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Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California

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and Robert Margolis

Environmental Energy
Technologies Division

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The work described in this paper was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy (Office of Planning, Budget & Analysis), and by the Office of Electricity Delivery and Energy Reliability (Electric Markets Technical Assistance Program) of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

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Prepared for the

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Assistant Secretary for Energy Efficiency and Renewable Energy
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Executive Summary

Introduction

Markets for customer-sited photovoltaic (PV) systems are expanding rapidly, albeit from a small base. Government incentives aimed at encouraging reductions in the cost of PV over time are the principal drivers for the recent worldwide growth in grid-connected PV capacity.

This report provides an in-depth statistical analysis of PV system costs in California. Through mid-November 2005, a total of 130 MW_{AC} of grid-connected solar capacity was installed throughout California,[i] making that state the dominant market for PV in the United States, though it still stands a distant third on a worldwide basis behind Germany and Japan.

The results presented here are based on an analysis of 18,942 grid-connected PV systems totaling 254 MW_{AC},[ii] either installed, approved for installation, or waitlisted (approved but awaiting program funding) under what are currently the two largest PV programs in the state. This analysis provides insights on California's PV market by exploring cost trends, and by untangling the various factors that affect the cost of PV systems. Results also have important policy ramifications, as they address the interaction between incentive levels and installed costs, and the relative cost of different PV applications.

California's Solar Programs

California's PV market is driven by a mixture of state and local incentives. Most prominent are capital cost rebates – denominated in $ per Watt – offered to PV system installers or owners to "buy down" the installed cost of solar installations. The two most significant current rebate programs are overseen by the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC), and it is on these two programs that our analysis is based.

The CEC has administered a PV rebate program since March 1998, focusing more recently on grid-connected systems under 30 kW in size. The CPUC's program began accepting applications in July 2001, and provides rebates to PV systems of at least 30 kW in size. Both programs primarily target customers served by the state's investor-owned utilities.[iii] Over time, both programs have altered the structure and size of their incentives for PV installations, as shown in Figure ES-1. In particular, the CEC initiated five gradual reductions beginning in 2003, while the CPUC imposed a single large reduction in late 2004 and a more recent reduction in mid-December 2005. On January 12, 2006, the CPUC ordered a dramatic expansion of these programs with a $3.2 billion, 11-year program of declining incentives.

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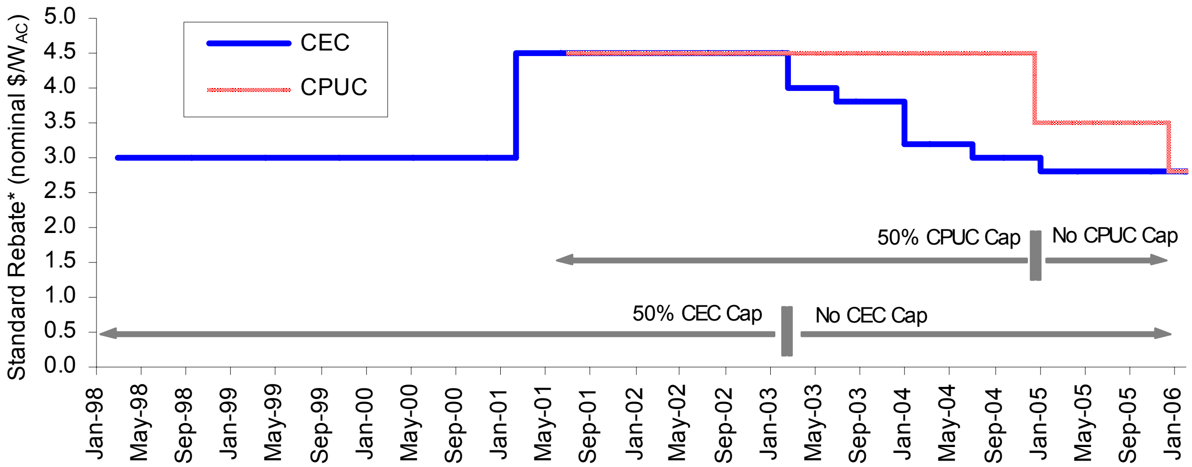
[i] This estimate of 130 MW_{AC} includes PV systems funded under municipal utility programs, in addition to the CEC and CPUC programs analyzed in this report.
[ii] Unless explicitly presented as otherwise, data on PV capacity and costs are expressed throughout this report in terms of W_{AC} (e.g., W_{AC}, kW_{AC}, MW_{AC}, $\$/W_{AC}$), which we convert (where necessary) from $W_{DC\text{-}STC}$ (DC Watts at standard test conditions) using a de-rate factor of 0.84. We acknowledge that many other solar programs and data sources use $W_{DC\text{-}STC}$, making comparisons of California data with those in other states and countries more difficult. Given, however, that our underlying system cost data is expressed in terms of W_{AC}, this is the standard that we use.
[iii] At various times, customers of publicly-owned utilities have also been eligible to participate.



* Within the CEC's program, systems installed on affordable housing and schools have, at times, received higher incentives; owner-installed systems have, at times, received lower incentives; systems >30 kW_{AC} were eligible for rebates from program inception to February 2003; and systems >10 kW_{AC} received $2.5/$W_{AC}$ (capped at 40%) from March 1999 to February 2001.

Figure ES-1. Standard Rebates for the CEC and CPUC Programs

Analysis Results

The CEC dataset used for our analysis was updated through April 2005, and contains 17,889 data records (72.8 MW_{AC}), including 12,856 completed systems (48.5 MW_{AC}) and 5,033 systems that had been approved for a rebate, but that were awaiting completion at the time we received the dataset (24.3 MW_{AC}). The CPUC program generally covers systems of at least 30 kW, and our dataset includes 1,053 data records (180.8 MW_{AC}), including 327 completed systems (35.7 MW_{AC}), 464 approved systems (73.4 MW_{AC}), and 262 waitlisted systems (71.7 MW_{AC}). Analysis of each dataset was conducted using multivariate regression techniques; the dependent variable was the pre-rebate installed cost of PV systems, in 2004 $/$W_{AC}$. Key findings include:

Solar Costs Have Declined Substantially Over Time, But Less So Under the CPUC's Program: In real dollar terms, average pre-rebate total installed costs under the CEC's program have declined substantially, from more than $12/$W_{AC}$ (2004 $) in 1998 to less then $9/$W_{AC}$ for 2004-05 (see Figure ES-2, where time is expressed in quarter-year intervals). Regression results show annual average cost reductions among the CEC-funded systems of approximately $0.70/$W_{AC}$, representing a 7.3% annual decline. Larger systems (e.g., 10-30 kW) funded by the CEC are found to have experienced more modest cost reductions than have smaller systems.

As suggested by Figure ES-2, some of the overall cost reductions within the CEC program are due to decreases in worldwide module costs (notwithstanding the recent increase in those costs).[iv] In fact, regression results confirm that changes in worldwide module costs have largely been passed through directly to PV system purchasers on a one-for-one basis. Much of the

[iv] Although the CEC database does, in some cases, contain disaggregated information on module, inverter, and labor costs, this information is only sparsely reported (and the CPUC database does not provide such information at all). As a result, we have used an external index of worldwide module costs over time from Strategies Unlimited to proxy module costs for each California system. Non-module costs are then simply the total system cost less the relevant module cost index value. Though it would be interesting to more narrowly pinpoint specific drivers of cost reductions, given current limitations in the data, the best we can do is to crudely split total costs into module and non-module costs. Collecting and analyzing more-detailed cost disaggregations data is an area ripe for future work.

overall cost reduction, however, has come from improvements in *non-module* costs – e.g., installation and balance of system costs.

This reduction in non-module costs for CEC-funded systems is encouraging. Unlike module costs, which are set in a worldwide market and are therefore heavily influenced by factors outside of the control of an individual PV program (e.g., demand for PV in Japan and Germany), non-module costs are potentially subject to the influence of local PV programs. And given (as noted above) that changes in worldwide module costs appear to simply flow through directly to total system costs, reducing non-module costs may be the most appropriate goal for local PV programs. Though we are unable to prove conclusively that non-module cost reductions in California have been *caused* by the state's incentive programs, our analysis results do show that non-module cost reductions have been significant.

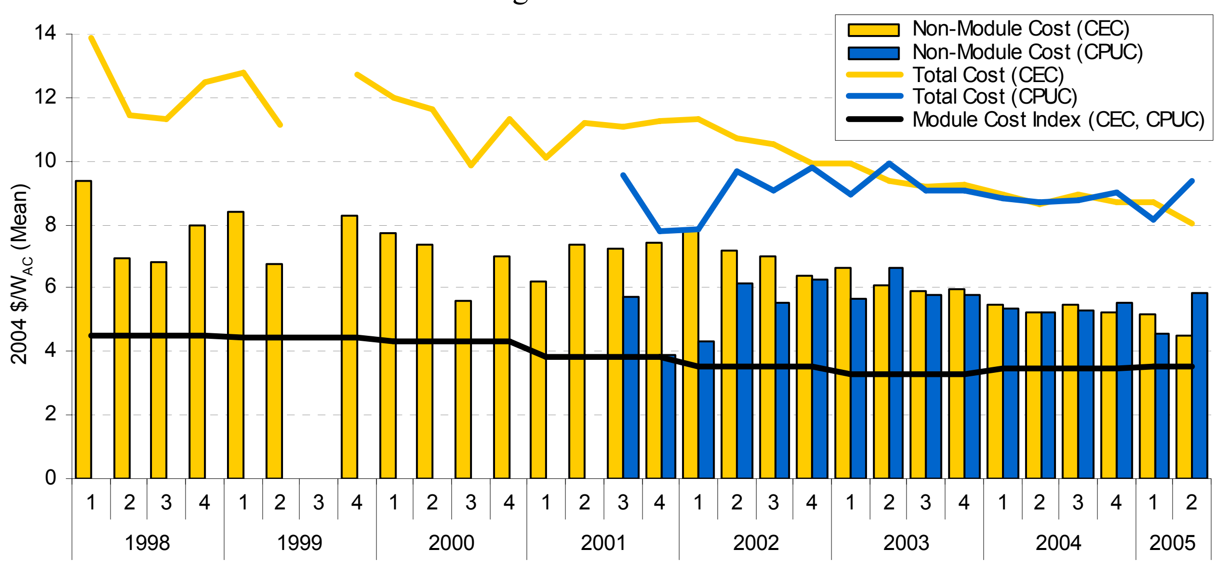


Figure ES-2. Costs Trends Over Time (CEC and CPUC)

In contrast to the longer-running CEC program, which exhibits clear downward cost trends over time, costs under the CPUC's program have declined more moderately (though Figure ES-2 does show a more substantial decline – in lock-step with the CEC program – since 2003). Compared to the $0.70/W_{AC}$ (7.3%) average cost reduction in the CEC dataset, regression results show that systems funded by the CPUC have seen annual average reductions of $0.36/W_{AC}$ (4.1%).[v] A regression of the *combined* CEC and CPUC datasets over the time period in which the two programs overlap shows similar annual reductions: $0.91/W_{AC}$ (CEC) and $0.36/W_{AC}$ (CPUC).

The more-aggressive (and visually apparent) CEC cost reductions may be due to the larger proportional labor and installation costs associated with smaller (< 30 kW) systems and the greater opportunities in that market segment for distribution and installation efficiency gains.[vi] Alternatively, it could be a result of policy design – whereas the CEC has (since 2003) gradually

[v] Though Figure ES-2 does not provide a clear visual trend of declining system costs over the entire duration of the CPUC program, the regression results – by controlling for other factors – are more reliable than the visual evidence provided in the Figure.
[vi] We find this same effect – smaller systems exhibiting greater cost reductions over time – not only across programs, but also within each of the two programs.

lowered its rebate over time, the CPUC has been slower to follow suit (see Figure ES-1). Though Figure ES-2 – which shows the CEC and CPUC costs declining lock-step since 2003 – would appear to discount these explanations, it is important to note the bivariate nature of Figure ES-2, and its failure to control for other variables (in contrast to multivariate regression analysis, which isolates the impact of each individual variable). Nonetheless, the quality of our data does not allow us to definitively explain the difference in cost reductions between the two programs, or even prove that the programs themselves are responsible for the cost reductions.[vii] We recommend that future work explore these questions in more detail.

Policy Incentives and Rebate Levels Impact Pre-Rebate Installed Costs: Figure ES-3 shows a tight relationship between standard rebate levels and average pre-rebate installed costs among the CEC-funded systems since mid-2000. This close relationship is confirmed through regression analysis. In particular, we find that each \$1/W_{AC} change in the rebate level has, on average, yielded a \$0.55-0.80/W_{AC} change in pre-rebate installed costs (with the range representing results from different regression models). In other words, when the CEC increased its rebate level by \$1.5/W_{AC} in early 2001, system purchasers may have only realized \$0.3-\$0.7/W_{AC} of that increase on average, with the remaining \$0.8-\$1.2/W_{AC} being "captured" by system retailers or installers through correspondingly higher prices. By the same token, regression results suggest that as the CEC has gradually reduced its rebate level since early 2003, system retailers have absorbed some of the decrease by reducing prices.

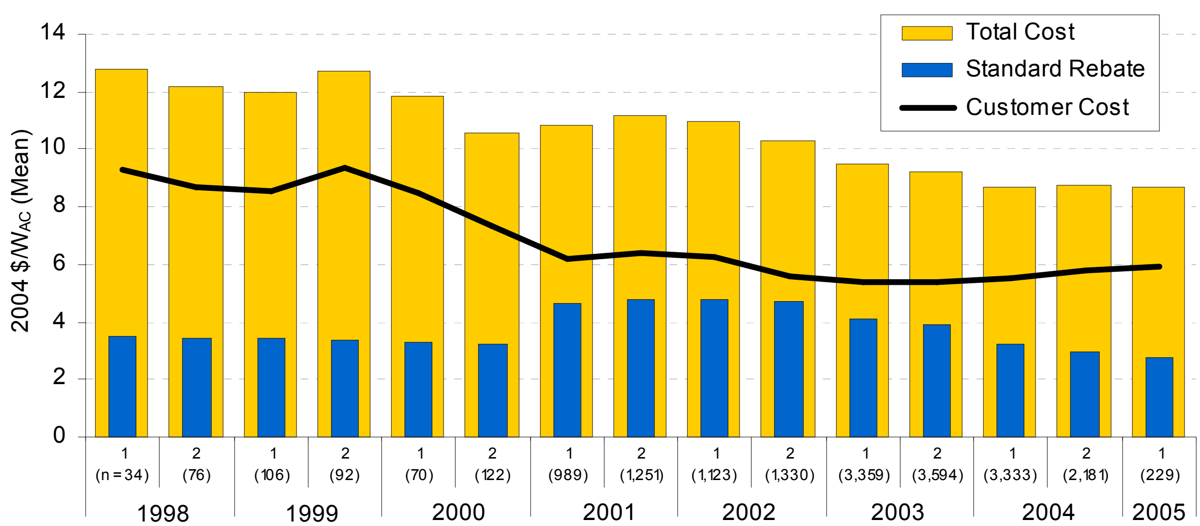


Figure ES-3. Impact of Standard Rebate Level on Average Installed Costs (CEC)

We also find some evidence that the existence of the percentage rebate cap prior to 2003 may have increased pre-rebate system costs somewhat under the CEC program. This result is

[vii] Though it is perhaps logical to assume that California's PV programs have caused, or at least contributed to, the empirical cost reductions, nothing in our analysis enables us to assign causation – i.e., we are unable to definitively conclude that the California programs are driving the cost reductions. To be able to assign causation, we would need to similarly analyze a "control" market – i.e., one in which no PV incentive programs exist. Identifying such a market for PV may be difficult or impossible, given the widespread public support that PV has garnered, but future work could at least analyze other markets in which PV is subsidized, but to a different extent or in a different manner than in California.

consistent with widespread speculation that this cap – which limited the size of the rebate to 50% of total eligible costs in an attempt to ensure that the program did not over-subsidize lower-cost eligible technologies (such as small wind) – has, perversely, encouraged artificial cost *inflation* as a way to maximize the dollar amount of the rebate.

Analysis of the CPUC dataset yields results that are substantially less policy-rich than those from the CEC's dataset. Nonetheless, we find evidence to support the oft-heard claim in California that the CPUC's richer incentives in recent years ($4.5/W_{AC}$ until December 2004, with a 50% cap) have not motivated system cost reductions to the same extent as under the CEC's program (the CEC's program also offered $4.5/W_{AC}$, but reduced that incentive earlier and more rapidly than did the CPUC – see Figure ES-1). As supported by Figure ES-4, regression results show that, among similar sized systems (20-40 kW), those funded by the CPUC's program have had pre-rebate installed costs that are on average roughly $0.60/W_{AC}$ higher than those funded by the CEC. Furthermore, some of the systems in the CPUC dataset received sizable local incentives (of more than $2/W_{AC}$), *in addition* to those offered under the CPUC's program. These systems recorded higher average costs of roughly $0.60/W_{AC}$ than did equivalent systems that did not have access to additional incentives. We also find some evidence (though not through the regression analysis) that the percentage rebate cap in place prior to December 2004 affected PV pricing during that period.

California has also offered a state income tax credit for systems under 200 kW in size, ranging from 7.5% to 15% of installed costs, depending on the year of installation. Statistical analysis of both the CEC and CPUC datasets offers evidence that the existence and size of the state tax credit has increased pre-rebate installed costs to some degree. Retail electricity rates, on the other hand, are not found to affect pre-rebate total installed costs, though as discussed in the body of the report, our retail electricity rate variable is imperfect.

In aggregate, these results suggest that heavy subsidies dampen, to some degree, the motivation of installers to provide, and/or customers to seek, lower installed costs.[viii]

Economies of Scale Drive Down Costs as System Size Increases: Focusing on the period in which both the CPUC and CEC programs were operating simultaneously, Figure ES-4 shows that average system costs fall substantially for larger systems (i.e., there are economies of scale) in both datasets, though both datasets also show a leveling off of those economies among larger system sizes. Regression results confirm these trends. The largest systems in the CEC dataset are roughly $2.5/W_{AC}$ cheaper than 1 kW installations. Meanwhile, the largest CPUC-funded systems are roughly $1.5/W_{AC}$ less expensive than the smaller systems funded by that program.[ix]

[viii] Though some might be inclined to read into these results an argument for switching from capacity-based to performance-based incentives, we note that there is nothing in our dataset or analysis that allows us to comment on the relative superiority of one incentive type over another.

[ix] The up tick in average installed costs for CPUC systems sized between 60 and 100 kW is somewhat of an anomaly, being heavily influenced by 59 identical applications (out of 209 total applications in this size range), all submitted on the same day, by the same installer, and at the same estimated installed cost of $9.82/W_{AC}$ (2004$).

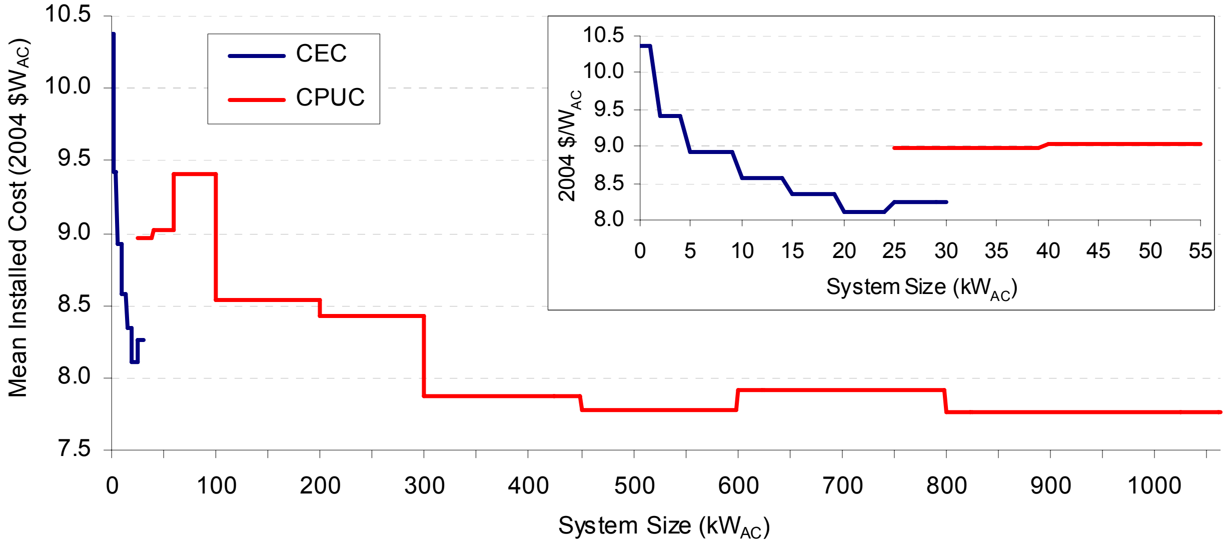


Figure ES-4. Installed Cost, by System Size (CEC and CPUC)

Systems Installed in Large New Home Developments and in Affordable Housing Projects Experience Much Lower Costs: Regression results show that systems installed (or planned for installation) under the CEC's program in large new residential developments (totaling 1,946 systems) have lower costs of approximately $\$1.2/W_{AC}$, on average, compared to the general retrofit market. Similarly, the 340 systems used in affordable housing applications, which often involve new construction and presumably enable bulk system installation, exhibit costs that are $\$1.9/W_{AC}$ lower than the general retrofit market. Systems installed in single new homes (or small clusters of new homes) exhibit modestly higher costs of approximately $\$0.18/W_{AC}$, perhaps due to the custom-designed nature of many of these systems, as well as a lack of the economies of scale possible in larger new home developments. Systems installed at schools (most are retrofits) do not have statistically significant differences in cost compared to the general retrofit market.

