LINKING PV COST AND PERFORMANCE TO AN ASSESSMENT OF PERFORMANCE-BASED INCENTIVES THAT MAXIMIZE TECHNOLOGY INNOVATION AND TRANSFORM PV TO AN INCENTIVES-FREE MARKET

George Simons, Itron, Inc.
Patrick Lilly, Kurt Scheuermann, Myles O'Kelly, Marvin Feldman (Itron, Inc.)
Pierre Landry, Southern California Edison

ABSTRACT

This paper presents the results of a study conducted by Itron for the California Public Utilities Commission (CPUC) to examine the relationships between solar photovoltaic (PV) performance, costs and PV incentive structures. The intent is twofold. The first intent is to create a baseline of PV performance and costs using actual performance data and reported costs from a large number of PV systems installed and operating in California. The second intent is to examine how PV performance and projected PV cost reductions can influence PV incentive payments. This study should help provide policy makers responsible for developing PV incentive programs with information that will result in incentive structures that fairly and transparently reward improved PV cost and performance while simultaneously providing a reasonable pathway to move PV towards an incentive-free market environment. PV performance monitoring data for over one hundred operating commercial, industrial and institutional solar PV systems are combined with projected electricity retail rates and future PV costs within a breakeven levelized cost model to produce associated PV incentive levels. Preliminary results for 39 prototype PV market scenarios provide insights into how PV incentive levels can be set to take advantage of utility-specific electricity retail rates, PV configuration and location, and projected PV cost reductions while facilitating the development of PV systems that can compete without incentives. Potential implications of these performance and cost-effectiveness results are discussed with respect to PV incentive programs and PV markets.

Introduction

The tremendous growth worldwide in photovoltaic (PV) sales over the past decade testifies to the avid interest in solar PV technologies. Over 800 megawatts (MW) of PV systems were installed in 2005 in Germany alone.[1] Much of the growth in German PV sales can be attributed to generous feed-in tariffs that made it economically attractive for businesses and homeowners to install PV systems. Within the United States, a number of states are promoting more rapid development of PV. California, New Jersey and Pennsylvania all have aggressive solar PV growth goals. Under the California Solar Initiative (CSI), $3.9 billion in incentives will be made available to support the growth of up to 3000 MW of new solar electricity generation capacity located at utility customer sites by 2017. Recent changes to New Jersey's Renewables Portfolio Standard (RPS) target a solar electric growth rate of nearly 2 million megawatt-hours per year. If successful, New Jersey's RPS will result in an installed solar capacity of nearly 1500 MW by 2021.

Due to the still high cost of PV technologies many states are investigating different PV incentive designs. Establishing an effective incentive design is important to the long-term success of PV market transformation. Incentives are a means of providing public support to help in market transformation of solar technologies that can

[1] Marketbuzz, 2006 World PV Industry Report Highlights, March 15, 2006

provide significant public benefits in the near-term and for decades to come. These incentives help to bridge the gap between the current costs of PV systems and the economic benefits received by their owners, thereby reducing risks to adopters of solar technologies. Incentives also encourage technology innovation that can accelerate the timeframe by which emerging technologies become cost competitive and move into mainstream markets that no longer need public support. Within California, the CPUC has indicated their belief that "solar technologies can improve and become more cost-effective with a 'push' from an incentive program and the 'pull' of a program design that encourages technological improvements.[2]" At the heart of this approach is the need to understand how changes in PV system performance and costs can impact incentive design.

Using actual PV performance information from the Self-Generation Incentive Program (SGIP), the study results provide insights into how changes in PV system location and configuration impact not only PV performance and incentive levels, but also influences how geographical distribution of PV systems may affect system owners and utility ratepayers. The economic breakeven approach developed in the course of this study suggests ways of linking improvements in PV technologies with declining incentive levels that allow for a deliberate and reasonable transition to a fully competitive solar market.

Approach

Our approach is based on the premise that an incentive should at a minimum make up the difference between the total costs borne by the PV system owner and the economic benefits accrued by the owner over the life of the PV system[3]. By setting the PV economic benefits equal to the PV system costs, we estimated the required incentive level needed for the PV owner to breakeven on their investment. We also assumed that as PV costs decrease and PV system performance increases, the difference between costs and benefits will shrink, thereby reducing required incentive levels in the future. Lastly, by examining PV cost and performance trends and the factors that could influence them, we were able to conduct sensitivity analyses showing how changes in future cost and performance of PV systems could impact PV incentive levels, program funding levels and the associated amount of installed PV capacity. The approach involves linking reported installed PV system costs and actual monitored PV system performance to incentive levels using a levelized cost model. Such an approach has been proposed by others, including Hoff and Starrs.[4]

