California Solar Initiative Cost-Effectiveness Evaluation

Prepared for:
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

April, 2011

Energy+Environmental Economics

California Solar Initiative Cost-Effectiveness Evaluation

Prepared for:
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

April, 2011

Energy and Environmental Economics, Inc.
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
415.391.5100
www.ethree.com

Table of Contents

LIST OF ACRONYMS

AB	Assembly Bill
B/C	Benefit/Cost
CalSEIA	California Solar Energy Industries Association
CCGT	Combined Cycle Gas Turbine
CCSE	California Center for Sustainable Energy
CEC	California Energy Commission
CO2	Carbon Dioxide
CPR	Clean Power Research
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
DG	Distributed Generation
DLAP	Default Load Aggregation Point
DSM	Demand-Side Management
E3	Energy and Environmental Economics, Inc.
EPBB	Expected Performance-Based Buydown
EPIA	European Photovoltaic Industry Association
IOU	Investor-Owned Utilities
ITC	Investment Tax Credit
kWh	Kilowatt-hour
LBL	Lawrence Berkeley National Laboratory
LCOE	Levelized Cost of Energy
MPR	Market Price Referent
MW	Megawatt

NEM	Net Energy Metering
NPV	Net Present Value
PACT	Program Administrator Cost Test
PBI	Performance Based Incentives
PCT	Participant Cost Test
PG&E	Pacific Gas and Electric
POU	Publicly-Owned Utility
PPA	Power Purchase Agreement
PV	Photovoltaic
RA	Resource Adequacy
REC	Renewable Energy Credit
RIM	Ratepayer Impact Measure
RPS	Renewable Portfolio Standard
SAS	Statistical Analysis Software
SB	Senate Bill
SCE	Southern California Edison
SCT	Societal Cost Test
SDG&E	San Diego Gas and Electric
SGIP	Self-Generation Incentive Program
SPM	Standard Practices Manual
T&D	Transmission and Distribution
TRC	Total Resources Cost

1 Executive Summary

The California Public Utilities Commission (CPUC) retained Energy and Environmental Economics, Inc. (E3) to perform a cost-effectiveness evaluation of the California Solar Initiative (CSI) in accordance with the CSI Program Evaluation Plan. This evaluation of the CSI program is one component of a larger contract award and analysis plan that also includes cost-effectiveness evaluation of Net Energy Metering (NEM), completed by E3 in January 2010, and a comparative distributed generation (DG) analysis, to be completed by E3 in 2011.

Three distinct solar rebate programs are offered under CSI:

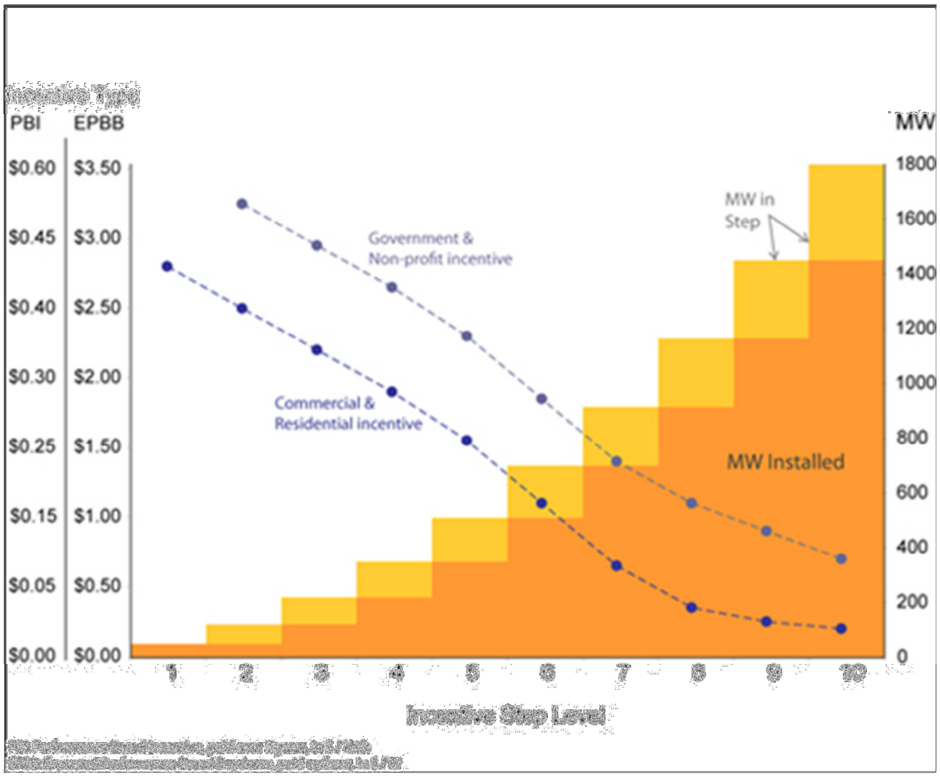
+ The CPUC-directed incentive program, aimed at customers in investor-owned utility territories, with a goal of 1,940 MW by 2016. The CPUC program is comprised of a general market program with a goal 1,750 MW, and a low income program with a goal of 190 MW.
+ The California Energy Commission (CEC) program for new home construction, with a goal of 360 MW.
+ A publicly-owned utility (POU) component with a goal of 660 MW.

The CPUC directed component provides incentives for solar system installations to customers of the state's three investor-owned utilities (IOUs): Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E). E3's evaluation focuses on the general market program.

1.1 Overview of the CPUC CSI Program

The California legislature authorized the CPUC to create the CSI program in 2006 with the passage of Senate Bill (SB) 1, which sought to create a self-sustaining solar market through the provision of incentives that would encourage private investment. In pursuit of this goal, the CSI program provides upfront or performance based incentives for residential, commercial, and governmental/non-profit customers. As the market for solar PV grows, installed costs are expected to decline, eventually to the point where incentives are no longer necessary. Incentives, therefore, decline in "steps" over time, as the MW goal for each step is achieved, as shown in Figure 1.

Figure 1: Overview of CSI incentives

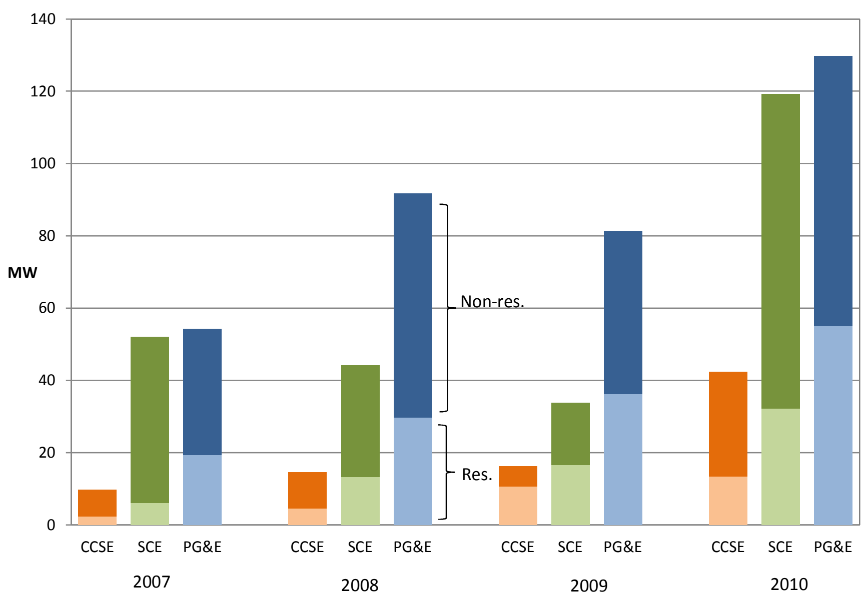


Source: CPUC

Clean solar generation installed through the CSI program enhances progress towards California's long-term renewable energy and GHG-emission goals.

Through the end of 2010, nearly 55,000 sites, representing 689 MW of solar PV (40% of the general market program goal) had received confirmed incentive reservations through the CSI program. Further, the rate of PV adoption increased from 2007-2010, as seen in Figure 2.

Figure 2: MW of Confirmed Reservations, Annual



1.2 Cost-Effectiveness Analysis Summary

The CSI cost-effectiveness evaluation considers the costs and benefits of solar PV and the CSI program from multiple perspectives: participating customers (Participant Test or PCT); program administrators (Program Administrator Cost Test (PACT)); ratepayers (Ratepayer Impact Measure (RIM) test), and society as a whole (Total Resources Cost (TRC) Test and Societal Cost Test (SCT)). Cost-effectiveness tests from each of these perspectives are formalized in the California Standard Practices Manual,[1] used for the evaluation of energy efficiency programs in California.

From each of these test perspectives, the study quantifies the costs and benefits of solar PV installed through the program. The primary focus is on two perspectives: the PCT and the TRC. The PCT tells us whether solar PV installed through the program is cost-effective from the perspective of participants. A projection of a positive participant benefit/cost ratio toward the end of the program when incentives are small or non-existent would suggest that the market for solar PV has become self-sustaining; participants will receive net economic benefits from installing solar even in the absence of an incentive program.

The TRC test and related SCT answer the question of whether the program provides economic benefits to society as a whole.

We give less attention to the PACT and RIM tests, in part because the results of these tests are almost pre-determined for a solar PV incentive program. The PACT compares direct utility costs to avoided energy and capacity costs. A program such as CSI – wherein customers bear the majority of the costs for the PV systems – will provide avoided cost benefits to the utility that are likely to exceed program costs, especially as incentives decline. It is thus no surprise that the PACT has a high ratio

[1] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, Governor's Office of Planning and Research, State of California, July 2002

of benefits to costs outside of the early years, when rebate incentives were highest.

The RIM test is the flip side of this coin, measuring the impact on ratepayers. In addition to covering incentives and other program costs, ratepayers must also make up for the lost revenue due to reduced utility sales from the PV systems. Since retail rates exceed avoided costs, the Benefit/Cost (B/C) ratio of the RIM test will always fall short of 1.0 when a program reduces sales. In other words, CSI provides upward pressure on utility rates. The same result is observed in energy efficiency programs.

1.2.1 CPUC DECISION ON COST-BENEFIT METHODOLOGY FOR DG

Decision (D.) 09-08-026 specifies a methodology for cost-effectiveness evaluation of DG programs, including CSI. The decision adopts several principles, which we discuss in detail in Section 2.3 of this report, including use of the SPM tests described in the previous section, and consideration of the market transformation effects of the program.

The market transformation effects of a solar PV incentive program are not easily quantified. The installed cost of solar PV in California is declining, but many factors contribute to this effect, including the global demand for PV modules and other incentives for solar PV, such as the federal investment tax credit (ITC). The CPUC understood these challenges of quantifying market transformation attributable to the CSI program and called for a *qualitative* assessment of market transformation.

Our approach is to provide an assessment of market transformation by considering whether the program appears to be on a trajectory to hit its goal of a transformed market for solar PV. We consider this from the PCT perspective, since participant economics will need to be favorable for the market to be self-sustaining, and the TRC perspective, to evaluate whether solar PV can be expected to be an economically beneficial investment for society as a whole.

1.2.2 COST-EFFECTIVENESS CALCULATIONS

The mechanics of the analysis are the same for future-looking market transformation considerations as for historical years under evaluation. In both cases, we estimate the stream of costs and benefits that accrue to the fleet of solar PV installed in a given program year, 2008-2016. To provide a more complete look at market transformation, we also consider solar PV installed after the end of the program and the expiration of the ITC, beginning in 2017 and extending through 2020.[2]

[2] In this report we refer to "expiration" of the ITC in 2017 or the "absence" of the ITC after 2016. In fact, in 2017 the ITC reverts to 10% from its current 30%. We use the terms "expiration," etc., to refer in shorthand to this reduction in the ITC (expiration of the ITC at its current level)

For the historical period of our analysis (2008 and 2009) we use actual program and customer data to the maximum extent possible.[3] This includes installed cost data by customer from the CSI program database, billing data by customer obtained from utilities, and actual program administration cost data. Metered solar PV output profiles were available in only a small number of cases, so we assigned appropriate PV output profiles to customers by a combination of simulation and statistical analysis, as described in Section 3.3.1.

Our analysis considers the total stream of 20-year lifecycle costs and benefits, based on a 20-year useful life assumption for solar PV.[4] Thus, we must forecast key variables, such as retail electric rates and hourly utility avoided costs, even in the case of our historical year analysis. The same forecasts are used for analysis of the future / market transformation period. To these we must also add forecasts of the installed cost for solar PV and program adoption rates.

Among our forecasted values, retail rate escalation and declining solar PV installed costs are key drivers of participant economics. For our base case analysis, we escalate retail rates at 4.47%, nominal, through 2020, and at 2% (the presumed rate of inflation) thereafter.[5] We derive our

[3] The bulk of our analysis was completed in 2010 before year-2010 program data were available; therefore, 2010 is a forecast year in our analysis.

[4] A 25-year useful life assumption is also commonly used for solar PV. Changing the useful life assumption from 20 to 25 years would not materially alter the conclusions of our analysis.

[5] The 4.47% nominal retail rate escalation is based on a separate E3 analysis of the cost of meeting a 33% RPS goal by 2020.

base case forecast of installed costs from an 80% progress ratio, wherein costs decline by 20% for every doubling of installed capacity. Our methods for creating these and other forecasts are described in detail in Section 3.3.

Because the analysis involves forecasts, and because complete data including metered PV output is not available for most customers even in the historical period, the analysis necessarily involves estimation and uncertainty. We perform sensitivity analyses to test for changes in our forecasts of underlying variables, such as natural gas prices, and have made every attempt to be as transparent as possible in revealing and explaining our data sources and assumptions, so that readers may assess our methodology and even test alternative assumptions. We have made available on our web site a financial *pro forma* and cost-effectiveness evaluation tool that represents, for a single solar PV installation determined by the user, the same cost-effectiveness tests and methodology as in our larger program study.[6]

1.3 Key Findings

1.3.1 PARTICIPANT ECONOMICS WILL NOT HINDER ADOPTION GOALS

CSI program incentives have set the program on a course to meet adoption goals. In terms of adoption and capacity goals, under our base

[6] http://www.ethree.com/public_projects/cpuc.html

case penetration forecast, the program falls less than 2 MW short of its installed capacity goal of 1,750 MW. While other potential barriers beyond the scope of our analysis may influence program penetration,[7] our analysis suggests participant economics will not limit solar PV adoption.

This is more evident in the residential sector, where PCT B/C ratios exceed 1.0 during every year of the analysis.[8] In the non-residential sector, we note that while the overall B/C ratio is slightly under 1.0 during 2008 and 2009, program adoption during this period was robust. For this reason, we expect adoption will continue as B/C ratios improve in future years, even though B/C ratios may fall slightly short of 1.0 in many years.

1.3.2 FORECASTS OF PARTICIPANT ECONOMICS SUGGEST THE RESIDENTIAL SOLAR PV MARKET WILL BE SELF-SUSTAINING BY 2017

More importantly, we forecast that by the program's completion in 2016, declining solar PV installed costs and increasing retail electric rates will make the program cost-effective for many residential customers even in the absence of CSI program incentives. In fact, we expect residential customers to enjoy a more favorable benefit/cost ratio without program

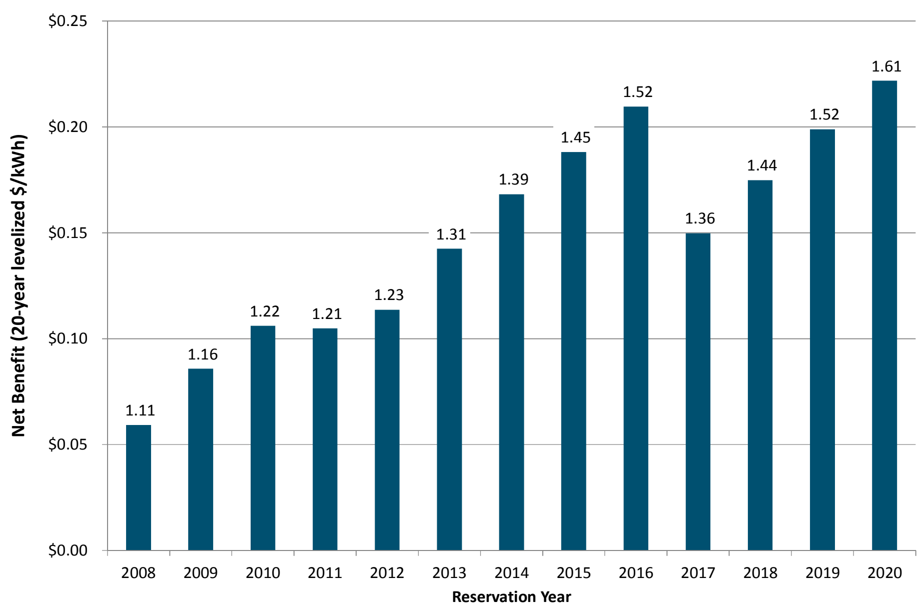
---

[7] One such potential barrier is program funding. D.10-09-046 addressed potential incentive budget shortfalls due to greater than expected performance-based incentives by, among other things, shifting some administrative budget to incentive payments. Even so, the program is expected to exhaust incentive budgets prior to achievement of MW goals. Our analysis assumes that adequate program budget will be available to fully fund MW goals.

[8] A benefit/cost ratio of exactly 1.0 means the benefits and costs measured over 20 years are exactly equal on an NPV basis.

incentives – and without the ITC – in 2017 than they did in 2009 with program incentives, as shown in Figure 3, which presents the trend of residential PCT net benefits resulting from our calculations.

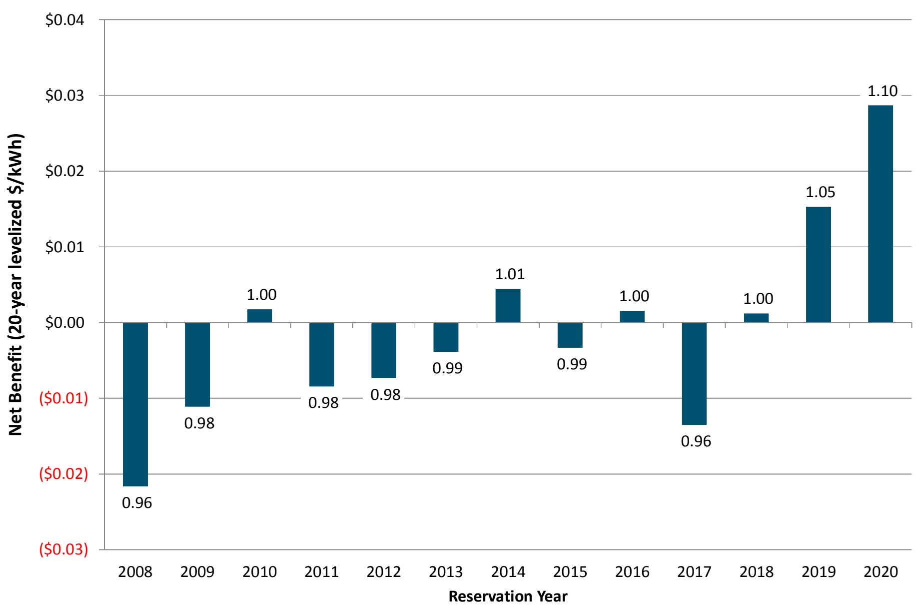
Figure 3: Historical and Forecast PCT Net Benefits, Base Case, Residential



Note: Labels show benefit/cost ratio

For non-residential customers, the picture is mixed (Figure 4). B/C ratios are below 1.0 in the early years, improve steadily until dropping with the presumed expiration of the 30% ITC in 2017, and improve rapidly again thereafter. Even in 2017, when the ITC reverts to 10%, participant economics are roughly similar to 2008 and 2009, when adoption was robust. Thus, while participant economics in the non-residential sector are not as unequivocally positive as in the residential sector, the potential for continued adoption in the eventual absence of CSI incentives still appears promising.

Figure 4: Historical and Forecast PCT Net Benefits, Base Case, Non-residential



Note: Labels show benefit/cost ratio. Figures 3 and 4 use different scales for the Y axis.

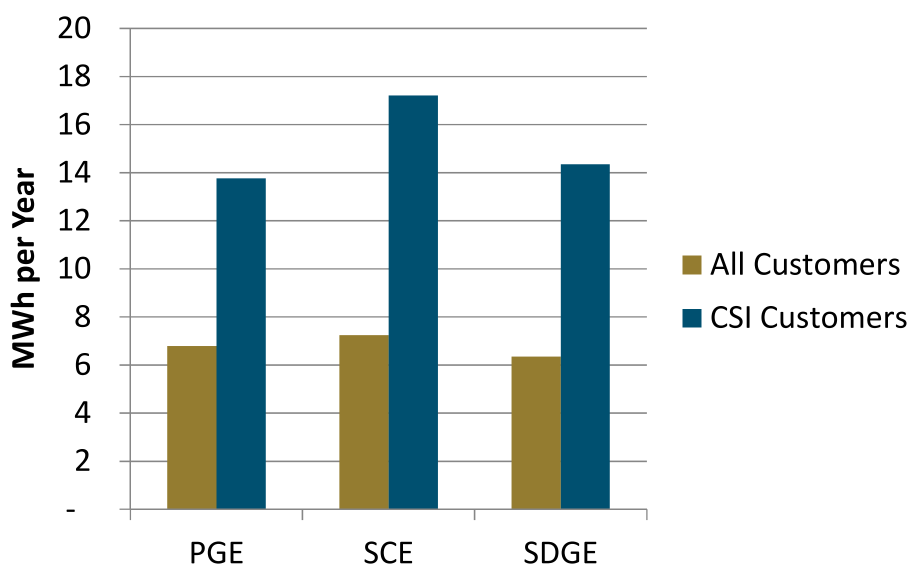
The key driver of changing participant economics after 2017 is projected rate increases and projected declines in solar PV costs. We tested the sensitivity of results to changes in these forecasts. As described in Section 4.2.4, under a high retail rate / aggressively declining cost sensitivity, non-residential B/C ratios are positive beginning in 2010 and every year thereafter. Under a low retail rate / conservative declining cost sensitivity, non-residential B/C ratios remain below 1.0 in all years and below 0.75 after expiration of the ITC.

The results for non-residential customers also vary by the type of entity. Commercial customers, which enjoy tax advantages from the installation of solar PV, are slightly better than break-even as a group in 2008, whereas governmental and especially non-profit customers have less favorable economics as a group and bring the overall non-residential B/C ratio down to 0.96 in 2008. See Section 4.1.2 for discussion.

1.3.3 WITHIN THE RESIDENTIAL SECTOR, LARGER CUSTOMERS ARE MORE LIKELY TO INSTALL SOLAR PV, AND LARGER CUSTOMERS ENJOY GREATER BENEFITS FROM SOLAR PV

Figure 5 shows that the average CSI customer uses more than twice the energy of the average residential customer.

Figure 5: Residential CSI Customer Energy Consumption Compared to Class Average



We hypothesize that higher-usage residential customers are more likely to install solar PV for several reasons. They are more likely to be higher income customers with better access to capital and more disposable income to invest. They have higher energy bills and higher marginal energy rates because of the tiered rate structure. And larger systems that are appropriate for larger residences tend to be less costly on a per-kW installed basis.

The economic advantage of CSI to higher-usage customers is clearly visible in Table 1, which shows lifetime participant benefits of CSI, expressed as levelized $/kWh generated.

Table 1: PCT results by customer size in levelized $/kWh generated, base case, 2008

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.17)	($0.09)	$0.08	($0.13)
	5 to 10 MWh	($0.05)	($0.02)	$0.04	($0.04)
	10 to 15 MWh	$0.05	$0.04	$0.13	$0.05
	15 to 25 MWh	$0.08	$0.10	$0.16	$0.09
	25 to 35 MWh	$0.10	$0.13	$0.19	$0.12
	35 to 50 MWh	$0.10	$0.14	$0.19	$0.13
	50 to 100 MWh	$0.10	$0.15	$0.20	$0.13
	100 to 500 MWh	$0.12	$0.17	$0.25	$0.15
	Average	$0.04	$0.08	$0.14	$0.06
Non-Res	0 to 5 MWh	($0.08)	($0.05)	($0.14)	($0.09)
	5 to 10 MWh	($0.06)	($0.04)	($0.06)	($0.06)
	10 to 15 MWh	($0.06)	($0.04)	($0.05)	($0.06)
	15 to 25 MWh	($0.04)	($0.03)	($0.01)	($0.03)
	25 to 35 MWh	($0.03)	($0.05)	($0.05)	($0.03)
	35 to 50 MWh	($0.03)	($0.04)	($0.04)	($0.03)
	50 to 100 MWh	($0.04)	($0.05)	($0.04)	($0.04)
	100 to 500 MWh	($0.04)	($0.05)	($0.05)	($0.04)
	Over 500 MWh	($0.02)	($0.04)	$0.02	($0.01)
	Average	($0.03)	($0.05)	($0.00)	($0.02)
Overall Average		$0.00	$0.08	$0.05	$0.02

1.3.4 FROM A SOCIETAL OR TOTAL RESOURCES PERSPECTIVE, THE PICTURE IS MIXED

Figure 6 and Figure 7 show historical and forecasted TRC results for each year of the program and beyond to 2020.

Figure 6: Historical and Forecast TRC Net Benefits, Base Case - Residential

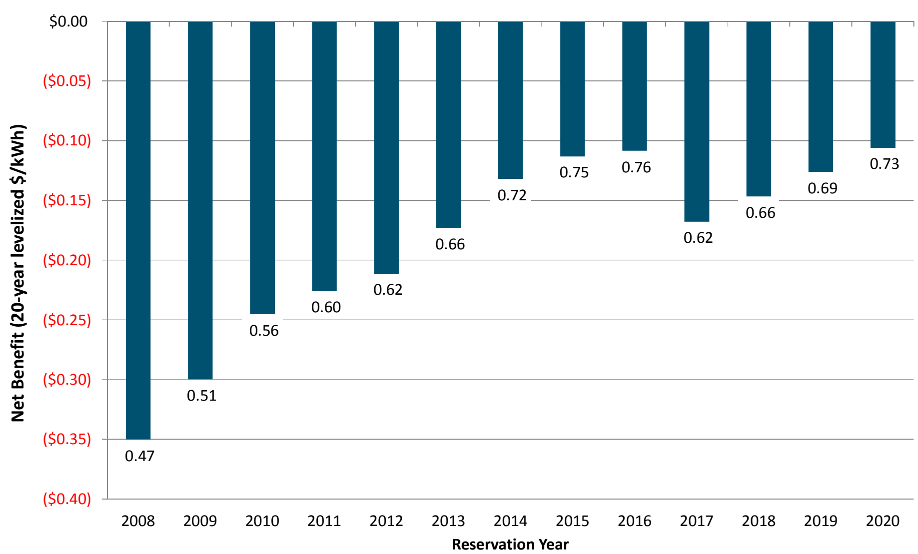
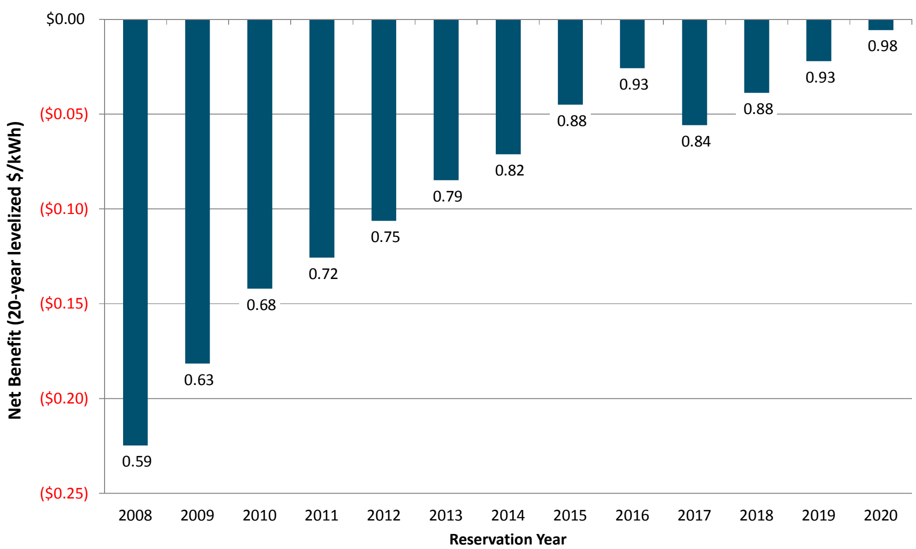


Figure 7: Historical and Forecast TRC Net Benefits, Base Case – Non-residential



While program economics improve rapidly each year until expiration of the ITC in 2017,[9] and then again thereafter, we do not project the TRC test to achieve a positive benefit/cost ratio during the study period. Simply put, this means solar PV remains a more expensive way to meet energy demand than the grid supplied power that would otherwise meet the load.

The monetization of certain unpriced externalities under the SCT does not fundamentally change these results, as discussed in Section 4.2.3. Nor do the changes in forecasted input values tested in our sensitivity analyses, as discussed in Section 4.2.4.

[9] The ITC is considered a benefit in our TRC and SCT tests because these tax benefits are external to the "society" under consideration; that is, the state of California.

It is important to remember that these are economic tests, and therefore only one measure with which to evaluate policy. There may be important non-economic criteria in support of solar PV; one possible example would be value judgments about land use apart from any economic value of the land. Such factors are not captured by the TRC or SCT.

1.4 Conclusions

The results of the cost-effectiveness analysis suggest several areas of consideration for policy makers.

1.4.1 WHAT ARE THE NON-ECONOMIC BENEFITS OF SOLAR PV?

The results show that the CSI program is not expected to be cost-effective from a TRC or SCT perspective over the life of the program, even if installed costs decline more rapidly than expected. That is, it will remain cheaper to get power from grid-supplied sources than from rooftop distributed solar PV. But development of a more distributed electricity supply system may have non-economic benefits that are not captured by the TRC and SCT tests. A clear articulation of any such benefits may help policy makers and program administrators focus on areas that are likely to further enhance them.

1.4.2 NON-RESIDENTIAL PARTICIPANT ECONOMICS ARE MORE TENUOUS AND SHOULD BE AN AREA OF FOCUS

From the residential participant perspective, cost-effectiveness is achieved early in the program, even in the absence of CSI rebate incentives. Meanwhile, non-residential B/C ratios remain closer to 1.0 throughout the analysis period, and in the absence of CSI rebates would not reach 1.0 until 2018. As noted earlier, within the non-residential sector, governmental and non-profit customers, especially, face challenging economics. Finally, incentives are in danger of expiring in the non-residential sector before program MW goals are met, due to the higher than expected performance-based incentive payouts to date.

Non-residential solar PV is more favorable from a societal perspective, as evidenced by the TRC and SCT test results. At the same time, it is the non-residential sector whose participant economics are the most tenuous. Given these conditions, policy-makers may wish to focus attention on the non-residential sector. Differences between commercial and governmental or non-profit customers and the potential for a "self-sustaining" market in each of these sectors may be a desirable area of focus for further study.

1.4.3 IS THERE AN OPPORTUNITY TO BRING DOWN COSTS FOR SMALL RESIDENTIAL CUSTOMERS?

Several factors suggest that installed system costs should continue to be a focus for the CSI program:

+ Installed system costs are a key driver of cost-effectiveness results from both the participant and societal perspectives
+ From a societal (or TRC) perspective, we do not expect solar PV to be cost-effective during the analysis period, particularly in the residential sector
+ Solar PV economics favor larger residential customers

Taken together, these observations suggest that a focus of policy should be a reduction in installed solar PV costs, particularly in the residential sector and particularly for smaller residential customers. While continuation of the current CSI program should continue to spur adoption and drive down costs, policy-makers may also wish to consider additional approaches.

One approach might be to promote a shift toward larger, community-based solar PV systems through a "solar shares" or "virtual net metering" approach. Larger systems have lower costs and better TRC results than rooftop solar, particularly as compared to smaller residential systems. Lowering costs through virtual net metering would improve TRC results and improve participant economics for smaller residential customers.

Virtual net metering (VNM) installations would be located near customers, but would be larger systems (for example up to 5 MW or up to 20 MW), of which customers would "purchase" a share. Such an arrangement would offer the economies of scale necessary to reduce systems costs, while maintaining a sense of customer ownership, as customers would see the installations in their communities. The systems could be utility-owned, community-owned, or third-party owned and could be procured through a competitive solicitation process.

2 Introduction

2.1 CSI Program Description

The CSI program was authorized by the CPUC in 2006, in response to Governor Schwarzenegger's Million Solar Roofs plan. The program has a budget of $2.167 billion over 10 years (2007-2016), with a goal to reach 1,940 MW of installed solar capacity by the end of 2016. Of this 1,940 MW, 1,750 MW comes from the general market program, which is administered through PG&E, SCE, and, in SDG&E territory, California Center for Sustainable Energy (CCSE). The cost-effectiveness study at hand is focused on the general market program.

Incentives for the general market program are divided into 10 steps, each with a target amount of capacity by customer class (residential, commercial, and government / non-profit). Targets are allocated across the three IOU service territories in proportion to electricity sales. Table 2 presents the target capacity in MW and the incentive level for each incentive step. The first 50 MW were allocated under the Self-Generation Incentive Program (SGIP); therefore no incentive values are shown for Step 1.