Installer Experience and Type Affects Costs: Within the CEC program, more-experienced installers and retailers are found to charge slightly more for their services – approximately $\$0.29/W_{AC}$ and $\$0.17/W_{AC}$, respectively – relative to those with less experience. In contrast, more-experienced installers under the CPUC's program have priced their systems at *lower* levels than less-experienced installers, with a differential of nearly $\$0.70/W_{AC}$ on average. The reason for this discrepancy between the two programs is unclear. Meanwhile, owner-installed systems in the CEC program (n=862) are found to have considerably lower reported costs than contractor-installed systems, with a $\$1.8/W_{AC}$ savings on average. Similarly, the sixteen CPUC-funded systems installed at fairgrounds by the California Construction Authority have come in at a substantially lower cost than other systems, with a cost differential of roughly $\$4/W_{AC}$, on average.[x] These results suggest that the CEC's current practice of providing reduced incentives for owner-installed systems is appropriate.

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[x] The California Construction Authority (CCA) is a Joint Powers Authority organized in August 1988 to provide financing, design, inspection and construction management services for fairgrounds throughout California. The low cost of the CCA systems is perhaps partially attributable to bulk equipment purchases for multiple fairground

The Impact of Module Type Varies By Program: In the CEC dataset, projects using thin film PV technology – of which there are 318 – are found to have had systematically lower costs than those relying on traditional crystalline silicon, with a differential of roughly \$0.70/W_{AC} on average, though this cost differential has narrowed over time. Though only bordering on statistical significance, projects using thin film technology in the CPUC dataset – of which there are 111 – are found to have slightly *higher* costs on average over the course of that program (~\$0.20/W_{AC}). The reason for this discrepancy between the two programs is unclear.

System Location Has Impacted Costs: The population density of the location of installation appears to have some effect on system costs in the CEC dataset, with more densely populated areas experiencing higher average costs. This finding is consistent with the idea that population density may be a proxy for the cost of living, and therefore labor costs. Meanwhile, CEC-funded systems installed outside of PG&E's service territory report lower average pre-rebate costs than those installed within PG&E's service territory. In contrast, CPUC-funded systems installed outside of PG&E's territory report higher pre-rebate costs on average. Further analysis would be required to understand why costs vary by service territory, and why these effects vary between the CEC- and CPUC-funded systems.

Conclusions and Recommendations

Results presented here reveal a number of expected, and some unexpected, trends. Perhaps of most importance, we find substantial reductions in PV system costs over time, especially among systems funded by the CEC's program. Although our analysis cannot, without comparison to a control group, definitively conclude that the CEC and CPUC programs *caused* these cost reductions, it is clear that – despite the lack of continuity and stability experienced by both programs – pre-rebate installed costs have come down.

Several policy recommendations derive from our analysis:

- ***Reducing non-module costs should be a primary goal of local PV programs.*** Unlike module costs, which are set in a worldwide market and are therefore heavily influenced by factors outside of the control of an individual PV program, non-module costs are potentially subject to the influence of local programs. State policymakers may wish to undertake programmatic activities aimed specifically at reducing non-module costs, which could range from targeted approaches to building local supply infrastructure (e.g., providing business development funding to installers, supporting standardized PV products, or offering installer training and certification), to something as simple as making PV system cost and performance data more publicly accessible to further encourage supply competition.

- ***Sustained, long-term programs may enable more significant cost reductions.*** Sustained, sizable, and stable markets for PV may be the most direct way of reducing non-module costs because such markets will presumably attract suppliers and encourage those suppliers to

projects. Some have also speculated that the CCA is able to install systems at apparently lower costs than the PV industry at large due to the fact that it has no marketing, sales, or overhead costs, and/or that certain internal costs are not reported. In other words, CCA-installed systems in the CPUC program are essentially the equivalent of owner-installed systems in the CEC program.

create an efficient delivery infrastructure. Though PV cost reductions in California are significant, at least among CEC-funded systems, experience from Japan suggests that deeper cost reductions are possible with a more sustained policy effort. In mid-January 2006, the CPUC issued an order that intends to create such a market with an 11-year, ~$3.2 billion program of declining incentives. A goal of the adopted program is to reduce rebate levels by roughly 10% each year, in nominal terms, far exceeding the recent system cost reductions seen under the California and Japanese programs.

- ***The structure and size of PV incentives should encourage cost reduction, not cost inflation.*** We find some troubling evidence that policy design has adversely impacted the cost of PV systems in California. For example, the 50% cap on the size of the rebate employed by both programs at one time or another appears to have, at best, impeded cost reductions, and at worst, contributed to artificial cost inflation. As such, the decision by both programs to abandon such percentage caps is a positive development; we encourage other PV programs to do the same. Furthermore, the total pre-rebate cost of PV installations in California has tracked, to some degree, the size of the rebate itself. Whether this link is merely representative of the "teething problems" that are typical of new programs,[xi] or should instead be of long-term concern is somewhat unclear. As rebates are reduced over time, however, we expect that the link between incentive levels and pre-rebate installed costs will be severed, as lower rebates require contractors to price systems at cost in order to ensure a sale. Hence, while rich incentives may be required initially to jump-start the market, over time the incentives should decline to a level that can support a functional market infrastructure without providing room for potential price manipulation.

- ***Targeted incentives that account for the relative economics of different system sizes and application types may be appropriate.*** Though there is a significant spread in the data, our analysis shows that installed costs are heavily dependent upon the size and type of installation. We find clear evidence of sizable economies of scale in PV installations. We also find that systems installed in large new home developments are, on average, far more economical than retrofitted systems. These results suggest that a further targeting of incentives to account for the relative economics of different system sizes and application types may be appropriate.

[xi] Such "teething problems" might include initial over-subsidization intended to spur the market, coupled with insufficient supply infrastructure to handle the resulting increase in demand, leading to lackluster competition and artificial price increases until new supply infrastructure enters the market.

1. Introduction

Markets for solar photovoltaic (PV) systems are expanding rapidly, albeit from a small base. In 2004, more than 955 MW_{AC} of PV capacity was installed worldwide, up from 658 MW_{AC} in 2003 (Maycock 2005).[1] The growth in worldwide annual capacity additions has averaged approximately 35% since 1996 (Maycock 2005), dominated by grid-connected applications. The global PV market had an estimated $11 billion in revenue in 2004 (Rogel 2005).

Despite this vigorous growth, the share of worldwide electricity demand met with photovoltaic power remains miniscule, well below 0.1%, and the aggregate expected electricity supply from the PV capacity added in 2004 equates to just one natural gas-fired baseload generating plant (or perhaps a dozen gas-fired peaking plants). The primary constraint to future expansion is economics. Simply put, solar PV is not yet cost-competitive in most grid-connected applications, and substantial cost reductions will be required for PV to meaningfully contribute to worldwide electricity supply (U.S. DOE 2005; Chaudhari et al. 2005; van der Zwaan and Rabl 2004; Poponi 2003). The good news is that significant cost reductions are possible, and some believe that solar power will have a bright future in a world in which environmental, security, and supply constraints could dampen interest in conventional generation (Rogel 2005; Makower and Pernick 2004; Pacala and Socolow 2004; Payne et al. 2001; U.S. DOE 2005).

Local, state, and federal government incentives are (and will continue to be) the principal drivers for the recent growth in grid-connected PV capacity (see, e.g., Haas 2003; Osborn et al. 2005; Bolinger and Wiser 2002; Duke et al. 2005). Common programs include rebates on the capital cost of the installations, high fixed tariffs paid for PV supply, tax incentives, and mandates for electricity suppliers to use solar power to meet customer demand. These policies are motivated by the widespread popular appeal of solar power, and the positive attributes of PV – modest environmental impacts, avoidance of fuel price and supply risks, coincidence with peak electrical demand, distributed generation located at the point of use, and installation modularity.

A key goal of these policy efforts is that of market transformation: to drive down the cost of PV over time to a level that does not require substantial government stimulation. The cost of PV installations is not uniform, however, and can vary based on time, system size, type of installation (e.g., retrofit vs. new home), installer experience, and other factors. Solar costs might also be affected by the level and design of policy incentives provided to those installations.

This paper presents the results of a statistical evaluation of cost trends in California's market for residential and commercial grid-connected PV. It is based on an analysis of 18,942 PV systems, totaling 254 MW, that as of mid-2005 had either been completed, approved, or waitlisted (i.e., approved but awaiting additional program funding) under California's two largest solar rebate programs: those operated by the California Energy Commission and California Public Utilities

[1] Unless explicitly presented as otherwise, data on PV capacity and costs are expressed throughout this report in terms of W_{AC} (e.g., W_{AC}, kW_{AC}, MW_{AC}, $\$/W_{AC}$), which we convert (where necessary) from $W_{DC\text{-}STC}$ (DC Watts at standard test conditions) using a de-rate factor of 0.84. We acknowledge that many other solar programs and data sources use $W_{DC\text{-}STC}$, making comparisons of California data with those in other states and countries more difficult. Given, however, that our underlying system cost data is expressed in terms of W_{AC}, this is the standard that we use.

Commission.[2] This analysis provides insights on California's PV market by exploring cost trends over time, and by helping to untangle the various factors that affect the installed cost of PV systems. Results may also have important policy ramifications in as much as they address the interaction between incentive levels and installed costs, and the relative cost of different solar applications.

A sizable literature has developed that explores historical PV cost trends. Much of this literature has used learning or experience curve theory to explore how increases in cumulative PV production have driven costs down over time. Findings from this literature vary, but most studies show that each doubling of cumulative production has historically led to a reduction in module prices of approximately 20% (see, e.g., Kobos et al. in press; McDonald and Schrattenholzer 2001; Neij 1997; IEA 2000; Schaeffer et al. 2004). Others have extrapolated these findings to argue that government deployment support for PV may be warranted to drive the industry down its learning curve and ultimately achieve costs that are comparable to or better than the cost of conventional electricity sources (see, e.g., van der Zwaan and Rabl 2004; Duke and Kammen 1999; Duke 2002).[3]

Our study has a narrower focus in that it seeks to uncover interesting cost trends from a single PV market. In so doing, the results presented here are expected to be of use to California's energy policymakers and stakeholders as existing solar incentive programs are revised, and as new and expanded programs are implemented. With a mid-January 2006 California Public Utilities Commission order to establish an 11-year, ~$3.2 billion program of declining incentives for PV, the results of this analysis are timely. Of course, California is not alone in its support for photovoltaic markets: a large number of other U.S. states also offer significant incentives for PV (Bolinger and Wiser 2002; Bolinger and Wiser 2003; Chen et al. 2005; Gouchoe et al. 2002), and new tax policies at the federal level promise to further stimulate the U.S. market in the years to come. A detailed exploration of PV cost trends in California may be of use for benchmarking purposes in these other markets. Finally, because California is the third largest market for PV worldwide, the results presented here are expected to be of broad international interest.

We begin in Section 2 of this paper by describing California's photovoltaic market. Section 3 then discusses the data that we obtained for our analysis, and the statistical methods used to evaluate those data. Section 4 presents multivariate regression results from our analysis of smaller residential and commercial solar installations (< 30 kW). Section 5 presents similar results from our analysis of larger commercial installations (generally ranging from 30 kW to as large as 1 MW). Section 6 compares the two datasets. We end the paper in Section 7 by highlighting important implications and conclusions.

[2] Future analysis could expand this evaluation to look at cross-state and perhaps cross-country comparisons of installed costs, and could use more up-to-date California data.
[3] Other studies that have explored average costs and (to a lesser degree) cost trends in the U.S. in recent years have focused on: Florida (Szaro 2003), LADWP (Honles 2003), Pennsylvania (Celentano 2005), a sample of 278 systems throughout the U.S. (Mortensen 2001), and projects funded under the TEAM-UP Program (SEPA 2001a, 2001b).

2. The California Solar Market in Context

2.1 Market Overview

California is the dominant market for PV in the United States, though it still stands a distant third on a worldwide basis behind Japan and Germany. According to the International Energy Agency (IEA), Japan added 228 MW_{AC} of solar PV capacity in 2004 for a cumulative total of 951 MW_{AC}. The size of Germany's market is in some dispute, with the IEA reporting that the country added 305 MW_{AC} in 2004, for a cumulative 667 MW_{AC}, while Photon International reports 647 MW_{AC} of additions in 2004 for a cumulative total of 1146 MW_{AC}.[4] Japan and Germany have used gradually declining capital rebates and high fixed power purchase tariffs, respectively, to spur market expansion. In aggregate, these two markets accounted for at least 60% of worldwide PV demand in 2004. The IEA reports that the U.S. added 76 MW_{AC} of PV in 2004 (including 52 MW_{AC} of grid-connected capacity), for a cumulative total of 307 MW_{AC}.

The California Energy Commission reports that California alone added more than 36 MW_{AC} of grid-connected PV in 2004. Through mid-November 2005, 130 MW_{AC} of grid-connected PV capacity was installed in California; Figure 1 shows the dramatic growth in the market since the year 2000 (data for 2005 represents a partial year, through mid-November).[5] According to SolarBuzz (2005), in 2004, California's grid-connected PV additions represented approximately 85% of all grid-connected additions in the United States.[6]

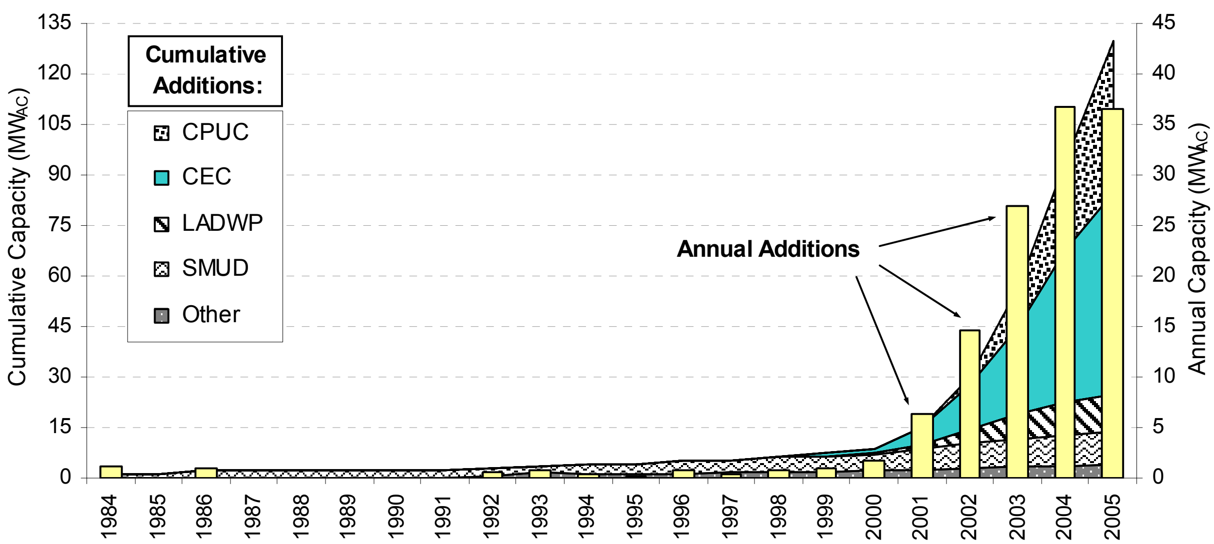


Figure 1. Grid-Connected Solar Capacity in California, through November 15, 2005

[4] For IEA data, see: http://www.oja-services.nl/iea-pvps/isr/index.htm. For Photon International data, see Photon International (2005). Data are converted from DC Watts at standard test conditions (as reported) to AC Watts using a de-rate factor of 0.84.

[5] The data presented in Figure 1, which includes systems installed under municipal utility programs, comes from the California Energy Commission's website, accessed on January 2, 2006: http://www.energy.ca.gov/renewables/emerging_renewables/GRID-CONNECTED_PV.XLS.

[6] IEA and CEC data, on the other hand, suggest that California's grid-connected PV market in 2004 represented 70% of the U.S. total (36 MW_{AC} out of 52 MW_{AC}).

2.2 Policy Incentives

California's grid-connected PV market is driven by a mixture of state and local incentives. Most prominent are capital cost rebates – denominated in $ per Watt – offered to PV system installers or owners to "buy down" the installed cost of solar installations. By reducing the cost of PV installations, these programs aim to increase PV sales, which should encourage manufacturers, sellers, and installers to expand their operations and improve distribution channels, thereby inducing overall system cost reductions. The two most significant current rebate programs are overseen by the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC), but significant rebates are also offered by the state's publicly owned utilities (e.g., SMUD, LADWP – see Figure 1).

California Energy Commission: The CEC has administered a PV rebate program (called the "Emerging Renewables Program"[7]) since March 1998, funded primarily by ratepayers of the state's investor-owned electric utilities (IOUs). From program inception to February 2003, the CEC provided rebates to both small and large PV systems installed by customers taking electric service from one of the state's IOUs. Starting in March 2003, the program has focused primarily on residential and small commercial systems under 30 kW in size.[8] As of May 2005, the CEC had paid out roughly $196 million of incentive funds to nearly 13,000 completed PV systems totaling 51 MW_{AC} of capacity. An additional $80 million was encumbered to approximately 5,000 (25 MW_{AC}) approved but not yet completed PV systems.[9] Historically, approximately 70% of all applications have resulted in completed systems.[10]

California Public Utilities Commission (CPUC): The CPUC's Self-Generation Incentive Program (SGIP) was established as a direct result of the state's energy crisis, and began accepting applications in July 2001. The program provides rebates for customer-sited PV systems of at least 30 kW in size (systems can exceed 1 MW in size, but the rebate only applies to the first 1 MW) and installed by customers taking electric or gas service from one of the state's IOUs. SGIP funds are collected from electric and gas ratepayers. As of June 2005, the program had paid out $142 million in incentive funds to 327 completed PV systems totaling nearly 36 MW_{AC} of capacity. An additional $300 million was obligated to 465 approved but not yet completed PV systems (totaling 74 MW_{AC}). 265 systems, totaling more than $250 million of rebate funds, were approved but on a waitlist due to insufficient program funding at current

[7] In addition to PV systems, small wind turbines, fuel cells using renewable fuels, and solar thermal electricity systems – all sized to generate less than 200% of the site's electricity needs on an annual basis – are eligible for the program. To date, PV systems have accounted for roughly 99% of all funded systems. For more information, see http://www.consumerenergycenter.org/erprebate/index.html.
[8] For certain periods of time, customers of publicly-owned utilities have also been eligible to participate.
[9] Additional systems have been completed and approved since April 2005. We use dated information here to be consistent with the dataset used in the subsequent analysis.
[10] The CEC's program was evaluated in 2000, and among other things, that evaluation found little reduction in installed costs for smaller solar systems over the program's first two years, but sizable cost reductions for larger systems (RER 2000).

incentive levels.[11] Compared to the CEC's program, a larger number of SGIP applications are either rejected or withdrawn, with an average drop-out rate of roughly 45%.[12]

Figure 2 depicts the historical demand for PV within each program through early- to mid-2005, shown in terms of the number of megawatts of PV applying for rebates over time. Quarterly application activity within the CEC's program was slow until the electricity crisis hit in 2000/2001 (the crisis was also the impetus for establishing the CPUC's program). Starting in 2003, volatility in quarterly applications within the CEC's program reflects, in large part, last-minute surges in the number of applications just prior to the regularly scheduled reduction in incentive levels every six months, on the first day of January and July.[13]

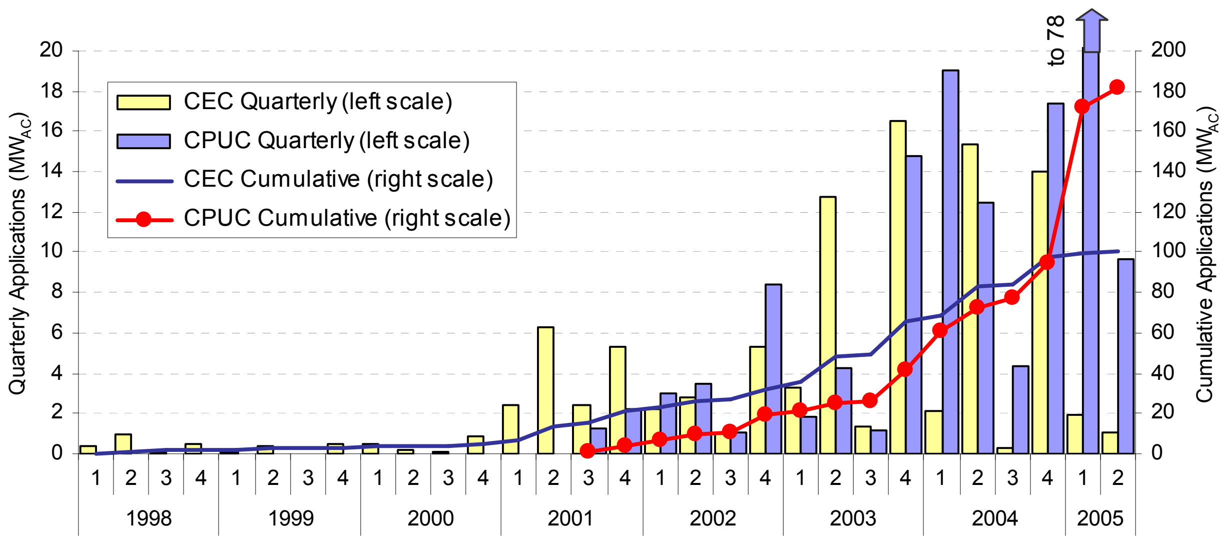


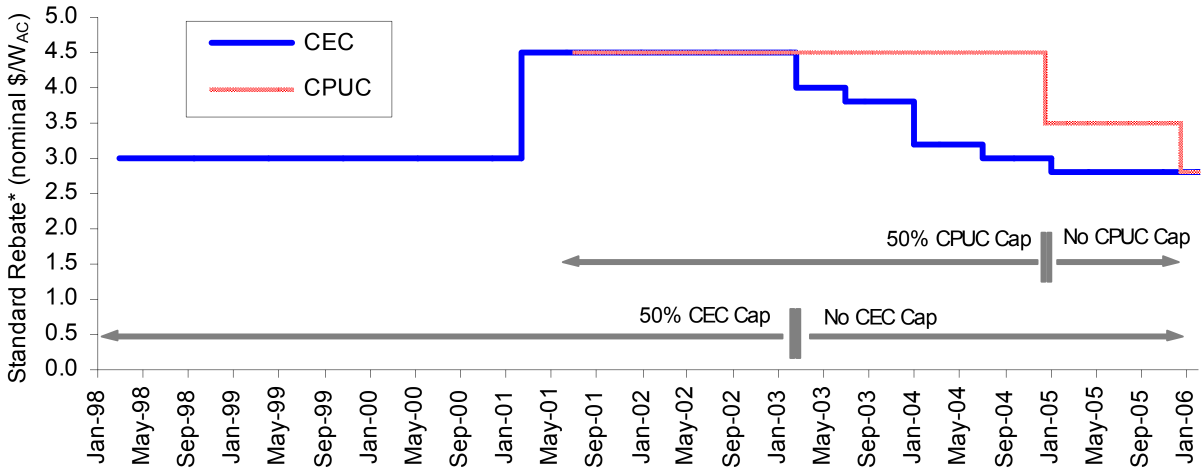
Figure 2. Quarterly and Cumulative Rebate Application History (CEC and CPUC)

Over time, both the CPUC and the CEC programs have altered the structure and size of their incentives for PV installations (see Figure 3). The CPUC initiated its incentives at $4.5/W_{AC}$, capped at 50% of pre-rebate installed costs, and dropped the incentive level to $3.5/W_{AC}$ with no percentage cap on December 16, 2004; the CPUC further reduced the incentive to $2.8/W_{AC}$ for applications received after December 15, 2005. The CEC's standard incentive started at $3/W_{AC}$ with a 50% incentive cap, increased during the energy crisis to $4.5/W_{AC}$, and has then declined progressively in recent years to its current level of $2.8/W_{AC}$. The percentage cap was eliminated in February 2003. Affordable housing, solar schools, and owner-installed installations, as well as larger systems, have – at various times – received different incentive levels and percentage caps.