For the levelized cost modeling we used an economic model previously developed by Itron in identifying the cost effectiveness of distributed generation systems deployed under the SGIP and which distributes costs and benefits on a 24-hour day, 365-day-per-year basis.[5] PV system costs are taken from SGIP Program Administrator reports and represent total eligible installed cost estimates. PV performance data for typical years are based on weather normalization analysis of actual monitored performance of SGIP PV systems. PV system costs are

[2] California Public Utilities Commission, Decision D.06-01-024, January 12, 2006

[3] In this study, PV economic benefits are considered only to be those recognized by PV system owners and limited to immediately tangible benefits such as displaced retail electricity value and tax benefits. We recognize that PV systems may provide other benefits to their owners such as increased property value and increased control over their electricity costs. However, due to the difficulty in quantifying these other benefits, we have considered only displaced electricity value and tax benefits.

[4] Hoff, T. and Margolis, R. "Economic Benefits of Performance-Based Incentives," July 2004 and Starrs,T. "Designing a Performance-Based Incentive for Photovoltaic Markets," Solar 2004 Conference Proceedings

[5] Itron, "CPUC Self-Generation Incentive Program Preliminary Cost-Effectiveness Evaluation Report," September 14, 2005

broken into major components and projected forward using empirical “learning curves” developed by others.[6,7] PV economic benefits consist primarily of displaced retail rate electricity and tax benefits (to the PV system owners). We based retail electricity rates on time of use (TOU) tariffs established by the utilities.

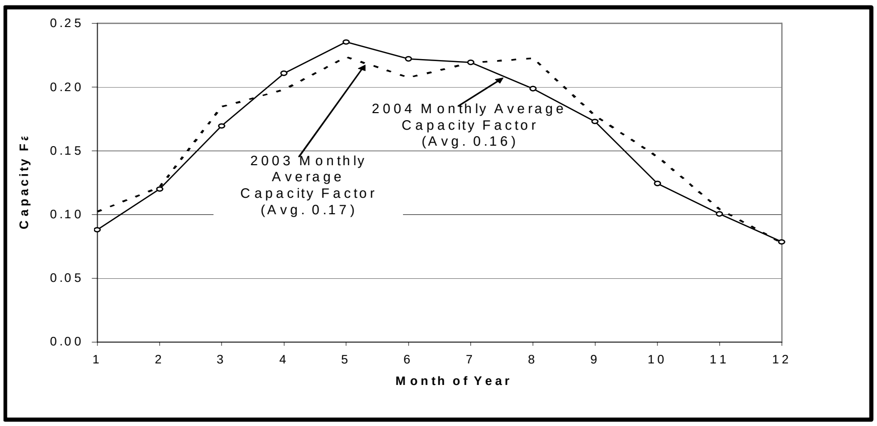
Results

PV System Performance

Baseline PV System Performance

Annual average capacity factors were found to be 17 percent in 2003 and 16 percent in 2004 as shown in Figure 1.[8] As expected, PV systems show seasonal changes in capacity factor. During summer months the capacity factor reaches nearly 25 percent. During late fall through early spring, capacity factors can drop well below 15 percent.

Figure 1: SGIP PV Capacity Factors for 2003 and 2004

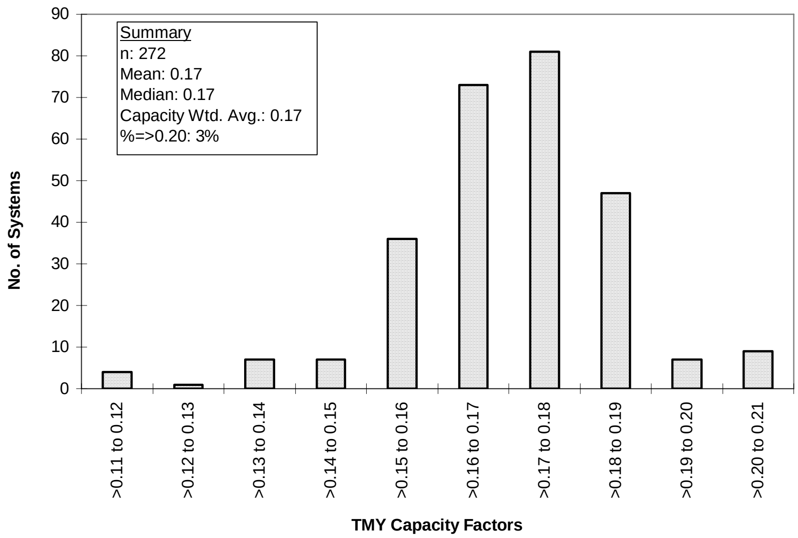


There is also significant variation in capacity factors between systems. Figure 2 shows the distribution of capacity factors for metered systems normalized to typical meteorological year conditions. While the average annual capacity factor is 17 percent, nearly 20 percent of the monitored systems had capacity factors ranging from 12 to 16 percent. Less than 3 percent of the metered systems had capacity factors above 20 percent.