Table 2: Incentive levels and capacity by incentive level step

Incentive Step		1	2	3	4	5	6	7	8	9	10
Target Capacity (MW)											
PG&E	Residential	n/a	10.10	14.40	18.70	23.10	27.40	31.00	36.10	41.10	50.50
	Non-residential	n/a	20.50	29.30	38.10	46.80	55.60	62.90	73.20	83.40	102.50
SCE	Residential	n/a	10.60	15.20	19.70	24.30	28.80	32.60	38.00	43.30	53.10
	Non-residential	n/a	21.60	30.80	40.10	49.30	58.60	66.30	77.10	87.80	107.90
SDG&E	Residential	n/a	2.40	3.40	4.40	5.40	6.50	7.30	8.50	9.70	11.90
	Non-residential	n/a	4.80	6.90	9.00	11.00	13.10	14.80	17.30	19.70	24.20
		50	70	100	130	160	190	215	250	285	350
Incentive Payment											
EPBB ($/Watt)											
	Residential	n/a	$2.50	$2.20	$1.90	$1.55	$1.10	$0.65	$0.35	$0.25	$0.20
	Commercial / Industrial	n/a	$2.50	$2.20	$1.90	$1.55	$1.10	$0.65	$0.35	$0.25	$0.20
	Government / Non-profit	n/a	$3.25	$2.95	$2.65	$2.30	$1.85	$1.40	$1.10	$0.90	$0.70
PBI ($/kWh)											
	Residential	n/a	$0.39	$0.34	$0.26	$0.22	$0.15	$0.09	$0.05	$0.03	$0.03
	Commercial / Industrial	n/a	$0.39	$0.34	$0.26	$0.22	$0.15	$0.09	$0.05	$0.03	$0.03
	Government / Non-profit	n/a	$0.39	$0.34	$0.26	$0.22	$0.15	$0.09	$0.05	$0.03	$0.03

The program offers two types of incentives. Expected Performance-Based Buydown (EPBB) incentives are a one-time, upfront payment based on expected PV production, and are intended for systems of less than 50 kW in size. Performance Based Incentives (PBI) are paid over five years (60 monthly payments) based on actual energy produced. PBI incentives are mandatory for systems 50 kW and larger; customers with smaller systems may opt-in to PBI.

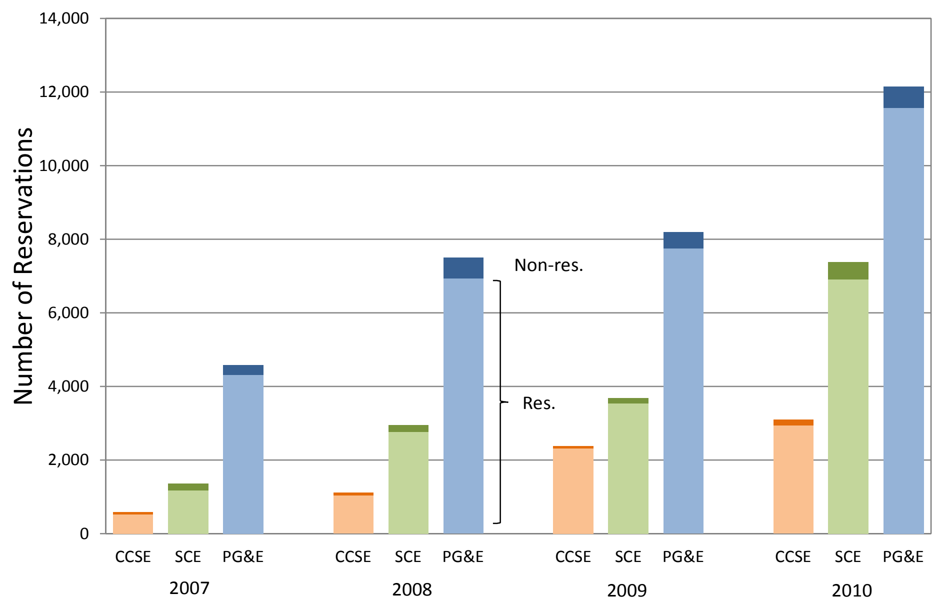
2.2 CSI Progress To-Date

Since its inception in 2007, the CSI program has been highly successful in spurring installation of solar PV in California. Through mid-2010, approximately 342 MW were installed under the CSI program at roughly

31,000 sites.[10] This does not reflect all program activity, as there is a lag between applications, incentive reservations, and completed installations.

Through the end of 2010, nearly 55,000 sites (of which nearly 95% were residential) had enrolled in the CSI program, as measured by confirmed reservations. Annual program adoption has increased each year since 2007, as shown in Figure 8 and Table 3.

Figure 8: CSI Annual Program Adoption as Measured by "Confirmed Reservations," by Year



[10] CPUC, California Solar Initiative Annual Program Assessment, June 30, 2010, p.8. Current statistics are available at www.CaliforniaSolarStatistics.com.

Table 3: CSI Program Adoption ("Confirmed Reservations") by Year

Utility	Customer Class	2007	2008	2009	2010
PG&E	Residential	4,313	6,936	7,760	11,560
	Non-Residential	263	567	436	575
	Total	*4,576*	*7,503*	*8,196*	*12,135*
SCE	Residential	1,184	2,770	3,542	6,903
	Non-Residential	179	185	143	468
	Total	*1,363*	*2,955*	*3,685*	*7,371*
SDG&E (CCSE)	Residential	528	1,046	2,311	2,950
	Non-Residential	56	71	62	161
	Total	*584*	*1,117*	*2,373*	*3,111*
All 3 IOUs	**Residential**	**6,025**	**10,752**	**13,613**	**21,413**
	Non-Residential	**498**	**823**	**641**	**1,204**
	Total	***6,523***	***11,575***	***14,254***	***22,617***
Total Cumulative Reservations					**54,969**

Source: **www.CaliforniaSolarStatistics.com**. "Working Data Set" updated through December 29, 2010 and downloaded January 4, 2011.

The annual capacity of CSI reservations is shown in Figure 9 and Table 4. Through 2010, confirmed reservations had been obtained for 689 MW of solar PV, or nearly 40% of the general market program goal of 1,750 MW.

While the number of residential sites vastly exceeds the number of non-residential sites, non-residential installations tend to be much larger and account for the majority of installed capacity. Of the 689 MW of cumulative confirmed reservations through 2010, 449 MW (65%) are non-residential.

Figure 9: MW of Confirmed Reservations, Annual

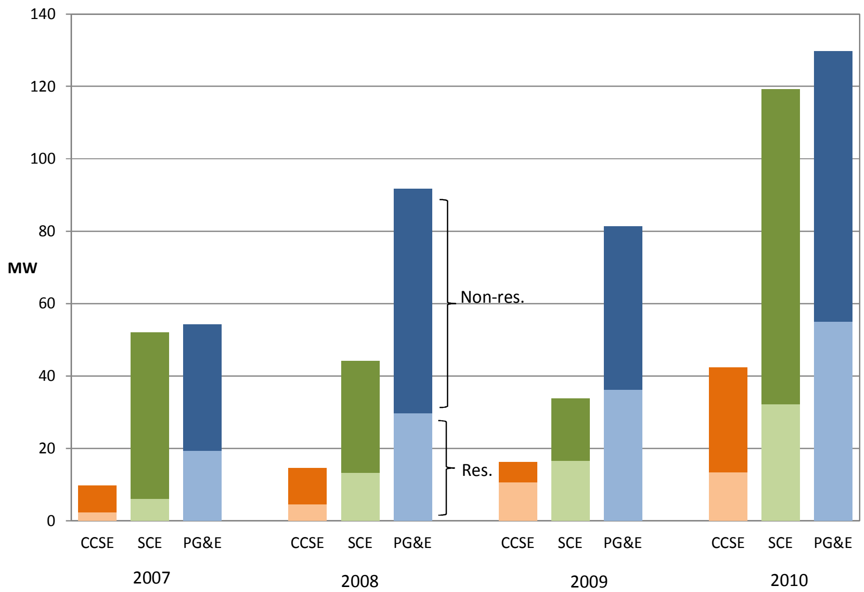


Table 4: Capacity of Confirmed Reservations by Year (MW)

Utility	Customer Class	2007	2008	2009	2010
PG&E	Residential	19	30	36	55
	Non-Residential	35	62	45	75
	Total	*54*	*92*	*81*	*130*
SCE	Residential	6	13	17	32
	Non-Residential	46	31	17	87
	Total	*52*	*44*	*34*	*119*
SDG&E (CCSE)	Residential	2	5	11	13
	Non-Residential	7	10	6	29
	Total	*10*	*14*	*16*	*42*
All 3 IOUs	**Residential**	**28**	**48**	**64**	**101**
	Non-Residential	**88**	**103**	**68**	**191**
	Total	***116***	***150***	***132***	***291***
Total Cumulative Capacity of Reservations					**689**

Source: www.CaliforniaSolarStatistics.com. “Working Data Set” updated through December 29, 2010 and downloaded January 4, 2011.

2.3 Framework for CSI Cost-Effectiveness Evaluation and Implementation of Principles from the CPUC Decision

The CPUC's Decision 09-08-026 lays out the methodology to be applied to cost-effectiveness evaluation of ratepayer supported DG programs. The decision adopts the following principles to guide DG cost-effectiveness evaluation:

+ DG should be evaluated based on tests from the California Standard Practice Manual (SPM)
+ E3's avoided cost methodology (adopted in D.05-04-024) should be used and inputs should be consistent with those used in the evaluation of energy efficiency (EE) programs
+ The method used by Itron in its SGIP Year 6 Impact Report should be used to determine the collective transmission and distribution (T&D) deferral benefits
+ The analysis should include consideration of market transformation effects
+ Net Energy Metering (NEM) bill credits and exports to the grid should be considered in the analysis

In each section below we discuss the implementation of the principles in our evaluation.

2.3.1 DG SHOULD BE EVALUATED BASED ON TESTS FROM THE CALIFORNIA SPM

The SPM is used for economic analysis of demand-side management (DSM) programs in California. It provides direction on benefit/cost tests designed to evaluate cost-effectiveness of demand-side resources from several perspectives:

+ Participant Cost Test (PCT). Measures the quantifiable benefits and costs to program participants.
+ Ratepayer Impact Measure (RIM) Test. Measures the effect on customer rates due to changes in utility revenues and costs resulting from the program. The RIM test is not specifically required by D.09-08-026, but we include it because it provides additional insight into program effects and is not difficult to compute once inputs have been established for other, required cost tests.
+ Program Administrator Cost Test (PACT). Measures the benefits and costs to the program administrator, without consideration of the effect on actual revenues. Differs from the RIM test in that it considers only the revenue requirement, ignoring any changes in revenue collection.
+ Total Resources Cost Test (TRC). Measures the total net economic effects of the program, including both participants' and program administrator's costs and benefits, without regard to who incurs the costs or receives the benefits. For a utility-specific program, the test can be thought of as measuring the overall welfare of the entire utility territory. For the statewide CSI program, the

relevant area under consideration is the state of California as a whole.

+ Societal Cost Test (SCT). The SCT is similar to the TRC, but broadens the universe of affected individuals to society as a whole, rather than just those in the program administrator territory. The SCT is also a vehicle for consideration of non-monetized externalities, which are not considered in the TRC.

Attachment A of D.09-08-026 provides a list of benefits and costs to be included in DG evaluation. Table 5 discusses the treatment of each benefit and cost in our analysis.

Table 5: Distributed Generation Cost-Benefit Inputs from D.09-08-026 and Treatment in CSI Evaluation

Benefit or Cost from Attachment A	Treatment in CSI Cost-Effectiveness Evaluation
Avoided Line Losses	Included in Avoided Cost calculations
Avoided purchase of energy commodity and Resource Adequacy costs	
Avoided Transmission and Distribution (T&D) costs (T&D Investment Deferrals)	Included in Avoided Cost calculations. Sensitivity for no T&D investment deferral.
Combined Heat and Power (CHP) plant specific benefits	Not applicable to CSI
CHP gas and electric bill savings	
Environmental benefits (CO2, NOx, and Particulate Matter Emissions)	Included in Avoided Cost calculations
Increased revenue (and IOU costs) from fuel transportation for gas-fired DG	Not applicable to CSI
Market transformation effects	Addressed
Net Energy Metering bill credits	Included
Rebates/Incentives	
Reduced electricity bills	

Benefit or Cost from Attachment A	Treatment in CSI Cost-Effectiveness Evaluation
Reliability benefits and costs (both system and customer ancillary services/VAR support)	Not included. Deemed insignificant for CSI
Standby charge exemption	Reflected in bill calculation
Tax credits/depreciation	Included
Utility interconnection not charged to DG customer	
Costs of DG system, interconnection, emission controls and offset purchases	
Net Energy Metering costs	
Nonbypassable charges (PGC, DWR, Nuclear decommissioning)	Reflected in bill calculation
Operation maintenance, fuel, ongoing emission offset purchases	Operational costs included
Program Administration	Included
Reduced revenue from standby charge exemptions	
Reduced Transmission, distribution, and non-fuel generation revenues	
Removal costs (less salvage)	Not included. Deemed insignificant for CSI
Utility interconnection	Included

In Section 3.3, we describe our derivation of key inputs from the list above.

2.3.2 E3'S AVOIDED COST METHODOLOGY SHOULD BE USED AND INPUTS SHOULD BE CONSISTENT WITH EE PROGRAMS

The CSI Cost-Effectiveness Evaluation uses E3's methodology for estimating utility avoided costs. To the extent possible, we use non-proprietary, publicly available data to estimate avoided costs. E3's avoided cost workbook is available on the E3 web site.[11]

When a customer meets load through on-site solar generation, the utility avoids the cost of meeting that load from other sources of generation. The major avoided cost components are:

+ Generation energy and capacity costs
+ T&D costs (investment deferral benefits)
+ Emissions
+ Line losses
+ Ancillary services
+ Avoided RPS purchases due to a reduction in aggregate system demand

We discuss avoided cost calculations in greater detail in Section 3.3.2 and in Appendix B.

2.3.3 THE METHOD USED BY ITRON IN ITS SGIP YEAR 6 IMPACT REPORT SHOULD BE USED FOR T&D DEFERRAL BENEFITS

Investment in transmission and distribution infrastructure is necessary when transmission or distribution systems approach their maximum capacity and continuing load growth is expected. A reduction in load,

[11] http://www.ethree.com/public_projects/cpuc.html

particularly during peak hours, can allow deferral of investment by increasing the headroom and allowing for additional load growth before maximum capacities are reached.

Transmission and distribution capacity investments are “lumpy” – that is, no investment is needed until maximum capacities are reached, at which point a significant investment may be necessary to increase line capacity and after which no further capacity investments may be necessary for several years until load growth once again overtakes available capacity. As lines approach capacity, reductions in load due to energy efficiency or distributed generation will have no deferral benefit unless they are collectively large enough to offset the anticipated load growth.

In its Year 6 SGIP Impact Report, Itron evaluated the location-specific impacts of the SGIP program and found it unlikely that the impacts on any specific transmission or distribution system were sufficient to result in identifiable cost savings. These results acknowledge and are driven by the “lumpiness” of T&D capacity planning and the relatively low production of PV on any specific feeder area.

Whereas the Itron Year 6 Impact Report was historical, our evaluation of the CSI program’s market transformation effects is prospective, estimating the value of solar PV that will be installed in future years. We do not know where future PV systems will be located, or where specific distribution or transmission bottlenecks will occur, and therefore cannot apply the Itron Year 6 method. We therefore use a marginal T&D avoided cost approach, as is done for energy efficiency.

The marginal T&D avoided cost method values CSI solar PV as one of many sources that contribute to load reduction, and therefore to potential T&D deferral. Each increment of peak load reduction from CSI solar PV is essentially given *pro rata* credit for its contribution to T&D deferral. The effect is to "smoothen" the lumpiness of T&D deferral benefits. This is the method used to value T&D deferral benefits for energy efficiency programs – energy efficiency measures are credited with a proportionate share of T&D deferral benefits in cost-effectiveness analysis, without any need to demonstrate that the sum total of the measures was actually large enough to defer a specific investment in a given year.

We note, also, that we conduct a sensitivity test for the alternative case; namely, that no T&D investment deferral benefits accrue from the CSI program (see Section 4.1.6). Inclusion or exclusion of T&D deferral benefits does not fundamentally alter the conclusions of the CSI evaluation. T&D deferral benefits account for roughly 10% of avoided costs and only roughly 5% of overall benefits under the Total Resources Cost test.

Some utilities have reported anecdotal evidence that net-metered solar PV does not result in any distribution capacity benefits and may even increase distribution system requirements. This issue will become clearer as further study is performed on the subject. Until then, we represent the argument against distribution deferral benefits with the sensitivity discussed above.

Going forward, if policy-makers wish to capture and track T&D avoided cost benefits, we recommend further study of the technical issues surrounding the effect of net-metered solar PV on the distribution system. We further suggest a program design that encourages PV to be located in congested areas (currently the incentive is uniform and no information is provided publicly on where capacity upgrades are needed), and that this element of the program design be integrated into the T&D planning functions of utilities.

2.3.4 THE ANALYSIS SHOULD INCLUDE CONSIDERATION OF MARKET TRANSFORMATION EFFECTS

A goal of the CSI program is to transform the market for rooftop solar PV such that the market is self-sustaining without the need for rebates and incentives. This goal acknowledges the fact that solar PV is not currently cost-effective for participants in the absence of rebate and tax incentives. Nor is it cost-effective for society as a whole when compared to existing utility procured sources of generation – that is, it would not be expected to pass the TRC test.

By growing the market for PV modules and the local infrastructure for marketing and installing solar PV, the program can be expected to drive down costs over time as economies of scale and other advancements are achieved. This market transformation effect of the program is not easily quantified. Nor is it a simple matter to determine the extent to which transformation in the solar PV market may be attributed to the CSI program.

Reduction in the cost of PV modules is known to be a function of the global, rather than local, market for solar PV. Technological innovation may drive down module cost regardless of any local activity. And local demand for PV may be partially driven by non-program forces, such as an increased interest in clean energy. The Commission understood these challenges and called for a qualitative assessment of market transformation effects. Although we present our results in numerical form for illustrative purposes, our evaluation remains a qualitative assessment for these reasons.

Our approach to evaluating market transformation is to forecast the costs and benefits of solar PV over the life of the program. If, by the end of the program, participants' can cost-effectively install solar PV without program incentives, the program will have achieved its goal to create a self-sustaining market for solar PV. If the total benefits of solar PV exceed total costs from a societal perspective (based on the TRC or SCT) then the program can be said to be beneficial not just to participants but to society as a whole.

2.3.5 NEM BILL CREDITS AND EXPORTS TO THE GRID SHOULD BE CONSIDERED IN THE ANALYSIS

To calculate bill effects, we developed two hourly load shapes: (1) customer gross load in the absence of PV and (2) customer net load after PV is installed. E3's subcontractor, Clean Power Research, derived billing determinants from these hourly load shapes and calculated monthly bills pre- and post-CSI installation.

The bill calculations in our CSI evaluation are similar to those in our NEM analysis completed in January, 2010. The calculations consider all NEM effects; the post-PV bill is calculated using a NEM rate, and any bill credits from one month are applied against the following month's bill.

We take into consideration effects from Assembly Bill (AB) 920, under which customers may begin, in January 2011, to receive compensation for any net-surplus kWh carryover at the end of the 12-month billing period. We have updated the AB 920 calculation from our NEM report following the CPUC's proposed decision on net compensation rate.[12] Whereas the NEM analysis used E3 avoided costs as a proxy for the final rate, in the CSI evaluation we use short-run avoided costs as represented by the average 2008 Default Load Aggregation Point (DLAP) prices, escalated by the retail rate escalation factor each year. Also, starting in

[12] The proposed decision in proceeding A.10-03-001 (http://docs.cpuc.ca.gov/efile/PD/126029.pdf) determines a rate using average Default Load Aggregation Point (DLAP) price from 7 am to 5 pm during the 12-month period over which the generation occurs.

2014, a REC value is added to this rate, consistent with the REC price throughout the analysis.

A more detailed discussion of NEM effects may be found in our NEM cost-effectiveness report.[13]

[13] Energy and Environmental Economics, Inc., Net-Energy Metering (NEM) Cost-Effectiveness Evaluation, January, 2010

3 Methodology

We evaluate the benefits and costs associated with solar PV and the CSI program on a 20-year lifecycle basis. For each program year, we develop the 20-year stream of values that comprise the inputs to the analysis. From the 20-year input streams we calculate several metrics, shown in Table 6. All calculations and results are in nominal dollars.

Table 6: Expression of Cost-Effectiveness Results

Benefit/Cost Ratio. The ratio of total NPV benefits to total NPV costs. A ratio greater than 1.0 indicates positive net benefits.
NPV ($). To calculate the net present value (NPV), we estimate the annual benefits and costs of the installed CSI solar PV for each year of the 20-year analysis period and take the present value of the stream of net costs using the appropriate discount rate for each cost test perspective.
Annualized Value ($/yr). The annualized cost value calculates the uniform annual stream of costs that would result in the same NPV. This differs from our estimated annual values in that the estimated annual values may vary from year-to-year (for example, declining due to degradation in solar PV system output), whereas the annualized value is uniform in real terms.
Levelized Value ($/kWh). The levelized value discounts the stream of future net costs and the stream of future solar PV output at the same discount rate, to represent the net cost over the life of the program on a $/kWh basis. This value is appropriate for comparison to other programs or measures that are often expressed in terms of levelized $/kWh, such as energy efficiency measures.

3.1 Historical vs. Prospective Analysis

For the historical years of our analysis – 2008 and 2009 – we use actual data from installed systems to the maximum extent possible. As described in greater detail in Section 3.3.1, this includes actual installed cost and 2008 billing data. Because we consider costs and benefits on a 20-year lifecycle basis, a forecast of many key inputs is necessary even for the historical program years of our analysis. For example, to calculate bill savings over the life of the solar PV, we must rely on a forecast of electricity rates.

As discussed in Section 2.3.4, we perform a prospective analysis of program years 2010-2016 to evaluate market transformation effects.[14] This estimation of future program performance relies on many of the same forecasts as the historical program year analysis – for example, electricity rates. It also requires forecasts of additional factors, including program adoption and installed solar PV costs.

In Section 3.3, we provide a detailed description of our derivation of key inputs and forecasts. This is preceded by an overview of the modeling approach in Section 3.2 below.

3.2 Modeling Overview

Our CSI evaluation uses a combination of Excel and SAS modeling. To the extent possible, we attempt to maximize transparency by using publicly available data and making our models available for public review. In this

[14] Although this final report was released in 2011, the bulk of the analysis was performed in 2010, before year-2010 program data was fully available.

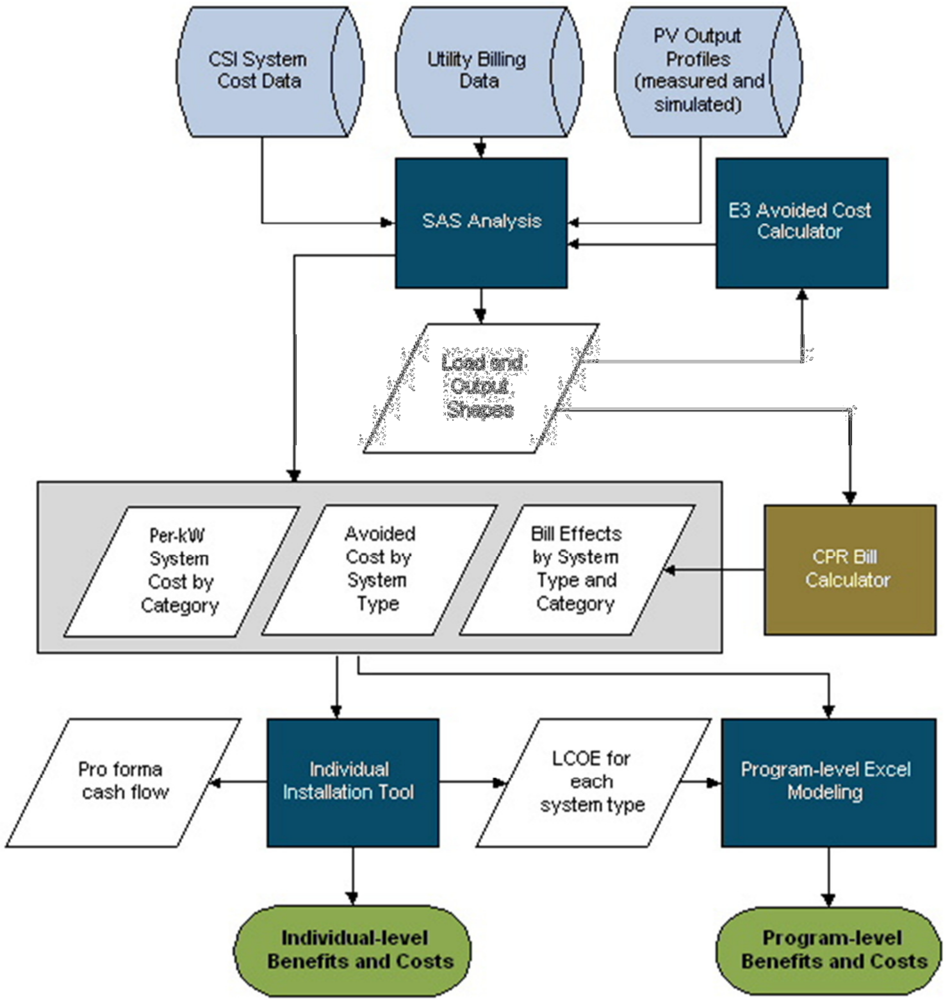
case, two factors limited our ability to do so: (1) we rely on actual customer billing data, which cannot be made public due to its sensitive nature, and (2) the sheer size of some of the data sets demands that we work in SAS, rather than the more easily shared Excel format.

Nevertheless, we are able to make our results largely transparent through the use of our Pro Forma Individual Installation tool.[15] This tool allows the user to select a single PV installation to be evaluated, based on system size, location, customer type, rate, and other characteristics. Based on this selection, the tool provides default inputs and calculates a financial *pro forma* to derive the levelized cost of energy (LCOE). In addition, the tool calculates the overall costs and benefits from each test perspective by assigning a proportional amount of administrative and other costs.

Figure 10 shows the relationship between the individual installation tool and additional modeling performed.

[15] Available at http://www.ethree.com/public_projects/cpuc.html

Figure 10: Flowchart of E3 Modeling Steps



As shown in Figure 10, the individual installation tool and the program-level modeling share the same foundational elements. System cost, avoided costs, and bill impacts are identical across both tools. Where the Individual Installation Tool calculates results for only a single system, the program-level modeling essentially repeats this analysis for every system (or, more precisely, category of system) in the program.

In the remainder of this chapter, we explain our derivation of each of the major input streams that factor into the modeling.

3.3 Development of Key Input Assumptions

This section describes derivation of key inputs to the CSI cost-effectiveness evaluation. Most of the inputs described below are benefits and costs nominated in Attachment A to D.09-08-026 (see Table 5 on page 28). Some additional, underlying input assumptions, such as gross and net load shapes, are also necessary to complete the analysis.

The categories of major inputs are as follows. This list includes all benefits and costs from the CPUC decision, as made explicit in the sub-level bullets.

- Pre- and Post-PV Load Shapes
- Utility Avoided Costs
    - Line losses
    - Avoided purchase of energy commodity and Resource Adequacy costs
    - Avoided T&D costs (investment deferral)
    - Environmental benefits (CO2, NOx, and particulate matter emissions)
- System Cost, Financing Assumptions, and Taxes
    - Tax credits/depreciation

    - Operation and maintenance cost
- Renewable Energy Credit (REC) revenue
    - Though not explicitly included in the decision, REC revenue is a benefit that accrues to participants in the event a market for tradeable RECs is established
- CSI Incentive Payment (and underlying adoption forecast)
    - Rebates/Incentives
- Bill Impacts
    - Reduced electricity bills
    - NEM bill credits
    - Standby charge exemption
    - Nonbypassable charges
    - Reduced transmission, distribution, and non-fuel generation revenues
- Metering, Interconnection, and Administrative Costs
    - Utility Interconnection
    - Utility interconnection not charged to the DG customer
    - Net Energy Metering costs
    - Program administration, based on administrators' 10-year program administration budgets

Our derivation of each of these input categories is described in detail in the sections that follow.

3.3.1 PRE- AND POST-PV LOAD SHAPES

Though not direct benefit or cost inputs, hourly pre- and post-PV load shapes are key underlying inputs to the analysis. To calculate bill impacts, one must derive actual billing determinants with PV installed as well as estimate the billing determinants that would have been realized had PV not been installed. Hourly load and consumption profiles are necessary to do so. Likewise, the utility avoided costs vary hourly, so an hourly PV output profile is required for accurate calculation of avoided costs.

Because hourly metered PV output data was available in only a small number of cases and hourly participant load data was not available at all, we needed to develop representative load and output shapes for each customer, or groups of customers. Our process for doing so is thoroughly described in our NEM cost-effectiveness evaluation,[16] and we do not reproduce that documentation in full here. Rather, we offer the following brief summary of the process:

+ Step 1: Develop gross annual consumption and load data. This operation uses utility billing data and PV system data.
+ Step 2: Create "bins" of like customers. We grouped customers into bins based on customer class, climate zone, retail rate, gross annual consumption, and ratio of annual PV output to annual

[16] *Ibid.* note 13.

load. This created a total of 1,253 bins, one of which is shown in the callout in Figure 11.

- Step 3: Estimate hourly load and output profiles. Hourly load data for each bin is based on utility load research data for the relevant type of customer. We developed hourly PV output profiles for each bin based on metered and simulated PV output data. For each bin, we combine two output profiles and two load profiles to produce four gross and net load profiles which are used for calculating program costs and benefits. Each profile provides an hourly load shape with PV installed (net load) and the load shape that would occur in the absence of PV (gross load). An example is shown in Figure 12.

Figure 11: Callout showing customer bin for Residential customers of PG&E, "Valley" climate zone, rate "E1," with gross consumption from 10-15 MWh and generation/consumption ratio of).4-0.6.

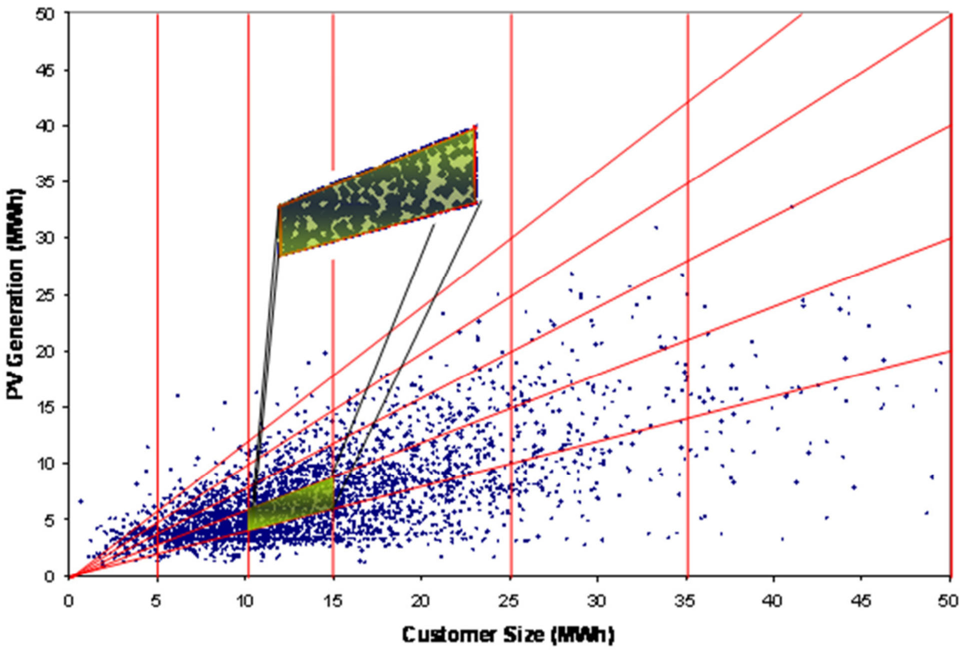
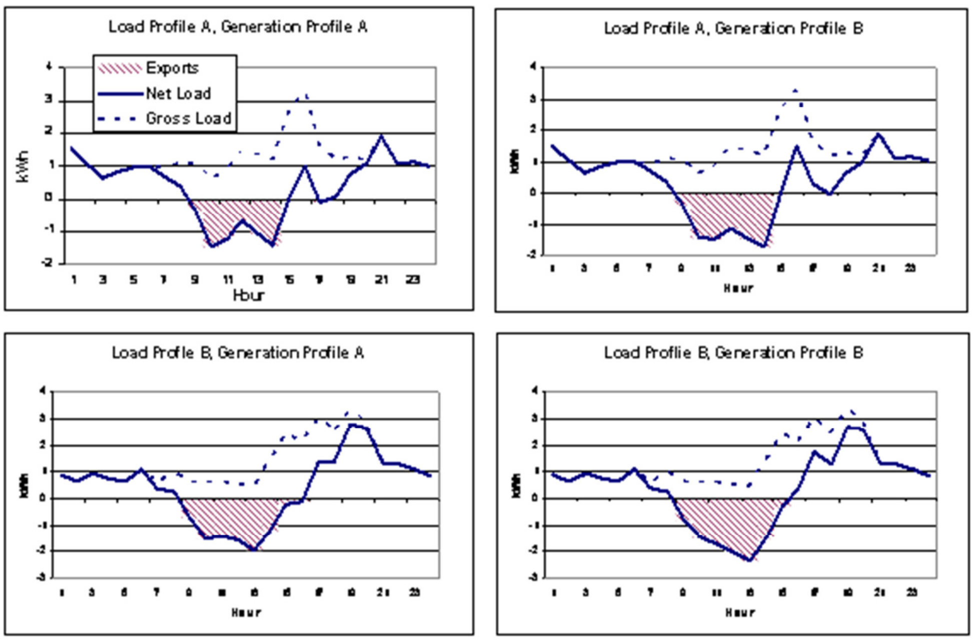


Figure 12: Representative gross and net load for a single example day for the bin shown in Figure 11.