[11] In late 2005, the CPUC decided to dramatically increase SGIP program funding for 2006 in part to help fund waitlisted projects.

[12] A large number of impact and process evaluation reports have been prepared for the SGIP (see, e.g., Itron 2003, 2004, 2005a; RER 2003). These reports often discuss pre-rebate installed costs, but do not analyze cost trends in any detail.

[13] The volatile pattern exhibited in 2003 and 2004 is not evident in the second quarter of 2005, because in Figure 2, the second quarter of 2005 is a partial quarter (running only through April 15). Furthermore, the CEC decided to forego the regularly scheduled reduction in incentive levels on July 1, 2005, leaving the rebate at $2.8/W_{AC}$ for the entire year.



* Within the CEC's program, systems installed on affordable housing and schools have, at times, received higher incentives; owner-installed systems have, at times, received lower incentives; systems >30 kW_{AC} were eligible for rebates from program inception to February 2003; and systems >10 kW_{AC} received $2.5/$W_{AC}$ (capped at 40%) from March 1999 to February 2001.

Figure 3. Evolution of the Standard Rebates for the CEC and CPUC Programs

In addition to these rebate programs, other policies supporting PV in California include: net metering requirements, simplified interconnection standards, exemptions of solar systems from certain utility fees (specifically, "standby" and "exit" fees), and an exemption of PV systems from state property taxes. California has also provided a state income tax credit (ITC) for systems 200 kW or smaller, which was as high as 15% from January 2001 through December 2003, dropping to 7.5% from January 2004 through December 2005. With highly "tiered" rate structures, and time-of-use rates available to some customers, PV electricity in some cases offsets retail electricity rates of more than $0.20/kWh.

Finally, the federal government has allowed commercial systems an attractive five-year accelerated depreciation schedule and a federal ITC of 10%, which increased to 30% on January 1, 2006 (and will remain at 30% through 2007, unless extended). Residential systems are also eligible for a 30% federal ITC (capped at $2000) in calendar years 2006 and 2007 (unless extended).

2.3 Market Concerns

Several pertinent concerns have been expressed about the California solar programs, some of which will be informed by the analysis presented in this report.

Some have questioned whether *current* (or even possibly *future*) funding commitments are (or will be) sufficient to drive PV system costs down to competitive levels in a reasonable period of time. Recent increases in the cost of silicon and therefore solar cells, modules, and installations have added some weight to these concerns, though most believe that the current silicon shortage will be temporary and that PV module costs will continue their march downward within several years (Rogel 2005). It is also important to keep in mind that silicon and PV module costs are determined in a worldwide market that is largely outside of the influence of California's PV programs, while installation and balance of system (i.e., non-module) costs may be largely determined at the local level, and are therefore subject to the influence of local PV programs. As such, trends in *total system* installed costs are arguably a less-appropriate measure of program success than are trends in *non-module* (or balance of system) installed costs.[14]

Others have noted the historical lack of continuity and stability in the existing programs, illustrated in Figure 2 by the notable variability and gaps in quarterly incentive applications, and driven by changes in the incentive levels and availability of funds. This lack of certainty may lower investor confidence in the California market, and limit efficiencies in manufacturing and distribution, thereby compromising the ability of the program to achieve cost reductions (Osborn et al. 2005; Steigelmann et al. 2005). The state's energy agencies apparently agree with this contention, writing jointly: "California policies are clearly supportive of the on-grid solar market, but that support was unevenly distributed and often unavailable." (CEC and CPUC 2005).

There have also been some misgivings about the size and structure of the incentive programs themselves. For example, some have questioned whether the size of the incentives has (at times) been so large as to compromise the willingness of installers to lower total installed prices for customers (Osborn et al. 2005; CEC 2005). Others have expressed the view that when the size of the CEC and CPUC's rebates were limited to a certain percentage of pre-rebate installed costs, the existence of those percentage caps may have dampened incentives for system cost reductions. As an example, under a binding 50% cap, every $1 in cost reduction will reduce the incentive payment by $0.5, meaning that the customer captures only 50% of the cost savings. Likewise, the customer will pay only 50% of any cost increase. So although in theory a percentage cap can help to prevent over-subsidization and can reduce the need to regularly adjust fixed rebate levels in response to system cost changes, the specific mechanics of the percentage cap *do not* provide a strong incentive for cost reductions, and – even more vexing – *do* provide opportunities for gaming of the program (Bolinger and Wiser 2003; RER 2003).[15] Finally, some have wondered whether the state should place more emphasis on certain PV applications where cost competitiveness may be more readily achieved; for example, incorporating PV systems into new building construction, where design and installation efficiencies may help lower customer costs.

At least some of these concerns have already been, or are in the process of being, addressed. The CEC eliminated the percentage cap on its rebates in February 2003, and the CPUC followed suit in December 2004 (see Figure 3, above). Meanwhile, Gov. Schwarzenegger has announced his support for the California Million Solar Roofs initiative, with a goal of encouraging 3,000 MW of new solar PV systems through a long-term, sustained, declining incentive program. The

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[14] In Sections 4-6 we present evidence showing that most of the recent cost reductions in California's PV markets (at least for smaller systems) have come from non-module costs, though our analysis is not robust enough to conclude that such cost reductions have been *caused* by California's PV programs.

[15] Gaming opportunities range from the relatively straightforward "gold-plating" of systems with expensive features, knowing that the rebate program will pick up half of the incremental cost, to much more nefarious schemes. As an example of the latter, there have been anecdotal reports of installers artificially pricing systems (that, for example, actually cost $8/W) at $9/W in order to maximize the dollar amount of the rebate ($4.5/W, capped at 50% of eligible costs), and then sharing the ill-gotten incremental rebate with the system purchaser, to the financial benefit of both purchaser and installer. In this light, it is interesting to note that 30% of all PV systems funded by the CPUC during the period in which the 50% cap was in place were priced from \$8.75-\$9.25/W_{AC} (50% were priced from \$8-\$9.25/W_{AC}). The corresponding numbers in the four-month period of our sample after the cap was dropped (in mid-December 2004) are 5% and 11.5%, respectively, with the entire cost distribution having shifted to the left (i.e., toward lower costs).

CPUC – in conjunction with the CEC – is developing an implementation plan for this initiative, and on January 12, 2006 approved the outlines of such a program. The program will place some new emphasis on the residential new construction market (through incentives offered by the CEC), though not to the exclusion of retrofit markets, and is envisioned to be sizable (~$3.2 billion) and stable (~11 years) enough to significantly reduce system costs over time. Incentive levels are slated to drop by an average of at least 10% each year. Incentives may ultimately vary to some degree by system size or market segment, though the CPUC declined to establish such differentiated incentives initially (except for low-income and affordable housing projects, which will receive higher incentive levels). A pay-for-performance incentive structure is to be explored. Though many of the details remain to be resolved, this order will dramatically expand the PV market in the state.

3. Data and Methodology

3.1 Data

Data on installed PV costs and other variables come primarily from the program databases provided by the CEC (for systems less than 30 kW) and the CPUC (for systems 30 kW and above). The CEC dataset was provided to us in May 2005, and the CPUC database was updated through June 2005.[16] Table 1 summarizes the content of each dataset, after the data were cleaned and data records with missing entries were eliminated (see Appendix A for more details on our data manipulation and cleaning procedures).

Table 1. Summary Information on the Two Final Datasets

	CEC	CPUC
System Size Range	0.024 kW – 30 kW*	25 kW** – 1,063 kW
System Cost Restriction	$4/W_{AC}$ – $30/W_{AC}$	$4/W_{AC}$ – $30/W_{AC}$
Systems Eliminated Due to Cost Restriction	85 (0.5 MW)	4 (1.3 MW)
System Status for Those Included in Final Dataset		
Completed	12,856 (48.5 MW)	327 (35.7 MW)
Approved	5,033 (24.3 MW)	464 (73.4 MW)
Waitlisted	0 (00.0 MW)	262 (71.7 MW)
TOTAL	17,889 (72.8 MW)	1,053 (180.8 MW)
Application Date Range	03/20/98 – 04/15/05	07/23/01 – 04/15/05
Completion Date Range	04/08/98 – 04/07/05	06/18/02 – 05/17/05

* The CEC program initially funded systems over 30 kW in size, but ceased providing funding to such systems in March 2003. We exclude these larger systems from our analysis (a total of 66 systems, and 9.1 MW of capacity) to ensure that a limited number of outliers do not unduly affect our analysis results.
** Although the CPUC program rules state that only systems of at least 30 kW in size are eligible, the CPUC database does contain a few systems less than 30 kW (and as low as 25 kW).

Our final cleaned CEC dataset covers a total of 17,889 data records (72.8 MW_{AC}), including 12,856 completed systems (48.5 MW_{AC}) and 5,033 systems that had been approved for a rebate, but that were awaiting completion at the time we received the database (24.3 MW_{AC}).[17] The data include rebate applications received from March 1998 to April 2005, and project completion dates of April 1998 to April 2005. To minimize the possible influence of outliers, our analysis only includes systems under 30 kW in size, and with costs in the range of $4 to $30/W_{AC}$.[18]

The CPUC program generally covers systems of at least 30 kW in size (though a small number of systems are marked as under this size range in the database that we received), and our final

[16] More recent data are now available from both programs, and future analysis should use these updated data.
[17] We do not include systems whose rebate applications were declined, or whose application was approved but subsequently cancelled.
[18] Systems with costs outside of this range likely represent data entry errors, or atypically cheap or expensive systems. Different reasonable system cost restrictions were tested, with limited effect on regression results.

dataset includes 1,053 data records (180.8 MW_{AC}), including 327 completed systems (35.7 MW_{AC}), 464 approved systems (73.4 MW_{AC}), and 262 waitlisted systems (71.7 MW_{AC}). Applications were received from July 2001 to April 2005, and systems have completion dates from June 2002 to May 2005. As with the CEC data, to mitigate the possible influence of outliers, our analysis only includes systems with costs in the range of \$4-\$30/W_{AC}.[19]

3.2 Variables

In all cases, the dependent variable is the pre-rebate per-unit total installed cost of individual PV systems, in \$/W_{AC}, calculated by dividing total pre-rebate installed costs by system size.[20] For completed systems, this cost figure represents actual costs as reported to rebate program administrators. For approved or waitlisted systems, the cost represents an approximation of actual costs provided upon rebate application; because costs are often established by contract prior to the submission of a rebate application, these costs are considered relatively firm. All dollar values are translated into real 2004\$, using historical monthly CPI data (seasonally adjusted). System size is denominated in W_{AC}, which equates to module $W_{DC\text{-}PTC}$ (DC Watts at PVUSA test conditions) multiplied by the inverter efficiency rating.[21] Note that many other solar programs and data sources use $W_{DC\text{-}STC}$ (DC Watts at standard test conditions), making comparisons of California data with those in other states somewhat more difficult.

A more appropriate dependent variable would be one that accounts for system performance – i.e., \$/kWh rather than \$/W. This metric would enable us to, for example, normalize the additional cost of a tracking system used to enhance system performance. Because system performance data are not regularly collected by the CEC or CPUC programs, however, we were forced to use the "second-best" choice of dependent variable, \$/W_{AC}.[22]

Table 2 identifies and defines the independent variables used for each dataset, while Table 3 provides summary statistics; for more information on variable definition, and on our data manipulation and data cleaning procedures, see Appendix A.

- ***Date of Application:*** Both datasets include a variable for the date of rebate application, in months. One would generally expect that pre-rebate installed costs would decline with time due to manufacturing improvements and distribution channel efficiencies. Though this variable does allow us to track cost changes over time, it is important to note that we are unable to test whether the CEC and CPUC programs *caused* these cost reductions. To test

[19] Different system cost restrictions were tested, with some impact on regression results. With no easy way of determining which cost range was objectively "right," we opted to maintain consistency with the CEC dataset.
[20] Though California's PV programs will support systems with battery back-up, the extra costs of such back-up are not eligible for incentive payments. Costs reported here represent "eligible costs," excluding any costs for battery back-up.
[21] The approach used to calculate inverter efficiencies has changed over the course of the rebate programs. The data presented here for system size are based on the inverter efficiency ratings used at the time of system rebate application. An analysis of inverter efficiency ratings over time shows little change in average ratings (less than 1%, on average), so changes in rating methodologies should not be a major source of error in the results presented later.
[22] Future work might also explore using customer demand (e.g., applications received) as the dependent variable to evaluate the determinants of demand for solar PV systems.

for such causation would require cost data from a control market in which state incentives are not provided (or are provided at lower levels than in California).[23]

- ***System Size:*** Both datasets also include a variable for system size. With presumed economies of scale and installation, larger systems are expected to come in at lower costs.
- ***Policy-Based Variables****:* Though one might hope that the size of policy incentives would have no impact on pre-rebate installed costs, it is possible that the positive impact of these incentives on the economics of a solar PV system might dampen the motivation for system installers to aggressively reduce pre-rebate installed costs. Policy variables incorporated in the CEC dataset include the level of the rebate, the existence of a percentage cap, the level of the state tax credit, and the utility-specific applicable retail electricity rate.[24] Similar variables were tested on the CPUC dataset, but for reasons discussed later, our final model runs only include as policy variables the level of the state tax credit, the utility-specific retail rate, and whether particular installations had access to other sizable financial incentives (most prominently, incentives offered by a local utility that are, to some degree, additional to the incentives offered by the CPUC; similar data were not provided by the CEC).
- ***System Installation Status:*** Dummy variables for approved (CEC and CPUC) and waitlisted (CPUC) systems are included, to test for any systematic variations in system costs between completed systems, and approved and waitlisted systems.
- ***System Location:*** Dummy variables for the location of the system (defined by utility service territory) are included to test for any systematic differences in installed costs in these territories, relative to systems located in PG&E's service area. We have no hypothesis as to why costs might differ by utility service territory, other than the potential impact of differences in cost of living or retail rates (each of which is addressed through its own separate variable).
- ***Installation Type:*** Four non-overlapping dummy variables for various system installation types are included to test for differences in pre-rebate installed costs, relative to systems installed in standard residential or commercial retrofit applications. These variables are only possible for the CEC dataset, and include systems installed: (1) in bulk in large, new-home residential developments; (2) in single new homes or small clustered new-home developments; (3) as part of an affordable housing project; or (4) on a school. One would expect that systems installed in bulk in new construction (large residential development, and affordable housing) would come in at lower costs.
- ***Installer and Retailer Experience and Type:*** A number of dummy variables are included to test for the impact of installer and retailer experience, and type. For the CEC dataset, the available data allow us to test for the impact of installer experience and retailer experience on pre-rebate system prices, and to test for whether owner-installed systems are more or less expensive than contractor-installed systems. The CPUC dataset allows us to test for the impact of installer experience; we also include a dummy variable for systems installed by the California Construction Authority (effectively, an owner-installer) because on visual

[23] We recommend that future work evaluate PV costs across multiple markets to test for such effects.
[24] Because our retail rate variable is constructed from *average* retail rates, and therefore only indirectly accounts for the highly tiered rate structures facing most Californians, it is far from perfect (for more information on the construction of this variable, see Appendix A). Future work that more accurately characterizes and quantifies the specific retail rate that will be displaced by each PV system would be beneficial.

inspection of the data it was clear that these systems have been substantially less expensive than the more common contractor-installed systems in the CPUC dataset.[25]

- ***Population Density:*** Population density, by zip code, was included for the CEC dataset (missing zip codes did not allow us to replicate this variable for the CPUC dataset). One might expect that system costs would be lower in more densely populated areas due to the existence of PV supplier competition; on the other hand, these areas may experience higher costs because of the typically higher cost-of-living in urban areas and the impact of those costs on installation labor expenses.
- ***Thin Film:*** Both datasets have a dummy variable for systems using thin-film PV technology, a less common but potentially less-expensive PV technology than crystalline silicon.
- ***Module Cost Index:*** Pre-rebate installed costs are also expected to vary based on the prevailing cost of PV modules, measured here as an annual average of global module prices, and ultimately included only for the CEC dataset.[26]

Several additional variables were also explored, without success. Of most relevance, we constructed and tested a variable for cumulative program-related PV installations, under the assumption that non-module system costs might follow a state- or program-specific learning curve (due, for example, to reductions in installation costs with installation experience). We found this variable to be somewhat collinear with time, however, and a linear representation of time fit our underlying data far better than cumulative PV additions, at least for the CEC dataset.[27] We also explored and tested several different representations of installation supply constraints, under the assumption that PV costs could rise at times when the installation infrastructure is strained. Despite several attempts, we were unable to construct a successful variable to measure these possible effects.

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[25] The California Construction Authority (CCA) is a Joint Powers Authority organized in August 1988 to provide financing, design, inspection and construction management services for fairgrounds throughout California. The low cost of the CCA systems is perhaps partially attributable to bulk equipment purchases for multiple fairground projects. Some have also speculated that the CCA is able to install systems at lower costs than the PV industry at large due to the fact that it has no marketing, sales, or overhead costs (and/or that certain internal costs are not reported). In other words, CCA-installed systems in the CPUC program are essentially the equivalent of owner-installed systems in the CEC program.

[26] Although the CEC database does, in some cases, contain disaggregated information on module, inverter, and labor costs, this information is only sparsely reported (and the CPUC database does not provide such information at all). As a result, we have used an external index of worldwide module costs over time from Strategies Unlimited to proxy module costs for each California system.

[27] More generally, using global photovoltaic price trends, Papineau (2006) finds that the addition of a time variable to a model that also includes cumulative production generally makes the cumulative production variable statistically insignificant, leading to questions over the predictive power of experience curves more generally.

Table 2. Independent Variables Used in Analysis

Name	Datasets		Definition
	CEC	CPUC	
TIME_MONTH	✕	✕	Date of application, in months, numbered consecutively from beginning of each program*
SYSTEM_SIZE	✕	✕	Size of installation (W_{AC})
MAX_STD_REBATE	✕	Tried/ Failed	Maximum standard rebate (2004 $/$W_{AC}$)**
REBATE_%_CAP	✕	Tried/ Failed	1 if rebate has a percentage cap
STATE_TAX_CREDIT	✕	✕	0, 7.5%, 15% state ITC depends on time of application, and system size
RETAIL_RATES	✕	✕	A function of system size (to determine whether residential or commercial retail rates are appropriate) and location (to determine applicable utility). See Appendix A for details.
OTHER_INCENTIVES		✕	1 if other incentives are greater than $2/$W_{AC}$
APPROVED	✕	✕	1 if approved, but not completed
WAITLISTED		✕	1 if waitlisted, but not completed
SCE	✕	✕	1 if in SCE's territory
SDG&E	✕	✕	1 if in SDG&E's territory
OTHER_UTILITY	✕	✕	1 if in another territory***
NEW_CONST_LARGE	✕		1 if installed with many other systems as part of a large new residential development
NEW_CONST_SINGLE	✕		1 if installed on a single new home, or as part of a small cluster of new homes
SCHOOLS	✕		1 if installed at a school
AFFORDABLE_HOUSING	✕		1 if installed as part of an affordable housing project
OWNER_INSTALLED	✕		1 if installed by owner
INSTALLER_EXPERIENCE	✕	✕	1 for installers in the top 5% of installation companies in terms of aggregate installations over course of program
RETAILER_EXPERIENCE	✕		1 for retailers in the top 5% of retailers in terms of aggregate installations over course of program
CALIF_CONST_AUTORITY		✕	1 for systems installed by California Construction Authority
POPULATION_DENSITY	✕		By zip code, population divided by geographic area (person/miles^2)
THIN_FILM	✕	✕	1 if system includes thin-firm PV modules
MODULE_COST_INDEX	✕	Tried/ Failed	Annual index of global PV module prices in the power sector (2004 $/$W_{DC-STC}$)

* We use the date of application (rather than completion) under the presumption that system costs are largely set, by contract, prior to the submission of a rebate application.
** This variable accounts for changes in standard rebates over time, but not non-standard rebates that have been provided for affordable housing, schools, and owner-installed systems
*** For the CEC data, other utility territories include: Sacramento (SMUD), Bear Valley Electric Service, Palo Alto, and 13 smaller publicly-owned utilities with just a few systems each. For the CPUC data, they include Los Angeles (LADWP), Sacramento (SMUD), and 14 smaller publicly-owned utilities with just a few systems each.