---

[6] Maycock , *The World Photovoltaic Market*, Paul D. Maycock. PV Energy Systems. 2002.
[7] Strategies Unlimited, *Five-year market forecast, 2002-2007*. Strategies Unlimited. Technical Report PM-52, 2003.
[8] Capacity Factors are expressed with respect to *rebated* system capacity. Rebated system capacities include adjustments that account for inverter efficiency and ambient temperature effects.

Figure 2: Distribution of TMY PV Capacity Factors Estimated for SGIP PV Systems



Performance of PV System Prototypes

Performance of PV systems implemented under the SGIP provides a reasonable baseline for current PV systems in California. However, it represents a mix of PV systems at various locations, with different configurations and orientations at a particular point in time. This mix will certainly change as new PV systems are deployed. To better understand the influence of location, configuration and orientation on future PV system performance and on incentive designs, we defined thirty-nine (39) PV system prototypes. Each prototype consists of a pairing of a location and one of three PV system configurations. The correspondence between locations and the three major California investor owned utilities (IOUs) is presented in Table 1.

Table 1: PV System Performance Prototypes

<table>
<tr><th colspan="2">Location</th><th>IOU</th><th>Configurations</th></tr>
<tr><td>Santa Rosa
Oakland</td><td>Red Bluff
Sacramento</td><td>(PG&E)</td><td rowspan="3">Horizontal
Facing South, 15˚ tilt
Facing Southwest, 30˚ tilt</td></tr>
<tr><td>Los Angeles
Big Bear
Pasadena
El Toro</td><td>Riverside
China Lake
El Centro</td><td>(SCE)</td></tr>
<tr><td>San Diego</td><td>Riverside</td><td>(SDG&E)</td></tr>
</table>

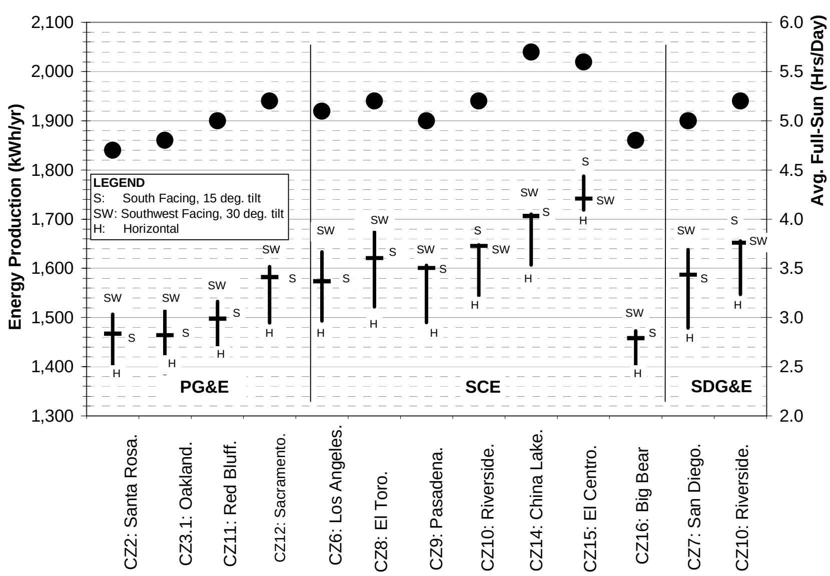
Summary PV system performance statistics for the 39 prototypes are presented in Table 2. The combined influences of climate, latitude, and configuration account for the highest energy production (1,788 kWh/yr) exceeding the lowest (1,373 kWh/yr) by 30%. A substantial portion of this variance is due to differences in solar resource.

Table 2: PV System Prototype Performance Summary

Summary Statistic	Full-Sun (Hrs/Day)	PV System Performance by Configuration kWh/yr & Capacity Factor (%) Tilt: 0 Azimuth: 0	Tilt: 15 Azimuth: S	Tilt: 30 Azimuth: SW
Range	4.7 to 5.7	1,373 to 1,742 15.7% to 19.9%	1,458 to 1,788 16.6% to 20.4%	1,473 to 1,718 16.8% to 19.6%
Median	5.1	1,490 17.0%	1,587 18.1%	1,633 18.6%
Mean	5.1	1,498 17.1%	1,588 18.1%	1,609 18.4%
Std. Dev.	0.3	103 1.2%	99 1.1%	79 0.9%

Solar resource and PV system energy production results for all 39 prototypes are presented in Figure 3. Greater solar resource generally corresponds with higher PV system energy production but there are exceptions. For example, the solar resource in the vicinity of China Lake is approximately 2% more plentiful than in the vicinity of El Centro. However, the typical PV system energy production estimated for the China Lake area is approximately 6% less than for a similar system in the vicinity of El Centro. This example illustrates the influence of ambient temperature on PV performance. The annual average temperature in China Lake is 12˚F higher, and PV system power output diminishes at higher temperatures, all else equal.