3.3.2 UTILITY AVOIDED COSTS

Utility avoided costs are a benefit under the PACT, RIM, TRC and SCT tests.

To compute avoided cost benefits, we develop a forecast of hourly avoided costs for 16 climate zones in California over the analysis period – in this case through 2040. The 20-year levelized hourly avoided cost values are multiplied by the representative PV output shapes described in Section 3.3.1 to arrive at the avoided cost value for the particular PV system. The avoided cost components include generation energy, line losses, ancillary services, generation capacity, T&D investment deferral, environmental costs, and avoided renewable purchases. A three-day snapshot of avoided costs in a selected climate zone is shown in Figure 13.

Figure 13: Three-day snapshot of avoided costs

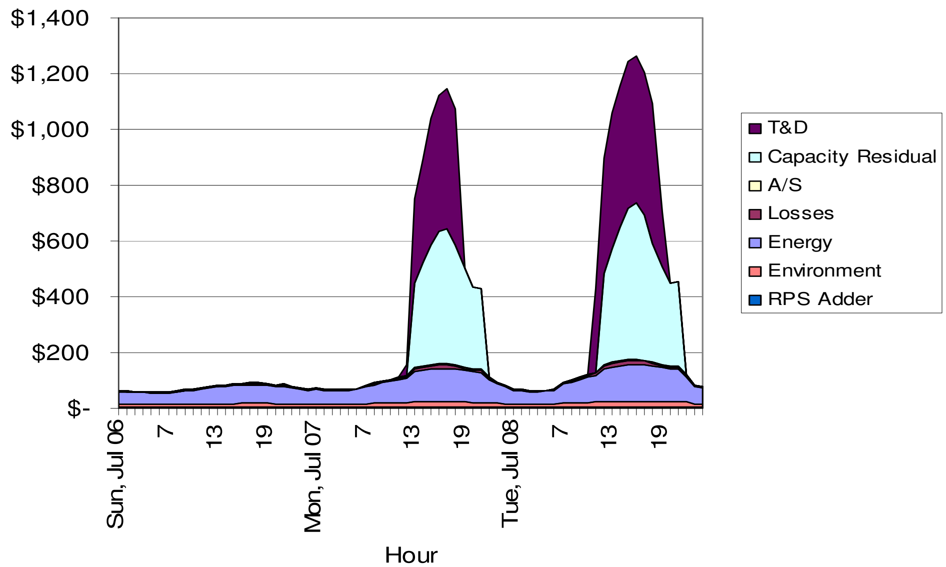


Figure 13 shows that in most hours, the primary component of avoided costs is avoided energy costs, which fluctuate from hour-to-hour reflecting variation in the market price of electricity. In a few hours, however, avoided costs spike due to the avoidance of significant generation capacity and T&D capacity costs. The three-day period in Figure 13 was selected to show this effect; during most days of the year no avoided generation capacity or T&D capacity costs are realized. Capacity costs are avoided only during peak system hours (hot summer days, in this case); the hours when constraints in capacity drives new investment.

The avoided cost methodology we used for the CSI cost-effectiveness evaluation is identical to the one we used for the NEM analysis. Compared to E3 avoided costs used for energy efficiency, these avoided costs include several updates:

+ **Update of Inputs.** We updated key inputs, including natural gas prices, electricity prices, and weather data.
+ **Generation Capacity Methodology.** In the EE avoided costs, generation capacity value was captured after the load-resource balance year, based on the all-in long-run costs of a new combined cycle combustion turbine (CCCT); prior to the resource balance year, any capacity value was assumed to be captured in energy prices. We have updated this method to include a capacity value in the short-run based on a proxy for Resource Adequacy (RA) market prices. After the resource balance year, capacity value is calculated based on the cost, net of market revenue, of a new CT. These capacity values are allocated over the top 250 hours of system load.
+ **Avoided RPS Purchases.** We added a new avoided cost component – avoided RPS purchases – to reflect the fact that as overall system demand declines, the quantity of renewable energy needed to meet the 33% RPS goal also declines. Since the cost of renewable energy is higher than its value in wholesale energy and capacity markets, an adder is necessary to capture the value. However, because there is no opportunity for reductions in

renewable purchases until the 33% goal is met (essentially, California IOUs must purchase and bring online renewable energy as fast as possible to meet the goal), we do not begin accruing these benefits until 2020, the presumed date for meeting the RPS goal.

This avoided RPS purchase benefit is distinct from any REC value of the energy. Utility RPS purchase requirements decline with reductions in system demand whether the distributed generation that is causing the reduction in system demand is renewable and clean, or fossil-fueled and carbon emitting.

Our avoided cost methodology is described in detail in Appendix B.

3.3.3 SYSTEM COST, FINANCING, AND TAXES

The installation and operational costs of solar PV are a cost in the PCT, TRC and SCT tests. A full accounting of PV costs includes the installed system cost, financing costs, tax effects, and operational maintenance costs. Because our market transformation analysis considers program economics into the future, we forecast these factors over the life of the program.

3.3.3.1 Installed System Cost – Historical Period

We used the CSI program database[17] of CSI systems to estimate system cost. The database provides a record of installed system cost and other system details for all installations under the CSI program. We excluded third-party-owned systems (11% of the data, in terms of number of customers) from our analysis due to reporting anomalies in some third-party data.[18]

We divided the remaining data into categories based on size. Table 7 shows the median cost, in $/Watt, of CSI installed systems by size category for the first three years of the program, as derived from the CSI program database.

[17] We had access to some data not accessible in the public report that allowed us to tie system costs to specific customers and to billing data.
[18] Cost values reported by third parties often appeared to be based on a present-valuing of power purchase agreement (PPA) costs, rather than the actual installed system cost.

Table 7: Median cost of installed systems by reservation year, from the CSI database (nominal $/Watt)

System Size Category	2007	2008	2009
Less than 10 kW	$8.01	$8.00	$7.42
10 to 100 kW	$7.72	$7.70	$6.88
100 to 500 kW	$7.02	$6.79	$6.12
Greater than 500 kW	$6.55	$6.33	$6.27

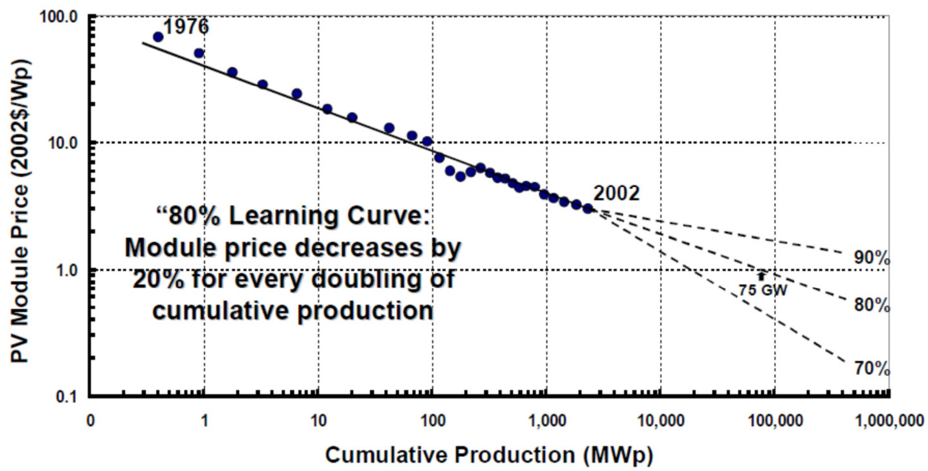
We used median cost to dampen the effect of outliers. The use of the median results in an average cost decrease of 5.0% below the mean, with percent changes within system size groupings ranging from -2.8% to 7.2%.

3.3.3.2 Installed System Cost Forecast – Progress Ratio

For our market transformation analysis, we forecast system costs for each year remaining in the program, 2010-2016, based on a *progress ratio* approach. A progress ratio represents the cost of production after a doubling in cumulative installed capacity.

In our base case analysis, we apply an 80% progress ratio to 2009 system costs, meaning that for every doubling in cumulative global installed capacity after 2009, installed system cost declines by 20%. An 80% progress ratio is consistent with studies on the historical learning curve for solar PV modules. An example is shown in Figure 14.

Figure 14: PV Module progress ratio from NREL study



Source: Thomas Surek, National Renewable Energy Laboratory, Progress in U.S. Photovoltaics: Looking Back 30 Years and Looking Ahead 20.

While solar progress ratios generally apply to module cost, in our study we apply an 80% progress ratio the full installed system cost. A Lawrence Berkeley National Laboratory (LBL) study[19] found that markets with large solar deployment programs tend to have lower installed system cost, suggesting that balance-of-system costs (such as installation and marketing) also decline with market growth. The study found that a significant portion of observed reductions in total installed cost were a result of reductions in non-module costs. In fact, this effect outweighed the influence of reductions in module cost.

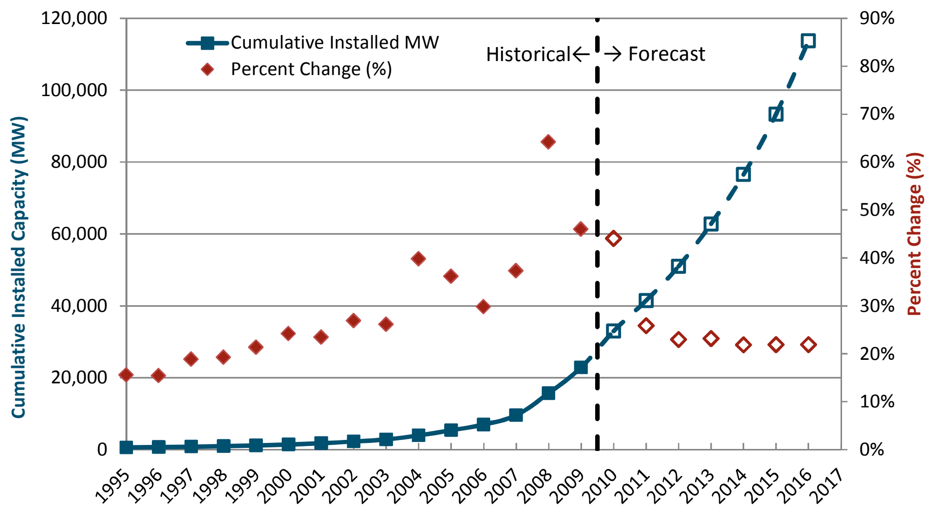
[19] Ryan Wiser, Galen Barbose, and Carla Peterman, *Tracking the Sun: The Installed Cost of Photovoltaics in the U.S. from 1998-2007*, Lawrence Berkeley National Laboratory, February, 2009.

Although we recognize there are natural limits on reductions in certain non-module costs (such as construction), we believe the simplifying assumption applying an 80% progress ratio to total installed cost is reasonable over the period of this study. In addition, we conduct sensitivity testing on progress ratios of 70% and 90% to examine the effect of alternative outcomes in installed cost trends.

3.3.3.3 Installed System Cost Forecast – Underlying Adoption Forecast

Calculation of an installed system forecast based on a progress ratio requires a forecast of cumulative installed capacity. We rely on a forecast of global installed PV capacity from the European Photovoltaic Industry Association (EPIA), shown in Figure 15.

Figure 15: Forecast of Global Installed Solar PV Capacity, Based on EPIA's Moderate Scenario[20]



EPIA's forecast shows that while historical growth rates have hovered between 20-30% annually (the solid red diamonds), in recent years growth rates have climbed higher – over 60% in 2008. In 2009, the growth rate was approximately 45%. EPIA forecasts a similar growth rate for 2010, and thereafter a return to annual growth rates between 20-30% (as shown in the hollow diamonds). The forecast predicts cumulative global solar PV capacity of more than 100 GW in 2016.

[20] Chart based on data from: *Global Market Outlook for Photovoltaics Until 2014*, European Photovoltaic Industry Association, May 2010.

3.3.3.4 Installed System Cost Forecast – Forecast Results

Figure 16 and Table 8 present the forecast of installed system cost resulting from the forecast methodology described above. By 2020, we project system costs in nominal dollars to be roughly in the $4/W-dc range or slightly higher depending on system size.

Figure 16: Forecast, in nominal dollars, of total installed system cost based on EPIA cumulative capacity forecast and 80% progress ratio

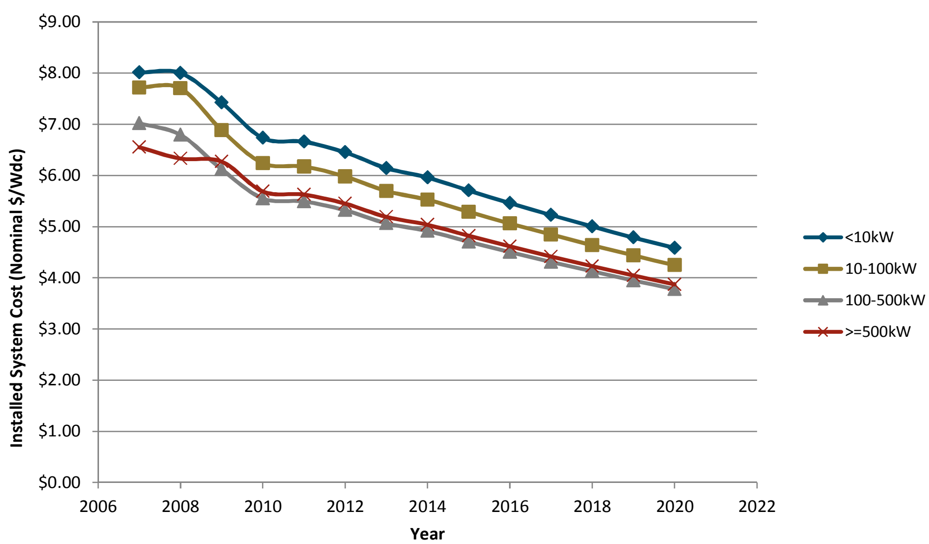
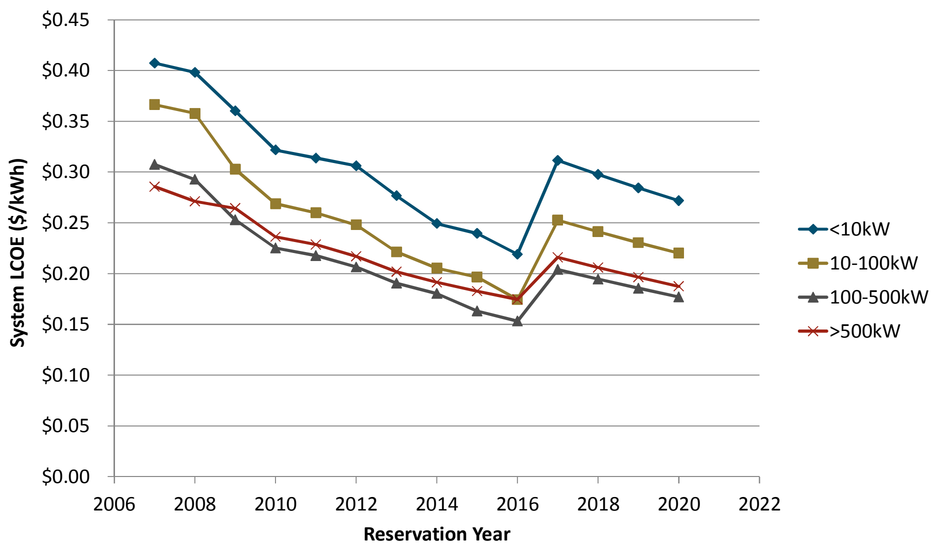


Table 8: Forecast of Total Installed System Cost Based on EPIA Cumulative Capacity Forecast and 80% Progress Ratio (nominal $)

System Size	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
<10 kW	8.01	8.00	7.42	6.73	6.66	6.45	6.14	5.96	5.70	5.46	5.23	5.00	4.79	4.58
10-100 kW	7.72	7.70	6.88	6.24	6.17	5.98	5.69	5.53	5.29	5.06	4.84	4.64	4.44	4.25
100-500 kW	7.02	6.79	6.12	5.55	5.49	5.32	5.07	4.92	4.70	4.50	4.31	4.12	3.95	3.78
>500 kW	6.55	6.33	6.27	5.69	5.63	5.45	5.19	5.04	4.82	4.61	4.42	4.23	4.04	3.87

For reference, Figure 17 shows the LCOE we calculate based on the projected system costs in Figure 16. LCOE declines until 2017, when the 30% ITC expires. After jumping in 2017, LCOE returns to a steady decline reflecting our projection of declining system costs. The financing assumptions underlying the LCOE calculations are described below in Section, 3.3.3.5.

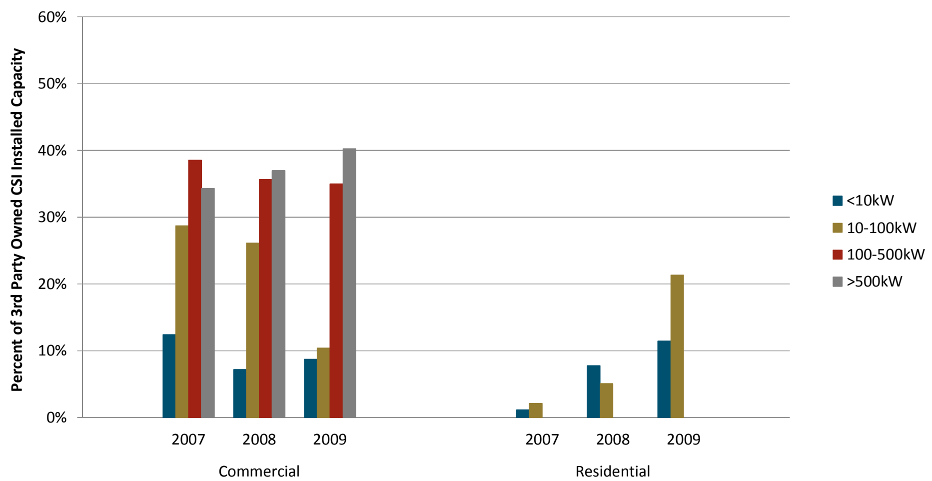
Figure 17: Levelized cost of energy (LCOE) by system size, factoring in tax benefits and REC value



3.3.3.5 Financing and Taxes

We evaluate the economics of CSI installations under both private ownership and third-party ownership (Power Purchase Agreement (PPA)) cases. The historical ratio of each type of financing is available from an examination of the data in the CSI program database. While the percentage of third-party financed cases remained relatively steady in the commercial and government / non-profit sectors from 2007-2009, the residential sector showed a marked increase in the proportion of installations that were third-party financed. A comparison of commercial and residential third-party financing is shown in Figure 18.

Figure 18: Comparison of commercial and residential class third-party financing



While some of this increase may be due to financing difficulties associated with the economic downturn, a significant factor is likely the development of a market for residential third-party financing following the launch of the CSI program, and communication of offers to residential customers. We forecast this trend continuing up to an assumed ceiling of 60% residential third-party financing, which is the observed ratio of third party financing in larger (100 kW to 500 kW) residential systems in 2009 (the only year for which data were available).

The economics of both private ownership and third-party financing are calculated in our individual installation tool, available on the E3 web site.[21] We evaluate 100% cash, 100% debt, and mixed debt/equity financing within the private ownership case. For third party-ownership, we calculate the revenue stream that a third-party would need from the customer to receive a return on investment, based on a financial *pro forma* developed from the third party perspective. The private ownership and PPA *pro formas* factor into the calculation of benefits and costs, including the LCOE, that flow into our benefit/cost tests. For the program-level modeling, we apply a mix of financing types corresponding to our forecast described above.

State and federal taxes are applied at the relevant rate for each customer type and ownership structure. We treat federal tax benefits as external to the "society" (the state of California) under evaluation in the TRC and SCT tests. Federal tax benefits and the ITC are thus counted as a benefit in these tests, as well as in the PCT.

For residential, privately-owned systems, the marginal income tax rate is applied. Table 9 shows tax assumptions used in the analysis. More information on tax treatment is available in the Individual Installation Tool, where users may review our *pro forma* treatment of taxes and other financing assumptions.

[21] http://www.ethree.com/public_projects/cpuc.html

Table 9: Tax assumptions

Customer Type	Financing Choice	Federal Tax Rate	State Tax Rate	Tax Credit Rate	Tax Credit Expiration	MACRS Term	Taxable Electricity?
Residential	Private Ownership - 100% Cash	28%	9.30%	30%	2016	5	No
	Private Ownership - Debt/Equity	28%	9.30%	30%	2016	5	No
	Private Ownership - 100% Debt	28%	9.30%	30%	2016	5	No
	Third Party Ownership - PPA/Lease	35%	8.84%	30%	2016	5	Yes
Commercial	Private Ownership - 100% Cash	35%	8.84%	30%	2016	5	No
	Private Ownership - Debt/Equity	35%	8.84%	30%	2016	5	No
	Private Ownership - 100% Debt	35%	8.84%	30%	2016	5	No
	Third Party Ownership - PPA/Lease	35%	8.84%	30%	2016	5	Yes
Government	Private Ownership - 100% Cash	0	0	0	0	0	No
	Private Ownership - Debt/Equity	0	0	0	0	0	No
	Private Ownership - 100% Debt	0	0	0	0	0	No
	Third Party Ownership - PPA/Lease	35%	8.84%	30%	2016	5	Yes
Non-Profit	Private Ownership - 100% Cash	0	0	0	0	0	No
	Private Ownership - Debt/Equity	0	0	0	0	0	No
	Private Ownership - 100% Debt	0	0	0	0	0	No
	Third Party Ownership - PPA/Lease	35%	8.84%	30%	2016	5	Yes

3.3.4 REC REVENUE

Per D.05-05-011 and D.07-01-018, customers installing CSI own the associated RECs; any revenue from RECs should be counted as a benefit in the PCT test. We include this benefit in our analysis beginning in 2014, an assumption which anticipates a market for tradeable RECs in the near future. If the system is privately owned, we credit the owner with the REC value without regard to whether the RECs are ultimately sold or are retained by the customer, under the logic that a customer who retains the REC values its ownership at the market value (or greater). In the case of a PPA, wherein the PPA provider typically takes ownership of the REC, we account for the REC value in calculating the PPA price.

Our estimate for the price of a REC is based on the spread in our avoided cost calculations between renewable generation and a combined-cycle gas turbine (CCGT), which has been, and is expected to continue to be, the marginal generation source in California. This value is roughly

$0.035/kWh, which is toward the high-end of "green energy" pricing premiums observed to date in California.[22] Basing the REC price on the spread between central station renewable and conventional generation implies that the price for a REC will settle at a level that makes utilities indifferent between meeting renewable goals via contracts for central station renewables or purchase of RECs, the expected result under a functioning liquid market.

The benefit of REC revenue that accrues to customers is distinct from the "Avoided RPS Purchases" benefit that accrues to utilities, described in our discussion of avoided costs in Section 3.3.2, above.

3.3.5 ADOPTION FORECAST AND INCENTIVE PAYMENTS

Incentive payments are a benefit under the PCT and a cost under the RIM and PACT tests. Calculation of incentive payments, which step down over time as MW goals are achieved, requires a forecast of CSI program adoption.

Our forecast of program adoption is based on cumulative *reservations awarded* in each year, rather than on cumulative solar *installed* through the end of the year. We adopt this convention for two reasons: (1) it is computationally cleaner to use reported data on reservations because we would otherwise need to forecast the lag between reservation and

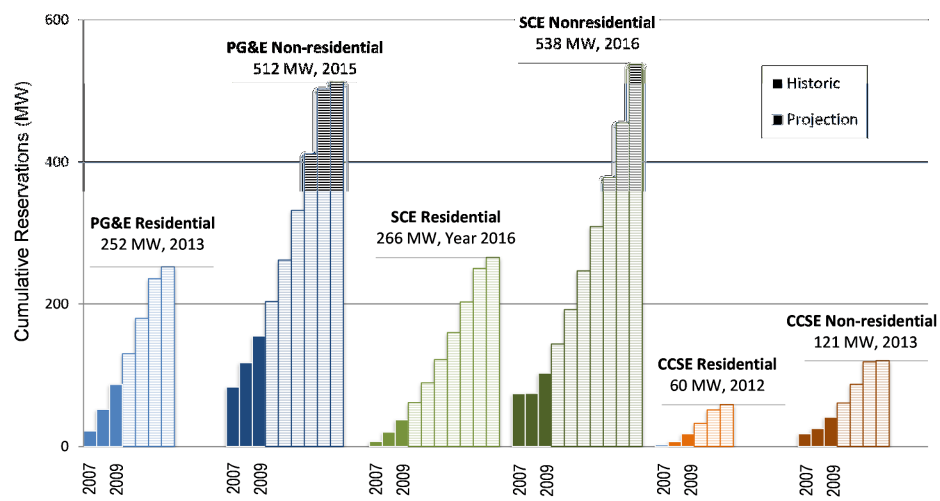
[22] http://apps3.eere.energy.gov/greenpower/buying/buying_power.shtml?state=CA

installation date (2) in our view, solar PV enrolled in the program and receiving incentives should be included in the analysis even if it is installed after 2016. The forecast corrects for any dropouts in reservations, as dropouts from one year are subtracted from the cumulative reservation count in future years.

Our base case adoption forecast is based on an examination of the historical adoption rate from 2007 through 2009. We separately examined the observed adoption rate in each customer class and utility and extrapolated the observed trend through 2016. There is no "correct" method for this extrapolation; for the most part, the historical data showed an increasing rate of adoption in each year, and we extended this trend in our extrapolation. The result is shown in Figure 19.[23]

[23] The forecast shown in Figure 19 was performed in 2010 before 2010 program adoption data were available. An examination of 2010 program data shows that PG&E and SCE are ahead of the forecast adoption schedule, and SDG&E is very slightly behind.

Figure 19: Adoption Forecast by Utility and Customer Class (Base Case)



The labels in Figure 19 show for each sector the number of confirmed reservation MW in 2016, or in the year we project the sector to be fully subscribed with confirmed reservations. There is some lag time between reservation and installation, and some dropouts and re-subscriptions are to be expected; therefore minor program activity may continue in each sector beyond the end year shown in Figure 19 before all installations are complete.

Subsequent to the creation of our forecast, it has come to light that PBI incentives were more costly than anticipated, as described and addressed in D.10-09-046. As a result, incentive budgets may be depleted before the program reaches its MW goals. The California Solar Statistics current program achievement forecast is compared to program goals in Table 10.

Table 10: California Solar Statistics (CSS) Forecasted CSI Achievement vs. Program Goal (MW)

	PG&E		SCE		SDG&E		Total
	Res	Non-Res	Res	Non-Res	Res	Non-Res	
Program Goal	252	512	266	539	60	121	1,750
CSS Forecast	241	302	261	389	62	67	1,322

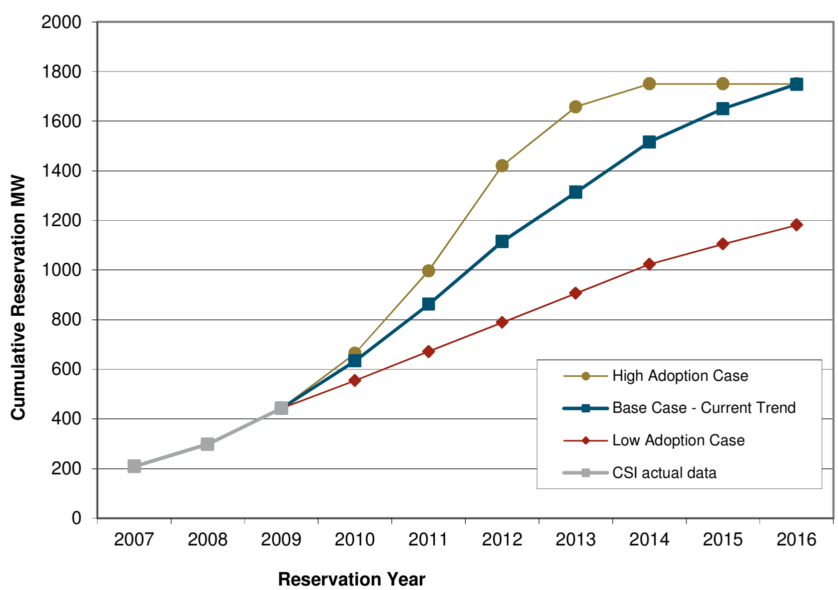
Source: http://www.californiasolarstatistics.ca.gov/reports/budget_forecast/, as of 1/24/11.

The current CSS forecast of program achievement (1,322 MW) falls short of the program goal of 1,750 MW. However, our analysis assumes the budget issue is solved in a way that allows the program to achieve planned goals. The effect of a changed forecast would mainly concern the timing of costs and benefits with a reduced number of installations; we would not expect significant changes to the fundamental conclusions of the analysis.

Under our forecast, some CSI segments, such as SDG&E residential, are expected to achieve their program goals well before 2016. For our cost-effectiveness evaluation, only installations up to the program goal are included in the analysis. In our base case forecast, based on the historical adoption trend, all sectors reach their MW goal by 2016 as shown in Figure 20.

The forecasts in Figure 20 show a flattening adoption over time. This flattening of the adoption curve does not reflect a slowing of demand for solar PV; rather, as program goals are met in each sector and no further installations in that sector are included in the analysis, though solar PV adoption outside of the program is expected to continue. As a result, the overall CSI program adoption curve flattens to reflect the more limited potential in the remaining sectors.

Figure 20: CSI Adoption Forecast – Cumulative Reservations (MW)



Given establishment of the adoption forecasts described above, calculation of incentive costs is straightforward. As CSI MW goals are met for each incentive step, the incentive paid for subsequent reservations steps down. We perform this operation separately for each utility and customer class segment, based on the respective forecasts. For example, Figure 21 summarizes the result for the PG&E residential sector.

Figure 21: Annual installed capacity and average rebate level under base case adoption forecast, PG&E residential sector

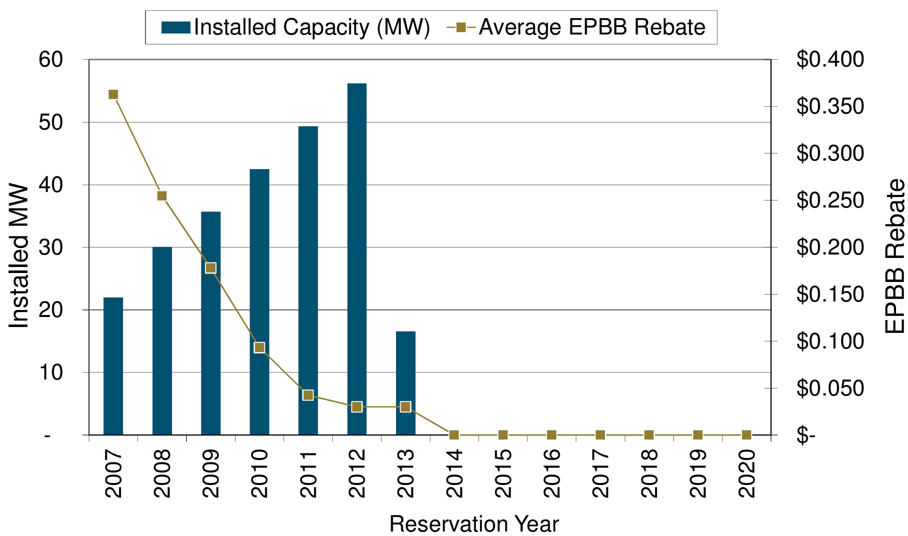


Figure 21 shows the step down in EPBB incentives against the annual forecasted MW for the segment.[24] We perform a similar analysis for PBI incentives.

Our forecasted mix of PBI and EPBB incentives is based on the historical distribution of incentive types from 2007-2009, which we obtained from the CSI program database. We calculated this distribution for each utility, customer class segment, and PV size bin.

[24] The drop in reserved capacity in 2013 indicates achievement of program MW targets. Solar PV adoption may continue to grow beyond 2013 in the absence of CSI incentives but these MW installed outside of the program are not relevant to our program evaluation.

3.3.6 BILL IMPACTS

Customer bill savings, including any AB 920 credits, are a benefit under the PCT and a cost under the RIM test. To calculate bills, we develop estimates of net load (with PV installed) and gross load (without the PV installed), as described in Section 3.3.1. We develop hourly load shapes for each, which we provide to our bill calculation partner, Clean Power Research (CPR). CPR's bill calculation tool[25] derives billing determinants, including energy charges, demand charges, and other rate charges, from the hourly load shapes and computes 12 monthly bills.

Any rate switching that occurs with the installation of solar PV is taken into account by our analysis. The bill from the gross load shape, representing what the customer would have paid were it not for the installed solar PV, is calculated based on the rate the customer was on before installing solar. The bill from the net load shape is calculated based on the rate to which the customer switched, i.e. the NEM rate.