Table 3. Summary Statistics of Variables Used in Analysis

Continuous Variables	CEC (< 30 kW)				CPUC (>= 30 kW)			
	Mean	Max	Min	Std. Dev.	Mean	Max	Min	Std. Dev.
INSTALLED_COST	9.6	29.3	4.1	2.2	8.8	23.7	4.4	1.6
TIME_MONTH	62.4	85.0	0.0	14.6	32.9	45.0	0.0	11.1
SYSTEM_SIZE	4.1	30.0	0.0	3.7	171.7	1,063	24.6	223.6
MAX_STD_REBATE	3.9	4.8	2.7	0.7	4.2	4.8	3.4	0.6
STATE_TAX_CREDIT	0.09	0.15	0.00	0.05	0.08	0.15	0.00	0.05
RETAIL_RATES	0.13	0.19	0.08	0.01	0.13	0.16	0.05	0.02
MODULE_COST_INDEX	3.5	4.5	3.3	0.2	3.5	3.9	3.3	0.1
POPULATION_DENSITY	2,629	52,959	0.25	4,147	n/a	n/a	n/a	n/a

Dummy Variables	CEC Observations (Dummy = 1)	CEC Percent of Total	CPUC Observations (Dummy = 1)	CPUC Percent of Total
REBATE_%_CAP	5,193	29%	678	64%
OTHER_INCENTIVES	n/a	n/a	56	5%
APPROVED*	5,033	28%	464	44%
WAITLISTED*	n/a	n/a	262	25%
SCE**	3,706	21%	294	28%
SDG&E**	3,247	18%	151	14%
OTHER_UTILITY**	139	1%	113	11%
NEW_CONST_LARGE†	1,946	11%	n/a	n/a
NEW_CONST_SMALL†	771	4%	n/a	n/a
SCHOOLS†	60	0%	n/a	n/a
AFFORDABLE_HOUSING†	340	2%	n/a	n/a
OWNER_INSTALLED	862	5%	n/a	n/a
INSTALLER_EXPERIENCE	9,454	53%	257	24%
RETAILER_EXPERIENCE	6,152	34%	n/a	n/a
CALIF_CONST_AUTHORITY	n/a	n/a	16	2%
THIN_FILM	318	2%	111	11%

* In addition to approved and waitlisted systems, the CEC and CPUC datasets include 12,856 and 327 completed systems, respectively.
** PG&E, which represents the "base" utility territory to which the others are compared, contains the majority of systems: 10,797 (60%) systems in the CEC dataset, and 495 (47%) systems in the CPUC dataset.[28]
† Standard retrofits represent the "base" type of system to which others are compared in the CEC dataset, and include 14,772 total systems (83%).

[28] The datasets do not easily allow us to hypothesize and test why PG&E appears to host a disproportional (at least relative to load) share of PV systems.

3.3 Methodology

Analysis was conducted using multivariate regression techniques, with the dependent variable the per-unit, pre-rebate installed cost ($\$/W_{AC}$).[29] White's Test showed the presence of heteroscedasticity (non-constant variance in the error structure) in a number of our ordinary least squares (OLS) regression results; accordingly, we consistently present corrected standard errors using the Generalized Method of Moments (GMM) in the results that follow.

We also explored the possibility of colinearity among independent variables, both by reviewing correlation coefficients and by sequentially adding or subtracting variables to test for correlated effects. In some cases, variables with significant colinearity were eliminated. As discussed below, we also developed a separate regression model that includes a subset of these collinear variables where complete variable elimination did not seem prudent.

Various functional forms were tested for the continuous independent variables. For many, we ultimately use a simple linear form. We use a logarithmic form for SYSTEM_SIZE because, upon visual inspection and after statistical tests, that functional form appeared to fit our underlying data better than the alternatives that we tested. The square root of POPULATION_DENSITY is used because it fits the data well, and because it is assumed that changes in density in sparsely populated areas will have a greater affect than similar changes in density in more-densely populated urban areas. We also tested alternative functional forms for the TIME_MONTH month, but none outperformed a simple linear model.

After testing a considerable number of alternative regression models, we developed four final models for both the CEC and the CPUC datasets:

- **Model 1** includes many of the independent variables listed earlier, but excludes the MODULE_COST_INDEX and the MAX_STD_REBATE variables. By excluding these variables, both of which are correlated with time, this model provides the best representation of aggregate cost reductions with time. (This model, as well as models 2 and 4, also excludes REBATE_%_CAP, STATE_TAX_CREDIT, and RETAIL_RATES).
- **Model 2** is equivalent to Model 1, but includes the MODULE_COST_INDEX and MAX_STD_REBATE variables, allowing an evaluation of the impact of the rebate on pre-rebate system costs, as well as an assessment of *non-module* cost reductions over time.
- **Model 3** is equivalent to Model 2, but adds three additional variables that experience some colinearity among themselves and with other independent variables, but that have policy interest: REBATE_%_CAP, STATE_TAX_CREDIT, and RETAIL_RATES.
- **Model 4** contains the same independent variables as Model 2, but includes a large number of crossed terms to determine whether the coefficients of certain variables included in other models are affected by time or by system size. The crossed variables include DATE_MONTH, NEW_CONST_LARGE, NEW_CONST_SMALL,

[29] We also explored using pre-rebate total installed cost as the dependent variable (2004 $), as opposed to per-unit pre-rebate installed costs (2004 $\$/W_{AC}$). The resulting total cost regression models explained a far greater fraction of total cost variation (i.e., had a much higher R^2, of around 0.9), but we chose to focus on the lower-R^2 per-unit cost results because they do not require a transformation of regression results to present the more intuitive and policy-relevant per-unit cost results.

OWNER_INSTALLED, INSTALLER_EXPERIENCE, RETAILER_EXPERIENCE, POPULATION_DENSITY, and THIN_FILM (the CPUC dataset does not contain many of these variables, and so includes fewer crossed terms).

Each of these models was applied to: (1) just the completed PV systems, (2) to "pooled" data including both completed and approved systems, and (3) in the case of the CPUC dataset, to pooled data including completed, approved, and waitlisted systems. Though some differences in regression results exist depending on which dataset was used, they are not substantial. The results that follow therefore emphasize the fully pooled datasets (i.e., completed and approved systems for the CEC; completed, approved, and waitlisted systems for the CPUC). For reference purposes, Appendix C presents regression results for just the completed systems.

Though we present results from all four models for both the CPUC and CEC pooled datasets, Model 2 was unsuccessful when applied to the CPUC SGIP data: coefficients for MODULE_COST_INDEX and the MAX_STD_REBATE were sometimes of opposite sign from what we expected, and colinearity was a clear problem. After numerous attempts, we were unsuccessful in rectifying this problem. We therefore place little emphasis on Model 2 results for the CPUC dataset. For a similar reason, we excluded the REBATE_%_CAP variable from the CPUC's Model 3 results. The unfortunate result of these exclusions is that the CPUC models provide substantially less policy richness than the CEC's models.

4. Analysis Results: CEC Systems Under 30 kW in Size

4.1 Summary Statistics

Figures 4 through 8 show in graphical format some of the potential relationships between pre-rebate installed cost (in 2004 $/$W_{AC}$) and a subset of the potential explanatory variables described in Section 3. The figures use the pooled CEC dataset of PV systems under 30 kW in size, including both completed and approved systems.

The overall average pre-rebate installed cost of the CEC systems is $9.6/$W_{AC}$ (2004 $), which equates to approximately $8.0/$W_{DC-STC}$ (assuming a 0.84 de-rating). A review of the bivariate relationships portrayed in Figures 4 and 5 suggest that average installed costs exhibit some economies of scale, most pronounced in systems less than 10 kW in size, and that average installed costs – over all system sizes – have generally declined over time.

In particular, Figure 4 shows that over the course of the program, average system costs for installations under 2 kW have been more than $10.5/$W_{AC}$ (2004 $), while systems over 10 kW have had average costs of roughly $8.5/$W_{AC}$ (2004 $). Meanwhile, Figure 5 shows that average pre-rebate installed costs (in 2004 $) have declined substantially over time (where time is expressed in half-year intervals), from more than $12/$W_{AC}$ in the initial year of the program to less than $9/$W_{AC}$ for the more recent installations.

Some of this cost decline is due to a reduction in high-cost outliers. For example, from 1998 through 2000, 14% of systems had costs greater than $4/W above the average system cost at that time. In 2004 and 2005, just 1% of systems had costs more than $4/W above the average system cost. This reduction in outliers is not surprising, and likely reflects a maturing PV market in which price competition is increasing over time. However, as shown by the cost distributions presented in Appendix B, the overall cost reductions are due not just to a narrowing of the cost range, but also to a shift of the distribution towards lower-cost systems.

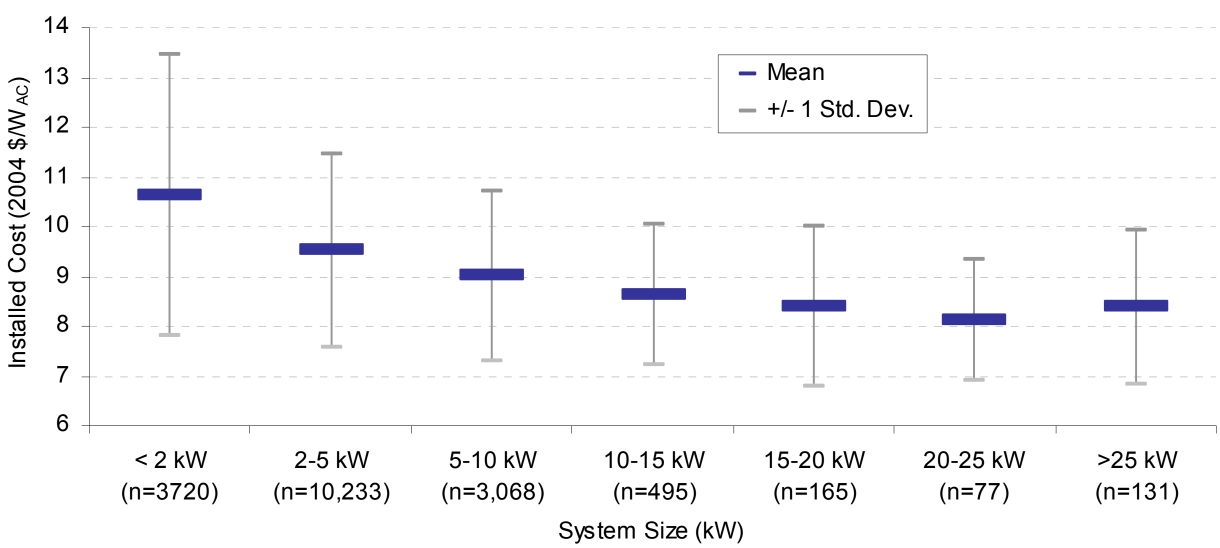
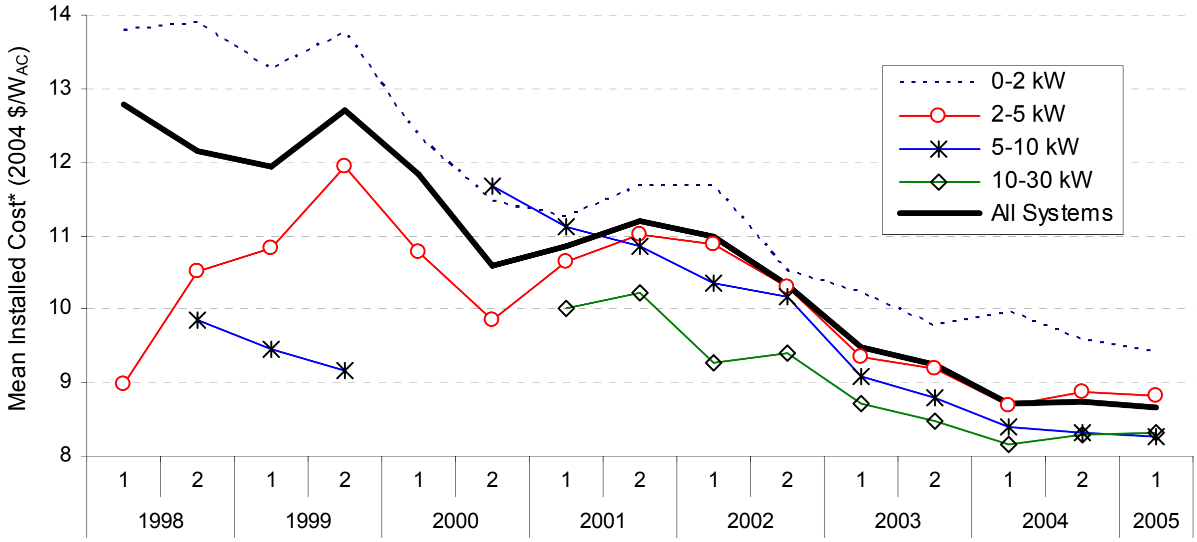


Figure 4. Average Installed Cost, by System Size (CEC)



* Within each system size bin, we excluded any 6-month period that contained fewer than 5 applications. This impacted only the 2 largest bins (>5 kW).

Figure 5. Average Installed Cost Over Time (6-Month Intervals), by System Size (CEC)

Figure 6 depicts many of the cost relationships revealed by our use of dummy variables. Though these bivariate results do not control for the impact of other variables, many of the relationships shown in Figure 6 (e.g., systems installed in new home construction and affordable housing costing less than retrofitted systems, owner-installed systems costing less than contractor-installed systems, etc.) are generally consistent with those revealed through the multivariate regression results, as presented in the next section.

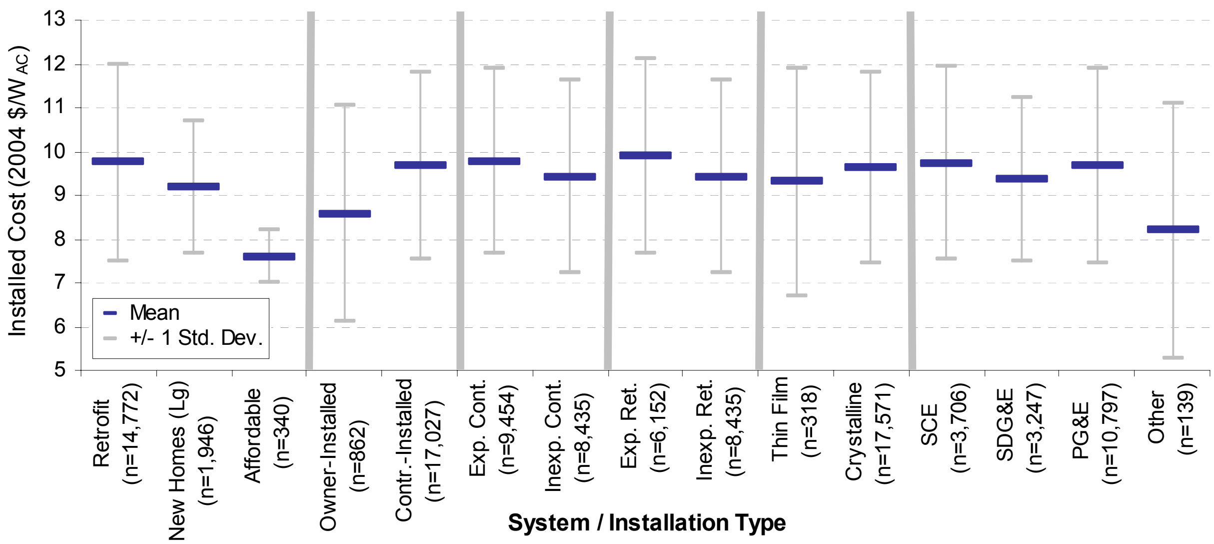


Figure 6. Average Installed Cost, by System or Installation Type (CEC)

Finally, Figures 7 and 8 illustrate the influence of module costs, non-module costs, and rebates on average pre-rebate total installed costs over time (with time expressed in half-year intervals). Specifically, Figure 7 shows a tight relationship between standard rebate levels and average pre-rebate installed costs, particularly since mid-2000, with pre-rebate installed costs following rebate levels both higher (in 2001) and then gradually lower (starting in 2003). The average cost to the PV customer has remained more or less constant since 2001, with some modest increase in customer costs since the end of 2003.

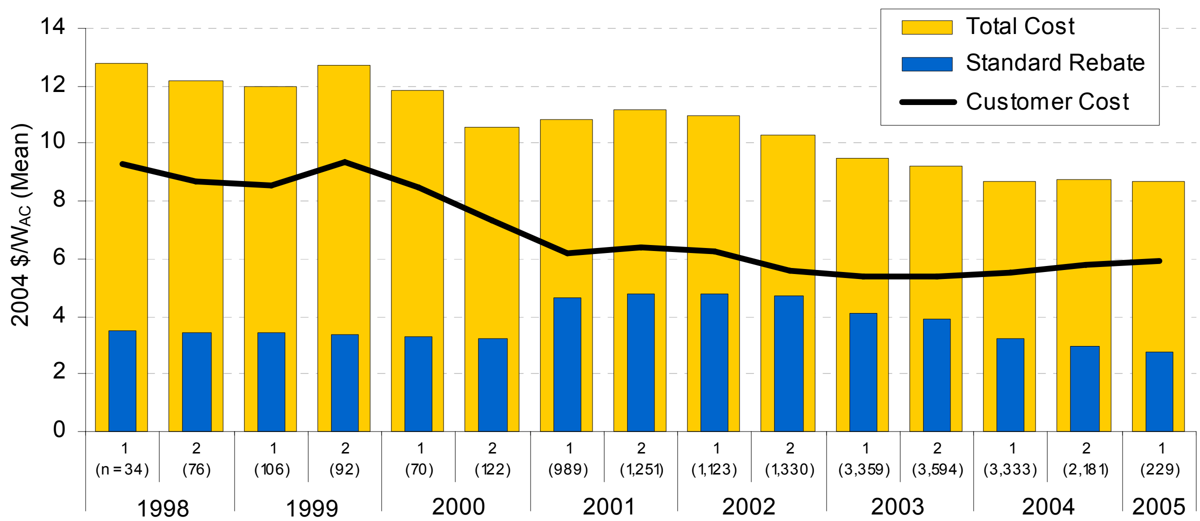


Figure 7. Impact of Standard Rebate Level on Average Installed Cost (CEC)

As shown in Figure 8, reductions in average total pre-rebate installed costs over time have been largely driven by reductions in non-module costs. Module costs (represented here by a generic module cost index – not by actual application data on module costs) have declined somewhat over the course of the CEC's program, but non-module costs have dropped significantly, from roughly \$8/W_{AC} (2004 \$) during the initial years of the program to just over \$5/W_{AC} (2004 \$) more recently. This trend in non-module costs is encouraging, and is perhaps the most that an individual PV program can hope to achieve given that module costs are set in a worldwide market and are therefore heavily influenced by factors outside of the control of the local program (e.g., demand for PV in Japan and Germany). As noted earlier, however, we are unable to prove conclusively that the reductions in non-module costs in California have been caused by the state's incentive programs absent analysis of non-module cost trends in other control markets.

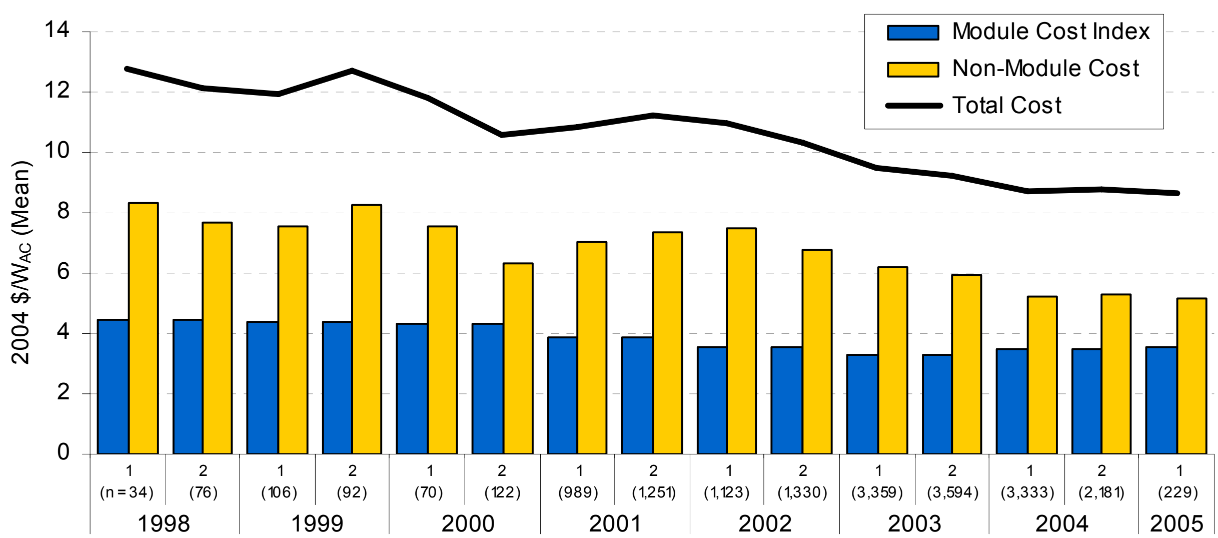


Figure 8. Average Installed Cost Over Time, by Module and Non-Module Costs (CEC)

4.2 Regression Results

The bivariate relationships shown above are intriguing, but regression analysis is required to control for the influence of other factors. Table 4 summarizes regression results for the four basic models specified earlier, as applied to the pooled CEC dataset for systems under 30 kW in size. Although these regressions only explain a fraction of the overall variance in the data (R^2 of 0.29 to 0.32), a large proportion of the independent variables have statistically significant (defined here as at least 90% significance, or p-values of less than 0.10) impacts on pre-rebate installed costs. Most of these relationships support the hypotheses reported earlier, and are consistent with corresponding regressions applied to just the CEC's completed PV systems (see Appendix C). There remains a significant amount of unexplained variation in the underlying data, however, suggesting that PV costs are impacted by a number of variables not included in our analysis[30] and/or that there is simply a considerable amount of unexplainable noise in PV system costs that may reflect an immature market in which price competition is not robust.

