to stimulate the PV market, ensuring that PV systems perform well is an important issue in PV program design. This review of 32 of the largest PV programs in the U.S. demonstrates that many different mechanisms to encourage proper system performance are being employed across the country. Each has its potential advantages, and the best set of approaches for any given program invariably depends on the specific performance issues of greatest concern and on the program's particular objectives and constraints. While the information presented in this paper provides a foundation for understanding the range of options available, further information is needed to better assess the relative merits of alternative strategies, particularly in regards to the costs and the efficacy in addressing performance issues. As such, we encourage program administrators to evaluate and share information about the effectiveness and costs of alternate approaches.

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