We assume that all CSI customers in our forecast period will be eligible for and will enroll in NEM rates. AB 510 expanded each utilities cap on NEM to 5% of aggregate customer demand, which should be adequate to accommodate the MW in the CSI program. For example, assuming PG&E's current peak load, the 5% gap is equivalent to over 1,040 MW

[25] CPR's bill calculation tool may be accessed via a spreadsheet tool that interfaces with the bill calculator. The spreadsheet user may input an 8760 hourly load shape. The tool will then "call" the bill calculator and return the derived billing determinants and monthly bills. The spreadsheet is available on E3's web site at http://www.ethree.com/CPUC_CSI.html.

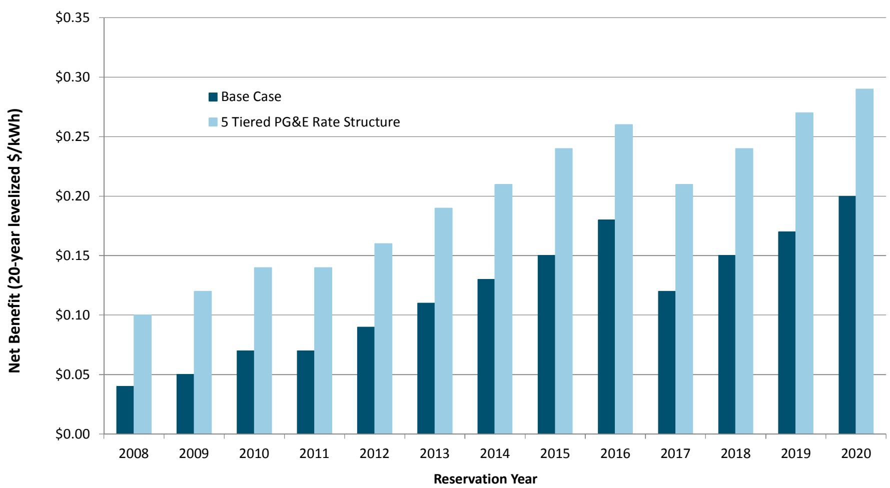
which is enough to accommodate the 760 MW goal for CSI plus an additional 280 MW of non-CSI solar or other NEM technologies.

To estimate annual bill savings over the 20-year analysis period, we adjust the calculated bill savings to reflect PV output degradation (1.25% per year) and retail rate increases (4.47% per year in nominal dollars until 2020, 2% per year after 2020). The bill calculation methodology for our CSI evaluation is consistent with that used in our NEM evaluation; we refer readers to our NEM report[26] for additional details on the bill calculation.

For PG&E, we calculate bills under the assumption that PG&E's proposed 3-tier rates are approved.[27] The 3-tier rates significantly lower the highest marginal rate paid by customers and have the effect of reducing overall benefits to residential customers by slightly more than 30% in all years (see Figure 22), but this difference does not change the overall implications for participant cost-effectiveness; the program remains cost-effective for residential customers from the PCT perspective in each year studied.

[26] *Ibid.* note 13.
[27] For computational simplicity, we use the proposed rates (A.10-03-014) for all years of the analysis, rather than attempting to model a change in rates that would include separate calculations for the historical 5-tier rates, the interim 3-tier rates, and the final proposed 3-tier rates.

Figure 22: Comparison of PCT Net Benefits Under PG&E's 5-Tier and Proposed 3-Tier Rate



3.3.7 INTERCONNECTION, BILLING, AND PROGRAM ADMINISTRATION COSTS

We include interconnection, billing, and program administration costs in the cost-effectiveness analysis. For interconnection costs, we include customer or utility borne costs, or both, depending on the test perspective. In response to our NEM data request, we received information about utility interconnection costs from only one utility and we apply this value – $574/customer – uniformly throughout our analysis.

From data request responses, we calculated a weighted average incremental billing cost by customer class, shown in Table 11. Arguably, incremental billing costs are a function of NEM and not a direct cost of CSI. However, NEM benefits are an important part of the overall economics of CSI-installed solar PV; we therefore fully account for NEM costs and benefits in our analysis.

Table 11: Weighted average per-customer monthly incremental billing cost

Customer Class	PG&E	SCE	SDG&E
Residential	$18.31	$3.02	$5.96
Non-residential	$18.31	$2.55	$17.44

Program administration costs in our analysis are based on the program administrators' 10-year program budget. We use actual reported expenditures for 2007-2009, allocated to residential and non-residential classes based on installed capacity. For 2010-2016 we allocate the remaining budget by MW of capacity installed, according to our forecast(s). Annual admin expenditures by utility are estimated at approximately: $9.4 million for PG&E, $9.9 million for SCE, and $2.1 million for SDG&E.

PBI incentives are more costly to administer than EPBB incentives. However, in our program-level analysis, this distinction is unimportant because we allocate each year's budget at the program, rather than individual installation, level.

4 Cost-Effectiveness Results

4.1 Historical Period (2008-2009)

Our CSI analysis evaluates historical program cost-effectiveness for the period 2008-2009 and forecasts the cost-effectiveness of future years 2010-2016 to evaluate market transformation effects. In this section we report results for the historical 2008-2009 period.

All results are presented in nominal dollars and pertain to the fleet of CSI installations reserved during the year evaluated. We present results for each of the test perspectives in several ways: benefit/cost ratio; net present value (NPV) over the 20-year analysis period; annualized benefits (costs); and levelized (per kWh-generated) net benefits (costs) (see Table 6 on page 37).

Historical period analysis uses actual recorded program data on system installation cost and is based on 2008 billing data.

4.1.1 BASE CASE DESCRIPTION

Our base case includes the following assumptions:

+ Installed system costs as reported by CSI participants

- Retail rate escalation of 4.47%, nominal, through 2020 and 2% nominal thereafter
- Capacity factor of installed solar PV based on metered or partially metered systems (517 data points) and simulated systems (297 data points)

4.1.2 PCT RESULTS – HISTORICAL

For the participant cost test, we include all relevant PCT costs and benefits previously described in Table 5 and Section 3.3, as shown in Table 12.

Table 12: Benefits and Costs in the PCT

Benefit or Cost Category	Treatment in PCT
System Cost, Financing, and Taxes	System cost and financing are a cost. Tax savings and credits are a benefit.
REC Revenue	Benefit to participants
Incentive Payments	Benefit to participants
Bill Impacts	Bill savings are a benefit to participants

Figure 23 along with Table 13, and Figure 24 along with Table 14, show the PCT results for the historical period under base case assumptions for the residential and non-residential segments, respectively.

In 2008, the program was cost-effective for the residential segment from the PCT perspective with the help of the CSI rebate. By 2009, declining system costs and increasing electricity rates made solar PV moderately cost-effective from the PCT perspective even without the CSI rebate, though the ITC was still needed.

Figure 23: PCT Results – Residential

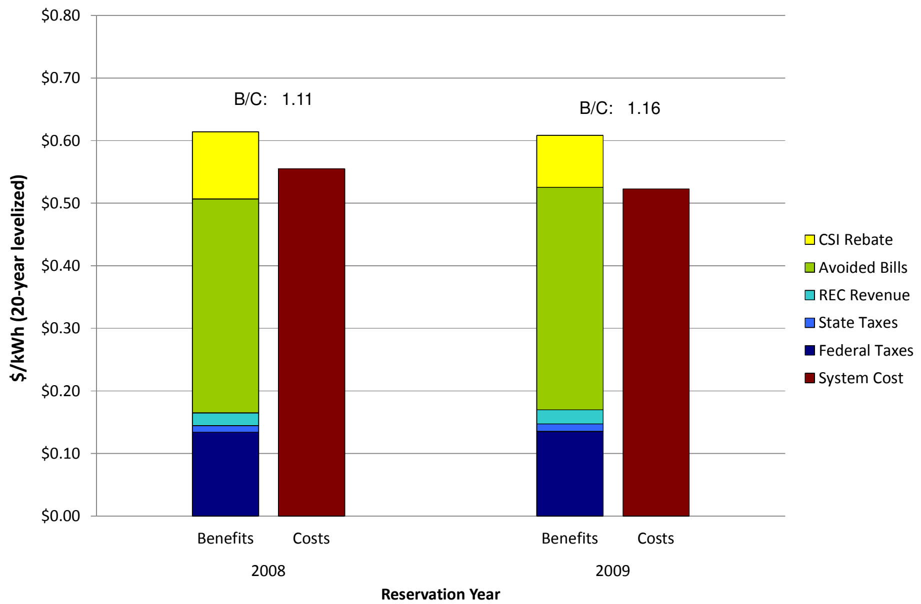


Table 13: Breakdown of PCT Results – Residential (Levelized $/kWh)

	2008	2009
System Cost	($0.555)	($0.523)
CSI Rebate	$0.107	$0.083
Avoided Bills	$0.342	$0.356
REC Revenue	$0.020	$0.022
State Taxes	$0.011	$0.012
Federal Taxes	$0.134	$0.135
Net Benefits	$0.059	$0.086

For non-residential customers, the program falls slightly short of being cost-effective from the PCT perspective even with the CSI rebate. The important difference is bill savings, which are much higher for residential customers due to the rate structure.

Figure 24: PCT Results – Non-residential

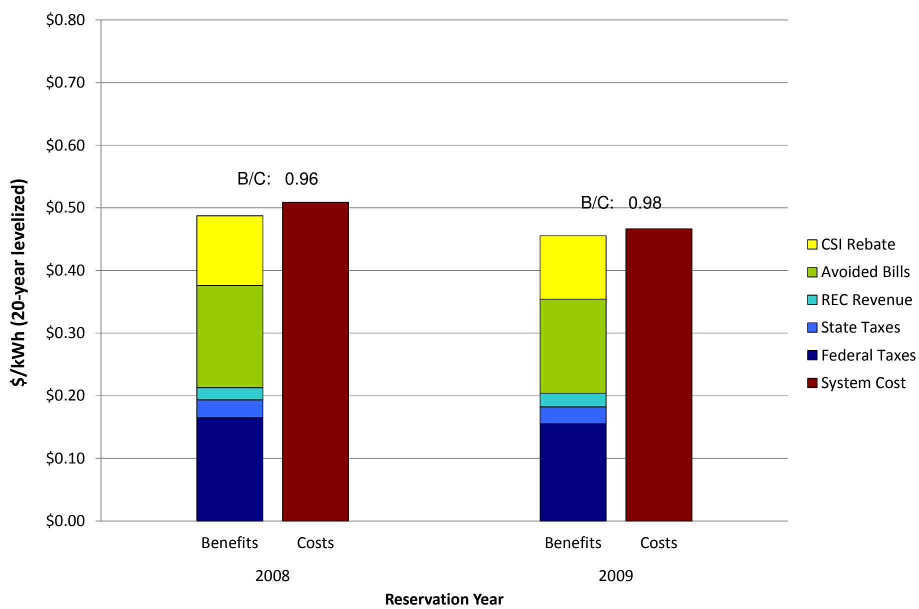
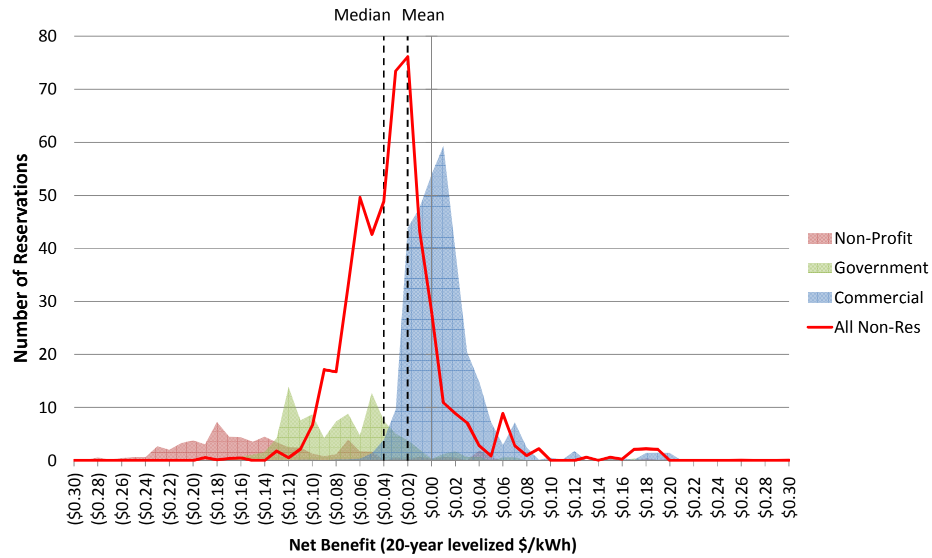


Table 14: Breakdown of PCT Results – Non-residential (Levelized $/kWh)

	2008	2009
System Cost	($0.509)	($0.467)
CSI Rebate	$0.111	$0.101
Avoided Bills	$0.163	$0.150
REC Revenue	$0.019	$0.021
State Taxes	$0.029	$0.027
Federal Taxes	$0.165	$0.155
Net Benefits	($0.022)	($0.011)

Despite an aggregate benefit/cost ratio slightly below 1.0, non-residential customers installed solar PV through the CSI program. Two factors help explain this apparent contradiction. First, the results are aggregate; on an individual level solar PV economics with CSI incentives are favorable for many non-residential customers. In particular, commercial customers, which are eligible for the ITC, fare better than government and non-profits, which are not. This can be seen in Figure 25, which compares cost-effectiveness results in 2008 for all non-residential customers. Commercial customers are centered around a break-even point, with a slightly longer tail of cost-effective customers, while government and non-profit customers are likely to have net costs.[28]

Figure 25: Comparison of Cost-Effectiveness Results for Commercial, Government, and Non-Profit Customers, 2008



[28] We did not break out the non-residential sector into its sub-components in our overall analysis for two reasons: (1) there was no way to distinguish between government and non-profit customers in the adoption history and forecast, and (2) the additional categorizations would have added substantial complexity and calculation requirements to our analysis.

Second, customers may obtain other benefits from solar PV not captured by the analysis, such as marketing value. Governmental and non-profit customers may also make the choice as a matter of policy or for philosophical reasons not directly related to economic payback.

4.1.2.1 Detailed PCT Results

We present additional PCT result detail by utility and customer class in Table 15 through Table 18. Table 15 shows that the residential sector passes the PCT with a positive B/C ratio in every case, while the non-residential sector falls short of passing the PCT in every case aside from SDG&E.

The remaining tables present the net benefits or costs in dollars. Table 16 shows that in 2009, on a net-present value basis, the total program has nearly $69 million in benefits from the participant perspective, with positive net benefits of more than $82 million in the residential sector, and net costs of slightly less than $13.5 million in the non-residential sector. As noted earlier, non-residential results vary between commercial, government, and non-profit customers.

Table 15: PCT Results, Base Case, B/C Ratio

		2008	2009
PG&E	Residential	1.06	1.09
	Non-Res	0.95	0.97
	Total	1.01	1.04
SCE	Residential	1.16	1.23
	Non-Res	0.90	0.95
	Total	1.15	1.07
SDG&E	Residential	1.27	1.31
	Non-Res	1.00	1.03
	Total	1.10	1.14
All IOUs	**Residential**	**1.11**	**1.16**
	Non-Res	**0.96**	**0.98**
	Total	**1.04**	**1.06**

Table 16: PCT Results, Base Case, 20-Year NPV ($M)

		2008	2009
PG&E	Residential	$15.32	$26.53
	Non-Res	($12.68)	($6.95)
	Total	$2.65	$19.58
SCE	Residential	$18.32	$33.29
	Non-Res	($0.38)	($9.65)
	Total	$17.94	$23.64
SDG&E	Residential	$8.52	$22.46
	Non-Res	($0.04)	$3.24
	Total	$8.48	$25.70
All IOUs	**Residential**	**$42.17**	**$82.28**
	Non-Res	**($13.09)**	**($13.36)**
	Total	**$29.07**	**$68.92**

Table 17 expresses the cost on an annualized basis over the life of the solar PV, revealing residential net benefits of greater than $5.5 million, annualized, for the fleet of solar PV installed in 2009, and non-residential net costs of slightly more than $1 million, annualized.

Table 17: PCT Results, Base Case, 20-Year Annualized ($M)

		2008	2009
PG&E	Residential	$1.04	$1.79
	Non-Res	($0.97)	($0.53)
	Total	$0.06	$1.26
SCE	Residential	$1.24	$2.25
	Non-Res	($0.03)	($0.76)
	Total	$1.21	$1.49
SDG&E	Residential	$0.58	$1.52
	Non-Res	($0.00)	$0.26
	Total	$0.57	$1.78
All IOUs	**Residential**	**$2.85**	**$5.56**
	Non-Res	**($1.00)**	**($1.03)**
	Total	**$1.85**	**$4.53**

Table 18: PCT Results, Base Case, 20-Year Levelized ($/kWh generated)

		2008	2009
PG&E	Residential	$0.036	$0.053
	Non-Res	($0.026)	($0.013)
	Total	$0.003	$0.019
SCE	Residential	$0.081	$0.109
	Non-Res	($0.049)	($0.022)
	Total	$0.077	$0.032
SDG&E	Residential	$0.135	$0.146
	Non-Res	($0.000)	$0.014
	Total	$0.051	$0.067
All IOUs	**Residential**	**$0.059**	**$0.086**
	Non-Res	**($0.022)**	**($0.011)**
	Total	**$0.022**	**$0.032**

Table 18 expresses the results on a levelized $/kWh-generated basis, for easy comparison to other energy measures. For residential participants, the program provides benefits averaging nearly $0.09/kWh, which compares to an average residential CSI rebate of slightly over $0.08/kWh in 2009. The net costs for non-residential customers are just over $0.01/kWh, while the average non-residential rebate was just over $0.10/kWh in 2009.

Participant economics vary by customer size, with larger customers enjoying more favorable economics, as shown in Table 19.

Table 19: PCT Results by Customer Size, Base Case, 2008 (Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.17)	($0.09)	$0.08	($0.13)
	5 to 10 MWh	($0.05)	($0.02)	$0.04	($0.04)
	10 to 15 MWh	$0.05	$0.04	$0.13	$0.05
	15 to 25 MWh	$0.08	$0.10	$0.16	$0.09
	25 to 35 MWh	$0.10	$0.13	$0.19	$0.12
	35 to 50 MWh	$0.10	$0.14	$0.19	$0.13
	50 to 100 MWh	$0.10	$0.15	$0.20	$0.13
	100 to 500 MWh	$0.12	$0.17	$0.25	$0.15
	Average	$0.04	$0.08	$0.14	$0.06
Non-Res	0 to 5 MWh	($0.08)	($0.05)	($0.14)	($0.09)
	5 to 10 MWh	($0.06)	($0.04)	($0.06)	($0.06)
	10 to 15 MWh	($0.06)	($0.04)	($0.05)	($0.06)
	15 to 25 MWh	($0.04)	($0.03)	($0.01)	($0.03)
	25 to 35 MWh	($0.03)	($0.05)	($0.05)	($0.03)
	35 to 50 MWh	($0.03)	($0.04)	($0.04)	($0.03)
	50 to 100 MWh	($0.04)	($0.05)	($0.04)	($0.04)
	100 to 500 MWh	($0.04)	($0.05)	($0.05)	($0.04)
	Over 500 MWh	($0.02)	($0.04)	$0.02	($0.01)
	Average	($0.03)	($0.05)	($0.00)	($0.02)
Overall Average		$0.00	$0.08	$0.05	$0.02

This variation by size is a factor of solar PV costs declining with increasing system size, and also, in the residential sector, of larger customers paying higher electric rates due to the tiered rate structure. Each row in Table

19 presents average results for the size category; individual customer net benefits could be higher or lower.

Table 20 shows the annualized $/customer results by customer, representing the average benefit or cost to customers of CSI program participation on an annual basis.

Table 20: PCT Results by Customer Size, Base Case, 2008 (Annualized $/customer/year)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($405)	($259)	$201	($314)
	5 to 10 MWh	($177)	($85)	$145	($128)
	10 to 15 MWh	$211	$243	$649	$259
	15 to 25 MWh	$463	$744	$1,073	$604
	25 to 35 MWh	$881	$1,443	$1,719	$1,159
	35 to 50 MWh	$1,187	$1,993	$2,199	$1,571
	50 to 100 MWh	$1,893	$3,477	$3,534	$2,655
	100 to 500 MWh	$8,137	$6,816	$30,989	$8,549
	Average	$181	$569	$706	$328
Non-Res	0 to 5 MWh	($247)	($116)	($952)	($341)
	5 to 10 MWh	($263)	($197)	($354)	($266)
	10 to 15 MWh	($378)	($328)	($387)	($377)
	15 to 25 MWh	($332)	($245)	($65)	($314)
	25 to 35 MWh	($314)	($678)	($737)	($356)
	35 to 50 MWh	($501)	($610)	($686)	($525)
	50 to 100 MWh	($1,089)	($1,674)	($1,071)	($1,104)
	100 to 500 MWh	($3,012)	($3,981)	($4,218)	($3,217)
	Over 500 MWh	($7,454)	($10,804)	$5,117	($4,432)
	Average	($2,349)	($2,458)	($28)	($2,027)
Overall Average		$11	$552	$648	$201

The disparity between smaller and larger residential customers is enhanced compared to Table 19 – not only are larger customers enjoying more favorable economics on a per-kWh basis, but they generate a much larger number of kWh. In the non-residential sector, larger customer have lower net costs on a per-kWh basis, but their much larger number of kWh generated more than compensates for this effect and total net costs are higher for these customers.

4.1.3 TRC RESULTS – HISTORICAL

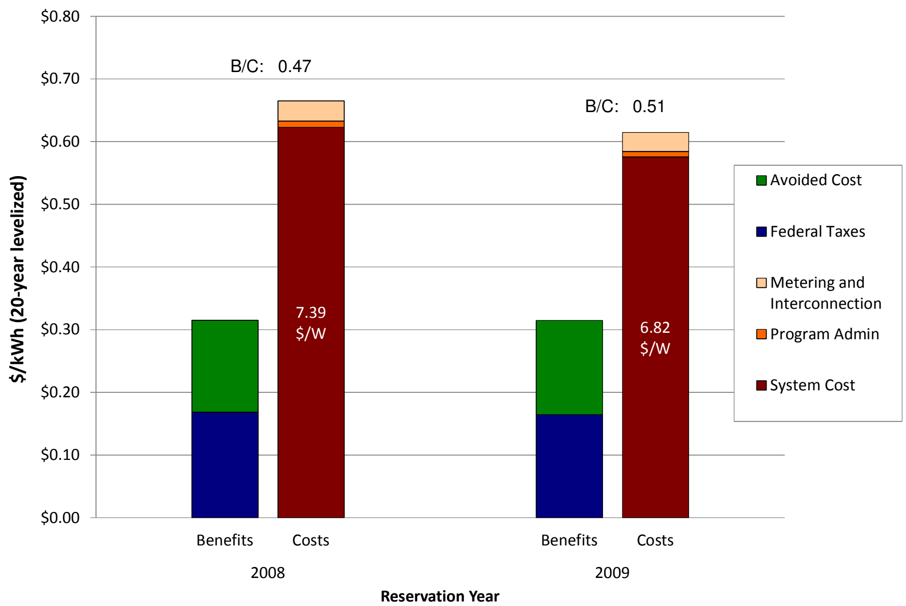
We include all relevant TRC costs and benefits in our analysis, as summarized in Table 21.

Table 21: Benefits and Costs in the TRC

Benefit or Cost Category	Treatment in PCT
Utility Avoided Costs	Included as a benefit in the TRC
System Cost, Financing, and Taxes	System costs are included as a cost. Tax benefits from *outside* the state (Federal tax incentives) are included as a benefit.
Metering, Interconnection, and Program Administration	Included as a cost in the TRC

Figure 26 along with Table 22, and Figure 27 along with Table 23, show TRC results for the residential and non-residential sectors, respectively. From the TRC perspective, system costs overwhelm the avoided cost of procuring energy from conventional sources. Even with the ITC – which is considered a TRC benefit in our analysis because it represents an inflow of money to our study area (the state of California) – the TRC test is still well in negative territory in these early years of the program. This result is to be expected for a program that seeks to transform the market for a developing technology.

Figure 26: TRC Results – Residential



For reference, the system cost bars in Figure 26 and Figure 27 show the installed system cost on a dollars-per-Watt basis. As mentioned earlier, these median system cost values are derived directly from the CSI program database.

Table 22: Breakdown of TRC Results – Residential (Levelized $/kWh)

	2008	2009
System Cost	($0.623)	($0.576)
Program Admin	($0.010)	($0.009)
Metering and Interconnection	($0.032)	($0.030)
Federal Taxes	$0.168	$0.165
Avoided Cost	$0.147	$0.150
Net Benefits	($0.350)	($0.300)

Figure 27: TRC Results – Non-residential

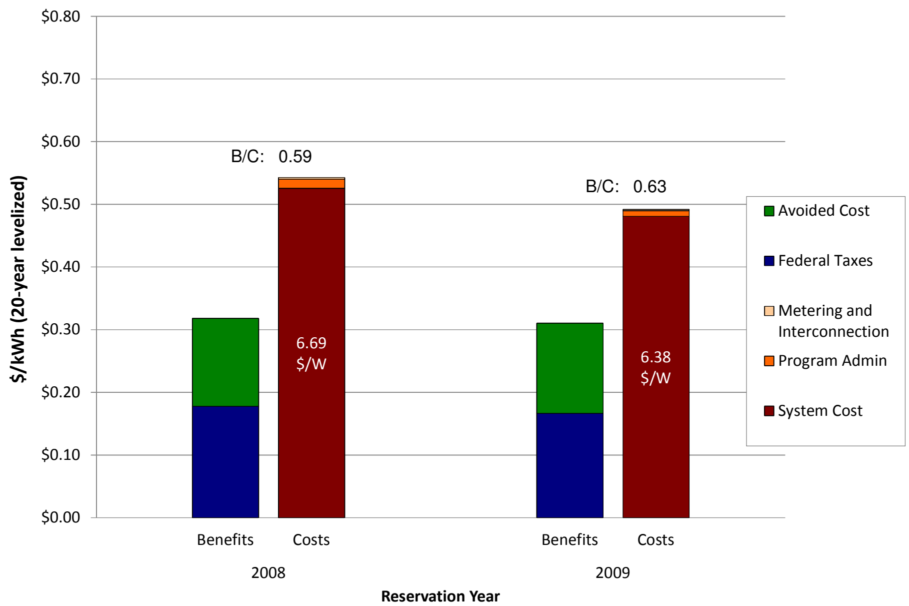


Table 23: Breakdown of TRC Results – Non-residential (Levelized $/kWh)

	2008	2009
System Cost	($0.525)	($0.481)
Program Admin	($0.015)	($0.009)
Metering and Interconnection	($0.002)	($0.002)
Federal Taxes	$0.178	$0.167
Avoided Cost	$0.140	$0.144
Net Benefits	($0.225)	($0.182)

4.1.3.1 Detailed TRC Results

Table 24 through Table 27 present TRC results by utility and customer class. As a whole, the program in 2008 resulted in installation of generation that was approximately $317 million more costly than grid supplied power. This value is based on a comparison to existing and projected grid-supplied power under the current policy regime. It does not include the grid-supplied cost of meeting a potential low-carbon future beyond the current 33% RPS. In this sense, transforming the electrical infrastructure to include larger amounts of clean DG may have presently unquantifiable benefits that are not included in the TRC test.

Further, measures of TRC cost-effectiveness are moving in the right direction. As program adoption helps drive down the costs of solar PV, and as the avoided cost of grid-supplied power continues to escalate over time, net TRC costs decline. This trend is explored in greater detail in Section 4.2, on market transformation.

Table 24: TRC Results, Base Case, B/C Ratio

		2008	2009
PG&E	Residential	0.47	0.51
	Non-Res	0.59	0.62
	Total	0.53	0.56
SCE	Residential	0.48	0.52
	Non-Res	0.32	0.64
	Total	0.47	0.59
SDG&E	Residential	0.48	0.53
	Non-Res	0.59	0.63
	Total	0.55	0.59
All IOUs	**Residential**	**0.47**	**0.51**
	Non-Res	**0.59**	**0.63**
	Total	**0.52**	**0.58**

Table 25: TRC Results, Base Case, 20-Year NPV ($M)

		2008	2009
PG&E	Residential	($126.77)	($131.12)
	Non-Res	($93.71)	($88.53)
	Total	($220.47)	($219.64)
SCE	Residential	($55.16)	($65.47)
	Non-Res	($5.03)	($69.68)
	Total	($60.19)	($135.15)
SDG&E	Residential	($15.29)	($31.32)
	Non-Res	($20.87)	($36.74)
	Total	($36.16)	($68.06)
All IOUs	**Residential**	**($197.22)**	**($227.90)**
	Non-Res	**($119.61)**	**($194.95)**
	Total	**($316.83)**	**($422.85)**

Table 26: TRC Results, Base Case, 20-Year Annualized ($M/year)

		2008	2009
PG&E	Residential	($10.82)	($11.19)
	Non-Res	($8.00)	($7.55)
	Total	($18.81)	($18.74)
SCE	Residential	($4.71)	($5.59)
	Non-Res	($0.43)	($5.95)
	Total	($5.14)	($11.53)
SDG&E	Residential	($1.30)	($2.67)
	Non-Res	($1.78)	($3.14)
	Total	($3.09)	($5.81)
All IOUs	**Residential**	**($16.83)**	**($19.45)**
	Non-Res	**($10.21)**	**($16.64)**
	Total	**($27.04)**	**($36.08)**

Table 27: TRC Results, Base Case, 20-Year Levelized ($/kWh generated)

		2008	2009
PG&E	Residential	($0.379)	($0.330)
	Non-Res	($0.218)	($0.189)
	Total	($0.289)	($0.254)
SCE	Residential	($0.308)	($0.271)
	Non-Res	($0.709)	($0.176)
	Total	($0.324)	($0.212)
SDG&E	Residential	($0.307)	($0.257)
	Non-Res	($0.217)	($0.175)
	Total	($0.247)	($0.205)
All IOUs	**Residential**	**($0.350)**	**($0.300)**
	Non-Res	**($0.225)**	**($0.182)**
	Total	**($0.289)**	**($0.231)**

In 2008, SCE non-residential TRC results show substantially higher costs, on a per-kWh generated basis, than the other utilities. This represents a temporary distortion rather than a true difference in cost-effectiveness. SCE was still ramping up its non-residential CSI program in 2008, and so its administrative costs were spread over a very small number of MW installed, which "overburdens" the 2008 non-residential results with high administrative costs. By 2009, SCE's non-residential cost-effectiveness already reaches a level in line with the other utilities.

4.1.4 PACT RESULTS – HISTORICAL

Costs and benefits included in the PACT are shown in Table 28.

Table 28: Benefits and Costs in the PACT

Benefit or Cost Category	Treatment in PCT
Utility Avoided Costs	Included as a benefit
Incentive Payments	Included, since the program administrator must fund the incentive payments
Metering, Interconnection, and Program Administration	Included as a cost in the PACT except when paid by participants

Figure 28 and Table 29 show PACT cost-effectiveness results. In 2008, the costs of administering the program, including incentives and interconnection, outweighed the avoided electricity supply costs. By 2009, with avoided costs increasing somewhat due to inflation, and the incentive payment dropping somewhat due to achievement of incentive step capacity goals, the program crossed into cost-effective territory from the PACT perspective.

Figure 28: PACT Results – Full Program (Residential and Non-residential)

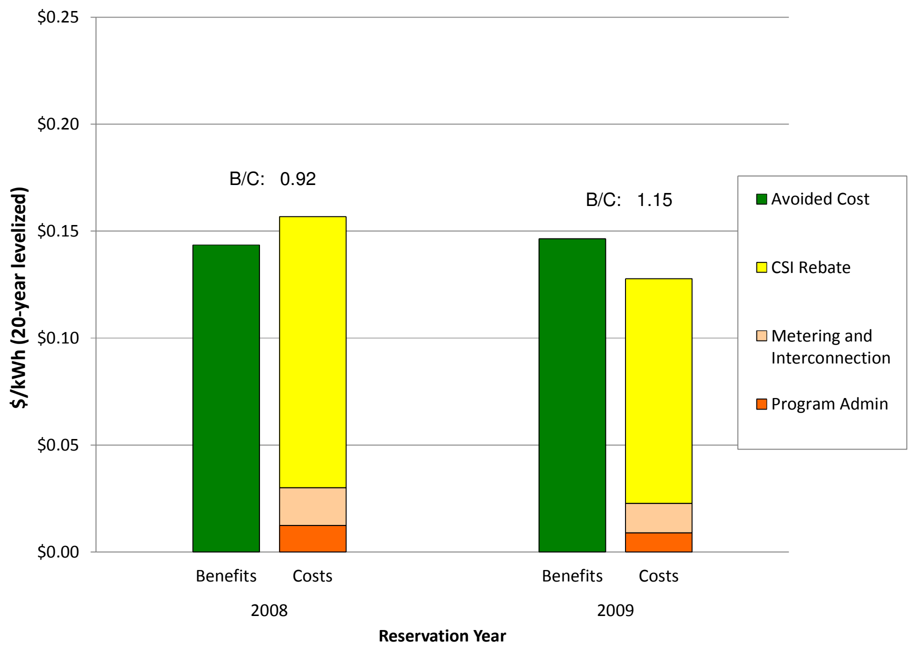


Table 29: Breakdown of PACT Results – Full Program (Residential and Non-residential) (Levelized $/kWh)

	2008	2009
CSI Rebate	($0.127)	($0.105)
Program Admin	($0.012)	($0.009)
Metering and Interconnection	($0.018)	($0.014)
Avoided Cost	$0.144	$0.146
Net Benefits	($0.013)	$0.019

4.1.5 RIM RESULTS – HISTORICAL

Costs and benefits included in the RIM are shown in Table 30.