4.2.1 The Impact of Time, Average Module Cost, and System Status

Model 1 results (see Table 4) show that, with each successive monthly period, an average cost reduction of \$0.058/W_{AC} (all data reported here will be in 2004 \$) has been experienced, equating to an annual reduction of approximately \$0.70/W_{AC}. At the mean system cost of \$9.6/W_{AC}, this represents a 7.3% annual reduction in pre-rebate installed costs, significantly outpacing the 2.6% average annual inflation rate over the approximately seven year period covered by the data (implying that prices have fallen in nominal terms as well).

Some of this decline is due to a decrease in the average cost of PV modules over the course of the program (notwithstanding recent increases in those costs – see Figure 8). Pre-rebate system costs may also be affected by changing rebate levels over time (see Figure 7). Model 2 includes independent variables that control for these influences, and the regression results show that even considering these effects, pre-rebate non-module system costs have dropped by an average of approximately \$0.025/W_{AC} each month, or \$0.30/W_{AC} each year. At the mean system cost, this non-module cost reduction is 3.1% per year, still exceeding (to a limited extent) the average impact of inflation on nominal costs over the seven-year time period.

Model 4, by including crossed terms, helps to illuminate how system size has influenced cost reductions over time. In particular, the coefficient for the variable DATE_MONTH x LN_SIZE indicates that larger systems have – on average – experienced a smaller drop in costs over time than have smaller systems. Applying this coefficient, a 10 kW PV system would experience an annual reduction in costs that is roughly \$0.20/W_{AC} less than that of a 2 kW system. That costs are dropping more rapidly for smaller systems should perhaps come as little surprise: with a greater fraction of costs used for labor and balance-of-systems, smaller PV systems may have the most to gain from distribution and installation channel efficiencies.

[30] For example, the low resolution of the data prohibited us from distinguishing between different product types that can have widely varying costs – e.g., roof-mounted systems vs. tracking systems vs. systems structured as carports.

Table 4. Regression Results for CEC Dataset (PV Systems < 30 kW)

Variable	Model 1		Model 2		Model 3		Model 4	
	coef.	*p*	*Coef.*	*p*	*coef.*	*p*	*coef.*	*p*
INTERCEPT	19.921	<0.01	11.562	<0.01	12.334	<0.01	14.202	<0.01
TIME_MONTH	-0.058	<0.01	-0.025	<0.01	-0.026	<0.01	-0.100	<0.01
LN_SYSTEM_SIZE	-0.846	<0.01	-0.853	<0.01	-0.856	<0.01	-1.411	<0.01
APPROVED	0.258	<0.01	0.377	<0.01	0.357	<0.01	0.257	<0.01
SCE	-0.098	<0.01	-0.101	<0.01	-0.109	<0.01	-0.081	0.02
SDG&E	-0.291	<0.01	-0.336	<0.01	-0.308	<0.01	-0.366	<0.01
OTHER_UTILITY	-2.126	<0.01	-2.436	<0.01	-2.518	<0.01	-2.432	<0.01
NEW_CONST_LARGE	-1.188	<0.01	-1.228	<0.01	-1.206	<0.01	-1.353	0.02
NEW_CONST_SMALL	0.179	<0.01	0.180	<0.01	0.175	<0.01	2.118	0.07
SCHOOLS	0.285	0.25	0.365	0.14	0.351	0.16	0.216	0.39
AFFORDABLE_HOUSING	-1.925	<0.01	-1.898	<0.01	-1.845	<0.01	-1.791	<0.01
OWNER_INSTALLED	-1.755	<0.01	-1.800	<0.01	-1.803	<0.01	-0.686	0.58
INSTALLER_EXPERIENCE	0.282	<0.01	0.288	<0.01	0.288	<0.01	1.925	<0.01
RETAILER_EXPERIENCE	0.169	<0.01	0.171	<0.01	0.170	<0.01	0.325	0.51
SQRT_POP_DENSITY	4.2E-03	<0.01	4.2E-03	<0.01	4.2E-03	<0.01	1.9E-02	<0.01
THIN_FILM	-0.699	<0.01	-0.732	<0.01	-0.733	<0.01	-5.389	<0.01
MAX_STD_REBATE			0.730	<0.01	0.556	<0.01	0.794	<0.01
MODULE_COST_INDEX			1.008	<0.01	0.906	<0.01	1.218	<0.01
REBATE_%_CAP					0.219	0.08		
STATE_TAX_CREDIT					1.647	<0.01		
RETAIL_RATES					1.151	0.59		
DATE_MONTH x LN_SIZE							0.011	<0.01
NEW_CONST_LARGE x LN_SIZE							-0.685	<0.01
NEW_CONST_SMALL x LN_SIZE							-0.019	0.86
OWNER_INSTALLED x LN_SIZE							7.2E-03	0.96
INSTALLER_EXP x LN_SIZE							-0.079	0.16
RETAILER_EXP x LN_SIZE							0.075	0.18
SQRT_POP_DENSITY x LN_SIZE							-2.2E-03	<0.01
THIN_FILM x LN_SIZE							0.295	0.26
NEW_CONST_LARGE x TIME							0.083	<0.01
NEW_CONST_SMALL x TIME							-0.024	<0.01
OWNER_INSTALLED x TIME							-0.020	<0.01
INSTALLER_EXP x TIME							-0.015	<0.01
RETAILER_EXP x TIME							-0.012	<0.01
SQRT_POP_DENSITY x TIME							4.8E-05	0.21
THIN_FILM x TIME							0.042	<0.01
R-SQUARED	0.29		0.30		0.30		0.32	
OBSERVATIONS (n)	17,889		17,889		17,889		17,889	

The module cost index variable is included in Models 2, 3 and 4, and averages near unity in all cases (1.01, 0.91, and 1.22). This is to be expected, and shows that aggregate changes in average module costs translate directly into similar-sized changes in pre-rebate system installed costs. Approved but not yet completed systems are found to have costs that are on average \$0.25-\$0.38/W_{AC} higher than completed systems (depending on the regression run). The reason for this differential is not altogether clear, but may be due to the fact that most of the approved systems in the CEC's dataset have been recently submitted, during a time in which silicon shortages have yielded higher module costs.

4.2.2 Policies and Incentives

The level and design of the CEC's rebate also appears to have had a significant impact on pre-rebate installed costs. Though the coefficient is somewhat sensitive to model specification (due in part to colinearity with other variables), the regression results for MAX_STD_REBATE suggest – as does Figure 7 – that pre-rebate installed costs have tracked (to some degree) the level of the rebate itself, and that system purchasers have therefore not benefited from the *full* amount of the rebate (with some of it "captured" by system retailers or installers through higher prices).[31]

In particular, we find that each $1/$W_{AC}$ change in the rebate level has, on average, yielded a $0.55-0.80/$W_{AC}$ change in pre-rebate installed costs (the range reflects the results of the different regression runs for Models 2, 3, and 4). In other words, when the CEC increased its rebate level by $1.5/$W_{AC}$ (from $3/$W_{AC}$ to $4.5/$W_{AC}$) in early 2001, system purchasers only realized $0.3-$0.7/W_{AC} of that increase, with the remaining $0.8-$1.2/W_{AC} being "captured" by system retailers or installers through correspondingly higher prices. By the same token, our regression results (which do not distinguish between an *increase* or *decrease* in rebate levels[32]) suggest that as the CEC has gradually reduced its rebate level since early 2003, system retailers have absorbed some of the decrease by reducing prices, thereby leaving the net cost to the system purchaser essentially unchanged. These results are consistent with the bivariate relationships presented earlier in Figures 7 and 8.

Though colinearity problems exist for the variables added in Model 3 (REBATE_%_CAP, STATE_TAX_CREDIT, and RETAIL_RATES), regression results provide weak evidence that the existence of the percentage rebate cap may also have had some impact on pre-rebate system costs. Model 3 shows that average system costs were roughly $0.20/$W_{AC}$ higher during the period in which the percentage cap was in place, than when it was removed. There is also some evidence that the size of the state tax credit may have impacted system costs, with the coefficient for STATE_TAX_CREDIT implying that an increase in the credit from 0% to 15% was matched with an increase in system installed costs of approximately $0.25/$W_{AC}$. We find no statistical evidence that retail rates have had an impact on pre-rebate installed costs.[33]

4.2.3 System Size

Larger systems are found to be systematically less expensive than smaller systems, with LN_SYSTEM_SIZE showing statistically significant and sizable effects. Compared to a 1 kW system, regression results for Model 2 suggest that larger installations have lower costs as

[31] Though some might be inclined to read into these results an argument for switching from capacity-based to performance-based incentives, we note that there is nothing in our dataset or analysis that allows us to comment on the relative superiority of one incentive type over another.
[32] We did test for differential regression results depending on whether MAX_STD_REBATE increased or decreased, but were unable to find any significant results.
[33] Though again, our retail rate variable only indirectly accounts for California's highly tiered rate structure, and therefore may not be adequately specified.

follows: 3 kW (\$0.90/W_{AC} lower); 5 kW (\$1.4/W_{AC} lower); 10 kW (\$2/W_{AC} lower); and 30 kW (\$2.9/W_{AC} lower). These results are consistent with the bivariate relationships presented earlier in Figure 4, and show that economies of scale are particularly dramatic among smaller systems, but diminish somewhat among larger systems (i.e., costs drop by \$2/W_{AC} for 10 kW systems relative to 1 kW systems, but only drop by an additional \$0.90 W_{AC} for 30 kW systems).

4.2.4 Installation Type

The nature of the installation clearly has had a substantial impact on average pre-rebate installed costs. Systems installed or planned for installation in large new residential developments (totaling 1,946 systems) show cost reductions of approximately \$1.2/W_{AC}, on average, compared to the general retrofit market. Similarly, the 340 systems used in affordable housing applications, which often involve new construction and presumably enable bulk system installation, exhibit costs that are \$1.9/W_{AC} lower than the general retrofit market, on average. These results are directionally consistent with the bivariate relationships shown earlier in Figure 6. Systems installed in single new homes (or small clusters) exhibit modestly higher costs of approximately \$0.18/W_{AC} on average, perhaps due to the custom-designed nature of many of these systems, as well as a lack of the economies of scale possible in larger new home developments. Systems installed at schools (of which there are only 60, and most are retrofits) do not have statistically significant differences in cost compared to the general retrofit market.

Some of these cost differentials have varied with time and, to a lesser extent, with system size, as revealed by the results of Model 4. The cost savings associated with systems installed in large new home developments, for example, are shown to be higher for larger systems, but also to be narrowing over time. This latter finding is consistent with results presented in Appendix C, which show that *completed* large residential development projects have experienced cost savings that that have averaged \$1.7/W_{AC}, larger than the \$1.2/W_{AC} average cost advantage show when completed and approved systems are considered together. The cost disadvantage of systems installed individually or in small clusters on new homes has similarly been narrowing with time.

4.2.5 Module Type

Projects using thin film PV technology – of which there are 318 – are found to have had systematically lower costs than those relying on traditional crystalline silicon, with a differential of roughly \$0.70/W_{AC} on average. These results are generally consistent with the mean costs shown earlier in Figure 6. Model 4, however, shows that this cost differential has narrowed over time: the coefficient for the THIN_FILM x TIME variable is positive and statistically significant. This trend is also consistent with the regression results presented in Appendix C for only completed systems, which reveal that completed systems using thin film technology have had costs that are approximately \$0.90/W_{AC} lower than those employing crystalline silicon.

4.2.6 Installer/Retailer Type and Experience

Owner-installed systems (totaling 862 systems, or 5% of our dataset) are found to have considerably lower reported costs than contractor-installed systems, with a \$1.8/W_{AC} savings on average over the course of the CEC's rebate program. More-experienced installers and retailers are found to charge slightly more for their services, relative to installers and retailers with less experience: approximately \$0.29/W_{AC} and \$0.17/W_{AC}, respectively. These results are generally consistent with the bivariate relationships depicted earlier in Figure 6.

These differentials have, in some cases, changed with time and system size (see Model 4 results). The reported cost savings from owner-installed systems, for example, have increased over time. The cost disadvantage associated with more experienced installers and retailers, on the other hand, has decreased with time. There is also some statistical evidence (which is stronger in the completed-only regression than in the pooled regression) that installer experience imposes a less significant cost disadvantage on larger systems than on smaller ones.

4.2.7 System Location and Population Density

In comparison to the "base" service territory of PG&E (where 60% of the systems have been located), systems installed in other areas report lower pre-rebate costs. For example, systems located in SCE's service territory are found to be approximately \$0.10/W_{AC} cheaper, while systems located in SDG&E's territory have reported roughly \$0.30/W_{AC} lower costs, on average. Systems sited in other utility territories have reported substantially lower costs still, \$2.1-2.5/W_{AC} below those in PG&E.[34] These other territories primarily include public power utilities, and the lower costs reported for systems may reflect the presence of other local utility incentives that are not tracked by the CEC, or may otherwise reflect local bulk purchase and installation programs. These potential explanations are pure suppositions, however – nothing in our dataset or analysis allows us to definitively explain the inter-utility cost differences described above (we did try an imperfect measure of utility-specific retail rates, but with little success).

The population density of the location of installation also appears to have some effect on system costs, with more densely populated areas experiencing higher average costs. As an example, the regression results suggest that moving from an area with a population density of 500 per square mile to one of 7,000 per square mile (the mean population density in our data is 2,600) results in an average system cost increase of roughly \$0.25/W_{AC}. Model 4 results further show that this cost disadvantage appears to be greater for smaller systems. This finding is consistent with the idea that population density may be a proxy for the cost of living, and therefore labor costs. One would expect smaller systems to generally be more sensitive to labor costs than larger systems, because small systems likely require a greater proportionate amount of installation labor.

[34] If one considered just completed systems, as reported in Appendix B, these cost differentials are somewhat larger.

5. Analysis Results: CPUC Systems 30 kW and Above in Size

5.1 Summary Statistics

Focusing now on the larger systems (30 kW and above) under the CPUC's SGIP program, Figures 9 through 13 depict some of the potential relationships between pre-rebate installed cost and some of the pertinent explanatory variables described in Section 3. The figures use the pooled CPUC dataset including completed, approved, and waitlisted systems.

The overall average pre-rebate installed cost of the CPUC systems is \$8.8/W_{AC} (2004 \$), which equates to approximately \$7.4/W_{DC-STC} (assuming a 0.84 de-rating). A review of the data presented in Figure 9 suggests that, as was the case for CEC-funded systems, the average installed cost of CPUC-funded systems exhibits economies of scale, most pronounced for systems less than 450 kW. The up tick in average installed costs for systems sized between 60 and 100 kW is somewhat of an anomaly, being heavily influenced by 59 identical applications (out of 209 total applications in this size range), all submitted on the same day, by the same installer, and at the same estimated installed cost of \$9.82/W_{AC} (2004\$). Overall, the largest systems funded by the CPUC's program have costs that are on average roughly \$1/W_{AC} lower than the smaller systems funded by this program.

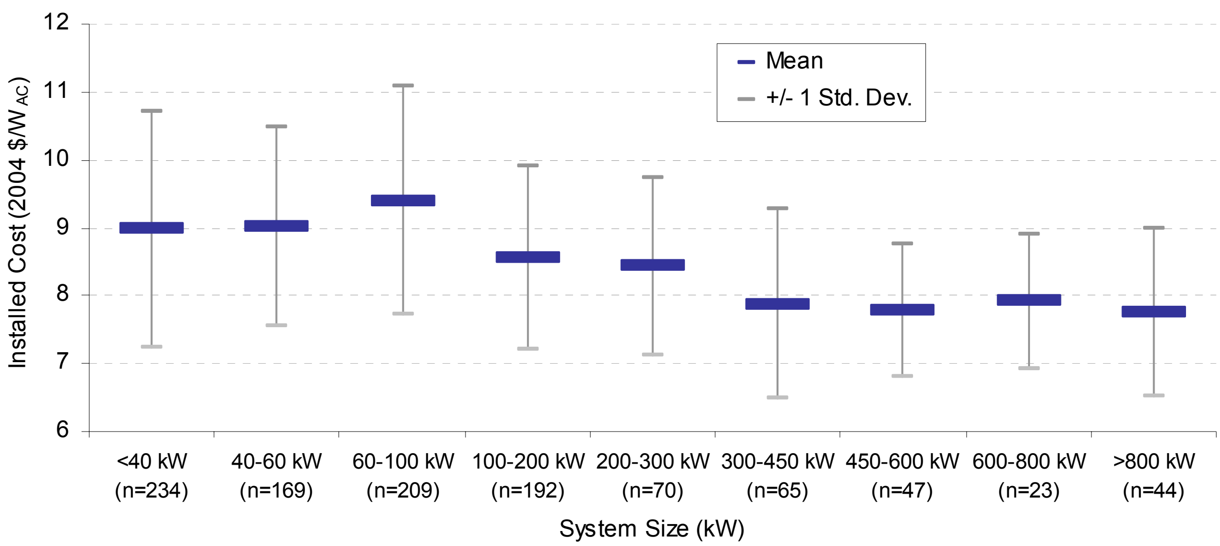
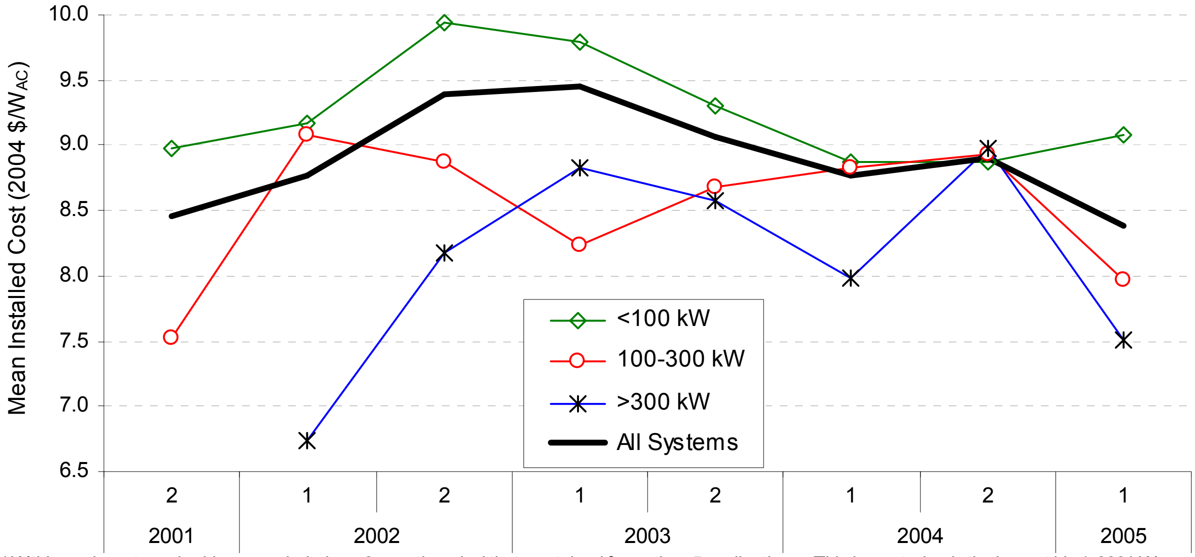


Figure 9. Average Installed Cost, by System Size (CPUC)

In contrast to the longer-running CEC program, which exhibited clear downward cost trends over time, costs under the CPUC's program have been far more flat (or even increasing, and then decreasing), as shown in Figure 10, though costs do appear to have declined since 2002. Appendix B presents the distribution of these costs, in modified histogram form, and shows that the distribution appears to have shifted toward lower-cost systems over time.



* Within each system size bin, we excluded any 6-month period that contained fewer than 5 applications. This impacted only the largest bin (>300 kW).

Figure 10. Average Installed Cost Over Time (6-Month Intervals), by System Size (CPUC)

Figure 11 depicts many of the cost relationships revealed by our use of dummy variables. Though not able to control for other factors, many of the relationships shown in Figure 11 are consistent with those revealed through multivariate regression results, as presented in the next section.