Figure 3: Typical Solar Resource and Energy Production (kWh/yr) for Prototypes



Three observations leap out from examining Figure 3. The first is the general dominance of a southwest orientation with a 30 degree tilt on PV generation. The second is the impact of location. Clearly, both configuration and location can play an important role in the performance of PV systems and therefore breakeven incentive levels. For example, PV systems located in climate zone 15; with a SW orientation and 30 degree tilt could be expected to have greater annual electricity production than PV systems located in climate zone 16, with a horizontal and south facing configuration. Lastly, Figure 3 indicates that PV electricity production may be substantially different from one utility service area to the next.

PV System Costs

SGIP PV cost data are summarized in Table 3. Only completed projects for which a check has been issued are included in the analysis. Since startup of the program, mean costs have increased from $7.94 per watt to $8.56 per watt. Cost decreases were seen from program year 2001 to 2004. However, cost increases of over 10% that occurred from program year 2001 to 2002 had not been overcome by program year 2004. A representative unit cost for 2004 would fall between $8.17 and $8.74 per Watt. For PV incentive analysis forecasting purposes a representative 2005 value of $8.25 per Watt is assumed ($8.50 in real 2006 dollars assuming 3% inflation). These values are close to those found by Ryan Wiser in his examination of SGIP PV system costs.[9]

Table 3: Eligible Cost Summary by Program Year (Nominal $ per Watt)

Summary Statistic	Program Year PY2001	PY2002	PY2003	PY2004
n	21	117	155	189
Range	$4.51 to $11.24	$4.50 to $16.19	$4.29 to $15.48	$5.57 to $12.57
Median	$8.16	$9.00	$8.69	$8.74
Mean	$7.94	$8.76	$8.78	$8.56
Weighted Mean	$7.26	$8.24	$8.34	$8.17

PV Incentive Analysis Results

Breakeven Incentive Distributions

The breakeven incentive requirement is the total net present value of the incentive that just provides a prospective PV owner an expectation that PV system costs will be offset by benefits (including the incentive). This balance marks a point of financial indifference where high costs no longer prevent decisions to purchase PV. Breakeven incentive requirements were calculated for thousands of unique combinations of factors (Program Year, discount rate, location-configuration-utility prototype, electricity price-PV cost scenario), each combination modeling the decision of a particular group of prospects. The scope of these calculations is summarized in Table 4.

Table 4: Scope of Breakeven Incentive Requirement Calculations

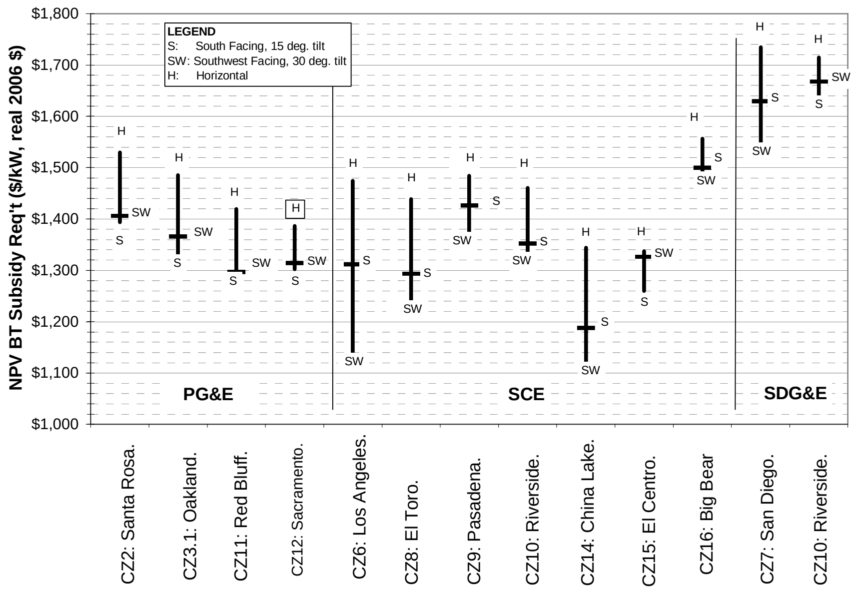
Factor	No.	Values
Location-Configuration-Utility Prototype	39	Utilities: PG&E-SCE-SDG&E Climate Zones: 12 PV Configurations: Flat, South @ 15˚, SW @ 30˚
Program Year (PY)	10	2007 - 2016
Electricity Price-PV Cost Scenario	3	Low: Low Retail Rate Increase & PV Cost Decrease Central: Central Retail Rate Increase & PV Cost Decrease High: High Retail Rate Increase & PV Cost Decrease
Federal Investment Tax Credit (FITC)	4	30% FITC: 2007, 2007-2009, 2007-2011 (reverting to 10% in all three scenarios)
Participant Discount Rate	5	0%, 3%, 6%, 9%, 12%

9 Wiser, Ryan, M. Bolinger, P. Cappers, and R. Margolis. *Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California.* Ernest Orlando Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division. LBNL-59282. January 2006.