Table 30: Benefits and Costs in the RIM Test

Benefit or Cost Category	Treatment in PCT
Utility Avoided Costs	Included as a benefit
Incentive Payments	Included as a cost
Bill Impacts	Included as a cost, since ratepayers must make up the lost revenue
Metering, Interconnection, and Program Administration	Included as a cost except when paid by participants

Figure 29 and Table 31 show RIM cost-effectiveness results. The costs and benefits are identical to those for the PACT, with the exception that the RIM test also includes bill reductions as a cost since this revenue must be collected from other customers. Utility electric sales to CSI customers decline as customers offset load, and this reduction in revenue must be made up by all ratepayers. This is not a factor in the PACT, which measures utility supply costs but does not consider revenue effects.

The loss of revenue is enough to drive the program well into negative territory from the RIM perspective. This result is expected and is common to other programs that reduce electric sales, such as energy-efficiency programs.

Figure 29: RIM Results – Full Program (Residential and Non-residential)

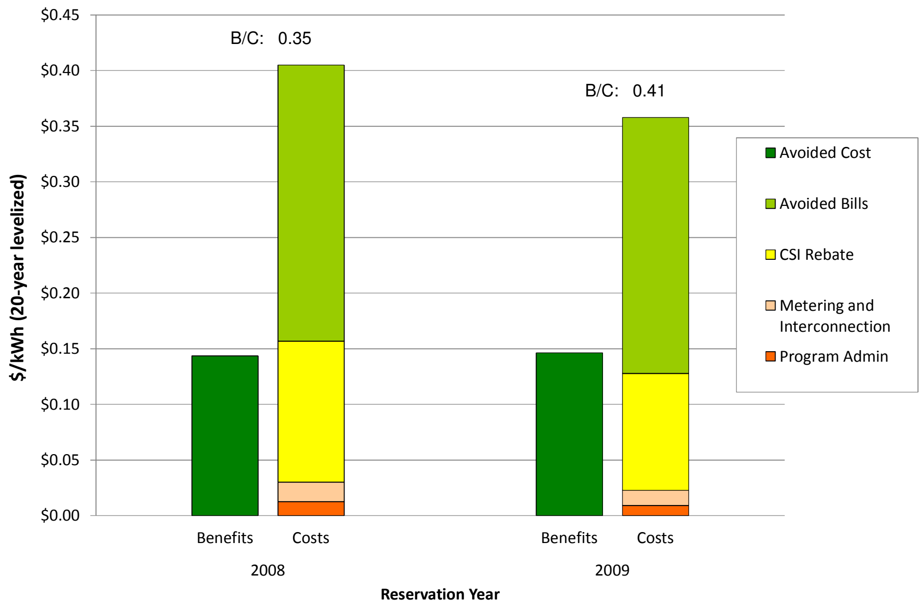


Table 31: Breakdown of RIM Results – Full Program (Residential and Non-residential) (Levelized $/kWh)

	2008	2009
CSI Rebate	($0.127)	($0.105)
Avoided Bills	($0.248)	($0.230)
Program Admin	($0.012)	($0.009)
Metering and Interconnection	($0.018)	($0.014)
Avoided Cost	$0.144	$0.146
Net Benefits	($0.262)	($0.212)

4.1.6 HISTORICAL PERIOD SENSITIVITY – T&D AVOIDED COSTS

The “no avoided T&D costs” sensitivity tests the effect of excluding T&D investment deferral from among the CSI avoided cost benefits. Excluding

T&D deferral benefits increases the total net cost of the program in 2008 by approximately $28 million, roughly 9%.

Table 32: Comparison of Base Case TRC Results to No T&D Sensitivity – 2008, Full Program (Residential and Non-residential)

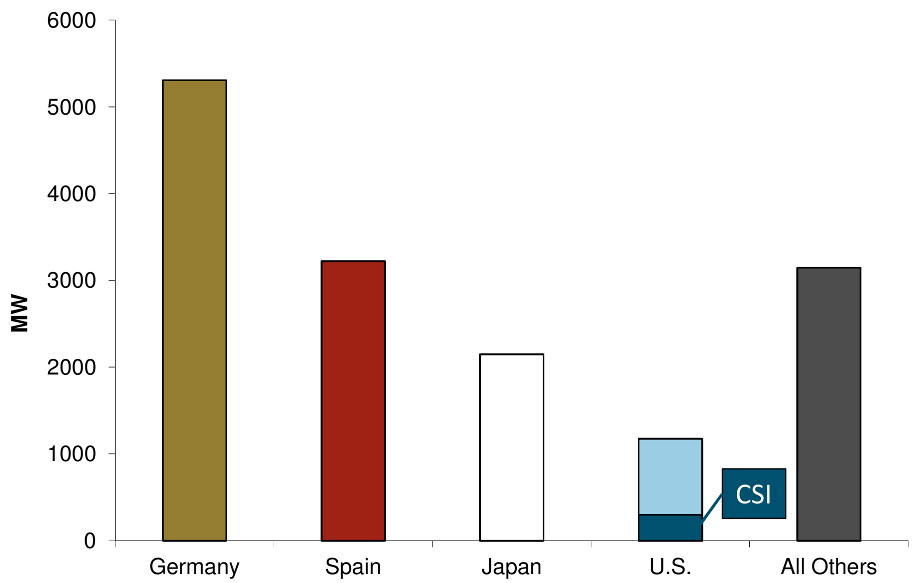
	Base Case TRC	No T&D Senstitivity	Change in Net Benefits
Benefit / Cost Ratio	0.52	0.48	
20-year NPV ($M)	($317)	($344)	-9%
20-year Annualized ($M)	($27)	($29)	
Levelized ($/kWh-generated)	($0.29)	($0.31)	

4.2 Forecasted Future Period (2010-2020)

The cost of installed CSI-eligible solar PV in California is declining. The CSI program is one of many forces contributing to this reduction in cost. Among other factors contributing to PV cost reductions are the federal ITC, which provides a larger incentive for PV than does the CSI program; global demand for PV modules independent of the CSI program; and technological innovation.

Although the CSI program accounted for only 3% of global installed solar capacity in 2008 (see Figure 30), it is not unreasonable to conclude that the CSI program is helping to transform the market for rooftop solar PV in California. While module cost is a function of global PV markets, total installed cost is dependent on many other factors, including installation and marketing costs. Many of these "balance of system" costs are a function of local, rather than global markets. In fact, an LBL study found that reductions in non-module costs were more significant than module cost reductions in the decline in total installed system cost for PV systems in the United States from 1998-2007.[29]

Figure 30: Global installed solar capacity by country, 2008



Source: EPIA for global capacity; CSI program reporting

While one may say with reasonable certainty that the CSI program is helping to transform the market for solar PV in California, assessing the magnitude of this effect is another matter entirely. Stated another way, it is not easy to determine the exact extent to which observed and

[29] *Ibid.* note 19.

forecasted reductions in solar PV cost can be attributed to the CSI program.

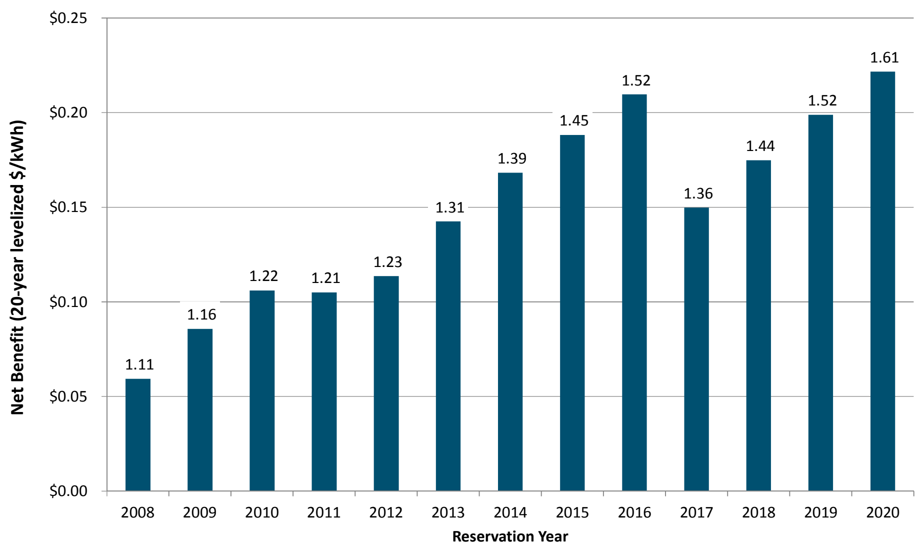
Rather than attempt to quantify this attribution of cost reductions to the CSI program and add this value as a benefit in the program costs and benefits to date, our market transformation analysis forecasts the cost-effectiveness results of the CSI program over the program life and beyond to 2020. Positive cost-effectiveness results toward the end of the program lifetime or slightly thereafter indicate that the program is on track to meet its market transformation goals, though readers may debate how close to this mark solar PV would have come in the absence of the program.

4.2.1 PCT RESULTS – FORECASTED FUTURE PERIOD

Figure 31 and Figure 32 show forecasted cost-effectiveness results for residential and non-residential participants, respectively, expressed as the levelized net benefit in $/kWh-generated. We forecast the residential sector, for which the PCT was already positive in 2008 and 2009, to experience increasing net benefits from solar PV, even as CSI incentives diminish and even after assumed expiration of the ITC in 2017. In this sense, the program appears to be well on track to meet its goal of achieving a market for solar PV that is self-sustaining in the absence of

CSI incentives in the residential sector.[30] We describe the sensitivity of these results to changes in underlying assumptions in Section 4.2.4.

Figure 31: Historical and Forecast PCT Net Benefits, Base Case, Residential



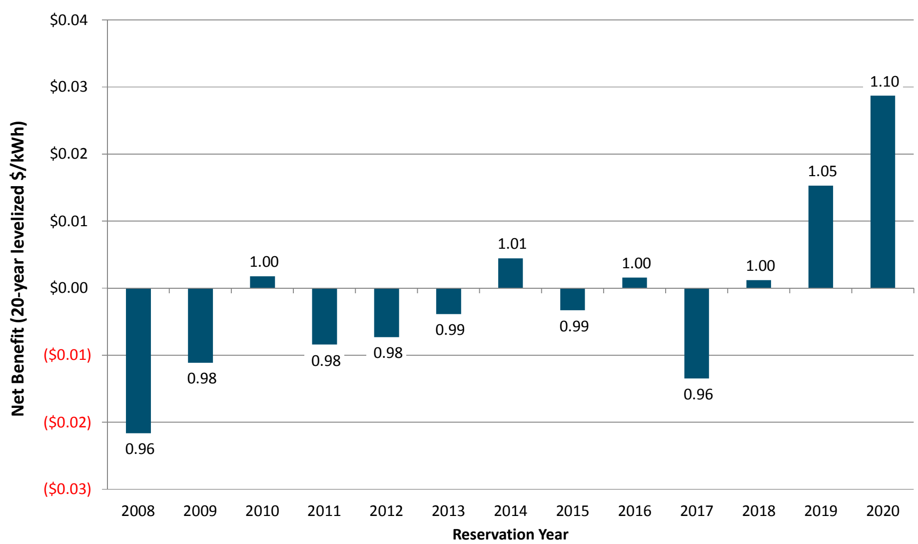
Note: Labels show benefit/cost ratio

Participant economics in the non-residential segment are less favorable but still show the program to be very close to reaching the goal of a market that is self-sustaining in the absence of CSI incentives. Initially, the non-residential sector as a whole is not cost-effective from the PCT perspective, but as forecasted PV costs decline, the PCT economics steadily improve, moving briefly into positive territory in 2010, 2014, and

[30] Of course, solar PV receives incentives other than CSI; in this sense, the market for solar PV cannot be said to be "self-sustaining" until all such incentives are eliminated. By our estimation, the residential market for solar PV will be self-sustaining without any incentives – that is, excluding the ITC, discontinuing the waiver of interconnection costs, and replacing NEM with payments for export based on DLAP prices – by 2013 or 2014.

2016. Year-to-year variations in the cost-effectiveness trend are in most cases due not to changes in underlying conditions, but rather to changes in the forecasted mix of customers. For example, SDG&E's non-residential program is expected to reach full subscription in 2012, and PG&E's in early 2015; the remaining non-residential systems – all SCE – are less cost-effective from the participant perspective due to SCE's rate structure. The dip from 2016 to 2017, however, is due to expiration of the ITC.

Figure 32: Historical and Forecast PCT Net Benefits, Base Case, Non-residential



Note: Labels show benefit/cost ratio

Economics improve rapidly after 2017; by 2018 the participant B/C ratio is already greater than 1.0. We describe the sensitivity of these results to changes in underlying assumptions in Section 4.2.4.

A more immediate concern may be problems with the non-residential incentive budget, which may result in an elimination of incentives before 2016, as discussed in Section 3.3.5. Without incentives, B/C ratios fall to the 0.88-0.94 range in 2012-2014 (assuming the progress in cost reduction remains unchanged), adding some risk that adoption will suffer.

Figure 33 and Figure 34 present key years in the cost-effectiveness forecast to help illustrate underlying trends. In both cases, as incentive step levels are achieved, CSI incentives decline from a significant portion of participant benefits in 2009 to a negligible portion in 2016, but this effect is expected to be more than compensated for by a decline in solar PV costs. In 2017, the expiration of the ITC causes participant economics to become less favorable, but by the end of our modeling period, in 2020, bill increases and declining PV costs have caused a rebound, and we project solar PV to be cost-effective under the PCT for both residential and non-residential customers.

Figure 33: Key Years in Forecasted PCT Results – Residential

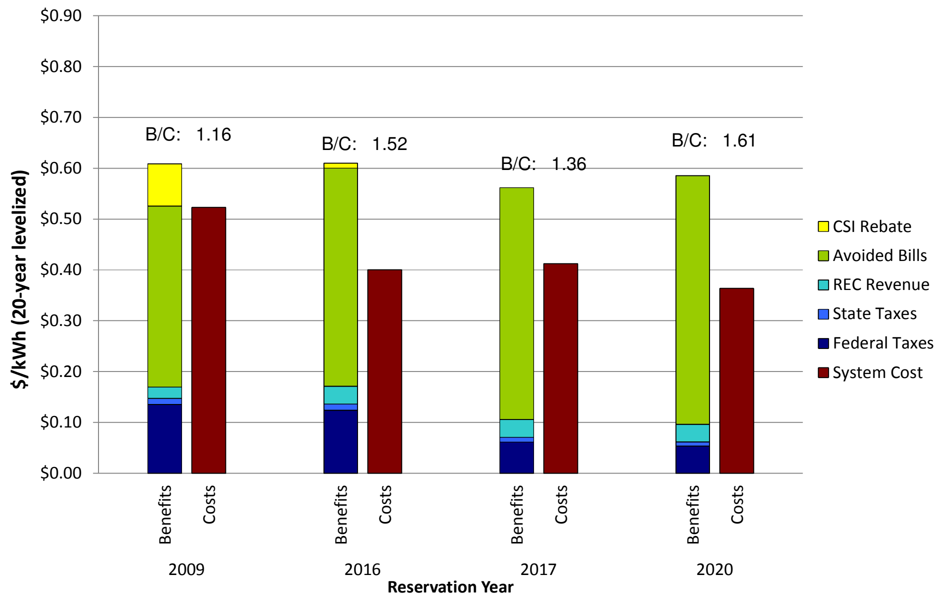
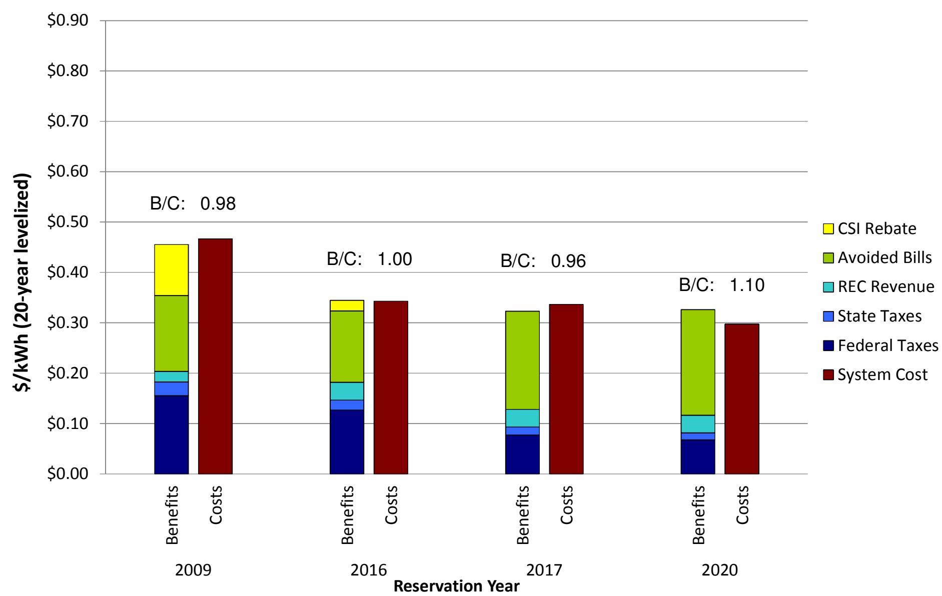


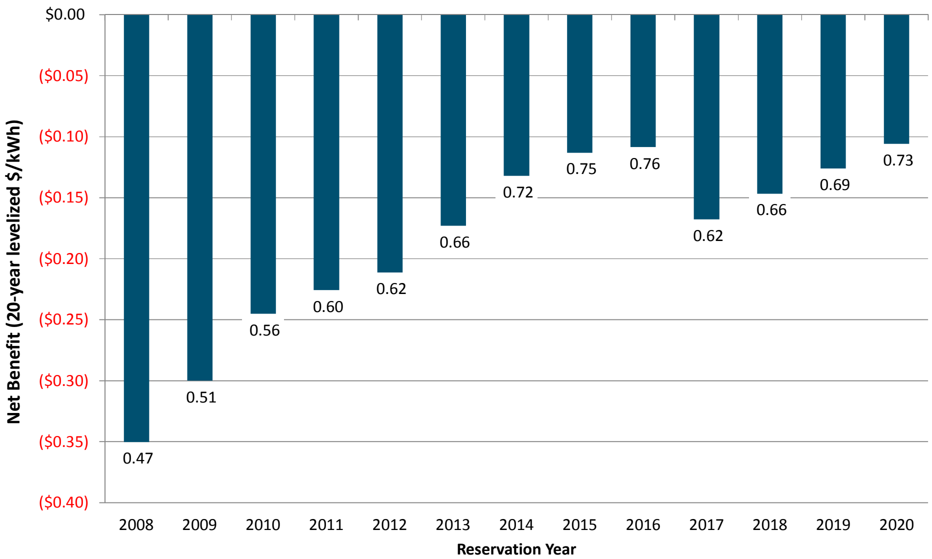
Figure 34: Key Years in Forecasted PCT Results – Non-residential



4.2.2 TRC RESULTS – FORECASTED FUTURE PERIOD

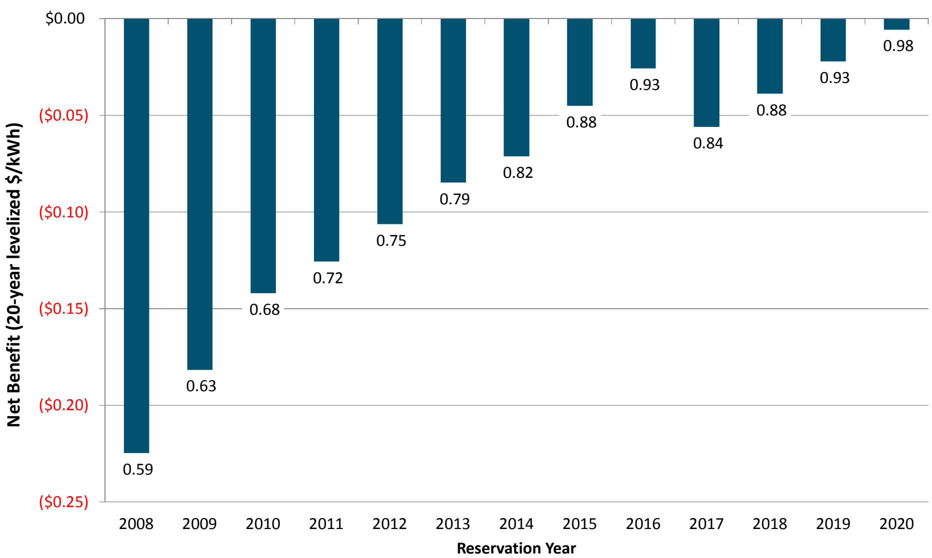
Figure 35 and Figure 36 show forecast TRC test results for the residential and non-residential sectors, respectively. From a TRC perspective, solar PV does not achieve positive net benefits during the analysis period under our base case assumptions. In other words, although the market for solar PV may have been transformed to a self-sustaining market in which participants install solar PV without the need for further incentives, from a California societal perspective, solar PV remains more expensive than the utilities' mix of grid-supplied power. This effect is more pronounced in the residential sector due to the higher per-Watt costs of smaller systems.

Figure 35: Historical and Forecast TRC Net Benefits, Base Case, Residential



Note: Labels show benefit/cost ratio

Figure 36: Historical and Forecast TRC Net Benefits, Base Case, Non-residential



Note: Labels show benefit/cost ratio

Figure 37 and Figure 38 illustrate the TRC cost-effectiveness trend by key component. Solar PV costs (shown in the cost bar labels for reference) decline over time, resulting in significant improvement in the B/C ratio from 2009 to 2016. The elimination of the ITC in 2017 causes a reduction in the B/C ratio, but by 2020, cost-effectiveness has recovered to roughly the 2016 level.

Figure 37: Key Years in Forecasted TRC Results – Residential

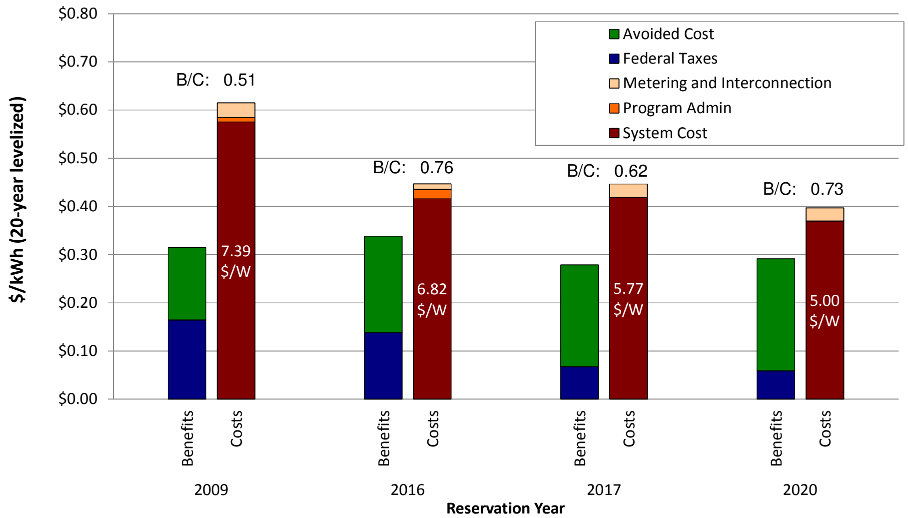
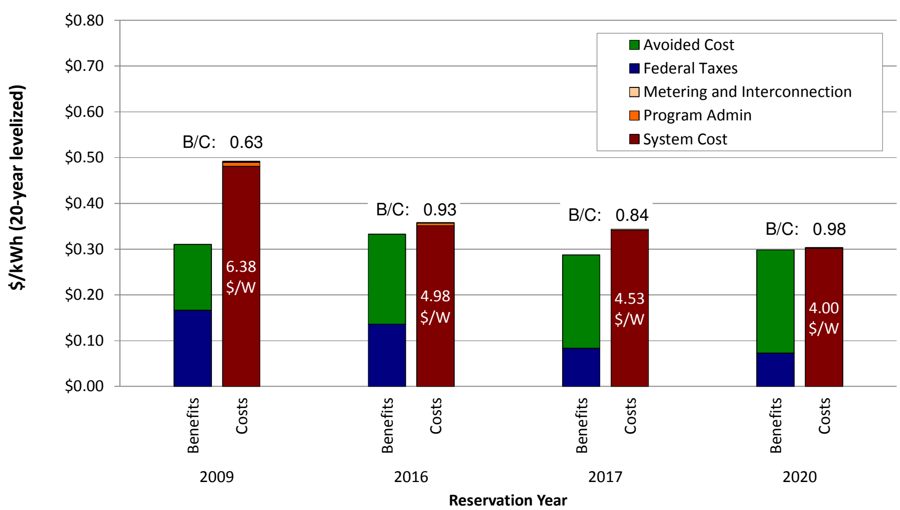


Figure 38: Key Years in Forecasted TRC Results – Non-residential



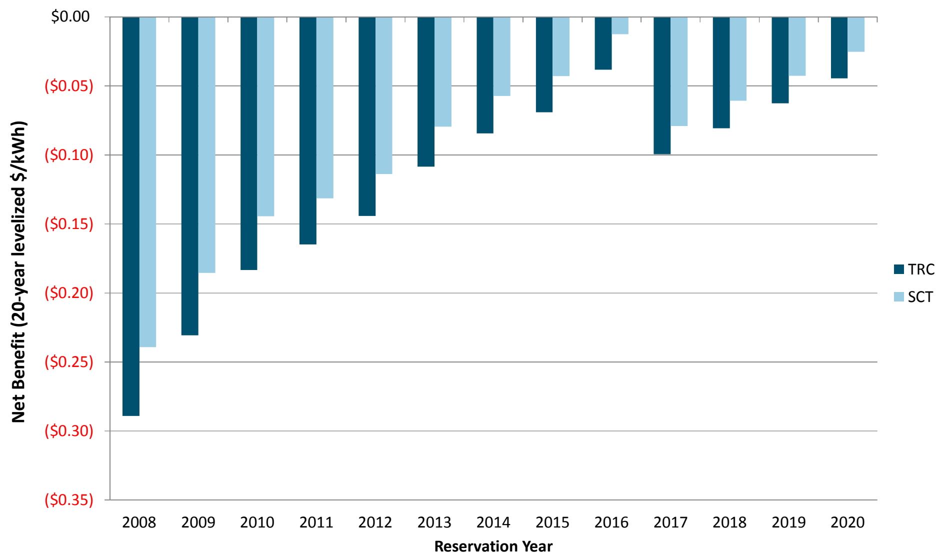
4.2.3 EXTERNALITIES AND THE SOCIETAL TEST

From a societal cost test (SCT) perspective, results are not markedly different than the TRC. The SCT we computed differs in two ways from the TRC. First, a lower discount rate is used: 3% real (5.06% nominal) for the SCT vs. 8.65% nominal for the TRC. Second, we consider unpriced externalities that do not factor into the TRC test.

To value unpriced externalities, we relied on a study by the National Academy of Sciences,[31] which found a value of $0.01/kWh at the high end of the range for unpriced externalities. Together, a lower discount rate and inclusion of the unpriced externality value does not meaningfully change the cost-effectiveness results, as shown in Figure 39.

[31] National Research Council of the National Academies, *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use*, National Academies Press, Washington, D.C., 2010.

Figure 39: Comparison of SCT to TRC Results, Base Case, All Sectors (Residential and Non-residential)



The $0.01/kWh value of externalities in the National Academy of Sciences study is based primarily on a monetization of health effects resulting from pollution, though national security costs are also considered. No attempt is made to measure ecosystem externalities that do not directly impact human health.

Some other studies have found higher values for unpriced externalities. A CalSEIA study,[32] for example, found that solar PV should be valued at $0.05 - $0.12/kWh above the MPR, but includes many benefits measured in our cost-effectiveness methodology. Once these redundancies are

[32] California Solar Energy Industries Association, *Implementing the Feed In Tariff or Small-Scale Solar Photovoltaics in California: Incremental Value Not Captured in the 2009 Market Price Referent*, April 23, 2010.

eliminated, a value of roughly $0.02 - $0.03/kWh is implied for unpriced externalities. Even if the higher $0.03/kWh is used to value externalities, the societal cost-effectiveness results only become positive for one year, reaching a B/C ratio of 1.02 in 2016, immediately prior to expiration of the ITC.

A potential positive externality of CSI is the installation of more energy efficiency. There is some evidence that customers installing solar PV also install more energy efficiency measures than they would have in the absence of CSI,[33] due at least in part to the requirement that "reasonable and cost-effective" energy efficiency improvements be made as a condition for receiving CSI incentives.[34] While we do not attempt to quantify the energy efficiency effect in this study, the issue warrants further investigation.

4.2.3.1 Macroeconomic Effects

The DG cost-effectiveness decision requires the contractor "to suggest a methodology for quantifying the employment and tax revenue effects of our DG programs so that parties can comment on this area further,"[35] but directs the contractor not to include these effects in the present evaluation. In our view, use of an Input-Output (I-O) model is an

---

[33] See Itron, *Ibid*. note 1, pp.ES-25–ES-33.
[34] Public Utilities Code Section 2851 (a)(3).
[35] D.09-08-026, p.40.

accepted and reasonable method for evaluating macroeconomic effects, such as employment and tax revenue.

In its evaluation of the SGIP program, TIAX describes the IMPLAN I-O model, in combination with Social Accounting Matrix analysis.[36] We believe that such an approach is appropriate and do not reproduce its description here. We note, however, that care must be given to consider not only the direct and indirect benefits that result from investment in solar PV, but also the direct and indirect costs of this investment.

For example, while rooftop solar PV investment undoubtedly creates many jobs in the state of California, successful PV penetration will reduce the need for central station generation, and therefore will reduce employment in that sector. The appropriate macroeconomic measure is the net effect on jobs.

Perhaps more importantly, rooftop solar PV has the effect of raising retail rates, since the revenue losses exceed the avoided costs. The macroeconomic effects of rate increases must also be considered. Consumers who pay higher electric bills have less disposable income to spend elsewhere. Some businesses may respond to higher electric rates by moving their operations out-of-state to regions with lower electric rates. While utilities may negotiate special rates to retain such

[36] *Cost-Benefit Analysis of the Self-Generation Incentive Program*, TIAX LLC., Prepared for the California Energy Commission, October 2008, pp.19-21.

customers, the result will be higher rates for other customers, exacerbating the effects for those customers.

The TIAX study addresses loss of jobs in central station generation and reductions in consumer spending,[37] but does not consider loss of manufacturing jobs due to business relocation as a result of rate increases. While the rate impacts of any single program such as CSI may be too small to cause manufacturer flight, policy-makers should attempt to recognize the potential for the combined rate effects of multiple programs and policies to impact business location decisions.

4.2.4 SENSITIVITY ANALYSES

We tested several alternative scenarios to our forecasts of future conditions:

- Gas price forecast
- Resource Balance Year
- Progress ratio and retail rate escalation
- T&D Capacity Value

We describe each in the sections that follow.

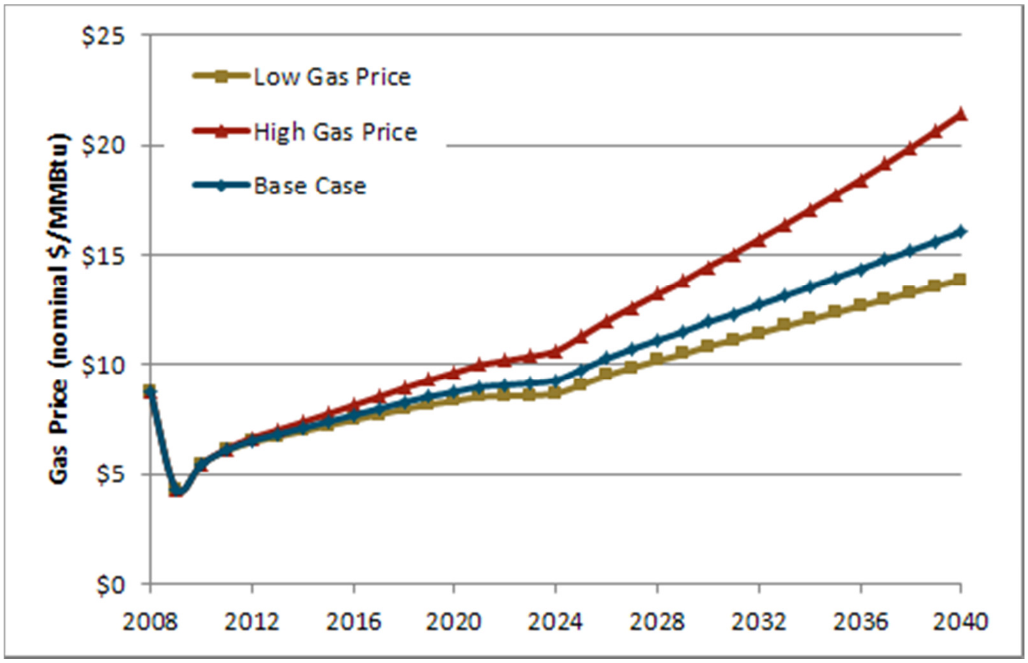
[37] *Ibid.* pp.48-52.

4.2.4.1 Gas Price Forecast

The forecast of natural gas prices delivered to California generators is a driver of avoided costs. Gas generators are on the margin in California for nearly all hours of the year and therefore set the market price. The cost of natural gas makes up the vast majority of the variable operating cost of gas-fired generators, so the marginal value of energy is directly proportional to the cost of natural gas.