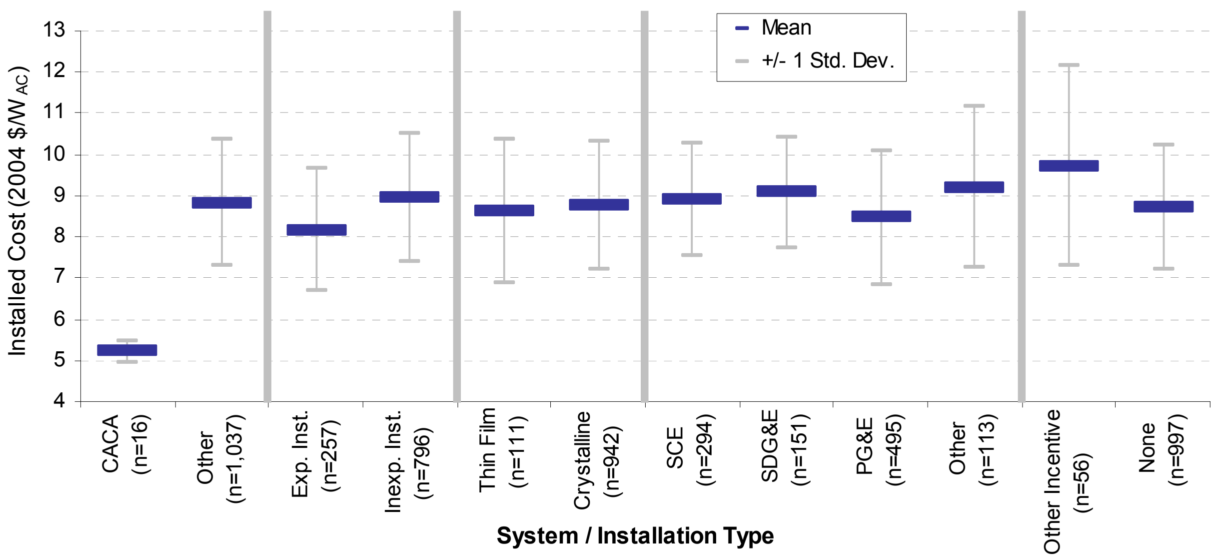


Figure 11. Average Installed Cost, by System or Installation Type (CPUC)

Finally, Figures 12 and 13 illustrate the influence of module costs, non-module costs, and rebates on average pre-rebate total installed costs over time (with time expressed in half-year intervals). The relationships depicted here are not as strong as they were under the CEC's program, perhaps in part because of the relatively short history of the program, coupled with an unwavering rebate level over most of that time period.[35]

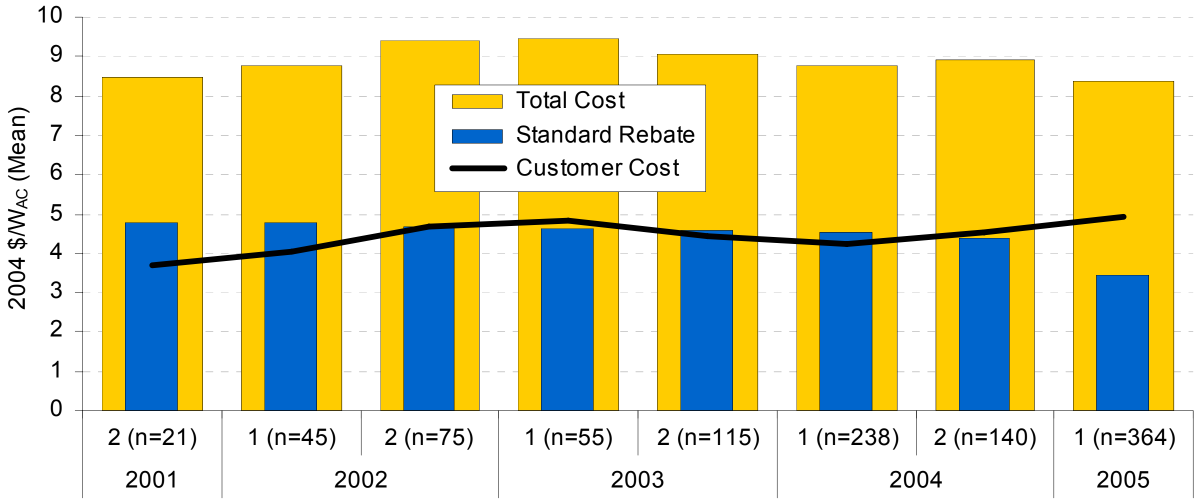


Figure 12. Impact of Rebate Level on Average Installed Cost (CPUC)

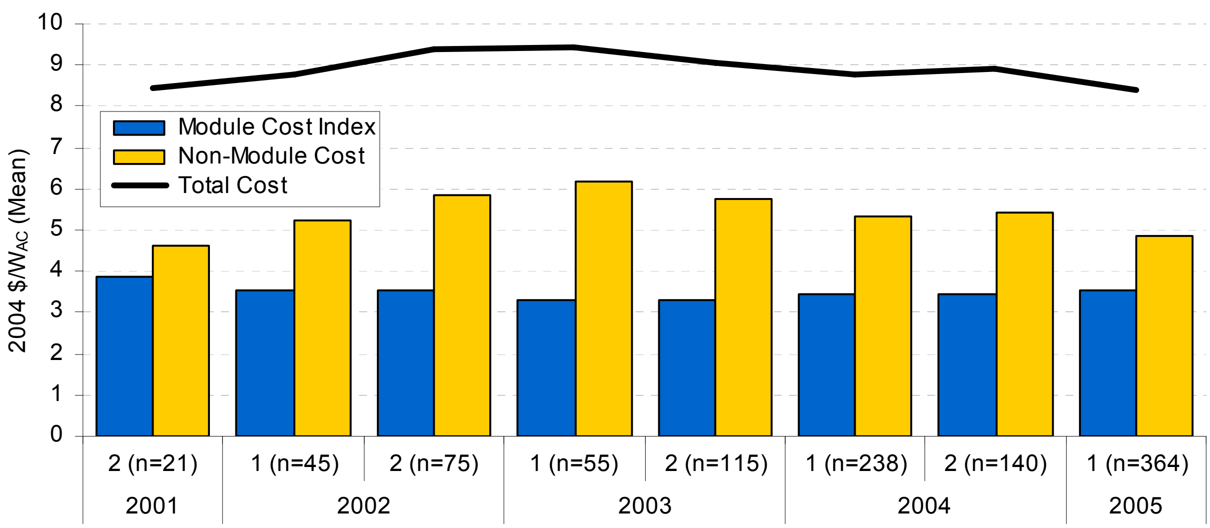


Figure 13. Average Installed Cost Over Time, by Module and Non-Module Costs (CPUC)

5.2 Regression Results

As with the earlier CEC analysis, Table 5 summarizes our regression results for the fully pooled CPUC dataset for the four basic models specified earlier (regression results for just the completed systems are reported in Appendix C). The regressions only explain a fraction of the overall variance in the data (R^2 of 0.25), and a higher proportion of the independent variables are

[35] Our data and analysis are not sufficient to allow us to conclude with certainty the reasons for the differences between the CPUC and CEC programs.

statistically insignificant (i.e., p-value >0.10) than in the earlier CEC results. This may be caused by the much smaller sample size of the CPUC dataset, or more fundamentally from greater "noise" in that dataset. Nonetheless, a number of the independent variables are significant, and many of the relationships support the hypotheses reported earlier.

Table 5. Regression Results for CPUC Dataset (PV Systems 25 - 1,063 kW)

Variable	Model 1		Model 2		Model 3		Model 4	
	coef.	*P*	*coef.*	*p*	*coef.*	*p*	*coef.*	*p*
INTERCEPT	11.258	<0.01	18.565	<0.01	10.753	<0.01	12.022	<0.01
TIME_MONTH	-0.030	<0.01	-0.053	<0.01	-0.026	<0.01	-0.049	0.03
LN_SYSTEM_SIZE	-0.322	<0.01	-0.335	<0.01	-0.232	<0.01	-0.510	<0.01
APPROVED	0.067	0.69	0.209	0.32	0.077	0.66	0.065	0.71
WAITLISTED	-0.222	0.32	-0.354	0.19	-0.265	0.23	-0.270	0.23
SCE	0.309	<0.01	0.292	0.01	0.283	0.02	0.282	0.01
SDG&E	0.486	<0.01	0.501	<0.01	0.400	0.07	0.430	<0.01
OTHER_UTILITY	0.072	0.69	0.054	0.76	0.009	0.97	0.059	0.74
OTHER_INCENTIVES	0.626	0.10	0.626	0.09	0.567	0.13	0.676	0.08
INSTALLER_EXPERIENCE	-0.686	<0.01	-0.671	<0.01	-0.673	<0.01	-0.134	0.76
CALIF_CONST_AUTHORITY	-4.028	<0.01	-4.096	<0.01	-4.042	<0.01	-3.649	<0.01
THIN_FILM	0.183	0.18	0.172	0.23	0.206	0.14	-2.434	<0.01
MODULE_COST_INDEX			-1.116	0.13				
MAX_STD_REBATE			-0.635	<0.01				
STATE_TAX_CREDIT					3.011	0.06		
RETAIL_RATES					-1.695	0.70		
DATE_MONTH x LN_SIZE							0.005	0.34
INSTALLER_EXP x LN_SIZE							-0.075	0.37
THIN_FILM x LN_SIZE							0.450	<0.01
INSTALLER_EXP x TIME							-0.005	0.61
THIN_FILM x TIME							0.016	0.26
R-SQUARED	0.25		0.25		0.25		0.25	
OBSERVATIONS (n)	1,053		1,053		1,053		1,053	

5.2.1 The Impact of Time, Average Module Cost, and System Status

Though Figure 10 does not provide a clear visual trend of declining system costs over time, our Model 1 regression results (which control for the impact of other variables) reveals an average cost reduction of \$0.03/W_{AC} per month (all data reported here will be in 2004 \$), equating to an annual reduction that has averaged \$0.36/W_{AC}. At the mean system cost of \$8.8/W_{AC}, this represents a 4.1% annual reduction in pre-rebate installed costs, outpacing the 2.4% average inflation rate over the nearly four-year period covered by the data. Appendix C shows that for completed systems, the average cost reductions have been slightly larger at \$0.44/W_{AC} per year.

These yearly cost declines are substantially smaller than those for the CEC dataset (which had annual average reductions of approximately \$0.70/W_{AC}), though it deserves note that the larger systems (i.e., 10-30 kW) in the CEC dataset were found to be on a more moderate cost trajectory over time, relative to the smaller systems supported by the CEC. Similarly, though not statistically significant (p = 0.34), the coefficient on the crossed DATE_MONTH x LN_SIZE in our Model 4 results for the CPUC suggests that larger CPUC systems may also have witnessed less pronounced reductions over time than smaller systems. It is not entirely clear whether the more modest average cost declines in the CPUC dataset are due to: (1) fundamental differences in the design of the CEC and CPUC programs; (2) differences in the size of the underlying PV systems; or (3) differences in the time periods covered (with the CEC's program operating over a seven-year period, compared to the CPUC's four-year period). Some of these issues are explored further in Section 6.

As reported in Section 4.2.1, our analysis of the CEC data revealed that some of the annual cost reductions were due to changes in PV module costs. We were unable to replicate this finding with the CPUC dataset. As mentioned earlier, we were unsuccessful in developing a reasonable set of Model 2 results for the CPUC dataset, as both the MODULE_COST_INDEX and the MAX_STD_REBATE variables showed coefficients of the opposite sign than expected, with colinearity being a clear problem. We therefore heavily discount our Model 2 results here, and are unable to say anything definitive about the impact of module cost changes on system installed costs. These results suggest that the CPUC's dataset is more "noisy" and that cost trends are less-discernable than was the case with the CEC dataset (the bivariate figures in Section 5.1 also support this contention).

Though not statistically significant, waitlisted systems appear to have been priced somewhat below (by ~$0.25/W_{AC}$) completed systems on average, perhaps suggesting that costs have a tendency to rise between the date of application and completion. On the other hand, similar results are not found for approved systems.

5.2.2 Policies and Incentives

Our inability to formulate a useful Model 2 for the CPUC dataset yields overall results that are substantially less policy-rich than those based on the CEC's dataset. The coefficient for MAX_STD_REBATE, for example, is of the opposite sign that one would expect, suggesting that it may be picking up some unknown trend in the data (for the completed-only dataset in Appendix C, the coefficient is positive, but not statistically significant). Similarly, due to colinearity with the MAX_STD_REBATE variable, we were unable to include a REBATE_%_CAP variable in Model 3. We again find no statistical evidence that retail rates have had an impact on pre-rebate installed costs, though as noted earlier, our retail rate variable is imperfect.

Despite these limitations, at least two interesting policy-related results derive from our regression analysis of the CPUC dataset:

- First, as with the CEC data, we find some weak evidence that the size of the state tax credit has affected pre-rebate installed costs (though colinearity is again of some concern here). Specifically, the coefficient for STATE_TAX_CREDIT implies that an increase in the state credit from 0% to 15% was matched with an increase in installed costs of approximately $0.45/W_{AC}$. The same result, however, is not supported by the completed-only regressions in Appendix C, which show a statistically insignificant coefficient for this variable.

- Second, we find that the existence of other sizable local incentives for PV installations (which are, to some degree, additive to the CPUC's incentives) have affected system installed costs. Specifically, the 56 PV systems that have received (or will receive) local incentives of more than $2/W_{AC}$ (typically offered by the local publicly owned utility) have recorded higher costs of ~$0.60/W_{AC}$, on average (these results are largely consistent with the bivariate relationship shown in Figure 11). For the 38 completed PV installations receiving such incentives, the average differential is higher, at approximately ~$0.80/W_{AC}$ (see Appendix C). This suggests that heavy subsidies dampen, to some degree, the motivation of installers to provide, and/or customers to seek, lower installed costs.

In addition, though we were unable to evaluate the impact of the percentage rebate cap through regression analysis, it is interesting to note that 30% of all PV systems funded by the CPUC during the period in which the 50% cap was in place were priced from $8.75-$9.25/W_{AC}$ (50% were priced from $8-$9.25/W_{AC}$). The corresponding numbers in the four-month period of our sample after the cap was dropped (in mid-December 2004) are 5% and 11.5%, respectively, with the entire cost distribution having shifted to the left (i.e., toward lower costs). These summary statistics support the contention that the percentage cap had the effect of inflating costs.

5.2.3 System Size

As with the CEC-funded systems, larger installations are found to be systematically less expensive than smaller systems on average. Based on Model 1 results, and compared to a 30 kW system, we find that larger installations have lower average costs as follows: 100 kW ($0.40/W_{AC}$ lower); 250 kW ($0.70/W_{AC}$ lower); 500 kW ($0.90/W_{AC}$ lower); and 1,000 kW ($1.1/W_{AC}$ lower). These regression results are largely consistent with the bivariate relationships depicted in Figure 9 (again, discounting the 60-100 kW size range due to potential data anomalies).

5.2.4 Module Type

Though only bordering on statistical significance (and far from significance in the completed-only regressions reported in Appendix C), projects using thin film technology – of which there are 111 – are found to have had slightly higher costs on average over the course of the CPUC program (~$0.20/W_{AC}$). This differs from the CEC results, which showed systematically lower costs of roughly $0.70/W_{AC}$ on average. The reasons for this difference are unclear. Model 4 demonstrates that the CPUC thin film cost differential has varied with system size, with larger thin film systems being relatively more expensive (compared to crystalline silicon) than smaller thin film installations.

5.2.5 Installer Type and Experience

Unlike the CEC results, more-experienced installers under the CPUC's program have priced their systems at lower levels than less-experienced installers, with a differential of nearly $0.70/W_{AC}$ on average (experienced installers of completed systems have had prices ~$0.45/W_{AC}$ lower than their less-experienced counterparts, on average). Model 4 shows that this differential has not changed markedly with time, or with system size (though Model 4 results in Appendix C suggest that the advantages of installer experience for completed systems have narrowed with time). Why the impact of installer experience varies between the CEC and CPUC datasets is unclear.

Relative to the other systems in the dataset, the 16 systems managed and installed by the California Construction Authority have come in at a substantially and surprisingly lower cost of ~$4/$W_{AC}$, on average. This may be due to the bulk purchase of PV equipment made possible by these multiple installations, and by the fact that the Construction Authority sought to bid out different elements of their projects separately, eliminating the need for a value-added, full-service installer. Some have also speculated that the CCA is able to install systems at apparently lower costs than the PV industry at large due to the fact that it has no marketing, sales, or overhead costs, and/or that certain internal costs are not reported.

5.2.6 System Location

In comparison to the majority of systems installed in PG&E's territory (where 47% of the CPUC-funded systems have been located), systems installed in other areas report higher pre-rebate costs. Systems located in SCE's service territory are found to be approximately $0.30/$W_{AC}$ more expensive, while systems located in SDG&E's territory have reported roughly $0.45/$W_{AC}$ higher costs, on average (the OTHER_UTILITY variable is not statistically significant). The reasons for these inter-utility cost differences (which differ from the CEC results) are unclear, and would require further analysis. Furthermore, similar results are not found in the regressions for completed systems shown in Appendix C, where none of the utility dummy variables reach statistical significance.

6. Comparing the CEC and CPUC Programs

Sections 4 and 5 analyzed the CEC and CPUC datasets separately, not allowing for ready comparison between the two programs. In this section we are interested in two specific questions that can be explored through a combined, side-by-side analysis of the two programs:

- Are there significant pre-rebate installed cost differences between the two programs?
- Have costs declined with time in a comparable fashion across the two programs?

6.1 Fundamental Cost Variations Between Systems Funded by the Two Programs

The CEC and CPUC programs have operated over different time periods, and have targeted different system sizes, complicating direct comparisons between the two. Figure 14 shows average pre-rebate system installed costs, by size range, for both the CEC and CPUC programs. The figure only includes rebate applications received during the period of time (within our sample) in which both programs were operating contemporaneously: July 1, 2001 to April 15, 2005. Clearly, economies of scale exist, with larger installations coming in at significantly lower costs than smaller ones. The smaller graph inset in the upper right-hand corner of Figure 14 zooms in on the 0-55 kW size range, to more clearly depict the system size range in which the two programs overlap.[36]

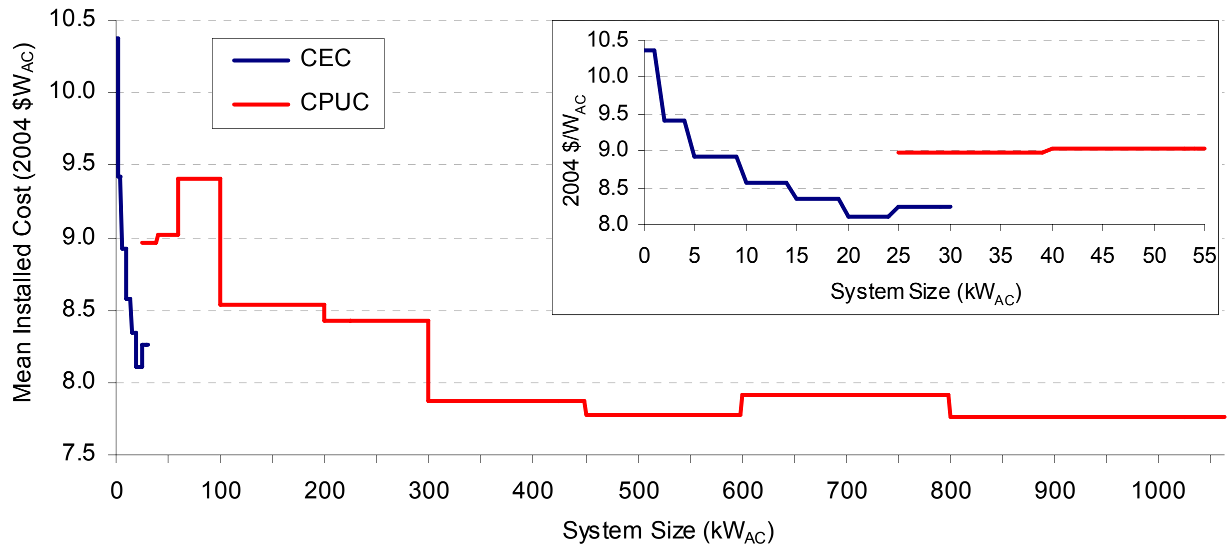


Figure 14. Average Installed Cost, by System Size (CEC and CPUC)

Though systems funded by the CPUC's program have, on average, exhibited somewhat lower costs than those funded by the CEC's program, the opposite appears to be the case when considering only similar-sized systems. This can be seen not only in Figure 14, but also Table 6, which presents summary statistics for systems in the 20-40 kW range from both programs. These data suggest that for similar-sized systems installed over the same time period, CPUC-

[36] Although the CPUC program nominally funds only systems that are at least 30 kW in size, it has funded two systems below that threshold, with reported sizes as low as 25 kW.

funded installations have been more expensive than CEC-funded systems (by $0.77/$W_{AC}$ for the pooled dataset that includes completed, approved, and waitlisted systems, and by $1.21/$W_{AC}$ for just the completed systems).

Table 6. Cost Variations Between the CEC and CPUC Programs: Descriptive Statistics (20-40 kW systems, approved between 07/01/01 and 04/15/05)

	Fully Pooled Data	
	CEC	**CPUC**
Observations (n)	202	237
Average System Size (kW)	26.0 kW	32.7 kW
Mean System Cost ($/$W_{AC}$)	$8.20/$W_{AC}$	$8.97/$W_{AC}$

A simple regression of the same data included in Table 6 (focusing on the fully pooled dataset, but now including both CPUC and CEC data) yields the same basic conclusion, while controlling for variations in system size and application date. The coefficient for CPUC_DUMMY in Table 7 shows that among similar-sized systems, those funded by the CPUC's program exhibit pre-rebate installed costs that have been $0.60/$W_{AC}$ higher than those funded by the CEC.

Table 7. Cost Variations Between the CEC and CPUC Programs: Regression Results (20-40 kW systems, approved between 07/01/01 and 04/15/05)

Variable	Coefficient	p-value
INTERCEPT	8.887	<0.01
TIME_MONTH	-0.030	<0.01
LN_SYSTEM_SIZE	0.101	0.86
CPUC_DUMMY	0.612	<0.01
R-SQUARED	0.10	
OBSERVATIONS (n)	439	

These findings support the oft-heard claim in California that the CPUC's richer incentives in recent years ($4.5/$W_{AC}$ until December 2004, with a 50% cap – see Figure 3 from Section 2.2) have not motivated system cost reductions to the same extent as under the CEC's program (the CEC's program also offered $4.5/$W_{AC}$ at one time, but reduced that incentive more rapidly than the CPUC). This finding is also consistent with results presented earlier that showed that rebate levels (for the CEC dataset) and the availability of other incentives (for the CPUC dataset) have influenced pre-rebate installed costs among both datasets.[37]

[37] Some might speculate that unaccounted-for differences in the two programs, rather than (or in addition to) policy design, could explain the higher installed costs among CPUC-funded systems. For example, Section 4 found that within the CEC program, owner-installed systems, as well as systems installed on new home and affordable housing developments, cost significantly less on average than retrofit systems. Since these three applications (i.e., owner-installed, new home construction, and affordable housing) are unique to the CEC program (due to the 30 kW size threshold, which more or less precludes them from the CPUC program), some might speculate that these types of programmatic differences have driven the cost differential shown in Tables 6 and 7. Though our analysis does not enable us to lay such contentions entirely to rest, we reiterate that Tables 6 and 7 pertain *only to systems of 20-40 kW in size* – i.e., a size range in which few, if any, CEC-funded owner-installed, new home construction, or affordable housing systems reside. As such, we find it likely that the cost differences are caused by differences in policy design.