Incentive requirement results for Program Year 2007 broken out by PV system location and configuration are presented in Figure 4. Three values are reported for each climate zone: one for each of the three PV system configurations. In this graphic "H" indicates horizontal PV system, "SW" indicates southwestern facing PV system tilted at 30˚, and "S" indicates south facing PV system tilted at 15˚. Cases with the highest utility rates and those in the most favorable PV climate zones require the lowest incentive levels.

Incentive requirements are highest for PV prototypes within the SDG&E service territory. Within climate zones the horizontal prototype always requires more incentive than the tilted prototypes. In general, PG&E and SDG&E scenarios have higher incentive requirements than do SCE prototypes. The higher peak energy rates faced by SCE customers are a "non-Program" incentive to utilize PV systems. The relatively lower peak energy rates seen by SDG&E customers have the reverse effect, necessitating higher PV incentives to achieve a balance between lifecycle costs and economic benefits faced by PV system owners.

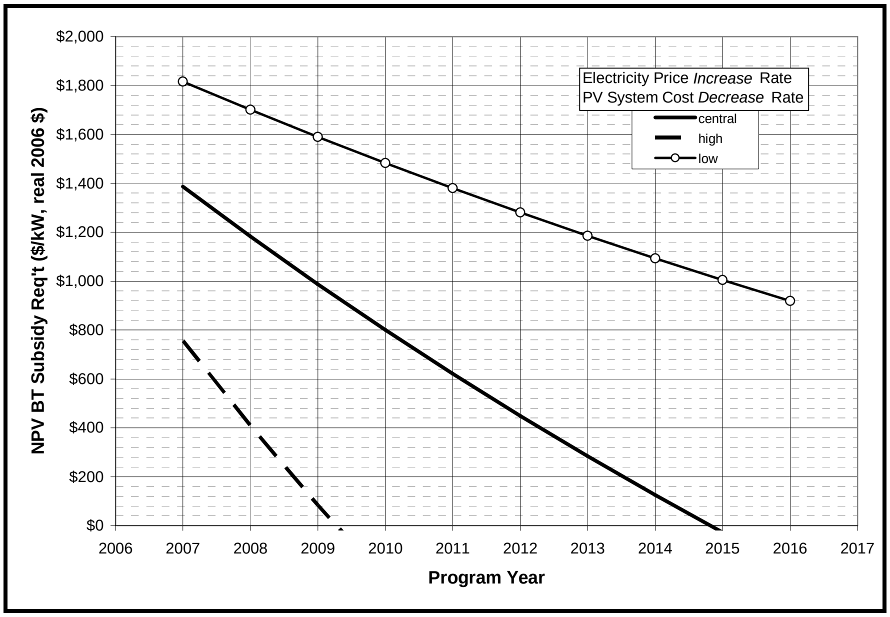
Figure 4: Year 2007 Incentive Requirement Distribution by Utility, Climate Zone, and PV System Configuration (Central Electricity Rates and PV Costs)



Year 2007 incentive requirements are influenced by electric utility electricity rates, climate, and PV system configuration. Incentive requirements for other years are likely to grow increasingly different. Several key influential factors that will drive incentive requirements include PV system costs, utility electricity rates, Federal Investment Tax Credit (FITC) availability and magnitude, and discount rate assumed to apply to PV system owners.

The influence of PV system costs and utility electricity rates is summarized in Figure 5. The results are not intended to be projections of likely incentive requirements in the future because investment tax credit regulations are expected to change. Rather, they are intended to illustrate the general trends introduced by just two of the many factors influencing PV markets: electric utility retail rates, and PV system costs. Under the low case trend (i.e., slowing rising electricity rates, slowly declining PV costs and equal distribution of PV systems among the various representative locations and configurations), the rate at which the required incentive declines over time is relatively low. Conversely, if electricity rates increase rapidly, and PV costs decrease rapidly (i.e., the high PV installation activity assumptions) then the need for PV incentives would disappear in 2012.[10]