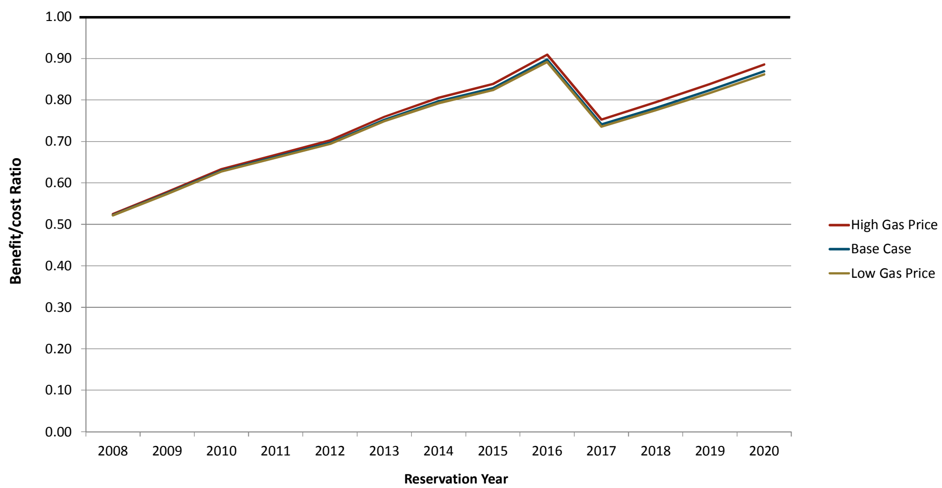
Our base case, low, and high gas forecasts are shown in Figure 40. Our long-term base case natural gas forecast follows the MPR methodology. The low gas forecast grows at an annual rate 0.5% below the base case, while the high gas forecast grows at an annual rate 1.0% above the base case. High and low forecasts reflect a spread in the underlying long-term fundamentals forecasts on which the MPR forecast is based.

Figure 40: Base Case, Low, and High Forecasts of Natural Gas Prices



While the spread between low and high gas forecasts is substantial, especially in later years of the forecast, the effect on cost-effectiveness results is small, as can be seen in Figure 41.

Figure 41: Changes in Projected TRC Cost-Effectiveness Based on Gas Price Sensitivity Testing



The negligible effect of gas prices on cost-effectiveness has to do with the generation capacity value in our avoided costs. The value of generation capacity is calculated as the difference between the annual fixed cost of a new simple-cycle gas turbine and the margins that plant could make in the real-time energy market. As the value of energy increases with natural gas price, so do the margins that a generator can earn—as a result, if all other components are held equal, higher gas prices will result in a lower value of capacity. In terms of average annual avoided costs, the declining capacity value that results from higher gas prices acts in a countervailing manner to the increase in energy value.

4.2.4.2 Resource Balance Year

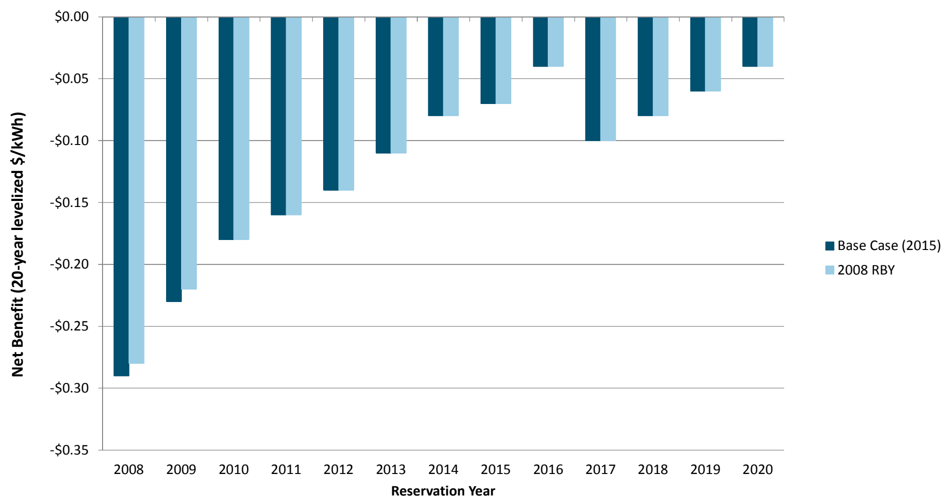
Presently, California has an excess of generation capacity compared to load. The resource balance year represents the point at which load in

California is expected to be equal to generation capacity plus required reserves, and the point, therefore, at which additional generation capacity must be procured.

The resource balance year is a factor in avoided costs, since as long as California has an excess of generation capacity, there should be less than full avoided capacity benefits associated with a reduction in load – additional generation would have been procured even in the absence of the load reduction (see Section 3.3.2 and Appendix B for more detailed discussion of capacity value and avoided costs).

Nevertheless, the resource balance year sensitivity shows that changing the resource balance year from our base case assumption of 2015 to the sensitivity assumption of 2008 has little effect on the cost-effectiveness of the CSI program.

Figure 42: Comparison of TRC Results Under Base Case with Resource Balance Year of 2015 to Resource Balance Year of 2008



The value of generation capacity, which is the only component of the avoided costs that varies with the resource balance year, accounts for 30-40% of the value of typical PV systems. The cost-effectiveness analysis is based on a lifecycle approach, with a 20-year life for solar PV. Beginning in 2015, avoided costs for a 2008 resource balance year are identical to those for a 2015 resource balance year. Thus, the 2008 vintage of solar PV receives identical avoided costs for 2015-2027. For the reservations in years 2008-2015, the 20-year lifetime is increasingly diluted by years after 2015, resulting in more generation capacity value being awarded until the results are identical to the base case.

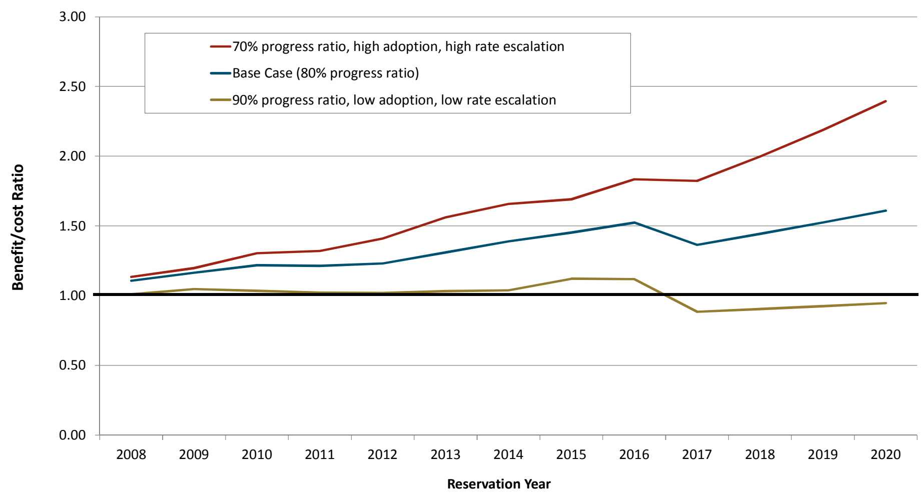
Due to the above factors, the difference in average avoided costs using a 2008 versus a 2015 resource balance year for the earliest vintage – 2008 – is only about 8%. Avoided costs, in turn, make up only about 50% of benefits prior to 2015, further diluting the effects. The differential between avoided costs under the two assumptions diminishes for each year's vintage of installed solar; by 2015 the results are identical.

4.2.4.3 Progress Ratio, Electric Rate Escalation, and Adoption Rate

Two key drivers of future cost-effectiveness from the participant perspective are the progress ratio for reduction in installed solar PV costs and the rate at which electricity rates are forecasted to rise. We combine these variables into unified future scenarios to examine their combined effect. We assume that low costs and high rates will lead to greater adoption, therefore our aggressive progress ratio / high rate escalation scenario also includes our high adoption forecast. Conversely, our conservative progress ratio / low rate escalation scenario includes a low adoption forecast assumption.

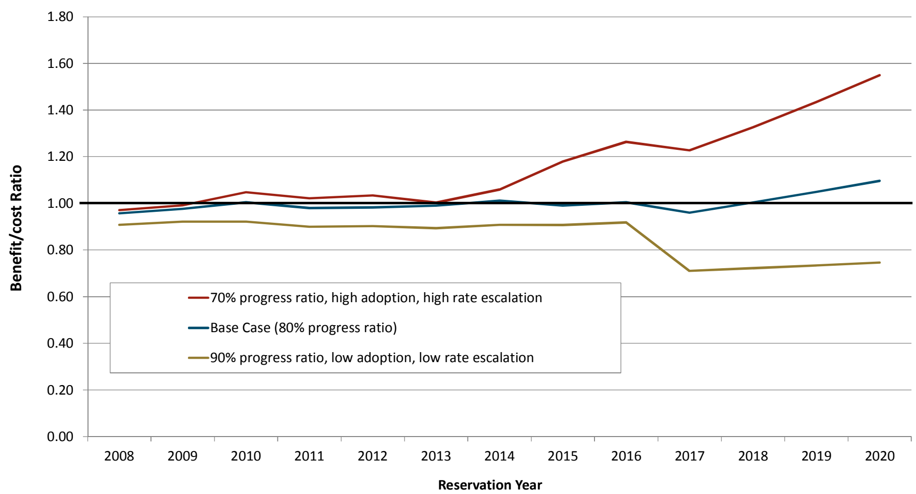
From the perspective of residential participants, solar PV under the CSI program is cost-effective even under an assumption of higher solar PV costs and lower rate escalation (Figure 43), though the expiration of the ITC in 2017 pushes the residential PCT into negative territory in this case. Under an assumption of lower PV costs and higher rate escalation, the economics are quite favorable to residential customers and benefits dwarf costs in the out years.

Figure 43: PCT Results for Residential Sector – Progress Ratio and Electricity Rate Escalation Sensitivities



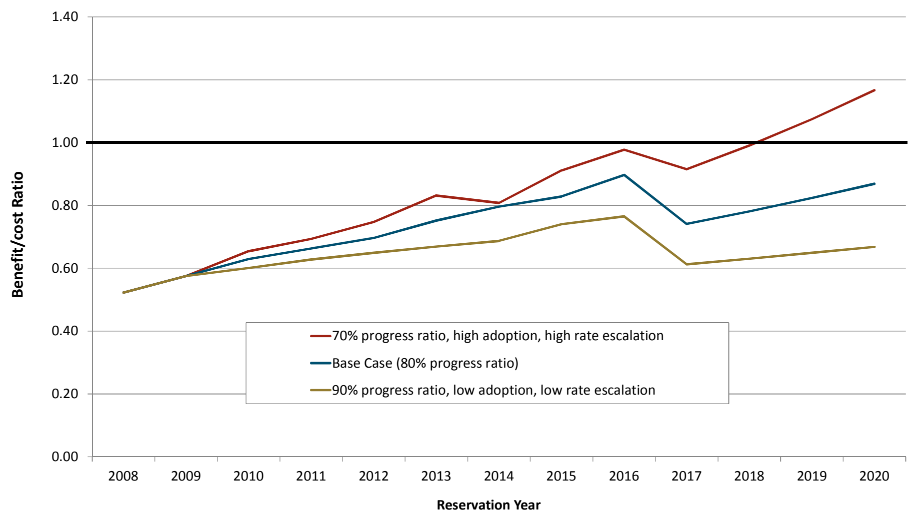
For non-residential customers, the difference between the scenarios is even more significant (Figure 44). Under the base case, the non-residential PCT B/C ratio is close to 1.0 throughout most of the study period. Assuming low PV costs and high rate escalation, the economics become markedly favorable toward the end of the program, and after 2010 non-residential customers are enjoying an excess of benefits over costs that even the elimination of the ITC in 2017 hardly dampens. But if PV costs stay on a higher trajectory and retail rates escalate more slowly, the PCT remains in negative territory for non-residential customers throughout the study period.

Figure 44: PCT Results for Non-residential Sector – Progress Ratio and Electricity Rate Escalation Sensitivities



From a TRC perspective (Figure 45), a slower decline in PV costs increases the amount by which benefits fall short of costs. However, if the more aggressive 70% progress ratio is achieved, benefits very nearly match costs in 2016, and exceed costs by 2019 after recovering from the loss of the ITC.

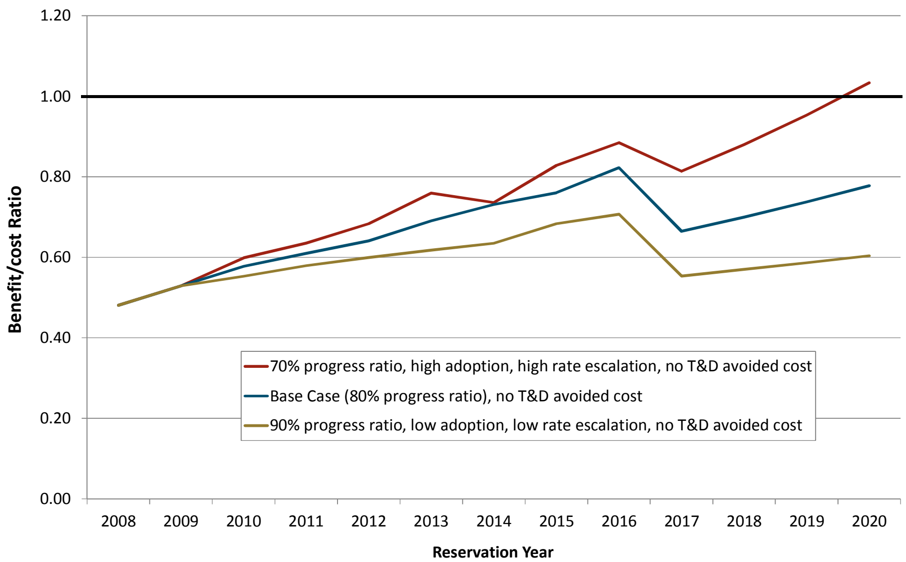
Figure 45: TRC Results – Progress Ratio and Electricity Rate Escalation Sensitivities – All Sectors (Residential and Non-Res)



4.2.4.4 T&D Capacity Value

Figure 46 shows the effects of excluding T&D investment deferral benefits. It is otherwise identical to Figure 45. Excluding T&D benefits lowers the overall cost-effectiveness of the program from the TRC perspective, but does not fundamentally change the conclusions of the analysis.

Figure 46: TRC Results Excluding T&D Avoided Cost Benefits – Progress Ratio and Electricity Rate Escalation Sensitivities – All Sectors (Residential and Non-Res)



APPENDIX A:

DETAILED RESULTS TABLES

Table 1: PCT Results by Customer Size, Base Case, 2008 (20-year NPV, $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($3.65)	($0.47)	$0.28	($3.83)
	5 to 10 MWh	($4.78)	($0.60)	$0.55	($4.83)
	10 to 15 MWh	$4.57	$1.93	$1.91	$8.42
	15 to 25 MWh	$8.87	$7.54	$2.99	$19.39
	25 to 35 MWh	$4.40	$4.84	$1.34	$10.59
	35 to 50 MWh	$2.15	$2.48	$0.60	$5.23
	50 to 100 MWh	$1.22	$1.62	$0.42	$3.27
	100 to 500 MWh	$1.15	$0.97	$0.42	$2.53
	Average	$15.32	$18.32	$8.52	$42.17
Non-Res	0 to 5 MWh	($0.03)	($0.00)	($0.02)	($0.04)
	5 to 10 MWh	($0.09)	($0.00)	($0.01)	($0.09)
	10 to 15 MWh	($0.14)	($0.00)	($0.01)	($0.15)
	15 to 25 MWh	($0.19)	($0.00)	($0.00)	($0.19)
	25 to 35 MWh	($0.14)	($0.01)	($0.03)	($0.18)
	35 to 50 MWh	($0.18)	($0.01)	($0.03)	($0.23)
	50 to 100 MWh	($0.76)	($0.04)	($0.16)	($0.96)
	100 to 500 MWh	($4.65)	($0.18)	($1.16)	($5.99)
	Over 500 MWh	($6.51)	($0.13)	$1.38	($5.25)
	Average	($12.68)	($0.38)	($0.04)	($13.09)
Overall Average		$2.65	$17.94	$8.48	$29.07

Table 2: PCT Results by Customer Size, Base Case, 2008 (20-year Annualized $M/year)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.25)	($0.03)	$0.02	($0.26)
	5 to 10 MWh	($0.32)	($0.04)	$0.04	($0.33)
	10 to 15 MWh	$0.31	$0.13	$0.13	$0.57
	15 to 25 MWh	$0.60	$0.51	$0.20	$1.31
	25 to 35 MWh	$0.30	$0.33	$0.09	$0.72
	35 to 50 MWh	$0.15	$0.17	$0.04	$0.35
	50 to 100 MWh	$0.08	$0.11	$0.03	$0.22
	100 to 500 MWh	$0.08	$0.07	$0.03	$0.17
	Average	$1.04	$1.24	$0.58	$2.85
Non-Res	0 to 5 MWh	($0.00)	($0.00)	($0.00)	($0.00)
	5 to 10 MWh	($0.01)	($0.00)	($0.00)	($0.01)
	10 to 15 MWh	($0.01)	($0.00)	($0.00)	($0.01)
	15 to 25 MWh	($0.01)	($0.00)	($0.00)	($0.02)
	25 to 35 MWh	($0.01)	($0.00)	($0.00)	($0.01)
	35 to 50 MWh	($0.01)	($0.00)	($0.00)	($0.02)
	50 to 100 MWh	($0.06)	($0.00)	($0.01)	($0.08)
	100 to 500 MWh	($0.36)	($0.01)	($0.09)	($0.47)
	Over 500 MWh	($0.49)	($0.01)	$0.11	($0.39)
	Average	($0.97)	($0.03)	($0.00)	($1.00)
Overall Average		$0.06	$1.21	$0.57	$1.85

Table 3: PCT Results by Customer Size, Base Case, 2008 (20-year Annualized $/customer/year)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($405)	($259)	$201	($314)
	5 to 10 MWh	($177)	($85)	$145	($128)
	10 to 15 MWh	$211	$243	$649	$259
	15 to 25 MWh	$463	$744	$1,073	$604
	25 to 35 MWh	$881	$1,443	$1,719	$1,159
	35 to 50 MWh	$1,187	$1,993	$2,199	$1,571
	50 to 100 MWh	$1,893	$3,477	$3,534	$2,655
	100 to 500 MWh	$8,137	$6,816	$30,989	$8,549
	Average	$181	$569	$706	$328
Non-Res	0 to 5 MWh	($247)	($116)	($952)	($341)
	5 to 10 MWh	($263)	($197)	($354)	($266)
	10 to 15 MWh	($378)	($328)	($387)	($377)
	15 to 25 MWh	($332)	($245)	($65)	($314)
	25 to 35 MWh	($314)	($678)	($737)	($356)
	35 to 50 MWh	($501)	($610)	($686)	($525)
	50 to 100 MWh	($1,089)	($1,674)	($1,071)	($1,104)
	100 to 500 MWh	($3,012)	($3,981)	($4,218)	($3,217)
	Over 500 MWh	($7,454)	($10,804)	$5,117	($4,432)
	Average	($2,349)	($2,458)	($28)	($2,027)
Overall Average		$11	$552	$648	$201

Table 4: PCT Results by Customer Size, Base Case, 2008 (20-year Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.17)	($0.09)	$0.08	($0.13)
	5 to 10 MWh	($0.05)	($0.02)	$0.04	($0.04)
	10 to 15 MWh	$0.05	$0.04	$0.13	$0.05
	15 to 25 MWh	$0.08	$0.10	$0.16	$0.09
	25 to 35 MWh	$0.10	$0.13	$0.19	$0.12
	35 to 50 MWh	$0.10	$0.14	$0.19	$0.13
	50 to 100 MWh	$0.10	$0.15	$0.20	$0.13
	100 to 500 MWh	$0.12	$0.17	$0.25	$0.15
	Average	$0.04	$0.08	$0.14	$0.06
Non-Res	0 to 5 MWh	($0.08)	($0.05)	($0.14)	($0.09)
	5 to 10 MWh	($0.06)	($0.04)	($0.06)	($0.06)
	10 to 15 MWh	($0.06)	($0.04)	($0.05)	($0.06)
	15 to 25 MWh	($0.04)	($0.03)	($0.01)	($0.03)
	25 to 35 MWh	($0.03)	($0.05)	($0.05)	($0.03)
	35 to 50 MWh	($0.03)	($0.04)	($0.04)	($0.03)
	50 to 100 MWh	($0.04)	($0.05)	($0.04)	($0.04)
	100 to 500 MWh	($0.04)	($0.05)	($0.05)	($0.04)
	Over 500 MWh	($0.02)	($0.04)	$0.02	($0.01)
	Average	($0.03)	($0.05)	($0.00)	($0.02)
Overall Average		$0.00	$0.08	$0.05	$0.02

Table 5: PCT Results by Customer Size, Base Case, 2009 (20-year NPV, $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($4.10)	($0.51)	$0.37	($4.23)
	5 to 10 MWh	($4.38)	($0.01)	$1.36	($3.03)
	10 to 15 MWh	$7.20	$4.05	$5.02	$16.27
	15 to 25 MWh	$13.03	$13.15	$8.11	$34.30
	25 to 35 MWh	$6.44	$8.14	$3.64	$18.22
	35 to 50 MWh	$3.25	$4.16	$1.65	$9.06
	50 to 100 MWh	$1.88	$2.72	$1.18	$5.78
	100 to 500 MWh	$1.63	$1.59	$1.11	$4.34
	Average	$26.53	$33.29	$22.46	$82.28
Non-Res	0 to 5 MWh	($0.02)	($0.01)	($0.03)	($0.06)
	5 to 10 MWh	($0.06)	($0.03)	($0.01)	($0.10)
	10 to 15 MWh	($0.09)	($0.09)	($0.02)	($0.21)
	15 to 25 MWh	($0.09)	($0.03)	$0.00	($0.11)
	25 to 35 MWh	($0.03)	($0.28)	($0.04)	($0.35)
	35 to 50 MWh	($0.02)	($0.21)	($0.02)	($0.26)
	50 to 100 MWh	($0.29)	($1.11)	($0.18)	($1.57)
	100 to 500 MWh	($2.35)	($5.00)	($1.67)	($9.02)
	Over 500 MWh	($3.99)	($2.88)	$5.20	($1.67)
	Average	($6.95)	($9.65)	$3.24	($13.36)
Overall Average		$19.58	$23.64	$25.70	$68.92

Table 6: PCT Results by Customer Size, Base Case, 2009 (20-year Annualized $M/year)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.28)	($0.03)	$0.03	($0.29)
	5 to 10 MWh	($0.30)	($0.00)	$0.09	($0.20)
	10 to 15 MWh	$0.49	$0.27	$0.34	$1.10
	15 to 25 MWh	$0.88	$0.89	$0.55	$2.32
	25 to 35 MWh	$0.44	$0.55	$0.25	$1.23
	35 to 50 MWh	$0.22	$0.28	$0.11	$0.61
	50 to 100 MWh	$0.13	$0.18	$0.08	$0.39
	100 to 500 MWh	$0.11	$0.11	$0.08	$0.29
	Average	$1.79	$2.25	$1.52	$5.56
Non-Res	0 to 5 MWh	($0.00)	($0.00)	($0.00)	($0.00)
	5 to 10 MWh	($0.01)	($0.00)	($0.00)	($0.01)
	10 to 15 MWh	($0.01)	($0.01)	($0.00)	($0.02)
	15 to 25 MWh	($0.01)	($0.00)	$0.00	($0.01)
	25 to 35 MWh	($0.00)	($0.02)	($0.00)	($0.03)
	35 to 50 MWh	($0.00)	($0.02)	($0.00)	($0.02)
	50 to 100 MWh	($0.02)	($0.09)	($0.01)	($0.12)
	100 to 500 MWh	($0.18)	($0.40)	($0.13)	($0.71)
	Over 500 MWh	($0.30)	($0.23)	$0.41	($0.11)
	Average	($0.53)	($0.76)	$0.26	($1.03)
Overall Average		$1.26	$1.49	$1.78	$4.53

Table 7: PCT Results by Customer Size, Base Case, 2009 (20-year Annualized $/customer/year)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($384)	($209)	$110	($256)
	5 to 10 MWh	($136)	($1)	$147	($60)
	10 to 15 MWh	$281	$377	$698	$373
	15 to 25 MWh	$574	$962	$1,193	$794
	25 to 35 MWh	$1,088	$1,797	$1,906	$1,474
	35 to 50 MWh	$1,511	$2,478	$2,474	$2,015
	50 to 100 MWh	$2,465	$4,319	$4,003	$3,426
	100 to 500 MWh	$9,767	$8,312	$33,567	$11,070
	Average	$265	$767	$761	$475
Non-Res	0 to 5 MWh	($177)	($51)	($840)	($169)
	5 to 10 MWh	($177)	($89)	($276)	($145)
	10 to 15 MWh	($241)	($148)	($325)	($190)
	15 to 25 MWh	($146)	($28)	$27	($67)
	25 to 35 MWh	($64)	($341)	($455)	($250)
	35 to 50 MWh	($59)	($218)	($253)	($178)
	50 to 100 MWh	($378)	($774)	($537)	($624)
	100 to 500 MWh	($1,397)	($1,973)	($2,777)	($1,875)
	Over 500 MWh	($4,187)	($4,462)	$8,864	($671)
	Average	($1,178)	($1,120)	$1,720	($806)
Overall Average		$175	$412	$828	$349

Table 8: PCT Results by Customer Size, Base Case, 2009 (20-year Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.16)	($0.08)	$0.05	($0.11)
	5 to 10 MWh	($0.04)	($0.00)	$0.04	($0.02)
	10 to 15 MWh	$0.06	$0.07	$0.14	$0.08
	15 to 25 MWh	$0.09	$0.12	$0.18	$0.12
	25 to 35 MWh	$0.12	$0.16	$0.21	$0.15
	35 to 50 MWh	$0.13	$0.18	$0.22	$0.16
	50 to 100 MWh	$0.13	$0.19	$0.23	$0.17
	100 to 500 MWh	$0.14	$0.20	$0.27	$0.18
	Average	$0.05	$0.11	$0.15	$0.09
Non-Res	0 to 5 MWh	($0.05)	($0.02)	($0.12)	($0.06)
	5 to 10 MWh	($0.04)	($0.02)	($0.05)	($0.03)
	10 to 15 MWh	($0.04)	($0.02)	($0.04)	($0.03)
	15 to 25 MWh	($0.02)	($0.00)	$0.00	($0.01)
	25 to 35 MWh	($0.01)	($0.03)	($0.03)	($0.02)
	35 to 50 MWh	($0.00)	($0.01)	($0.01)	($0.01)
	50 to 100 MWh	($0.01)	($0.03)	($0.02)	($0.02)
	100 to 500 MWh	($0.02)	($0.03)	($0.03)	($0.03)
	Over 500 MWh	($0.01)	($0.02)	$0.03	($0.00)
	Average	($0.01)	($0.02)	$0.01	($0.01)
Overall Average		$0.02	$0.03	$0.07	$0.03

Table 9: PCT Results by Customer Size, Base Case, 2017 (20-year NPV, $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($9.46)	($2.06)	($2.48)	($14.00)
	5 to 10 MWh	$0.80	$1.30	$6.38	$8.48
	10 to 15 MWh	$38.92	$20.37	$27.80	$87.09
	15 to 25 MWh	$61.12	$62.34	$48.26	$171.73
	25 to 35 MWh	$27.81	$36.88	$21.10	$85.80
	35 to 50 MWh	$13.99	$18.86	$9.53	$42.38
	50 to 100 MWh	$7.98	$12.42	$6.65	$27.05
	100 to 500 MWh	$6.55	$7.16	$6.02	$19.73
	Average	$147.72	$157.26	$123.28	$428.26
Non-Res	0 to 5 MWh	($0.01)	($0.04)	($0.07)	($0.12)
	5 to 10 MWh	$0.01	($0.13)	($0.01)	($0.13)
	10 to 15 MWh	$0.01	($0.47)	($0.07)	($0.54)
	15 to 25 MWh	$0.24	($0.27)	$0.03	($0.00)
	25 to 35 MWh	$0.42	($1.18)	($0.02)	($0.78)
	35 to 50 MWh	$0.46	($1.20)	$0.15	($0.60)
	50 to 100 MWh	$0.67	($5.09)	$0.24	($4.17)
	100 to 500 MWh	($2.79)	($33.05)	($5.11)	($40.96)
	Over 500 MWh	($4.80)	($28.93)	$26.52	($7.21)
	Average	($5.79)	($70.36)	$21.64	($54.50)
Overall Average		$141.93	$86.91	$144.92	$373.76

Table 10: PCT Results by Customer Size, Base Case, 2017 (20-year Annualized $M/year)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.64)	($0.14)	($0.17)	($0.95)
	5 to 10 MWh	$0.05	$0.09	$0.43	$0.57
	10 to 15 MWh	$2.63	$1.38	$1.88	$5.89
	15 to 25 MWh	$4.13	$4.21	$3.26	$11.61
	25 to 35 MWh	$1.88	$2.49	$1.43	$5.80
	35 to 50 MWh	$0.95	$1.27	$0.64	$2.87
	50 to 100 MWh	$0.54	$0.84	$0.45	$1.83
	100 to 500 MWh	$0.44	$0.48	$0.41	$1.33
	Average	$9.99	$10.63	$8.33	$28.95
Non-Res	0 to 5 MWh	($0.00)	($0.00)	($0.01)	($0.01)
	5 to 10 MWh	$0.00	($0.01)	($0.00)	($0.01)
	10 to 15 MWh	$0.00	($0.04)	($0.01)	($0.04)
	15 to 25 MWh	$0.02	($0.02)	$0.00	($0.00)
	25 to 35 MWh	$0.03	($0.09)	($0.00)	($0.06)
	35 to 50 MWh	$0.04	($0.10)	$0.01	($0.05)
	50 to 100 MWh	$0.05	($0.40)	$0.02	($0.33)
	100 to 500 MWh	($0.22)	($2.61)	($0.40)	($3.23)
	Over 500 MWh	($0.36)	($2.28)	$2.11	($0.53)
	Average	($0.44)	($5.56)	$1.73	($4.26)
Overall Average		$9.55	$5.08	$10.06	$24.69

Table 11: PCT Results by Customer Size, Base Case, 2017 (20-year Annualized $/customer/year)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($350)	($255)	($181)	($287)
	5 to 10 MWh	$10	$41	$173	$57
	10 to 15 MWh	$599	$571	$960	$672
	15 to 25 MWh	$1,062	$1,371	$1,763	$1,317
	25 to 35 MWh	$1,853	$2,450	$2,747	$2,273
	35 to 50 MWh	$2,570	$3,378	$3,547	$3,090
	50 to 100 MWh	$4,132	$5,932	$5,629	$5,195
	100 to 500 MWh	$15,486	$11,228	$45,141	$16,527
	Average	$607	$1,089	$1,039	$841
Non-Res	0 to 5 MWh	($27)	($53)	($521)	($98)
	5 to 10 MWh	$8	($140)	($55)	($58)
	10 to 15 MWh	$9	($229)	($411)	($151)
	15 to 25 MWh	$117	($82)	$104	($0)
	25 to 35 MWh	$256	($438)	($65)	($165)
	35 to 50 MWh	$348	($383)	$413	($127)
	50 to 100 MWh	$268	($1,093)	$198	($499)
	100 to 500 MWh	($501)	($4,018)	($2,312)	($2,572)
	Over 500 MWh	($1,521)	($13,806)	$12,282	($920)
	Average	($291)	($2,517)	$3,114	($1,001)
Overall Average		$535	$424	$1,173	$641

Table 12: PCT Results by Customer Size, Base Case, 2017 (20-year Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.15)	($0.09)	($0.08)	($0.12)
	5 to 10 MWh	$0.00	$0.01	$0.05	$0.02
	10 to 15 MWh	$0.13	$0.10	$0.20	$0.14
	15 to 25 MWh	$0.17	$0.18	$0.27	$0.19
	25 to 35 MWh	$0.21	$0.22	$0.30	$0.23
	35 to 50 MWh	$0.22	$0.24	$0.31	$0.25
	50 to 100 MWh	$0.22	$0.26	$0.32	$0.26
	100 to 500 MWh	$0.22	$0.27	$0.36	$0.27
	Average	$0.12	$0.16	$0.20	$0.15
Non-Res	0 to 5 MWh	($0.01)	($0.02)	($0.08)	($0.03)
	5 to 10 MWh	$0.00	($0.03)	($0.01)	($0.01)
	10 to 15 MWh	$0.00	($0.03)	($0.05)	($0.02)
	15 to 25 MWh	$0.01	($0.01)	$0.01	($0.00)
	25 to 35 MWh	$0.02	($0.04)	($0.00)	($0.01)
	35 to 50 MWh	$0.02	($0.03)	$0.02	($0.01)
	50 to 100 MWh	$0.01	($0.04)	$0.01	($0.02)
	100 to 500 MWh	($0.01)	($0.05)	($0.02)	($0.03)
	Over 500 MWh	($0.00)	($0.05)	$0.05	($0.00)
	Average	($0.00)	($0.05)	$0.03	($0.01)
Overall Average		$0.05	$0.04	$0.10	$0.05