6.2 Consistency of Cost Reductions Between Systems Funded by the Two Programs

Analysis results presented in Sections 4 and 5 suggest that the CEC's program for smaller (< 30 kW) PV systems has yielded greater cost reductions over time than has the CPUC's program for larger (30 kW and above) systems. This is somewhat supported by the summary information provided in Figure 15, which shows mean installed costs over time (expressed in monthly intervals), by date of rebate application. Although average installed costs in both programs have been on a similar trajectory (and in a very similar range) since mid-2003, earlier CPUC costs exhibit significant variability with little apparent trend. The bivariate nature (i.e., cost vs. time, with no attempt to control for other variables) of the graph, however, makes it difficult to draw conclusions from Figure 15 alone.

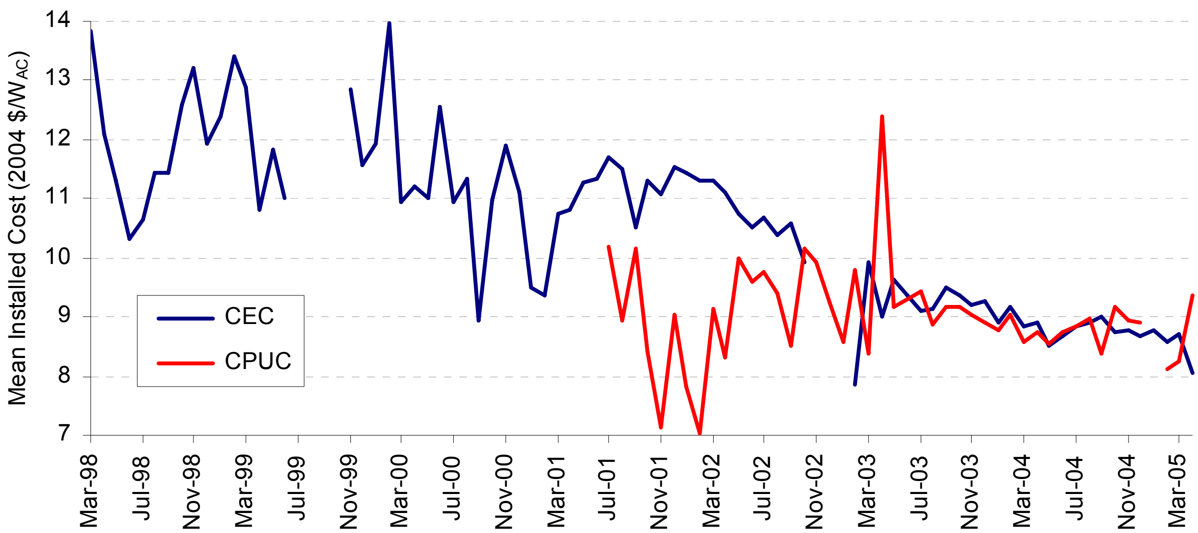


Figure 15. Average Installed Cost Over Time (CEC and CPUC)

To investigate this question statistically, we combine the CPUC and CEC datasets (including completed, approved, and waitlisted systems), again truncating the date range from July 1, 2001 to April 15, 2005. We include only those independent variables that were included in the earlier Model 1 results from Sections 4 and 5, crossed with either a CPUC or CEC dummy.[38]
Table 8 reports the results of this combined CPUC/CEC regression.

[38] We acknowledge that this combination of the two datasets is not perfect, and potentially excludes variables that could hold some explanatory power over differences in installed costs among the programs. For example, a few of the CPUC-funded systems may have been installed as shade-providing carports, which one would expect to have higher installed costs. Similarly, one of the installers active in the CPUC program often adheres PV modules to insulating roofing panels, which again could result in higher costs (while presumably delivering higher value as well). For the most part, the datasets were not robust enough to enable us to tease out and examine these potentially important variables.

Table 8. Regression Results for Pooled CPUC/CEC Dataset (systems approved between 07/01/01 and 04/15/05)

Variable	Coefficient	p-value
INTERCEPT	12.208	<0.01
TIME_MONTH	-0.076	<0.01
CPUC_TIME_MONTH	0.046	<0.01
LN_SYSTEM_SIZE	-0.814	<0.01
CPUC_LN_SYSTEM_SIZE	0.492	<0.01
CEC_APPROVED	0.457	<0.01
CPUC_COMPLETED	-0.950	<0.01
CPUC_APPROVED	-0.883	0.02
CPUC_WAITLISTED	-1.172	<0.01
CEC_SCE	-0.089	<0.01
CEC_SDG&E	-0.266	<0.01
CEC_OTHER_UTILITY	-2.333	<0.01
CEC_NEW_CONST_LARGE	-1.316	<0.01
CEC_NEW_CONST_SMALL	0.163	0.02
CEC_SCHOOLS	0.250	0.18
CEC_AFFORDABLE_HOUSING	-2.030	<0.01
CEC_OWNER_INSTALLED	-1.864	<0.01
CEC_INSTALLER_EXPERIENCE	0.228	<0.01
CEC_RETAILER_EXPERIENCE	0.144	<0.01
CEC_SQRT_POP_DENSITY	4.9E-3	<0.01
CEC_THIN_FILM	-0.594	<0.01
CPUC_SCE	0.309	<0.01
CPUC_SDG&E	0.486	<0.01
CPUC_OTHER_UTILITY	0.072	0.69
CPUC_OTHER_INCENTIVES	0.626	0.10
CPUC_INSTALLER_EXPERIENCE	-0.686	<0.01
CPUC_CALIF_CONST_AUTHORITY	-4.028	<0.01
CPUC_THIN_FILM	0.183	0.18
R-SQUARED	0.31	
OBSERVATIONS (n)	17,453	

Most of the results presented in this combined regression are consistent with our earlier findings. Economies of scale are found to exist, with greater economies among the smaller CEC-funded systems than the larger CPUC-funded systems. Experienced installers are found to charge more in the CEC dataset, but charge less in the CPUC dataset. The impact of the various utility service territory dummies also remains significant, with differences between the two datasets. Further work would be required to understand the reasons for these discrepancies. The results for the other variables included in the combined regression are also generally consistent with the results presented earlier.

Of most interest here, the TIME_MONTH coefficient shows that systems funded by the CEC over this time period experienced an average monthly decrease in pre-rebate installed cost of \$0.076/W_{AC} (\$0.91/W_{AC} each year). The CPUC_TIME_MONTH variable shows that the systems funded by the CPUC have experienced far more modest average cost declines of \$0.03/W_{AC} (\$0.36/W_{AC} each year). Annual average cost reductions for CEC-funded systems (< 30 kW) outpaced those of CPUC-funded systems (30 kW and above) by a multiplier of 2.5. As hypothesized earlier, this may be due to the more substantial (proportionally) labor and installation costs associated with smaller systems and the greater opportunities in that market segment for distribution and installation efficiency gains.[39] Alternatively, it could be a result of policy design – whereas the CEC has (since 2003) progressively lowered its rebate over time, the CPUC has been slower to follow suit. The fact that CEC- and CPUC-funded average system costs have apparently tracked each other since mid-2003 (see Figure 15), however, makes both of these explanations somewhat less likely. Ultimately, the quality of our data does not allow us to definitively explain the difference in cost reductions between the two programs, or even prove that the programs themselves are responsible for the cost reductions.[40] We recommend that future work explore these questions in more detail.

[39] As shown in Sections 4 and 5, we find this same effect – smaller systems exhibiting greater cost reductions over time – not only across programs, but also within each of the two programs.

[40] Though it is perhaps logical to assume that California's PV programs have caused, or at least contributed to, the empirical cost reductions, as discussed earlier, nothing in our analysis enables us to assign causation – i.e., we are unable to definitively conclude that the California programs are driving the cost reductions. To be able to assign causation, we would need to similarly analyze a "control" market – i.e., one in which no PV incentive programs exist. Identifying such a market for PV may be difficult or impossible, given the widespread public support that PV has garnered, but future work could at least analyze other markets in which PV is subsidized, but to a different extent or in a different manner than in California.

7. Conclusions and Recommendations

The promise of electricity generated from photovoltaics is alluring: PV is renewable, clean, distributed, modular, and fuel-free. In an era of concern about energy security, energy price volatility, and the global climate, solar energy offers one potential technological solution. As a result, adoption of solar power is accelerating, driven primarily by government incentives. But cost reductions remain vital for the long-run success of the solar market. A recent report prepared for the CPUC, for example, suggests that the CPUC's SGIP is not yet cost-effective from a societal or non-participant perspective (Itron 2005b).

Historical experience, engineering studies, and learning curve theory tell us that solar costs will drop over time, though the degree of future price reduction remains uncertain. A primary goal of government incentive programs is to encourage these cost reductions. In fact, some have argued that long-term, sustained government deployment programs will be necessary to drive investments in manufacturing and system delivery infrastructure, and thereby reduce costs.

Japan's success in creating a sizable, stable, and well-functioning residential solar market through a sustained long-term commitment to progressively lower rebates is often cited as evidence of this effect (see, e.g., Osborn et al. 2005). The Japanese program supported more than 220,000 residential PV systems from its inception in 1994 through 2004, including over 60,000 in 2004 alone. Costs for standard 3 kW residential systems averaged roughly $\$6.2/W_{DC}$ in 2004, or $\$7.4/W_{AC}$. These costs have declined over time as a well-functioning market infrastructure has developed, with residential PV costs declining by an average of 8.3% annually from 1998 to 2004 (in real Yen/kW for standard 3 kW systems) (RTS 2004; RTS 2005).

The analysis presented in this paper finds clear evidence that the California market has also experienced reductions in PV costs over time. Cost reductions are particularly significant for CEC-funded systems, where regression results show an average annual decline of approximately $\$0.70/W_{AC}$ – nearly twice that achieved under the CPUC program.[41] At the means of the data, this represents annual average percentage declines of 7.3% and 4.1% for CEC- and CPUC-funded systems, respectively. Although our analysis cannot, without comparison to a control group, definitively conclude that the CEC and CPUC programs *caused* these cost reductions, it is clear that – despite the lack of continuity and stability experienced by both programs – pre-rebate installed costs have come down, especially among the CEC-funded systems.

Some of these overall cost reductions are due to decreases in worldwide module costs (notwithstanding the recent increase in those costs). Much of the cost reductions, however, appear to have come from improvements in *non-module* costs – e.g., installation and balance of system costs. These reductions in non-module costs are encouraging because they demonstrate improvements in the delivery infrastructure for PV in California.

Several policy recommendations fall out of our analysis:

[41] This cost decline is generally consistent with that found by Mortensen (2001), who looked at 278 systems installed between 1997 and 2000, and found annual cost reductions over time of $\$0.60/ W_{DC}$ (in real, 1997 dollars).

Reducing non-module costs should be a primary goal of local PV programs. Unlike module costs, which are set in a worldwide market and are therefore heavily influenced by factors outside of the control of an individual PV program (e.g., demand for PV in Japan and Germany), non-module costs are potentially subject to the influence of local PV programs. Our analysis of the CEC dataset, for example, shows that module costs appear to be directly passed through one-for-one to the system purchaser, leaving non-module costs – e.g., installation and balance of system costs – as the remaining cost items potentially influenced by a local PV program. Though we are unable to prove conclusively that non-module cost reductions in California have been *caused* by the state's incentive programs, our analysis results do show that non-module cost reductions have been significant. State incentive programs may wish to undertake programmatic activities aimed specifically at reducing non-module costs, which could range from targeted approaches to building local supply infrastructure (e.g., providing business development funding to installers, supporting standardized PV products, or offering installer training and certification), to something as simple as making PV system cost and performance data more publicly accessible and transparent to further encourage supply competition.

Sustained, long-term programs may enable more significant cost reductions. Sustained, sizable, and stable markets for PV may be the most direct way of reducing non-module costs because such markets will presumably attract suppliers and encourage those suppliers to create an efficient delivery infrastructure. Though California's cost reductions are significant, experience from Japan suggests that deeper cost reductions are possible. Japan's average residential system cost of $7.4/W_{AC}$ in 2004 (for standard 3 kW installations) compares to an average of roughly $8.8/W_{AC}$ in California (for 2-5 kW systems with application dates in 2004). Moreover, just focusing on CEC-funded installations in the 2-5 kW size range with application dates of 1999-2004 (see Figure 7[42]), the average annual cost reduction has been 5.2%, substantially below the 8.9% annual average reduction for 3 kW systems installed in Japan over the same period. Since 2001, however, average annual residential system cost reductions in Japan and California have been approximately equal, at 7.3% for California and 6.7% for Japan. These data perhaps suggest that as the CEC's solar program has scaled up it has begun to experience a similar cost-reduction dynamic as evidenced in Japan, but that further cost declines are possible. In mid-January 2006, the CPUC issued an order that intends to create a much more sizable and stable market for PV in California; a key goal of that program is to replicate and even exceed the cost reductions seen under the Japanese program (the adopted program is to reduce rebate levels by roughly 10% each year, in nominal terms, far exceeding the recent system cost reductions seen under the California and Japanese programs).

The structure and size of PV incentives should encourage cost reduction, not cost inflation. We find some troubling evidence that policy design has adversely impacted the cost of PV systems in California. For example, the 50% cap on the size of the rebate employed by both programs at one time or another appears to have, at best, impeded cost reductions, and at worst, contributed to artificial cost inflation. As such, the decision by both programs to abandon such percentage caps is a positive development; we recommend that other state PV incentive programs do the same. Furthermore, the total pre-rebate cost of PV installations in California has tracked, to some degree, the size of the rebate itself. In particular, there appears to be a tight relationship between rebate levels and average pre-rebate installed costs among CEC-funded

[42] Data for 1998 are not included here due to the limited number of systems in that year.

systems. The CPUC's relatively richer rebate also appears to have resulted in some cost inflation for systems installed under that program. This is particularly true for systems that also received sizable local incentives, *in addition* to those offered under the CPUC's program. These results suggest that heavy subsidies can dampen, at least to some degree, the motivation of installers to provide, and/or customers to seek, lower installed costs. Whether this link is merely representative of the "teething problems" that are typical of new programs,[43] or should instead be of long-term concern is somewhat unclear. As rebates are reduced over time, however, we might expect that the link between incentive levels and total pre-rebate installed costs will be severed, as lower rebates require contractors to price systems at cost (with a reasonable margin for profit) in order to ensure a sale. Hence, while rich incentives may be required initially to jump-start the market, over time the incentives should decline to a level that can support a functional market infrastructure without providing room for potential price manipulation.[44]

Targeted incentives that account for the relative economics of different system sizes and application types may be appropriate. Analysis presented in this paper suggests that installed costs are heavily dependent upon the size and type of installation. Though there is a significant spread in the data, we find clear evidence of sizable economies of scale in PV installations, with larger PV systems coming in (on average) at significantly lower installed costs than smaller systems. We also find that systems installed in large new home developments are, on average, far more economical than retrofitted systems, or even systems installed in smaller new home clusters. Systems installed on affordable housing, which also often involve new construction and presumably enable bulk system installation, also show significant savings on an installed cost basis. Finally, the data reveal that owner-installed systems in the CEC program, and systems installed by the California Construction Authority (which might also be considered owner-installed systems, of a sort) in the CPUC program, have come in at substantially lower costs than contractor-installed systems.[45] In aggregate, these results suggest that a further targeting of incentives to account for the relative economics of different system sizes and application types may be appropriate.[46]

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[43] Such "teething problems" might include initial over-subsidization intended to spur the market, coupled with insufficient supply infrastructure to handle the resulting increase in demand, leading to lackluster competition and artificial price increases until new supply infrastructure enters the market.

[44] Though some might be inclined to draw from this discussion of capacity-based incentives an argument in favor of performance-based incentives, we note that nothing in our dataset or analysis permits a comparison of these different types of incentives.

[45] These results suggest that the CEC's current practice of providing reduced incentives for owner-installed systems is appropriate.

[46] Targeting PV incentives may become even more critical under the Energy Policy Act of 2005's new or expanded federal tax credits for PV, which went into effect in January 2006. Specifically, certain entities (e.g., non-taxable entities or taxable entities subject to the alternative minimum tax) will not be able to benefit from the new or expanded federal tax credits. Furthermore, the new 30% residential credit is capped at $2,000, which means that it is worth relatively more to smaller than to larger residential PV systems. These differential impacts suggest that unless states fine-tune their incentives, they may end up disadvantaging certain market segments, while over-subsidizing others.

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Appendix A: Data Manipulation and Cleaning

A considerable amount of data cleaning and manipulation was required for the CEC and, to a much lesser extent, for the CPUC datasets. Tables 9 and 10 summarize these details.

Table 9. Data Manipulation and Cleaning: CEC Dataset

CEC Variable	Data Manipulation and Cleaning
SYSTEM COST	Dependent variable, expressed in terms of $/W$_{AC}$. Only systems with costs ranging from $4-30/W$_{AC}$ were included in the analysis. Systems with costs outside of this range likely represent data entry errors, or atypically cheap or expensive systems. Different reasonable system cost restrictions were tested, with limited effect on regression results. These cost restrictions eliminated 85 systems, totaling 0.5 MW, from the analysis. Costs represent "eligible costs," excluding any costs for battery back-up. The data used in our analysis are based on the inverter efficiency ratings used at the time of system rebate application. An analysis of inverter efficiency ratings over time shows little change in average ratings (less than 1%, on average), so changes in rating methodologies should not be a major source of error in the results. In the database provided by the CEC, we used the "system cost" field over the "total system cost" field, where available. System costs were converted to real 2004 dollars.
TIME_MONTH	Date of application, in months, numbered consecutively from beginning of each program. We tested alternative functional forms, as well as different time periods (e.g., quarterly, semi-annual), but none outperformed a simple monthly linear model. In the dataset provided by the CEC, we used the "@30date" field (representing the date the application was received by the CEC) where available and when that date preceded the "date received" field; we used the "date received" field otherwise (representing the date on which the system application was entered into the CEC dataset – sometimes up to a month after the application was actually received). Where neither field was filled in, we were in some cases able to estimate a date based on other information provided in the CEC dataset.
SYSTEM_SIZE	Limited to systems less than 30 kW in size. The CEC program initially funded systems over 30 kW in size, but ceased providing funding to such systems in March 2003. We exclude these larger systems from our analysis (a total of 66 systems, and 9.1 MW of capacity) to ensure that a limited number of outliers do not unduly affect our analysis results. We use a logarithmic functional form because, upon visual inspection and after statistical tests, that functional form appeared to fit our underlying data better than the alternatives that we tested. The AC size data used in our analysis are based on the inverter efficiency ratings used at the time of system rebate application.
MAX_STD_REBATE	Equals the CEC's published rebate for contractor-installed systems (not on schools or affordable housing) in $/W$_{AC}$ (2004 $). In nominal dollars, this variable equals $3/W$_{AC}$ from inception to Feb 8, 2001, when it increases to $4.5/W$_{AC}$. Thereafter, it decreases to $4/W$_{AC}$ on February 19, 2003, $3.8/W$_{AC}$ on July 1, 2003, $3.2/W$_{AC}$ on January 1, 2004, $3/W$_{AC}$ on July 1, 2004, and $2.8/W$_{AC}$ on January 1, 2005. For systems above 10 kW, the standard rebate dropped from $3/W$_{AC}$ to $2.5 W$_{AC}$ prior to February 8, 2001 – the date was determined through a review of incentive applications. We maintained an application-date-based determination of standard incentive levels, even where actual incentive payments seemed to disagree with those value (such discrepancies were notable during the transition from $3 to $4.5/W$_{AC}$ incentive levels, when customers were able to update earlier applications at the higher incentive level).

CEC Variable	Data Manipulation and Cleaning
REBATE_%_CAP	Dummy variable equal to 1 when the rebate is capped at 50% (or 40% for systems above 10 kW for a short duration) of eligible installed costs (from program inception through February 18, 2003). We attempted to develop a variable to reflect the degree to which the percentage cap was binding, but that variable did not out-perform the simple one used here. Variable only used only in Model 3.
STATE_TAX_CREDIT	State tax credit (15% for systems installed in 2001-2003, 7.5% for systems installed in 2004-2005; 0% otherwise) was signed by the Governor on October 8, 2001. Given that our dates are based on application receipt, rather than system completion, for the purposes of this variable we assume that there is an "expected" 6-month lag between application receipt and project completion. We therefore set this variable equal to 15% for applications received from October 8, 2001 through June 30, 2003; 7.5% for applications received from July 1, 2003 through June 30, 2005, and 0% for all other dates. Only applies to systems under 200 kW in size. Used only in Model 3.
RETAIL_RATES	We assumed that systems less than or equal to 6 kW are residential systems (and so pay residential retail rates), and systems larger than 6 kW are commercial systems (and so pay commercial retail rates). For each reservation, we first determine in what utility service territory the system is located. If PGE, SCE, SDGE, SMUD, or LADWP, this variable equals the average residential or commercial retail rate (from Energy Information Administration, or EIA, databases) from the current and previous 11 months (12-month average). EIA average retail rate data for all other utilities is annual (i.e., not monthly), so if system is installed in any utility service territory other than those mentioned above, this variable equals the applicable *annual* average residential or commercial retail rate at the time of application. So, for each reservation, the retail rate variable is a function of system size (to determine whether residential or commercial retail rates are appropriate) and location (to determine applicable utility). Used only in Model 3.
APPROVED	Dummy variable equal to 1 if the rebate application has been approved, but not yet completed. We included the following database categories of systems as "approved:" A (approved), CR (claim received), ET (extended), H (hold), and W (warning letter). We did not include systems that had been cancelled (C), declined (D), expired (EX), or received but not yet approved (R). The default is a completed system (PC, for "project complete").
SCE	Dummy variable equal to 1 if the system is or will be installed in SCE's service territory. Where field is not filled in, used zip code or city to estimate appropriate territory. Fixed small number of clearly discrepant entries. Default location is PG&E service territory.
SDG&E	Dummy variable equal to 1 if the system is or will be installed in SDG&E's service territory. Where field is not filled in, used zip code or city to estimate appropriate territory. Fixed small number of clearly discrepant entries. Default location is PG&E service territory.
OTHER_UTILITY	Dummy variable equal to 1 if the system is or will be installed in a utility service territory other than PG&E's, SCE's, or SDG&E's. Where field is not filled in, used zip code or city to estimate appropriate territory. Fixed small number of clearly discrepant entries. Default location is PG&E service territory.