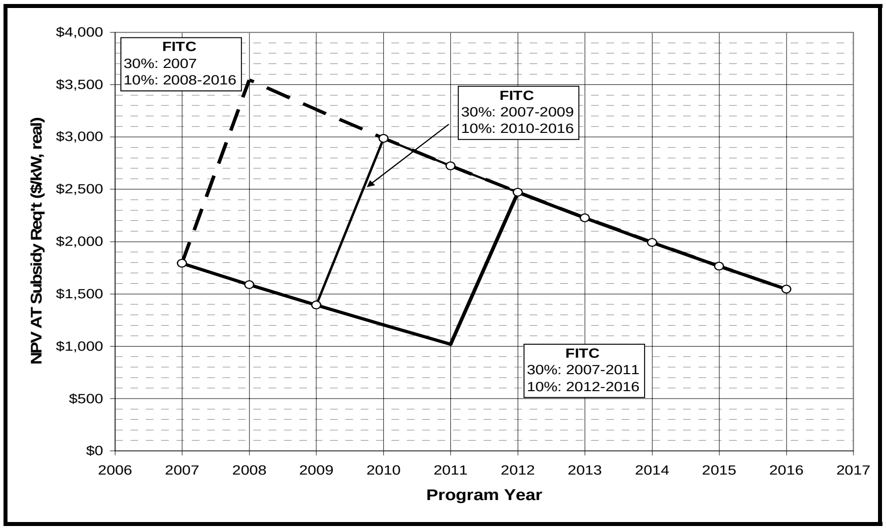
Figure 5: Representative NPV Incentive Requirement versus Program Year and Retail Electric Rate & PV Cost Scenario



The influence of the federal investment tax credit on incentive requirement is illustrated in Figure 6. Again the horizontal PV system in the vicinity of Sacramento and subject to PG&E rates is used for illustration purposes. In this example, the required incentive level at a 30 percent FITC in year 2007 is approximately $1700/kW. However, if the FITC was 10 percent in 2007, then the required incentive level would be approximately $3500/kW, or nearly twice the incentive required with a 30 percent FITC.

[10] All subsidy requirement values are expressed in real terms using constant 2006 dollars to enable direct examination of trends caused by factors of principal interest (e.g., falling PV system costs). During implementation of an incentive designed in this manner these real values would require adjustment to account for actual, observed inflation rates.

Figure 6: Representative NPV Incentive Requirement versus Program Year and Federal Investment Tax Credit



PV Incentive Structure Results

While the net present value of breakeven incentive requirement modeling yields data necessary to design performance based incentives, this information is not sufficient. A policy determination must be made regarding which incentive structure is preferred, CBI or PBI. Alternatively, a hybrid structure could be developed. In the case of PBI, design questions include how many years the payments will be spread over, and whether and how the payments might change over those years. Quantitative results are presented based on the specific PBI structures summarized in Table 5.

Table 5: PBI Structures Included in Quantitative Modeling

PBI Structural Element	Quantitative Modeling Basis Alternatives
Duration	• Fixed 5-year PBI
Temporal variability	• Fixed (same PBI rate in all 5 years)
Geographic/Utility variability	• Single statewide PBI • Three PBI rates (one for each IOU)

Single Statewide Incentive Results

For both the CBI and the PBI statewide incentive rates are based on the median of the breakeven incentive requirements calculated for the 39 prototypes. For 2007 the governing prototype is a horizontal PV system located in the vicinity of Sacramento and subject to PG&E electricity prices. By definition the CBI incentive rate is equal to the NPV incentive requirement for this prototype: $1,386 per kW (real 2006 $). Table 6 lists comparative CBI and PBI levels for 2007.

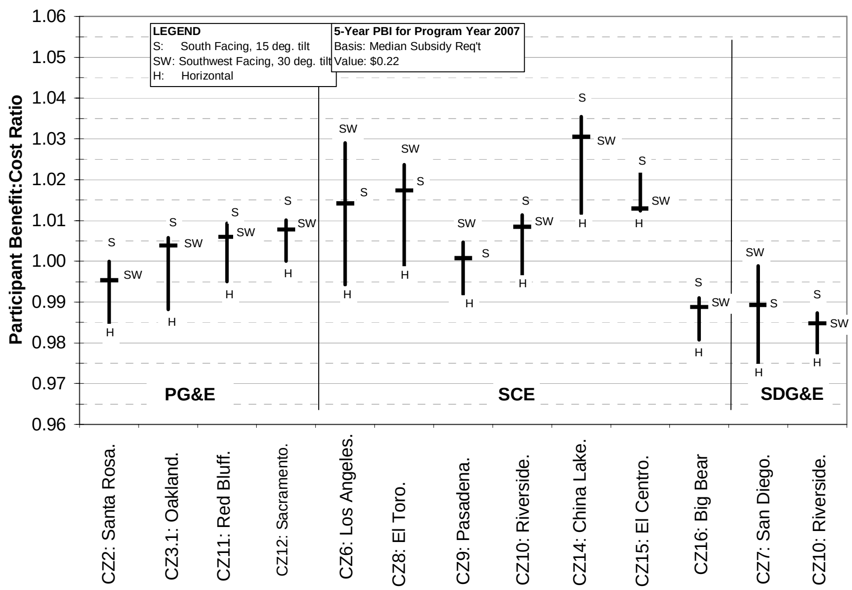
Table 6: Statewide Incentive Rates for 2007