Table 13: TRC Results by Customer Size, Base Case, 2008 (20-year NPV, $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($7.43)	($1.38)	($0.92)	($9.73)
	5 to 10 MWh	($29.06)	($7.25)	($3.34)	($39.65)
	10 to 15 MWh	($30.05)	($10.94)	($3.54)	($44.54)
	15 to 25 MWh	($34.56)	($19.28)	($4.35)	($58.19)
	25 to 35 MWh	($12.31)	($8.69)	($1.67)	($22.67)
	35 to 50 MWh	($5.70)	($4.02)	($0.69)	($10.41)
	50 to 100 MWh	($3.15)	($2.37)	($0.46)	($5.98)
	100 to 500 MWh	($2.23)	($1.24)	($0.30)	($3.77)
	Average	($126.77)	($55.16)	($15.29)	($197.22)
Non-Res	0 to 5 MWh	($0.16)	($0.08)	($0.04)	($0.28)
	5 to 10 MWh	($0.60)	($0.12)	($0.04)	($0.75)
	10 to 15 MWh	($0.83)	($0.27)	($0.06)	($1.16)
	15 to 25 MWh	($1.53)	($0.43)	($0.10)	($2.06)
	25 to 35 MWh	($1.51)	($0.36)	($0.16)	($2.03)
	35 to 50 MWh	($1.74)	($0.43)	($0.23)	($2.41)
	50 to 100 MWh	($4.79)	($0.72)	($1.01)	($6.52)
	100 to 500 MWh	($22.22)	($1.77)	($5.44)	($29.43)
	Over 500 MWh	($60.34)	($0.85)	($13.78)	($74.97)
	Average	($93.71)	($5.03)	($20.87)	($119.61)
Overall Average		($220.47)	($60.19)	($36.16)	($316.83)

Table 14: TRC Results by Customer Size, Base Case, 2008 (20-year Annualized $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.63)	($0.12)	($0.08)	($0.83)
	5 to 10 MWh	($2.48)	($0.62)	($0.29)	($3.38)
	10 to 15 MWh	($2.56)	($0.93)	($0.30)	($3.80)
	15 to 25 MWh	($2.95)	($1.65)	($0.37)	($4.97)
	25 to 35 MWh	($1.05)	($0.74)	($0.14)	($1.93)
	35 to 50 MWh	($0.49)	($0.34)	($0.06)	($0.89)
	50 to 100 MWh	($0.27)	($0.20)	($0.04)	($0.51)
	100 to 500 MWh	($0.19)	($0.11)	($0.03)	($0.32)
	Average	($10.82)	($4.71)	($1.30)	($16.83)
Non-Res	0 to 5 MWh	($0.01)	($0.01)	($0.00)	($0.02)
	5 to 10 MWh	($0.05)	($0.01)	($0.00)	($0.06)
	10 to 15 MWh	($0.07)	($0.02)	($0.01)	($0.10)
	15 to 25 MWh	($0.13)	($0.04)	($0.01)	($0.18)
	25 to 35 MWh	($0.13)	($0.03)	($0.01)	($0.17)
	35 to 50 MWh	($0.15)	($0.04)	($0.02)	($0.21)
	50 to 100 MWh	($0.41)	($0.06)	($0.09)	($0.56)
	100 to 500 MWh	($1.90)	($0.15)	($0.46)	($2.51)
	Over 500 MWh	($5.15)	($0.07)	($1.18)	($6.40)
	Average	($8.00)	($0.43)	($1.78)	($10.21)
Overall Average		($18.81)	($5.14)	($3.09)	($27.04)

Table 15: TRC Results by Customer Size, Base Case, 2008 (20-year Annualized $/customer)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($1,042)	($962)	($833)	($1,007)
	5 to 10 MWh	($1,356)	($1,290)	($1,122)	($1,320)
	10 to 15 MWh	($1,754)	($1,736)	($1,519)	($1,728)
	15 to 25 MWh	($2,277)	($2,401)	($1,972)	($2,289)
	25 to 35 MWh	($3,111)	($3,267)	($2,703)	($3,133)
	35 to 50 MWh	($3,973)	($4,073)	($3,208)	($3,948)
	50 to 100 MWh	($6,189)	($6,406)	($4,856)	($6,141)
	100 to 500 MWh	($19,954)	($11,045)	($28,080)	($16,055)
	Average	($1,895)	($2,162)	($1,598)	($1,934)
Non-Res	0 to 5 MWh	($1,691)	($23,343)	($2,624)	($2,511)
	5 to 10 MWh	($1,954)	($23,788)	($2,248)	($2,295)
	10 to 15 MWh	($2,467)	($25,081)	($2,778)	($3,142)
	15 to 25 MWh	($2,899)	($25,409)	($2,916)	($3,559)
	25 to 35 MWh	($3,529)	($26,062)	($4,520)	($4,255)
	35 to 50 MWh	($5,111)	($26,236)	($5,713)	($6,045)
	50 to 100 MWh	($7,458)	($30,306)	($7,230)	($8,094)
	100 to 500 MWh	($15,874)	($41,990)	($21,388)	($17,350)
	Over 500 MWh	($78,142)	($79,709)	($54,804)	($72,485)
	Average	($19,345)	($35,193)	($25,714)	($20,627)
Overall Average		($3,073)	($2,346)	($3,485)	($2,940)

Table 16: TRC Results by Customer Size, Base Case, 2008 (20-year Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.44)	($0.35)	($0.35)	($0.42)
	5 to 10 MWh	($0.41)	($0.33)	($0.33)	($0.39)
	10 to 15 MWh	($0.39)	($0.32)	($0.31)	($0.36)
	15 to 25 MWh	($0.37)	($0.31)	($0.30)	($0.34)
	25 to 35 MWh	($0.36)	($0.30)	($0.29)	($0.33)
	35 to 50 MWh	($0.34)	($0.29)	($0.28)	($0.32)
	50 to 100 MWh	($0.33)	($0.28)	($0.27)	($0.30)
	100 to 500 MWh	($0.29)	($0.27)	($0.23)	($0.28)
	Average	($0.38)	($0.31)	($0.31)	($0.35)
Non-Res	0 to 5 MWh	($0.52)	($10.71)	($0.41)	($0.69)
	5 to 10 MWh	($0.44)	($4.83)	($0.42)	($0.51)
	10 to 15 MWh	($0.37)	($3.38)	($0.36)	($0.46)
	15 to 25 MWh	($0.32)	($2.83)	($0.33)	($0.40)
	25 to 35 MWh	($0.31)	($2.13)	($0.31)	($0.37)
	35 to 50 MWh	($0.29)	($1.79)	($0.30)	($0.34)
	50 to 100 MWh	($0.28)	($1.02)	($0.29)	($0.30)
	100 to 500 MWh	($0.24)	($0.58)	($0.23)	($0.25)
	Over 500 MWh	($0.20)	($0.32)	($0.20)	($0.20)
	Average	($0.22)	($0.71)	($0.22)	($0.22)
Overall Average		($0.29)	($0.32)	($0.25)	($0.29)

Table 17: TRC Results by Customer Size, Base Case, 2009 (20-year NPV, $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($7.84)	($1.68)	($1.86)	($11.38)
	5 to 10 MWh	($30.43)	($8.78)	($6.85)	($46.06)
	10 to 15 MWh	($31.29)	($13.17)	($7.29)	($51.75)
	15 to 25 MWh	($35.66)	($22.96)	($8.96)	($67.58)
	25 to 35 MWh	($12.47)	($10.14)	($3.42)	($26.02)
	35 to 50 MWh	($5.69)	($4.63)	($1.40)	($11.72)
	50 to 100 MWh	($3.09)	($2.70)	($0.92)	($6.71)
	100 to 500 MWh	($2.17)	($1.41)	($0.60)	($4.18)
	Average	($131.12)	($65.47)	($31.32)	($227.90)
Non-Res	0 to 5 MWh	($0.15)	($0.25)	($0.07)	($0.48)
	5 to 10 MWh	($0.59)	($0.45)	($0.06)	($1.10)
	10 to 15 MWh	($0.80)	($1.22)	($0.10)	($2.12)
	15 to 25 MWh	($1.45)	($2.10)	($0.17)	($3.72)
	25 to 35 MWh	($1.42)	($2.24)	($0.28)	($3.95)
	35 to 50 MWh	($1.61)	($2.86)	($0.40)	($4.87)
	50 to 100 MWh	($4.37)	($7.93)	($1.75)	($14.05)
	100 to 500 MWh	($19.99)	($29.52)	($9.55)	($59.07)
	Over 500 MWh	($58.14)	($23.09)	($24.36)	($105.59)
	Average	($88.53)	($69.68)	($36.74)	($194.95)
Overall Average		($219.64)	($135.15)	($68.06)	($422.85)

Table 18: TRC Results by Customer Size, Base Case, 2009 (20-year Annualized $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.67)	($0.14)	($0.16)	($0.97)
	5 to 10 MWh	($2.60)	($0.75)	($0.58)	($3.93)
	10 to 15 MWh	($2.67)	($1.12)	($0.62)	($4.42)
	15 to 25 MWh	($3.04)	($1.96)	($0.76)	($5.77)
	25 to 35 MWh	($1.06)	($0.87)	($0.29)	($2.22)
	35 to 50 MWh	($0.49)	($0.40)	($0.12)	($1.00)
	50 to 100 MWh	($0.26)	($0.23)	($0.08)	($0.57)
	100 to 500 MWh	($0.18)	($0.12)	($0.05)	($0.36)
	Average	($11.19)	($5.59)	($2.67)	($19.45)
Non-Res	0 to 5 MWh	($0.01)	($0.02)	($0.01)	($0.04)
	5 to 10 MWh	($0.05)	($0.04)	($0.01)	($0.09)
	10 to 15 MWh	($0.07)	($0.10)	($0.01)	($0.18)
	15 to 25 MWh	($0.12)	($0.18)	($0.01)	($0.32)
	25 to 35 MWh	($0.12)	($0.19)	($0.02)	($0.34)
	35 to 50 MWh	($0.14)	($0.24)	($0.03)	($0.42)
	50 to 100 MWh	($0.37)	($0.68)	($0.15)	($1.20)
	100 to 500 MWh	($1.71)	($2.52)	($0.82)	($5.04)
	Over 500 MWh	($4.96)	($1.97)	($2.08)	($9.01)
	Average	($7.55)	($5.95)	($3.14)	($16.64)
Overall Average		($18.74)	($11.53)	($5.81)	($36.08)

Table 19: TRC Results by Customer Size, Base Case, 2009 (20-year Annualized $/customer)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($927)	($872)	($692)	($870)
	5 to 10 MWh	($1,197)	($1,159)	($941)	($1,143)
	10 to 15 MWh	($1,540)	($1,549)	($1,278)	($1,499)
	15 to 25 MWh	($1,981)	($2,119)	($1,663)	($1,975)
	25 to 35 MWh	($2,656)	($2,826)	($2,261)	($2,657)
	35 to 50 MWh	($3,344)	($3,480)	($2,644)	($3,291)
	50 to 100 MWh	($5,113)	($5,412)	($3,939)	($5,020)
	100 to 500 MWh	($16,380)	($9,280)	($22,829)	($13,453)
	Average	($1,652)	($1,903)	($1,339)	($1,662)
Non-Res	0 to 5 MWh	($1,523)	($1,282)	($2,035)	($1,432)
	5 to 10 MWh	($1,752)	($1,662)	($1,702)	($1,711)
	10 to 15 MWh	($2,181)	($2,046)	($2,099)	($2,098)
	15 to 25 MWh	($2,524)	($2,226)	($2,212)	($2,333)
	25 to 35 MWh	($3,049)	($2,914)	($3,536)	($3,000)
	35 to 50 MWh	($4,322)	($3,109)	($4,505)	($3,527)
	50 to 100 MWh	($6,237)	($5,969)	($5,744)	($6,020)
	100 to 500 MWh	($13,090)	($12,577)	($17,232)	($13,336)
	Over 500 MWh	($69,011)	($38,724)	($44,484)	($53,158)
	Average	($16,749)	($8,738)	($20,782)	($12,972)
Overall Average		($2,595)	($3,188)	($2,706)	($2,779)

Table 20: TRC Results by Customer Size, Base Case, 2009 (20-year Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.39)	($0.32)	($0.29)	($0.36)
	5 to 10 MWh	($0.36)	($0.30)	($0.27)	($0.33)
	10 to 15 MWh	($0.34)	($0.28)	($0.26)	($0.31)
	15 to 25 MWh	($0.33)	($0.27)	($0.26)	($0.29)
	25 to 35 MWh	($0.30)	($0.26)	($0.24)	($0.27)
	35 to 50 MWh	($0.29)	($0.25)	($0.23)	($0.26)
	50 to 100 MWh	($0.27)	($0.24)	($0.22)	($0.25)
	100 to 500 MWh	($0.24)	($0.23)	($0.18)	($0.22)
	Average	($0.33)	($0.27)	($0.26)	($0.30)
Non-Res	0 to 5 MWh	($0.47)	($0.59)	($0.32)	($0.49)
	5 to 10 MWh	($0.39)	($0.34)	($0.31)	($0.36)
	10 to 15 MWh	($0.33)	($0.28)	($0.27)	($0.29)
	15 to 25 MWh	($0.28)	($0.25)	($0.25)	($0.26)
	25 to 35 MWh	($0.27)	($0.24)	($0.24)	($0.25)
	35 to 50 MWh	($0.24)	($0.21)	($0.24)	($0.22)
	50 to 100 MWh	($0.23)	($0.20)	($0.23)	($0.21)
	100 to 500 MWh	($0.20)	($0.17)	($0.19)	($0.18)
	Over 500 MWh	($0.18)	($0.15)	($0.17)	($0.17)
	Average	($0.19)	($0.18)	($0.18)	($0.18)
Overall Average		($0.25)	($0.21)	($0.21)	($0.23)

Table 21: TRC Results by Customer Size, Base Case, 2017 (20-year NPV, $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($13.22)	($2.81)	($4.24)	($20.28)
	5 to 10 MWh	($50.23)	($14.53)	($15.28)	($80.04)
	10 to 15 MWh	($50.93)	($21.86)	($16.00)	($88.79)
	15 to 25 MWh	($57.03)	($37.89)	($19.46)	($114.38)
	25 to 35 MWh	($19.47)	($16.36)	($7.23)	($43.06)
	35 to 50 MWh	($8.74)	($7.32)	($2.89)	($18.95)
	50 to 100 MWh	($4.58)	($4.21)	($1.83)	($10.63)
	100 to 500 MWh	($2.79)	($2.14)	($0.95)	($5.87)
	Average	($207.01)	($107.11)	($67.88)	($382.00)
Non-Res	0 to 5 MWh	($0.17)	($0.20)	($0.09)	($0.45)
	5 to 10 MWh	($0.65)	($0.37)	($0.08)	($1.10)
	10 to 15 MWh	($0.89)	($0.92)	($0.13)	($1.94)
	15 to 25 MWh	($1.61)	($1.57)	($0.22)	($3.40)
	25 to 35 MWh	($1.63)	($1.88)	($0.38)	($3.89)
	35 to 50 MWh	($1.83)	($2.33)	($0.54)	($4.70)
	50 to 100 MWh	($4.80)	($6.89)	($2.34)	($14.03)
	100 to 500 MWh	($21.02)	($24.91)	($11.89)	($57.82)
	Over 500 MWh	($66.48)	($19.08)	($28.57)	($114.13)
	Average	($99.07)	($58.15)	($44.23)	($201.45)
Overall Average		($306.08)	($165.27)	($112.11)	($583.45)

Table 22: TRC Results by Customer Size, Base Case, 2017 (20-year Annualized $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($1.13)	($0.24)	($0.36)	($1.73)
	5 to 10 MWh	($4.29)	($1.24)	($1.30)	($6.83)
	10 to 15 MWh	($4.35)	($1.87)	($1.37)	($7.58)
	15 to 25 MWh	($4.87)	($3.23)	($1.66)	($9.76)
	25 to 35 MWh	($1.66)	($1.40)	($0.62)	($3.67)
	35 to 50 MWh	($0.75)	($0.62)	($0.25)	($1.62)
	50 to 100 MWh	($0.39)	($0.36)	($0.16)	($0.91)
	100 to 500 MWh	($0.24)	($0.18)	($0.08)	($0.50)
	Average	($17.66)	($9.14)	($5.79)	($32.60)
Non-Res	0 to 5 MWh	($0.01)	($0.02)	($0.01)	($0.04)
	5 to 10 MWh	($0.06)	($0.03)	($0.01)	($0.09)
	10 to 15 MWh	($0.08)	($0.08)	($0.01)	($0.17)
	15 to 25 MWh	($0.14)	($0.13)	($0.02)	($0.29)
	25 to 35 MWh	($0.14)	($0.16)	($0.03)	($0.33)
	35 to 50 MWh	($0.16)	($0.20)	($0.05)	($0.40)
	50 to 100 MWh	($0.41)	($0.59)	($0.20)	($1.20)
	100 to 500 MWh	($1.79)	($2.13)	($1.01)	($4.93)
	Over 500 MWh	($5.67)	($1.63)	($2.44)	($9.74)
	Average	($8.45)	($4.96)	($3.77)	($17.19)
Overall Average		($26.12)	($14.10)	($9.57)	($49.79)

Table 23: TRC Results by Customer Size, Base Case, 2017 (20-year Annualized $/customer)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($617)	($438)	($391)	($524)
	5 to 10 MWh	($780)	($577)	($521)	($673)
	10 to 15 MWh	($989)	($773)	($698)	($865)
	15 to 25 MWh	($1,250)	($1,052)	($897)	($1,107)
	25 to 35 MWh	($1,637)	($1,372)	($1,188)	($1,440)
	35 to 50 MWh	($2,027)	($1,654)	($1,359)	($1,744)
	50 to 100 MWh	($2,994)	($2,540)	($1,959)	($2,577)
	100 to 500 MWh	($8,327)	($4,232)	($8,950)	($6,211)
	Average	($1,047)	($936)	($722)	($941)
Non-Res	0 to 5 MWh	($499)	($304)	($720)	($410)
	5 to 10 MWh	($584)	($417)	($616)	($516)
	10 to 15 MWh	($730)	($477)	($736)	($583)
	15 to 25 MWh	($845)	($513)	($777)	($647)
	25 to 35 MWh	($1,055)	($753)	($1,285)	($897)
	35 to 50 MWh	($1,482)	($783)	($1,639)	($1,035)
	50 to 100 MWh	($2,066)	($1,599)	($2,089)	($1,809)
	100 to 500 MWh	($4,154)	($3,271)	($5,829)	($3,929)
	Over 500 MWh	($23,810)	($9,865)	($14,179)	($16,930)
	Average	($5,656)	($2,248)	($6,799)	($4,038)
Overall Average		($1,416)	($1,178)	($1,115)	($1,277)

Table 24: TRC Results by Customer Size, Base Case, 2017 (20-year Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.26)	($0.16)	($0.16)	($0.22)
	5 to 10 MWh	($0.24)	($0.15)	($0.15)	($0.19)
	10 to 15 MWh	($0.22)	($0.14)	($0.14)	($0.18)
	15 to 25 MWh	($0.21)	($0.14)	($0.14)	($0.16)
	25 to 35 MWh	($0.19)	($0.12)	($0.13)	($0.15)
	35 to 50 MWh	($0.18)	($0.12)	($0.12)	($0.14)
	50 to 100 MWh	($0.16)	($0.11)	($0.11)	($0.13)
	100 to 500 MWh	($0.12)	($0.10)	($0.07)	($0.10)
	Average	($0.21)	($0.13)	($0.14)	($0.17)
Non-Res	0 to 5 MWh	($0.15)	($0.14)	($0.11)	($0.14)
	5 to 10 MWh	($0.13)	($0.08)	($0.11)	($0.11)
	10 to 15 MWh	($0.11)	($0.06)	($0.10)	($0.08)
	15 to 25 MWh	($0.09)	($0.06)	($0.09)	($0.07)
	25 to 35 MWh	($0.09)	($0.06)	($0.09)	($0.07)
	35 to 50 MWh	($0.08)	($0.05)	($0.09)	($0.07)
	50 to 100 MWh	($0.08)	($0.05)	($0.08)	($0.06)
	100 to 500 MWh	($0.06)	($0.05)	($0.06)	($0.05)
	Over 500 MWh	($0.06)	($0.04)	($0.05)	($0.05)
	Average	($0.06)	($0.05)	($0.06)	($0.06)
Overall Average		($0.12)	($0.08)	($0.09)	($0.10)

Table 25: SCT Results by Customer Size, Base Case, 2008 (20-year NPV, $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($8.72)	($1.54)	($1.03)	($11.29)
	5 to 10 MWh	($34.04)	($8.10)	($3.77)	($45.91)
	10 to 15 MWh	($35.16)	($12.25)	($4.00)	($51.41)
	15 to 25 MWh	($40.35)	($21.60)	($4.91)	($66.87)
	25 to 35 MWh	($14.33)	($9.72)	($1.89)	($25.94)
	35 to 50 MWh	($6.62)	($4.49)	($0.78)	($11.89)
	50 to 100 MWh	($3.65)	($2.65)	($0.52)	($6.81)
	100 to 500 MWh	($2.53)	($1.38)	($0.33)	($4.24)
	Average	($147.94)	($61.73)	($17.24)	($226.91)
Non-Res	0 to 5 MWh	($0.17)	($0.08)	($0.04)	($0.30)
	5 to 10 MWh	($0.66)	($0.12)	($0.04)	($0.82)
	10 to 15 MWh	($0.91)	($0.27)	($0.07)	($1.25)
	15 to 25 MWh	($1.68)	($0.44)	($0.11)	($2.23)
	25 to 35 MWh	($1.67)	($0.37)	($0.18)	($2.22)
	35 to 50 MWh	($1.94)	($0.44)	($0.26)	($2.64)
	50 to 100 MWh	($5.34)	($0.74)	($1.12)	($7.21)
	100 to 500 MWh	($24.62)	($1.87)	($5.98)	($32.47)
	Over 500 MWh	($65.49)	($0.91)	($14.91)	($81.31)
	Average	($102.50)	($5.24)	($22.71)	($130.45)
Overall Average		($250.43)	($66.96)	($39.96)	($357.35)

Table 26: SCT Results by Customer Size, Base Case, 2008 (20-year Annualized $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.57)	($0.10)	($0.07)	($0.74)
	5 to 10 MWh	($2.22)	($0.53)	($0.25)	($3.00)
	10 to 15 MWh	($2.29)	($0.80)	($0.26)	($3.35)
	15 to 25 MWh	($2.63)	($1.41)	($0.32)	($4.36)
	25 to 35 MWh	($0.94)	($0.63)	($0.12)	($1.69)
	35 to 50 MWh	($0.43)	($0.29)	($0.05)	($0.78)
	50 to 100 MWh	($0.24)	($0.17)	($0.03)	($0.44)
	100 to 500 MWh	($0.17)	($0.09)	($0.02)	($0.28)
	Average	($9.65)	($4.03)	($1.13)	($14.81)
Non-Res	0 to 5 MWh	($0.01)	($0.01)	($0.00)	($0.02)
	5 to 10 MWh	($0.04)	($0.01)	($0.00)	($0.05)
	10 to 15 MWh	($0.06)	($0.02)	($0.00)	($0.08)
	15 to 25 MWh	($0.11)	($0.03)	($0.01)	($0.15)
	25 to 35 MWh	($0.11)	($0.02)	($0.01)	($0.15)
	35 to 50 MWh	($0.13)	($0.03)	($0.02)	($0.17)
	50 to 100 MWh	($0.35)	($0.05)	($0.07)	($0.47)
	100 to 500 MWh	($1.61)	($0.12)	($0.39)	($2.12)
	Over 500 MWh	($4.27)	($0.06)	($0.97)	($5.31)
	Average	($6.69)	($0.34)	($1.48)	($8.51)
Overall Average		($16.34)	($4.37)	($2.61)	($23.32)

Table 27: SCT Results by Customer Size, Base Case, 2008 (20-year Annualized $/customer)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($936)	($821)	($717)	($894)
	5 to 10 MWh	($1,215)	($1,102)	($967)	($1,169)
	10 to 15 MWh	($1,569)	($1,486)	($1,312)	($1,526)
	15 to 25 MWh	($2,033)	($2,057)	($1,704)	($2,012)
	25 to 35 MWh	($2,770)	($2,796)	($2,332)	($2,742)
	35 to 50 MWh	($3,529)	($3,479)	($2,763)	($3,448)
	50 to 100 MWh	($5,475)	($5,468)	($4,172)	($5,345)
	100 to 500 MWh	($17,351)	($9,385)	($23,448)	($13,811)
	Average	($1,691)	($1,850)	($1,378)	($1,702)
Non-Res	0 to 5 MWh	($1,425)	($17,934)	($2,206)	($2,060)
	5 to 10 MWh	($1,647)	($18,284)	($1,871)	($1,907)
	10 to 15 MWh	($2,084)	($19,468)	($2,318)	($2,603)
	15 to 25 MWh	($2,443)	($19,739)	($2,424)	($2,948)
	25 to 35 MWh	($2,992)	($20,275)	($3,816)	($3,554)
	35 to 50 MWh	($4,351)	($20,373)	($4,850)	($5,064)
	50 to 100 MWh	($6,365)	($23,867)	($6,151)	($6,845)
	100 to 500 MWh	($13,451)	($33,943)	($17,968)	($14,637)
	Over 500 MWh	($64,865)	($65,170)	($45,338)	($60,121)
	Average	($16,182)	($28,015)	($21,400)	($17,204)
Overall Average		($2,669)	($1,996)	($2,944)	($2,536)

Table 28: SCT Results by Customer Size, Base Case, 2008 (20-year Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.40)	($0.30)	($0.30)	($0.37)
	5 to 10 MWh	($0.37)	($0.28)	($0.28)	($0.34)
	10 to 15 MWh	($0.35)	($0.27)	($0.27)	($0.32)
	15 to 25 MWh	($0.33)	($0.26)	($0.26)	($0.30)
	25 to 35 MWh	($0.32)	($0.25)	($0.25)	($0.28)
	35 to 50 MWh	($0.31)	($0.25)	($0.24)	($0.28)
	50 to 100 MWh	($0.29)	($0.24)	($0.24)	($0.26)
	100 to 500 MWh	($0.25)	($0.23)	($0.19)	($0.24)
	Average	($0.34)	($0.26)	($0.26)	($0.31)
Non-Res	0 to 5 MWh	($0.44)	($8.23)	($0.35)	($0.57)
	5 to 10 MWh	($0.37)	($3.72)	($0.35)	($0.42)
	10 to 15 MWh	($0.31)	($2.62)	($0.30)	($0.39)
	15 to 25 MWh	($0.27)	($2.20)	($0.28)	($0.33)
	25 to 35 MWh	($0.26)	($1.66)	($0.26)	($0.31)
	35 to 50 MWh	($0.25)	($1.39)	($0.26)	($0.29)
	50 to 100 MWh	($0.24)	($0.81)	($0.25)	($0.26)
	100 to 500 MWh	($0.20)	($0.47)	($0.20)	($0.21)
	Over 500 MWh	($0.17)	($0.26)	($0.17)	($0.17)
	Average	($0.18)	($0.56)	($0.18)	($0.19)
Overall Average		($0.25)	($0.28)	($0.21)	($0.25)

Table 29: SCT Results by Customer Size, Base Case, 2009 (20-year NPV, $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($9.28)	($1.86)	($2.12)	($13.26)
	5 to 10 MWh	($35.94)	($9.73)	($7.80)	($53.47)
	10 to 15 MWh	($36.92)	($14.62)	($8.29)	($59.83)
	15 to 25 MWh	($41.99)	($25.48)	($10.20)	($77.66)
	25 to 35 MWh	($14.61)	($11.20)	($3.88)	($29.69)
	35 to 50 MWh	($6.65)	($5.10)	($1.58)	($13.33)
	50 to 100 MWh	($3.59)	($2.97)	($1.03)	($7.58)
	100 to 500 MWh	($2.47)	($1.54)	($0.65)	($4.66)
	Average	($154.27)	($72.49)	($35.57)	($262.33)
Non-Res	0 to 5 MWh	($0.17)	($0.27)	($0.08)	($0.52)
	5 to 10 MWh	($0.64)	($0.48)	($0.07)	($1.19)
	10 to 15 MWh	($0.88)	($1.27)	($0.11)	($2.26)
	15 to 25 MWh	($1.58)	($2.17)	($0.18)	($3.94)
	25 to 35 MWh	($1.56)	($2.35)	($0.31)	($4.22)
	35 to 50 MWh	($1.77)	($2.95)	($0.45)	($5.16)
	50 to 100 MWh	($4.80)	($8.29)	($1.93)	($15.02)
	100 to 500 MWh	($21.74)	($30.40)	($10.37)	($62.51)
	Over 500 MWh	($62.62)	($23.31)	($25.97)	($111.90)
	Average	($95.76)	($71.49)	($39.46)	($206.71)
Overall Average		($250.03)	($143.98)	($75.03)	($469.04)

Table 30: SCT Results by Customer Size, Base Case, 2009 (20-year Annualized $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.61)	($0.12)	($0.14)	($0.87)
	5 to 10 MWh	($2.35)	($0.63)	($0.51)	($3.49)
	10 to 15 MWh	($2.41)	($0.95)	($0.54)	($3.90)
	15 to 25 MWh	($2.74)	($1.66)	($0.67)	($5.07)
	25 to 35 MWh	($0.95)	($0.73)	($0.25)	($1.94)
	35 to 50 MWh	($0.43)	($0.33)	($0.10)	($0.87)
	50 to 100 MWh	($0.23)	($0.19)	($0.07)	($0.49)
	100 to 500 MWh	($0.16)	($0.10)	($0.04)	($0.30)
	Average	($10.07)	($4.73)	($2.32)	($17.12)
Non-Res	0 to 5 MWh	($0.01)	($0.02)	($0.00)	($0.03)
	5 to 10 MWh	($0.04)	($0.03)	($0.00)	($0.08)
	10 to 15 MWh	($0.06)	($0.08)	($0.01)	($0.15)
	15 to 25 MWh	($0.10)	($0.14)	($0.01)	($0.26)
	25 to 35 MWh	($0.10)	($0.15)	($0.02)	($0.28)
	35 to 50 MWh	($0.12)	($0.19)	($0.03)	($0.34)
	50 to 100 MWh	($0.31)	($0.54)	($0.13)	($0.98)
	100 to 500 MWh	($1.42)	($1.98)	($0.68)	($4.08)
	Over 500 MWh	($4.09)	($1.52)	($1.69)	($7.30)
	Average	($6.25)	($4.66)	($2.58)	($13.49)
Overall Average		($16.32)	($9.40)	($4.90)	($30.61)

Table 31: SCT Results by Customer Size, Base Case, 2009 (20-year Annualized $/customer)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($839)	($738)	($601)	($775)
	5 to 10 MWh	($1,081)	($982)	($818)	($1,015)
	10 to 15 MWh	($1,389)	($1,315)	($1,113)	($1,325)
	15 to 25 MWh	($1,783)	($1,799)	($1,447)	($1,735)
	25 to 35 MWh	($2,381)	($2,388)	($1,961)	($2,319)
	35 to 50 MWh	($2,988)	($2,930)	($2,285)	($2,862)
	50 to 100 MWh	($4,542)	($4,545)	($3,386)	($4,342)
	100 to 500 MWh	($14,287)	($7,749)	($19,022)	($11,489)
	Average	($1,487)	($1,611)	($1,163)	($1,463)
Non-Res	0 to 5 MWh	($1,279)	($1,047)	($1,730)	($1,187)
	5 to 10 MWh	($1,471)	($1,335)	($1,434)	($1,411)
	10 to 15 MWh	($1,831)	($1,632)	($1,759)	($1,710)
	15 to 25 MWh	($2,108)	($1,761)	($1,845)	($1,890)
	25 to 35 MWh	($2,560)	($2,331)	($2,983)	($2,451)
	35 to 50 MWh	($3,631)	($2,451)	($3,812)	($2,857)
	50 to 100 MWh	($5,241)	($4,768)	($4,863)	($4,923)
	100 to 500 MWh	($10,886)	($9,902)	($14,303)	($10,792)
	Over 500 MWh	($56,835)	($29,904)	($36,264)	($43,080)
	Average	($13,855)	($6,855)	($17,070)	($10,519)
Overall Average		($2,259)	($2,598)	($2,281)	($2,357)

Table 32: SCT Results by Customer Size, Base Case, 2009 (20-year Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.36)	($0.27)	($0.25)	($0.32)
	5 to 10 MWh	($0.33)	($0.25)	($0.24)	($0.30)
	10 to 15 MWh	($0.31)	($0.24)	($0.23)	($0.28)
	15 to 25 MWh	($0.29)	($0.23)	($0.22)	($0.26)
	25 to 35 MWh	($0.27)	($0.22)	($0.21)	($0.24)
	35 to 50 MWh	($0.26)	($0.21)	($0.20)	($0.23)
	50 to 100 MWh	($0.24)	($0.20)	($0.19)	($0.22)
	100 to 500 MWh	($0.21)	($0.19)	($0.15)	($0.19)
	Average	($0.30)	($0.23)	($0.22)	($0.26)
Non-Res	0 to 5 MWh	($0.40)	($0.48)	($0.27)	($0.41)
	5 to 10 MWh	($0.33)	($0.27)	($0.26)	($0.30)
	10 to 15 MWh	($0.27)	($0.22)	($0.23)	($0.24)
	15 to 25 MWh	($0.24)	($0.20)	($0.21)	($0.21)
	25 to 35 MWh	($0.23)	($0.19)	($0.20)	($0.20)
	35 to 50 MWh	($0.21)	($0.17)	($0.20)	($0.18)
	50 to 100 MWh	($0.19)	($0.16)	($0.19)	($0.17)
	100 to 500 MWh	($0.17)	($0.14)	($0.16)	($0.15)
	Over 500 MWh	($0.15)	($0.12)	($0.14)	($0.14)
	Average	($0.16)	($0.14)	($0.14)	($0.15)
Overall Average		($0.22)	($0.17)	($0.17)	($0.20)