CEC Variable	Data Manipulation and Cleaning
NEW_CONST_LARGE	Dummy variable equal to 1 if the system is or will be installed on a new home (during construction phase) as part of an effort to install PV on multiple homes within a new subdivision. Generally must include at least three homes to qualify. Determinations made both according to CEC database "Category" and "Utility" fields, as well as a judgment based on "Contractor" field in some cases (where it is clear that the system is part of a larger development). Default is a residential retrofit system.
NEW_CONST_SINGLE	Dummy variable equal to 1 if the system is or will be installed on a new home (during construction phase), but *not* as part of an effort to install PV on multiple homes within a new subdivision. Generally must include less than three homes to qualify. Determinations made both according to CEC database "Category" and "Utility" fields, as well as a judgment based on "Contractor" field in some cases (where it is clear that the system is part of a larger development). Default is a residential retrofit system.
SCHOOLS	Dummy variable equal to 1 if the system is or will be installed on a school, based on CEC database "Category" field.
AFFORDABLE_HOUSING	Dummy variable equal to 1 if the system is or will be installed on affordable housing, based on CEC database "Category" field.
OWNER_INSTALLED	Dummy variable equal to 1 if the system clearly is or will be installed by the system owner, rather than a hired contractor, based on CEC database "C-Install" and "C_field." If not clearly indicated as owner installed, we assumed that systems were contractor installed (though we acknowledge likely errors in making this assumption).
INSTALLER_EXPERIENCE	Installers are identified as "experienced" installers (variable = 1) if they rank within the top 5% of all installers in terms of the number of systems completed over the entire data period. Used contractor ID numbers in CEC database. Fixed clear ID number errors; filled in blanks with most likely values in numerous instances based on contractor or retailer name; consolidated IDs for firms that appeared to be the same; created new IDs where missing values (over 1000 records); where no data provided, assumed that inexperienced installer.
RETAILER_EXPERIENCE	Retailers are identified as "experienced" retailers (variable = 1) if they rank within the top 5% of all retailers in terms of the number of systems completed over the entire data period. Cleaned up data entry errors, and made names consistent where possible and where a single firm appears to be entered under different names. Filled in blanks with best guesses, where necessary, based on historical contractor-retailer relationships.
POPULATION_DENSITY	Population density (population per square mile) was derived from zip code and/or address listings in the database, in combination with US Census Bureau data by zip code tabulation area. We used a square root functional form because it fits the data well, and because it is assumed that changes in density in sparsely populated areas will have a greater affect than similar changes in density in more densely populated urban areas. Used city average population density, where zip code is blank but city is identified. Filled in with statewide average values where data is lacking.
THIN_FILM	Dummy variable equal to 1 if the system involves thin-film (e.g., amorphous silicon, copper indium selenide, or cadmium telluride) rather than crystalline technology. This information was discernible from the module manufacturer and/or model number.

CEC Variable	Data Manipulation and Cleaning
MODULE_COST_INDEX	Annual variable that, from 1998-2004, equals the average cost (in 2004 $\$/W_{DC-STC}$) of power (rather than "commodity") modules from Strategies Unlimited (2005). 2005 value derived from the percentage change in Solar Buzz's "All Solar Module Index" from 2004 (average of monthly values) to 2005 (through October), applied to 2004 Strategies Unlimited value.

Table 10. Data Manipulation and Cleaning: CPUC Dataset

CPUC Variable	Data Manipulation and Cleaning
SYSTEM COST	Dependent variable, expressed in terms of $/$W_{AC}$. Only systems with costs ranging from $4-30/$W_{AC}$ were included in the analysis. Systems with costs outside of this range likely represent data entry errors, or atypically cheap or expensive systems. Different system cost restrictions were tested, with some impact on regression results. With no easy way of determining which cost range was objectively "right," we opted to maintain consistency with the CEC dataset (i.e., $4-30/$W_{AC}$). These cost restrictions eliminated 4 systems, totaling 1.3 MW, from the analysis. Data on eligible system costs should be broadly consistent with that reported for the CEC. Eliminated two systems labeled as PV systems that appeared to be wind systems. Eliminated records for which cost data were not provided (~220 projects on PG&E's waiting list). System costs were converted to real 2004 dollars.
TIME_MONTH	Date of application, in months, numbered consecutively from beginning of each program. We tested alternative functional forms, as well as different time periods (e.g., quarterly, semi-annual), but none clearly outperformed a simple monthly linear model.
SYSTEM_SIZE	Theoretically limited to systems of at least 30 kW in size, though the CPUC database does contain a few systems less than 30 kW (and as low as 25 kW). We use a logarithmic functional form because, upon visual inspection and after statistical tests, that functional form appeared to fit our underlying data no worse than the alternatives that we tested. The AC size data used in our analysis are based on the inverter efficiency ratings used at the time of system rebate application.
MAX_STD_REBATE	Equals the CPUC's published rebate for PV systems in $/$W_{AC}$ (2004 $) at the time of first application. In nominal dollars, this variable equals $4.5/$W_{AC}$ from inception through December 15, 2004, after which it decreased to $3.5/$W_{AC}$. Used in Model 2 only.
REBATE_%_CAP	Dummy variable equal to 1 when the rebate is capped at 50% of eligible installed costs (from program inception through December 15, 2004). Not used, due to colinearity problems.
STATE_TAX_CREDIT	State tax credit (15% for systems installed in 2001-2003, 7.5% for systems installed in 2004-2005; 0% otherwise) was signed by the Governor on October 8, 2001. Given that our dates are based on application receipt, rather than system completion, for the purposes of this variable we assume that there is an "expected" 6-month lag between application receipt and project completion. We therefore set this variable equal to 15% for applications received from October 8, 2001 through June 30, 2003; 7.5% for applications received from July 1, 2003 through June 30, 2005, and 0% for all other dates. Actual lag is closer to one year, but used 6-months to remain consistency with approach used for CEC dataset. Only applies to systems under 200 kW in size. Used only in Model 3.

CPUC Variable	Data Manipulation and Cleaning
RETAIL_RATES	We assumed that all systems funded by the CPUC program are commercial systems (and so pay commercial retail rates). For each reservation, we first determine in what utility service territory the system is located. If PGE, SCE, SDGE, SMUD, or LADWP, this variable equals the average commercial retail rate (from Energy Information Administration, or EIA, databases) from the current and previous 11 months (12-month average). EIA average retail rate data for all other utilities is annual (i.e., not monthly), so if system is installed in any utility service territory other than those mentioned above, this variable equals the applicable *annual* average commercial retail rate at the time of application. So, for each reservation, the retail rate variable is a function of system size (to determine whether residential or commercial retail rates are appropriate) and location (to determine applicable utility). Used only in Model 3.
OTHER_INCENTIVES	Dummy variable equal to 1 if the application indicates that the system will also receive other (i.e., non-CPUC) incentives of more than $2/W$_{AC}$. Note that systems have been able to only capture a portion of these other incentives, as the CPUC incentive is reduced to some degree when other incentives are offered (though the rules for this reduction have changed over time).
APPROVED	Dummy variable equal to 1 if the rebate application has been approved, but not yet completed. The default is a completed system.
WAITLISTED	Dummy variable equal to 1 if the rebate application has been waitlisted, due to insufficient program funding. The default is a completed system.
SCE	Dummy variable equal to 1 if the system is or will be installed in SCE's service territory. Default location is PG&E service territory.
SDG&E	Dummy variable equal to 1 if the system is or will be installed in SDG&E's service territory. Default location is PG&E service territory.
OTHER_UTILITY	Dummy variable equal to 1 if the system is or will be installed in a utility service territory other than PG&E's, SCE's, or SDG&E's. Default location is PG&E service territory.
INSTALLER_EXPERIENCE	Installers are identified as "experienced" installers (variable = 1) if they rank within the top 5% of all installers in terms of the number of systems completed over the entire data period. Filled in blank entries where possible; where not possible, assumed that installer was inexperienced.
CALIF_CONST_AUTHORITY	Dummy variable equal to 1 if the California Construction Authority is listed as the installer.
THIN_FILM	Dummy variable equal to 1 if the system involves thin-film (e.g., amorphous silicon, copper indium selenide, or cadmium telluride) rather than crystalline technology. This information was discernible from the module manufacturer and/or model number.
MODULE_COST_INDEX	Annual variable that, from 1998-2004, equals the average cost (in 2004 $/W$_{DC-STC}$) of power (rather than "commodity") modules from Strategies Unlimited (2005). 2005 value derived from the percentage change in Solar Buzz's "All Solar Module Index" from 2004 (average of monthly values) to 2005 (through October), applied to 2004 Strategies Unlimited value.

Appendix B: Cost Distributions Over Time

The distribution of PV system costs under the CEC and CPUC programs have changed over time. Figures 16 and 17 illustrate these trends for the CEC and CPUC, respectively. In the case of the CEC-funded systems, the distribution of system costs has both narrowed and shifted towards lower costs over time. For CPUC-funded systems, the distribution has shifted to the left with little noticeable narrowing of the distribution itself.

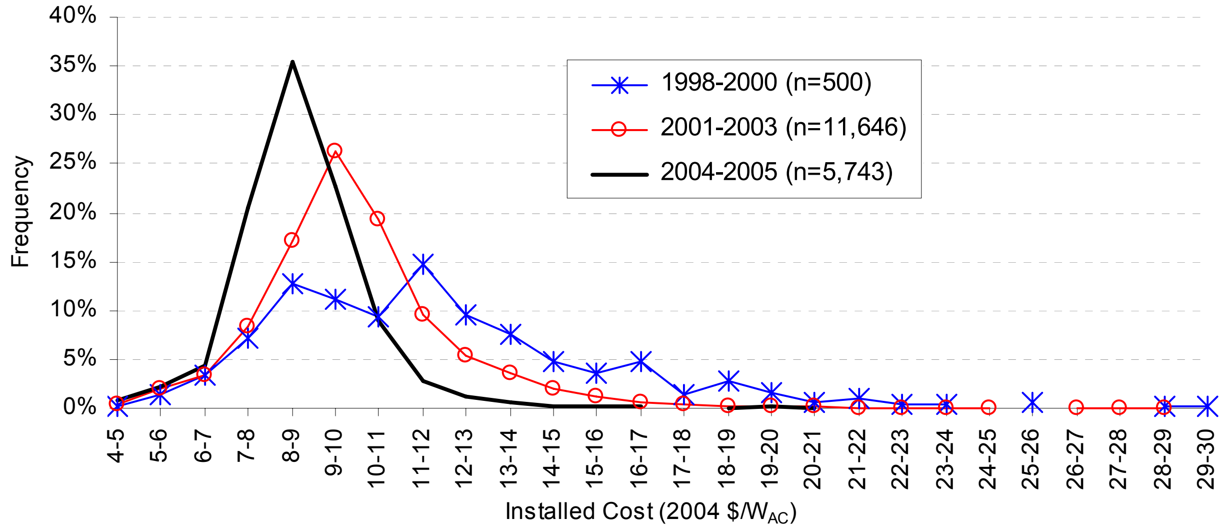

Figure 16. Distribution of System Costs Over Time (CEC)

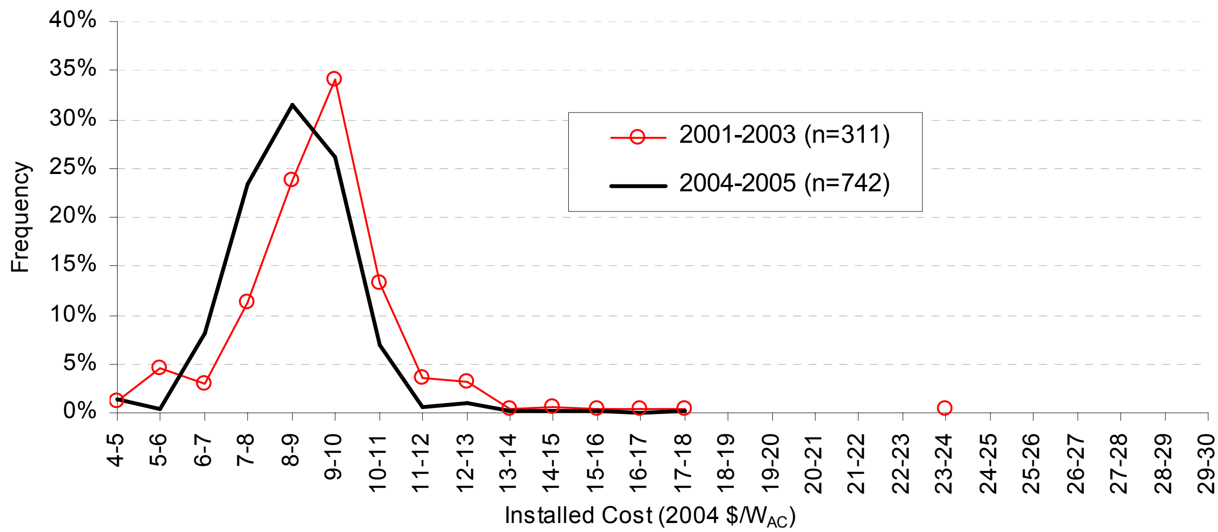

Figure 17. Distribution of System Costs Over Time (CPUC)

Appendix C: Additional Regression Analysis Results

Tables 11 through 13 provide summary statistics and regressions results for just the completed CEC- and CPUC-funded PV systems. Results presented here are reasonably consistent with those using the fully pooled data, presented in the body of the report.

Table 11. Summary Statistics of Variables Used in Analysis (Completed Systems Only)

Continuous Variables	CEC (< 30 kW)				CPUC (>= 30 kW)			
	Mean	Max	Min	Std Dev	Mean	Max	Min	Std Dev
INSTALLED_COST	9.9	29.3	4.1	2.3	9.0	17.2	4.8	1.7
TIME_MONTH	57.7	83.0	0.0	14.1	20.2	39.0	0.0	9.3
SYSTEM_SIZE	3.8	30.0	0.1	3.0	109.1	1,050	30.0	147.5
MAX_STD_REBATE	4.1	4.8	2.7	0.6	4.7	4.8	4.5	0.1
STATE_TAX_CREDIT	0.10	0.15	0.00	0.06	0.10	0.15	0.00	0.05
RETAIL RATES	0.13	0.19	0.08	0.01	0.14	0.16	0.07	0.02
MODULE_COST_INDEX	3.5	4.5	3.3	0.3	3.4	3.9	3.3	0.2
POPULATION_DENSITY	2,690	52,959	0.41	4,138	n/a	n/a	n/a	n/a

Dummy Variables	CEC Observations (Dummy = 1)	CEC Percent of Total	CPUC Observations (Dummy = 1)	CPUC Percent of Total
REBATE_%_CAP	5,149	40%	327	100%
OTHER_INCENTIVES	n/a	n/a	38	12%
SCE**	2,961	23%	81	25%
SDG&E**	1,945	15%	36	11%
OTHER_UTILITY**	132	1%	50	15%
NEW_CONST_LARGE†	710	6%	n/a	n/a
NEW_CONST_SMALL†	242	2%	n/a	n/a
SCHOOLS†	15	0%	n/a	n/a
AFFORDABLE_HOUSING†	75	1%	n/a	n/a
OWNER_INSTALLED	733	6%	n/a	n/a
INSTALLER_EXPERIENCE	7,147	56%	140	43%
RETAILER_EXPERIENCE	4,766	37%	n/a	n/a
CALIF_CONSTR_AUTHORITY	n/a	n/a	16	5%
THIN-FILM	265	2%	35	11%

** PG&E, which represents the "base" utility territory to which the others are compared, contains the majority of systems: 7,818 (61%) systems in the CEC dataset, and 160 (49%) systems in the CPUC dataset
† Standard retrofits represent the "base" type of system to which others are compared in the CEC dataset, and include 11,814 total systems (92%)

Table 12. Regression Results for CEC Dataset (Completed Systems Only)

Variable	Model 1		Model 2		Model 3		Model 4	
	coef.	*p*	*coef.*	*p*	*coef.*	*p*	*coef.*	*p*
INTERCEPT	20.488	<0.01	11.850	<0.01	11.794	<0.01	13.536	<0.01
TIME_MONTH	-0.058	<0.01	-0.024	<0.01	-0.024	<0.01	-0.090	<0.01
LN_SYSTEM_SIZE	-0.914	<0.01	-0.923	<0.01	-0.927	<0.01	-1.342	<0.01
SCE	-0.129	<0.01	-0.132	<0.01	-0.145	<0.01	-0.115	<0.01
SDG&E	-0.465	<0.01	-0.510	<0.01	-0.494	<0.01	-0.522	<0.01
OTHER_UTILITY	-2.244	<0.01	-2.576	<0.01	-2.683	<0.01	-2.581	<0.01
NEW_CONST_LARGE	-1.714	<0.01	-1.744	<0.01	-1.718	<0.01	-3.383	0.03
NEW_CONST_SMALL	0.331	<0.01	0.316	0.01	0.280	0.02	4.378	0.07
SCHOOLS	-0.219	0.78	0.049	0.95	-0.043	0.96	0.193	0.82
AFFORDABLE_HOUSING	-2.034	<0.01	-1.873	<0.01	-1.775	<0.01	-1.827	<0.01
OWNER_INSTALLED	-1.622	<0.01	-1.679	<0.01	-1.685	<0.01	-0.251	0.86
INSTALLER_EXPERIENCE	0.457	<0.01	0.466	<0.01	0.467	<0.01	2.314	<0.01
RETAILER_EXPERIENCE	0.187	<0.01	0.191	<0.01	0.189	<0.01	0.546	0.41
SQRT_POP_DENSITY	3.4E-03	<0.01	3.3E-03	<0.01	3.3E-03	<0.01	8.9E-03	0.38
THIN_FILM	-0.880	<0.01	-0.916	<0.01	-0.919	<0.01	-4.654	0.03
MAX_STD_REBATE			0.732	<0.01	0.560	<0.01	0.783	<0.01
MODULE_COST_INDEX			1.075	<0.01	1.173	<0.01	1.291	<0.01
REBATE_%_CAP					0.191	0.14		
STATE_TAX_CREDIT					2.325	<0.01		
RETAIL_RATES					0.929	0.69		
DATE_MONTH x LN_SIZE							0.010	<0.01
NEW_CONST_LARGE x LN_SIZE							-0.332	0.11
NEW_CONST_SMALL x LN_SIZE							-0.172	0.45
OWNER_INSTALLED x LN_SIZE							-0.079	0.65
INSTALLER_EXP x LN_SIZE							-0.168	0.05
RETAILER_EXP x LN_SIZE							0.060	0.43
SQRT_POP_DENSITY x LN_SIZE							-9.2E-04	0.44
THIN_FILM x LN_SIZE							0.199	0.52
NEW_CONST_LARGE x TIME							0.071	<0.01
NEW_CONST_SMALL x TIME							-0.041	<0.01
OWNER_INSTALLED x TIME							-0.016	0.04
INSTALLER_EXP x TIME							-8.7E-03	0.02
RETAILER_EXP x TIME							-0.015	<0.01
SQRT_POP_DENSITY x TIME							3.7E-05	0.43
THIN_FILM x TIME							0.042	<0.01
R-SQUARED	0.27		0.28		0.28		0.29	
OBSERVATIONS (n)	12,856		12,856		12,856		12,856	

Table 13. Regression Results for CPUC Dataset (Completed Systems Only)

Variable	Model 1		Model 2		Model 3		Model 4	
	coef.	*p*	*coef.*	*p*	*coef.*	*p*	*coef.*	*p*
INTERCEPT	11.989	<0.01	9.926	0.76	11.286	<0.01	12.938	<0.01
TIME_MONTH	-0.037	<0.01	-0.037	0.52	-0.037	<0.01	-0.085	0.08
LN_SYSTEM_SIZE	-0.431	<0.01	-0.441	<0.01	-0.453	<0.01	-0.527	0.11
SCE	0.035	0.87	0.039	0.85	0.050	0.82	-0.032	0.88
SDG&E	-0.273	0.28	-0.227	0.39	-0.065	0.88	-0.398	0.12
OTHER_UTILITY	-0.384	0.20	-0.381	0.21	-0.151	0.73	-0.380	0.27
OTHER_INCENTIVES	0.827	0.01	0.836	0.01	0.869	<0.01	0.728	0.05
INSTALLER_EXPERIENCE	-0.470	0.01	-0.452	0.02	-0.451	0.02	-0.693	0.45
CALIF_CONST_AUTHORITY	-4.210	<0.01	-4.230	<0.01	-4.181	<0.01	-3.766	<0.01
THIN_FILM	0.081	0.75	0.084	0.74	0.077	0.75	-2.929	0.05
MODULE_COST_INDEX			-0.842	0.16				
MAX_STD_REBATE			1.072	0.87				
STATE_TAX_CREDIT					-0.408	0.82		
RETAIL_RATES					5.461	0.46		
DATE_MONTH x LN_SIZE							0.006	0.62
INSTALLER_EXP x LN_SIZE							-0.206	0.30
THIN_FILM x LN_SIZE							0.683	0.02
INSTALLER_EXP x TIME							0.056	<0.01
THIN_FILM x TIME							0.003	0.90
R-SQUARED	0.35		0.35		0.35		0.37	
OBSERVATIONS (n)	327		327		327		327	