Incentive Structure	Rate & Disbursal
CBI	$1,386/kW 1-time payment
PBI	22¢/kWh for 5 years
Reference	6.6¢/kWh for 25 years

Central-boundary statewide PBI values for each program year are presented in Figure 7. This PBI design will result in a cost: benefit ratio for a PV system owner equal to exactly 1.0 for only one of the prospect scenarios. The remaining prospect scenarios will have cost: benefit ratios either higher or lower than 1.0.

The cost: benefit ratio results for PV owners summarized in Figure 7 show that this single statewide PBI is based on the incentive requirement of the median scenario customer in climate zone 3 on a PG&E electricity tariff. Six of the twelve (50%) PG&E prospective scenarios expect cost: benefit ratios exceeding 1.0, whereas 15 of the 21 (71%) SCE prospect scenarios can expect this level of financial performance. Consequently, this statewide PBI design would result in all but one of the six SDG&E prospect scenarios failing to achieve a participant cost: benefit ratio of at least 1.0. Thus other factors held constant, we would expect relatively fewer systems to be built in the SDG&E area under a PV support program if this incentive structure was employed.

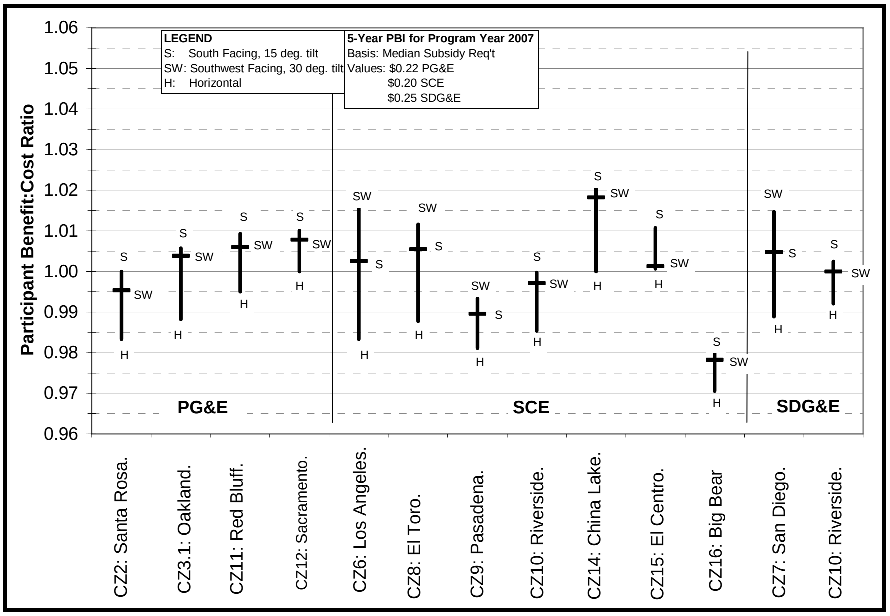
Figure 7: Impact of Statewide PBI (PY2007 – Central Retail Electric Rates and PV Costs)



Utility-Specific Incentive Results

Utility-specific PBI values are defined as the median of the breakeven incentive requirements calculated for the prospect scenarios corresponding to individual utility companies. This number of prospect scenarios varies depending on the number of climate zones. Cost: benefit ratios for PV system owners resulting from application of utility-specific PBI values are shown in Figure 8. Comparison of the statewide and utility-specific cost: benefit ratios presented in Figure 7 and Figure 8 reveals at least two noteworthy observations. First, whereas the statewide PBI results in most of the "winners" being customers of SCE, the utility-specific PBI yields a more balanced distribution among utilities. Second, while the utility-specific PBI produces the lowest mean participant cost: benefit ratio, the overall level of variability is lower for this PBI structure than for the single statewide PBI.

Figure 8: Impact of Utility-Specific PBI (PY2007 – Central Retail Electric Rates and PV Costs)



PV Incentive Program Implications

The analysis and results of the subsidy requirements, incentive levels, and project economics at the system prototype level were extended to the program level by applying an assumed 10-year program incentive budget profile to the system prototypes. Program-level PV capacity installation impacts are estimated for a hypothetical 10-year program whose annual budgets total $1 billion (real 2006 dollars). The budget in year 10 ($33 million) is assumed equal to 20% of the year 1 budget ($167 million); annual budgets in intervening years are assumed to vary linearly between these end points.[11]

The impacts on installed PV capacity (or activity levels) of a 10-year, $1 billion program will depend on numerous factors. Of particular importance is availability of 30% federal investment tax credits, solar resource and initial retail rates, and the combined effect of falling PV costs and rising electric utility prices. Impacts on PV capacity installed in California were calculated by combining annual incentive budgets with central boundary case breakeven subsidy requirement results. Breakeven subsidy requirements for the 39 system prototypes vary depending on location, configuration, and electric utility. Annual budgets were assumed to be distributed evenly across the 39 system prototypes. The federal investment tax credit was assumed to revert to 10% in 2008 (as currently planned).

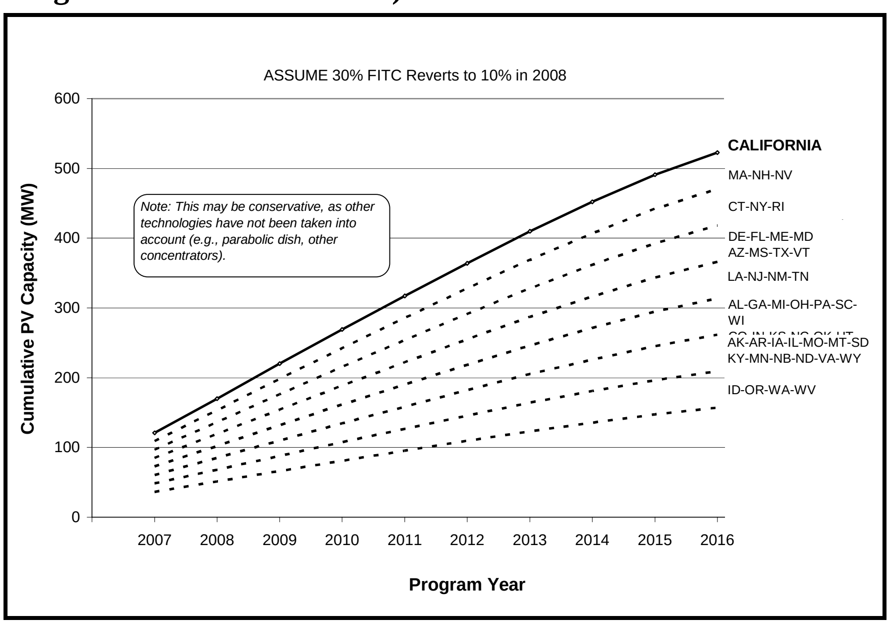
Impacts on PV capacity installed in other states were also estimated to lend additional perspective to the results calculated for California. Impacts for other states were calculated as the product of the statewide result for California and multipliers accounting for differences in retail electric rates and solar resources. For this simple illustrative comparison all other factors were assumed identical (e.g., state tax depreciation treatment, state tax credit provisions).

[11] Depending on the basis of the incentives (e.g., capacity versus performance) the annual budgets may not be the amount of money actually paid out during each Program Year (PY) because incentive payments could extend 5 or more years beyond the year in which the PV system is installed. Rather, it is the amount of money reserved for participants in particular program years.

Data from the Energy Information Administration were used to explore the influence of initial retail rates. For each state a retail rate multiplier was calculated as the ratio of the average May 2006 commercial retail rate for the state to that for California. Only five states had retail rates higher than California. For the other 44 states retail electric rates cause each PV program incentive dollar to yield less PV capacity than in California. Data from the National Renewable Energy Laboratory were used to explore the influence of solar resource. For each state a solar resource multiplier was calculated as the ratio of the representative solar resource for the state to the solar resource for California. The solar resource in San Francisco was used to represent the solar resource for California.

The PV capacity impacts of a 10-year, $1 billion program are summarized by program year and state in Figure 9. Separate results are presented for the 48 states (excluding Hawaii) because determination of the point in time when PV becomes economic without subsidies depends on rate structures in Hawaii and analysis of rate structures in Hawaii is outside the scope of this study. Based upon the PV market alone (e.g., ignoring other potential contributing technologies under solar programs) and without extension of the Federal Investment Tax Credits beyond 2007, the installed capacity estimated for California is 523 MW. At the other end of the spectrum is the 10-year, $1 billion program assuming retail rates and solar resource for Olympia, Washington, where total cumulative PV capacity is only one-third of that estimated for California. Whether or not the FITC is extended will have an important affect on how much PV could actually be installed over the life of any 10-year program.

Figure 9: Cumulative PV Capacity Impacts versus Program Year and State ($1 Billion Total Program – Hawaii Excluded)



Acknowledgements

We gratefully acknowledge the guidance and input provided by Ms. Lisa Paulo (California Public Utilities Commission) during the course of this project.