Table 33: SCT Results by Customer Size, Base Case, 2017 (20-year NPV, $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($16.36)	($3.36)	($5.08)	($24.80)
	5 to 10 MWh	($62.08)	($17.41)	($18.33)	($97.82)
	10 to 15 MWh	($62.93)	($26.25)	($19.22)	($108.41)
	15 to 25 MWh	($70.37)	($45.55)	($23.40)	($139.32)
	25 to 35 MWh	($23.96)	($19.61)	($8.68)	($52.25)
	35 to 50 MWh	($10.73)	($8.75)	($3.46)	($22.94)
	50 to 100 MWh	($5.60)	($5.03)	($2.18)	($12.81)
	100 to 500 MWh	($3.35)	($2.54)	($1.08)	($6.97)
	Average	($255.39)	($128.50)	($81.43)	($465.31)
Non-Res	0 to 5 MWh	($0.20)	($0.23)	($0.11)	($0.54)
	5 to 10 MWh	($0.77)	($0.41)	($0.09)	($1.28)
	10 to 15 MWh	($1.04)	($1.00)	($0.15)	($2.18)
	15 to 25 MWh	($1.86)	($1.65)	($0.25)	($3.76)
	25 to 35 MWh	($1.89)	($2.04)	($0.43)	($4.37)
	35 to 50 MWh	($2.10)	($2.44)	($0.63)	($5.17)
	50 to 100 MWh	($5.45)	($7.36)	($2.70)	($15.51)
	100 to 500 MWh	($23.24)	($25.62)	($13.23)	($62.09)
	Over 500 MWh	($73.39)	($18.89)	($30.61)	($122.88)
	Average	($109.94)	($59.64)	($48.20)	($217.78)
Overall Average		($365.32)	($188.14)	($129.63)	($683.09)

Table 34: SCT Results by Customer Size, Base Case, 2017 (20-year Annualized $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($1.07)	($0.22)	($0.33)	($1.62)
	5 to 10 MWh	($4.05)	($1.14)	($1.20)	($6.38)
	10 to 15 MWh	($4.11)	($1.71)	($1.25)	($7.07)
	15 to 25 MWh	($4.59)	($2.97)	($1.53)	($9.09)
	25 to 35 MWh	($1.56)	($1.28)	($0.57)	($3.41)
	35 to 50 MWh	($0.70)	($0.57)	($0.23)	($1.50)
	50 to 100 MWh	($0.37)	($0.33)	($0.14)	($0.84)
	100 to 500 MWh	($0.22)	($0.17)	($0.07)	($0.45)
	Average	($16.67)	($8.39)	($5.31)	($30.37)
Non-Res	0 to 5 MWh	($0.01)	($0.02)	($0.01)	($0.04)
	5 to 10 MWh	($0.05)	($0.03)	($0.01)	($0.08)
	10 to 15 MWh	($0.07)	($0.06)	($0.01)	($0.14)
	15 to 25 MWh	($0.12)	($0.11)	($0.02)	($0.25)
	25 to 35 MWh	($0.12)	($0.13)	($0.03)	($0.28)
	35 to 50 MWh	($0.14)	($0.16)	($0.04)	($0.34)
	50 to 100 MWh	($0.36)	($0.48)	($0.18)	($1.01)
	100 to 500 MWh	($1.52)	($1.67)	($0.86)	($4.05)
	Over 500 MWh	($4.79)	($1.23)	($2.00)	($8.02)
	Average	($7.17)	($3.89)	($3.15)	($14.21)
Overall Average		($23.84)	($12.28)	($8.46)	($44.58)

Table 35: SCT Results by Customer Size, Base Case, 2017 (20-year Annualized $/customer)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($584)	($401)	($358)	($490)
	5 to 10 MWh	($737)	($528)	($478)	($629)
	10 to 15 MWh	($935)	($710)	($641)	($807)
	15 to 25 MWh	($1,180)	($967)	($825)	($1,031)
	25 to 35 MWh	($1,541)	($1,257)	($1,090)	($1,336)
	35 to 50 MWh	($1,903)	($1,512)	($1,243)	($1,615)
	50 to 100 MWh	($2,798)	($2,318)	($1,785)	($2,375)
	100 to 500 MWh	($7,645)	($3,845)	($7,825)	($5,637)
	Average	($987)	($859)	($662)	($877)
Non-Res	0 to 5 MWh	($459)	($275)	($652)	($374)
	5 to 10 MWh	($531)	($358)	($554)	($460)
	10 to 15 MWh	($655)	($394)	($649)	($503)
	15 to 25 MWh	($747)	($412)	($678)	($547)
	25 to 35 MWh	($935)	($625)	($1,135)	($770)
	35 to 50 MWh	($1,301)	($627)	($1,453)	($870)
	50 to 100 MWh	($1,796)	($1,306)	($1,846)	($1,530)
	100 to 500 MWh	($3,511)	($2,573)	($4,959)	($3,226)
	Over 500 MWh	($20,099)	($7,468)	($11,619)	($13,941)
	Average	($4,800)	($1,763)	($5,666)	($3,338)
Overall Average		($1,292)	($1,026)	($986)	($1,144)

Table 36: SCT Results by Customer Size, Base Case, 2017 (20-year Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.25)	($0.15)	($0.15)	($0.20)
	5 to 10 MWh	($0.22)	($0.14)	($0.14)	($0.18)
	10 to 15 MWh	($0.21)	($0.13)	($0.13)	($0.17)
	15 to 25 MWh	($0.19)	($0.12)	($0.13)	($0.15)
	25 to 35 MWh	($0.18)	($0.11)	($0.12)	($0.14)
	35 to 50 MWh	($0.16)	($0.11)	($0.11)	($0.13)
	50 to 100 MWh	($0.15)	($0.10)	($0.10)	($0.12)
	100 to 500 MWh	($0.11)	($0.09)	($0.06)	($0.09)
	Average	($0.19)	($0.12)	($0.13)	($0.15)
Non-Res	0 to 5 MWh	($0.14)	($0.13)	($0.10)	($0.13)
	5 to 10 MWh	($0.12)	($0.07)	($0.10)	($0.10)
	10 to 15 MWh	($0.10)	($0.05)	($0.08)	($0.07)
	15 to 25 MWh	($0.08)	($0.05)	($0.08)	($0.06)
	25 to 35 MWh	($0.08)	($0.05)	($0.08)	($0.06)
	35 to 50 MWh	($0.07)	($0.04)	($0.08)	($0.06)
	50 to 100 MWh	($0.07)	($0.04)	($0.07)	($0.05)
	100 to 500 MWh	($0.05)	($0.04)	($0.05)	($0.04)
	Over 500 MWh	($0.05)	($0.03)	($0.04)	($0.04)
	Average	($0.05)	($0.04)	($0.05)	($0.05)
Overall Average		($0.11)	($0.07)	($0.08)	($0.09)

Table 37: PACT Results by Customer Size, Base Case, 2008 (20-year NPV, $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($1.47)	($0.30)	($0.76)	($2.53)
	5 to 10 MWh	($4.20)	($1.00)	($0.95)	($6.15)
	10 to 15 MWh	($3.28)	($0.93)	($0.59)	($4.80)
	15 to 25 MWh	($2.29)	($0.92)	($0.18)	($3.40)
	25 to 35 MWh	($0.27)	($0.28)	($0.03)	($0.59)
	35 to 50 MWh	$0.11	($0.03)	$0.01	$0.08
	50 to 100 MWh	$0.17	$0.06	$0.01	$0.25
	100 to 500 MWh	$0.17	$0.04	$0.01	$0.23
	Average	($10.85)	($3.35)	($2.50)	($16.71)
Non-Res	0 to 5 MWh	($0.07)	($0.08)	($0.01)	($0.16)
	5 to 10 MWh	($0.20)	($0.11)	($0.01)	($0.32)
	10 to 15 MWh	($0.19)	($0.25)	($0.02)	($0.46)
	15 to 25 MWh	($0.25)	($0.40)	($0.03)	($0.68)
	25 to 35 MWh	($0.22)	($0.32)	($0.02)	($0.56)
	35 to 50 MWh	($0.16)	($0.38)	($0.03)	($0.57)
	50 to 100 MWh	($0.13)	($0.56)	($0.08)	($0.77)
	100 to 500 MWh	$0.90	($1.13)	$0.05	($0.18)
	Over 500 MWh	$5.39	($0.33)	$0.90	$5.96
	Average	$5.07	($3.56)	$0.75	$2.26
Overall Average		($5.78)	($6.91)	($1.75)	($14.45)

Table 38: PACT Results by Customer Size, Base Case, 2008 (20-year Annualized $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.13)	($0.03)	($0.07)	($0.22)
	5 to 10 MWh	($0.36)	($0.09)	($0.08)	($0.52)
	10 to 15 MWh	($0.28)	($0.08)	($0.05)	($0.41)
	15 to 25 MWh	($0.20)	($0.08)	($0.02)	($0.29)
	25 to 35 MWh	($0.02)	($0.02)	($0.00)	($0.05)
	35 to 50 MWh	$0.01	($0.00)	$0.00	$0.01
	50 to 100 MWh	$0.01	$0.01	$0.00	$0.02
	100 to 500 MWh	$0.01	$0.00	$0.00	$0.02
	Average	($0.93)	($0.29)	($0.21)	($1.43)
Non-Res	0 to 5 MWh	($0.01)	($0.01)	($0.00)	($0.01)
	5 to 10 MWh	($0.02)	($0.01)	($0.00)	($0.03)
	10 to 15 MWh	($0.02)	($0.02)	($0.00)	($0.04)
	15 to 25 MWh	($0.02)	($0.03)	($0.00)	($0.06)
	25 to 35 MWh	($0.02)	($0.03)	($0.00)	($0.05)
	35 to 50 MWh	($0.01)	($0.03)	($0.00)	($0.05)
	50 to 100 MWh	($0.01)	($0.05)	($0.01)	($0.07)
	100 to 500 MWh	$0.08	($0.10)	$0.00	($0.02)
	Over 500 MWh	$0.46	($0.03)	$0.08	$0.51
	Average	$0.43	($0.30)	$0.06	$0.19
Overall Average		($0.49)	($0.59)	($0.15)	($1.23)

Table 39: PACT Results by Customer Size, Base Case, 2008 (20-year Annualized $/customer)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($206)	($207)	($693)	($262)
	5 to 10 MWh	($196)	($179)	($318)	($205)
	10 to 15 MWh	($191)	($147)	($255)	($186)
	15 to 25 MWh	($151)	($114)	($84)	($134)
	25 to 35 MWh	($69)	($106)	($54)	($81)
	35 to 50 MWh	$79	($34)	$24	$32
	50 to 100 MWh	$343	$176	$91	$255
	100 to 500 MWh	$1,541	$389	$1,058	$967
	Average	($162)	($131)	($261)	($164)
Non-Res	0 to 5 MWh	($727)	($22,762)	($752)	($1,433)
	5 to 10 MWh	($653)	($22,615)	($745)	($985)
	10 to 15 MWh	($572)	($23,411)	($943)	($1,258)
	15 to 25 MWh	($484)	($23,369)	($797)	($1,172)
	25 to 35 MWh	($512)	($23,198)	($636)	($1,176)
	35 to 50 MWh	($476)	($22,931)	($611)	($1,417)
	50 to 100 MWh	($199)	($23,484)	($592)	($955)
	100 to 500 MWh	$643	($26,810)	$199	($104)
	Over 500 MWh	$6,979	($31,220)	$3,583	$5,759
	Average	$1,046	($24,883)	$922	$390
Overall Average		($81)	($269)	($169)	($134)

Table 40: PACT Results by Customer Size, Base Case, 2008 (20-year Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.09)	($0.08)	($0.29)	($0.11)
	5 to 10 MWh	($0.06)	($0.05)	($0.09)	($0.06)
	10 to 15 MWh	($0.04)	($0.03)	($0.05)	($0.04)
	15 to 25 MWh	($0.02)	($0.01)	($0.01)	($0.02)
	25 to 35 MWh	($0.01)	($0.01)	($0.01)	($0.01)
	35 to 50 MWh	$0.01	($0.00)	$0.00	$0.00
	50 to 100 MWh	$0.02	$0.01	$0.01	$0.01
	100 to 500 MWh	$0.02	$0.01	$0.01	$0.02
	Average	($0.03)	($0.02)	($0.05)	($0.03)
Non-Res	0 to 5 MWh	($0.22)	($10.44)	($0.12)	($0.39)
	5 to 10 MWh	($0.15)	($4.60)	($0.14)	($0.22)
	10 to 15 MWh	($0.09)	($3.16)	($0.12)	($0.19)
	15 to 25 MWh	($0.05)	($2.60)	($0.09)	($0.13)
	25 to 35 MWh	($0.05)	($1.90)	($0.04)	($0.10)
	35 to 50 MWh	($0.03)	($1.57)	($0.03)	($0.08)
	50 to 100 MWh	($0.01)	($0.79)	($0.02)	($0.04)
	100 to 500 MWh	$0.01	($0.37)	$0.00	($0.00)
	Over 500 MWh	$0.02	($0.12)	$0.01	$0.02
	Average	$0.01	($0.50)	$0.01	$0.00
Overall Average		($0.01)	($0.04)	($0.01)	($0.01)

Table 41: PACT Results by Customer Size, Base Case, 2009 (20-year NPV, $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.82)	($0.28)	($1.11)	($2.22)
	5 to 10 MWh	($1.10)	($0.72)	($0.69)	($2.52)
	10 to 15 MWh	$0.33	($0.28)	$0.07	$0.12
	15 to 25 MWh	$2.21	$0.55	$1.11	$3.87
	25 to 35 MWh	$1.44	$0.47	$0.53	$2.44
	35 to 50 MWh	$0.93	$0.35	$0.26	$1.54
	50 to 100 MWh	$0.66	$0.32	$0.19	$1.17
	100 to 500 MWh	$0.59	$0.19	$0.16	$0.93
	Average	$4.94	$0.60	$0.50	$6.04
Non-Res	0 to 5 MWh	($0.06)	($0.15)	($0.01)	($0.22)
	5 to 10 MWh	($0.17)	($0.16)	($0.01)	($0.33)
	10 to 15 MWh	($0.14)	($0.31)	($0.01)	($0.46)
	15 to 25 MWh	($0.14)	($0.34)	($0.01)	($0.49)
	25 to 35 MWh	($0.10)	($0.26)	$0.01	($0.34)
	35 to 50 MWh	($0.01)	($0.13)	$0.03	($0.11)
	50 to 100 MWh	$0.33	$0.13	$0.15	$0.61
	100 to 500 MWh	$3.37	$2.05	$1.85	$7.27
	Over 500 MWh	$13.13	$2.60	$6.50	$22.23
	Average	$16.22	$3.45	$8.49	$28.16
Overall Average		$21.16	$4.05	$9.00	$34.20

Table 42: PACT Results by Customer Size, Base Case, 2009 (20-year Annualized $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.07)	($0.02)	($0.10)	($0.19)
	5 to 10 MWh	($0.09)	($0.06)	($0.06)	($0.21)
	10 to 15 MWh	$0.03	($0.02)	$0.01	$0.01
	15 to 25 MWh	$0.19	$0.05	$0.10	$0.33
	25 to 35 MWh	$0.12	$0.04	$0.04	$0.21
	35 to 50 MWh	$0.08	$0.03	$0.02	$0.13
	50 to 100 MWh	$0.06	$0.03	$0.02	$0.10
	100 to 500 MWh	$0.05	$0.02	$0.01	$0.08
	Average	$0.42	$0.05	$0.04	$0.52
Non-Res	0 to 5 MWh	($0.01)	($0.01)	($0.00)	($0.02)
	5 to 10 MWh	($0.01)	($0.01)	($0.00)	($0.03)
	10 to 15 MWh	($0.01)	($0.03)	($0.00)	($0.04)
	15 to 25 MWh	($0.01)	($0.03)	($0.00)	($0.04)
	25 to 35 MWh	($0.01)	($0.02)	$0.00	($0.03)
	35 to 50 MWh	($0.00)	($0.01)	$0.00	($0.01)
	50 to 100 MWh	$0.03	$0.01	$0.01	$0.05
	100 to 500 MWh	$0.29	$0.18	$0.16	$0.62
	Over 500 MWh	$1.12	$0.22	$0.55	$1.90
	Average	$1.38	$0.29	$0.72	$2.40
Overall Average		$1.81	$0.35	$0.77	$2.92

Table 43: PACT Results by Customer Size, Base Case, 2009 (20-year Annualized $/customer)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($97)	($147)	($414)	($170)
	5 to 10 MWh	($43)	($95)	($95)	($62)
	10 to 15 MWh	$16	($32)	$12	$4
	15 to 25 MWh	$123	$51	$207	$113
	25 to 35 MWh	$307	$131	$348	$249
	35 to 50 MWh	$544	$265	$488	$432
	50 to 100 MWh	$1,095	$641	$808	$875
	100 to 500 MWh	$4,464	$1,235	$5,912	$3,007
	Average	$62	$17	$22	$44
Non-Res	0 to 5 MWh	($606)	($745)	($229)	($651)
	5 to 10 MWh	($508)	($571)	($247)	($521)
	10 to 15 MWh	($382)	($513)	($308)	($456)
	15 to 25 MWh	($246)	($360)	($157)	($309)
	25 to 35 MWh	($214)	($333)	$144	($262)
	35 to 50 MWh	($19)	($139)	$285	($79)
	50 to 100 MWh	$477	$95	$503	$263
	100 to 500 MWh	$2,210	$874	$3,328	$1,642
	Over 500 MWh	$15,587	$4,364	$11,868	$11,193
	Average	$3,069	$432	$4,803	$1,874
Overall Average		$250	$95	$358	$225

Table 44: PACT Results by Customer Size, Base Case, 2009 (20-year Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.04)	($0.05)	($0.17)	($0.07)
	5 to 10 MWh	($0.01)	($0.02)	($0.03)	($0.02)
	10 to 15 MWh	$0.00	($0.01)	$0.00	$0.00
	15 to 25 MWh	$0.02	$0.01	$0.03	$0.02
	25 to 35 MWh	$0.04	$0.01	$0.04	$0.03
	35 to 50 MWh	$0.05	$0.02	$0.04	$0.03
	50 to 100 MWh	$0.06	$0.03	$0.05	$0.04
	100 to 500 MWh	$0.06	$0.03	$0.05	$0.05
	Average	$0.01	$0.00	$0.00	$0.01
Non-Res	0 to 5 MWh	($0.19)	($0.34)	($0.04)	($0.22)
	5 to 10 MWh	($0.11)	($0.12)	($0.05)	($0.11)
	10 to 15 MWh	($0.06)	($0.07)	($0.04)	($0.06)
	15 to 25 MWh	($0.03)	($0.04)	($0.02)	($0.03)
	25 to 35 MWh	($0.02)	($0.03)	$0.01	($0.02)
	35 to 50 MWh	($0.00)	($0.01)	$0.02	($0.01)
	50 to 100 MWh	$0.02	$0.00	$0.02	$0.01
	100 to 500 MWh	$0.03	$0.01	$0.04	$0.02
	Over 500 MWh	$0.04	$0.02	$0.04	$0.04
	Average	$0.03	$0.01	$0.04	$0.03
Overall Average		$0.02	$0.01	$0.03	$0.02

Table 45: PACT Results by Customer Size, Base Case, 2017 (20-year NPV, $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	$6.43	$3.10	$4.18	$13.72
	5 to 10 MWh	$32.37	$18.47	$17.69	$68.53
	10 to 15 MWh	$38.61	$29.84	$20.60	$89.04
	15 to 25 MWh	$49.87	$55.36	$26.78	$132.01
	25 to 35 MWh	$19.65	$26.03	$11.01	$56.69
	35 to 50 MWh	$9.65	$12.45	$4.71	$26.81
	50 to 100 MWh	$5.88	$7.59	$3.29	$16.77
	100 to 500 MWh	$5.02	$4.16	$2.68	$11.87
	Average	$167.48	$157.00	$90.95	$415.44
Non-Res	0 to 5 MWh	$0.16	$0.25	$0.14	$0.54
	5 to 10 MWh	$0.81	$0.83	$0.12	$1.76
	10 to 15 MWh	$1.45	$2.82	$0.25	$4.52
	15 to 25 MWh	$3.15	$5.46	$0.45	$9.06
	25 to 35 MWh	$3.27	$6.03	$0.81	$10.11
	35 to 50 MWh	$4.26	$8.66	$1.20	$14.11
	50 to 100 MWh	$12.88	$25.65	$5.42	$43.96
	100 to 500 MWh	$69.13	$111.24	$37.53	$217.91
	Over 500 MWh	$218.42	$98.19	$109.69	$426.30
	Average	$313.53	$259.13	$155.61	$728.27
Overall Average		$481.02	$416.13	$246.56	$1,143.71

Table 46: PACT Results by Customer Size, Base Case, 2017 (20-year Annualized $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	$0.55	$0.26	$0.36	$1.17
	5 to 10 MWh	$2.76	$1.58	$1.51	$5.85
	10 to 15 MWh	$3.29	$2.55	$1.76	$7.60
	15 to 25 MWh	$4.26	$4.72	$2.29	$11.27
	25 to 35 MWh	$1.68	$2.22	$0.94	$4.84
	35 to 50 MWh	$0.82	$1.06	$0.40	$2.29
	50 to 100 MWh	$0.50	$0.65	$0.28	$1.43
	100 to 500 MWh	$0.43	$0.36	$0.23	$1.01
	Average	$14.29	$13.40	$7.76	$35.45
Non-Res	0 to 5 MWh	$0.01	$0.02	$0.01	$0.05
	5 to 10 MWh	$0.07	$0.07	$0.01	$0.15
	10 to 15 MWh	$0.12	$0.24	$0.02	$0.39
	15 to 25 MWh	$0.27	$0.47	$0.04	$0.77
	25 to 35 MWh	$0.28	$0.51	$0.07	$0.86
	35 to 50 MWh	$0.36	$0.74	$0.10	$1.20
	50 to 100 MWh	$1.10	$2.19	$0.46	$3.75
	100 to 500 MWh	$5.90	$9.49	$3.20	$18.59
	Over 500 MWh	$18.64	$8.38	$9.36	$36.38
	Average	$26.75	$22.11	$13.28	$62.15
Overall Average		$41.05	$35.51	$21.04	$97.60

Table 47: PACT Results by Customer Size, Base Case, 2017 (20-year Annualized $/customer)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	$300	$484	$386	$355
	5 to 10 MWh	$503	$733	$604	$576
	10 to 15 MWh	$750	$1,055	$898	$867
	15 to 25 MWh	$1,093	$1,537	$1,235	$1,278
	25 to 35 MWh	$1,652	$2,183	$1,809	$1,896
	35 to 50 MWh	$2,238	$2,814	$2,213	$2,468
	50 to 100 MWh	$3,844	$4,575	$3,519	$4,064
	100 to 500 MWh	$14,989	$8,245	$25,381	$12,550
	Average	$863	$1,372	$967	$1,029
Non-Res	0 to 5 MWh	$465	$385	$1,097	$490
	5 to 10 MWh	$729	$938	$897	$826
	10 to 15 MWh	$1,195	$1,460	$1,434	$1,362
	15 to 25 MWh	$1,657	$1,782	$1,622	$1,728
	25 to 35 MWh	$2,113	$2,412	$2,781	$2,330
	35 to 50 MWh	$3,449	$2,906	$3,627	$3,105
	50 to 100 MWh	$5,550	$5,951	$4,841	$5,670
	100 to 500 MWh	$13,659	$14,608	$18,401	$14,807
	Over 500 MWh	$78,226	$50,774	$54,441	$63,241
	Average	$17,899	$10,018	$23,922	$14,598
Overall Average		$2,228	$2,967	$2,452	$2,503

Table 48: PACT Results by Customer Size, Base Case, 2017 (20-year Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	$0.13	$0.18	$0.16	$0.15
	5 to 10 MWh	$0.15	$0.19	$0.18	$0.17
	10 to 15 MWh	$0.17	$0.19	$0.18	$0.18
	15 to 25 MWh	$0.18	$0.20	$0.19	$0.19
	25 to 35 MWh	$0.19	$0.20	$0.20	$0.19
	35 to 50 MWh	$0.19	$0.20	$0.20	$0.20
	50 to 100 MWh	$0.20	$0.20	$0.20	$0.20
	100 to 500 MWh	$0.22	$0.20	$0.20	$0.21
	Average	$0.17	$0.20	$0.19	$0.18
Non-Res	0 to 5 MWh	$0.14	$0.18	$0.17	$0.16
	5 to 10 MWh	$0.16	$0.19	$0.17	$0.18
	10 to 15 MWh	$0.18	$0.20	$0.19	$0.19
	15 to 25 MWh	$0.19	$0.20	$0.19	$0.19
	25 to 35 MWh	$0.19	$0.20	$0.19	$0.19
	35 to 50 MWh	$0.19	$0.20	$0.19	$0.20
	50 to 100 MWh	$0.21	$0.20	$0.19	$0.20
	100 to 500 MWh	$0.21	$0.20	$0.20	$0.20
	Over 500 MWh	$0.20	$0.20	$0.20	$0.20
	Average	$0.20	$0.20	$0.20	$0.20
Overall Average		$0.19	$0.20	$0.20	$0.19

Table 49: RIM Results by Customer Size, Base Case, 2008 (20-year NPV, $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($3.82)	($0.85)	($1.15)	($5.82)
	5 to 10 MWh	($22.00)	($5.82)	($3.43)	($31.25)
	10 to 15 MWh	($29.90)	($10.84)	($4.57)	($45.32)
	15 to 25 MWh	($36.88)	($22.08)	($5.98)	($64.95)
	25 to 35 MWh	($13.95)	($10.98)	($2.44)	($27.37)
	35 to 50 MWh	($6.48)	($5.23)	($1.04)	($12.75)
	50 to 100 MWh	($3.58)	($3.18)	($0.71)	($7.47)
	100 to 500 MWh	($2.73)	($1.76)	($0.57)	($5.06)
	Average	($122.31)	($60.74)	($19.91)	($202.96)
Non-Res	0 to 5 MWh	($0.12)	($0.08)	($0.02)	($0.22)
	5 to 10 MWh	($0.45)	($0.11)	($0.03)	($0.59)
	10 to 15 MWh	($0.59)	($0.26)	($0.04)	($0.89)
	15 to 25 MWh	($1.10)	($0.42)	($0.08)	($1.59)
	25 to 35 MWh	($1.12)	($0.34)	($0.11)	($1.58)
	35 to 50 MWh	($1.27)	($0.41)	($0.17)	($1.85)
	50 to 100 MWh	($3.23)	($0.65)	($0.69)	($4.57)
	100 to 500 MWh	($13.70)	($1.45)	($3.26)	($18.41)
	Over 500 MWh	($41.47)	($0.61)	($11.82)	($53.90)
	Average	($63.04)	($4.33)	($16.22)	($83.59)
Overall Average		($185.36)	($65.07)	($36.13)	($286.55)

Table 50: RIM Results by Customer Size, Base Case, 2008 (20-year Annualized $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.33)	($0.07)	($0.10)	($0.50)
	5 to 10 MWh	($1.88)	($0.50)	($0.29)	($2.67)
	10 to 15 MWh	($2.55)	($0.93)	($0.39)	($3.87)
	15 to 25 MWh	($3.15)	($1.88)	($0.51)	($5.54)
	25 to 35 MWh	($1.19)	($0.94)	($0.21)	($2.34)
	35 to 50 MWh	($0.55)	($0.45)	($0.09)	($1.09)
	50 to 100 MWh	($0.31)	($0.27)	($0.06)	($0.64)
	100 to 500 MWh	($0.23)	($0.15)	($0.05)	($0.43)
	Average	($10.44)	($5.18)	($1.70)	($17.32)
Non-Res	0 to 5 MWh	($0.01)	($0.01)	($0.00)	($0.02)
	5 to 10 MWh	($0.04)	($0.01)	($0.00)	($0.05)
	10 to 15 MWh	($0.05)	($0.02)	($0.00)	($0.08)
	15 to 25 MWh	($0.09)	($0.04)	($0.01)	($0.14)
	25 to 35 MWh	($0.10)	($0.03)	($0.01)	($0.13)
	35 to 50 MWh	($0.11)	($0.03)	($0.01)	($0.16)
	50 to 100 MWh	($0.28)	($0.06)	($0.06)	($0.39)
	100 to 500 MWh	($1.17)	($0.12)	($0.28)	($1.57)
	Over 500 MWh	($3.54)	($0.05)	($1.01)	($4.60)
	Average	($5.38)	($0.37)	($1.38)	($7.13)
Overall Average		($15.82)	($5.55)	($3.08)	($24.45)

Table 51: RIM Results by Customer Size, Base Case, 2008 (20-year Annualized $/customer)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($536)	($595)	($1,045)	($602)
	5 to 10 MWh	($1,027)	($1,035)	($1,151)	($1,041)
	10 to 15 MWh	($1,745)	($1,720)	($1,961)	($1,759)
	15 to 25 MWh	($2,430)	($2,750)	($2,714)	($2,556)
	25 to 35 MWh	($3,525)	($4,129)	($3,944)	($3,783)
	35 to 50 MWh	($4,519)	($5,301)	($4,802)	($4,834)
	50 to 100 MWh	($7,028)	($8,609)	($7,438)	($7,668)
	100 to 500 MWh	($24,486)	($15,590)	($53,001)	($21,527)
	Average	($1,828)	($2,381)	($2,081)	($1,990)
Non-Res	0 to 5 MWh	($1,280)	($23,152)	($1,458)	($2,003)
	5 to 10 MWh	($1,454)	($23,316)	($1,617)	($1,789)
	10 to 15 MWh	($1,745)	($24,373)	($1,933)	($2,413)
	15 to 25 MWh	($2,082)	($24,657)	($2,335)	($2,758)
	25 to 35 MWh	($2,624)	($24,757)	($3,049)	($3,295)
	35 to 50 MWh	($3,724)	($24,792)	($4,107)	($4,633)
	50 to 100 MWh	($5,036)	($27,192)	($4,951)	($5,676)
	100 to 500 MWh	($9,788)	($34,461)	($12,794)	($10,851)
	Over 500 MWh	($53,711)	($56,995)	($47,000)	($52,113)
	Average	($13,015)	($30,304)	($19,980)	($14,416)
Overall Average		($2,584)	($2,536)	($3,481)	($2,659)

Table 52: RIM Results by Customer Size, Base Case, 2008 (20-year Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.23)	($0.22)	($0.43)	($0.25)
	5 to 10 MWh	($0.31)	($0.27)	($0.34)	($0.30)
	10 to 15 MWh	($0.39)	($0.32)	($0.40)	($0.37)
	15 to 25 MWh	($0.40)	($0.35)	($0.42)	($0.38)
	25 to 35 MWh	($0.40)	($0.37)	($0.43)	($0.39)
	35 to 50 MWh	($0.39)	($0.38)	($0.43)	($0.39)
	50 to 100 MWh	($0.37)	($0.38)	($0.42)	($0.38)
	100 to 500 MWh	($0.35)	($0.38)	($0.42)	($0.37)
	Average	($0.37)	($0.34)	($0.40)	($0.36)
Non-Res	0 to 5 MWh	($0.40)	($10.62)	($0.23)	($0.55)
	5 to 10 MWh	($0.33)	($4.74)	($0.30)	($0.40)
	10 to 15 MWh	($0.26)	($3.29)	($0.25)	($0.36)
	15 to 25 MWh	($0.23)	($2.74)	($0.27)	($0.31)
	25 to 35 MWh	($0.23)	($2.03)	($0.21)	($0.28)
	35 to 50 MWh	($0.21)	($1.69)	($0.22)	($0.26)
	50 to 100 MWh	($0.19)	($0.92)	($0.20)	($0.21)
	100 to 500 MWh	($0.15)	($0.48)	($0.14)	($0.16)
	Over 500 MWh	($0.14)	($0.23)	($0.18)	($0.15)
	Average	($0.15)	($0.61)	($0.17)	($0.16)
Overall Average		($0.24)	($0.35)	($0.25)	($0.26)

Table 53: RIM Results by Customer Size, Base Case, 2009 (20-year NPV, $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($3.72)	($1.07)	($2.10)	($6.89)
	5 to 10 MWh	($23.03)	($7.46)	($7.00)	($37.49)
	10 to 15 MWh	($32.45)	($14.16)	($10.03)	($56.64)
	15 to 25 MWh	($40.38)	($29.09)	($13.61)	($83.07)
	25 to 35 MWh	($15.40)	($14.51)	($5.58)	($35.49)
	35 to 50 MWh	($7.20)	($6.92)	($2.39)	($16.51)
	50 to 100 MWh	($3.96)	($4.23)	($1.63)	($9.82)
	100 to 500 MWh	($2.98)	($2.33)	($1.32)	($6.63)
	Average	($132.32)	($79.77)	($43.68)	($255.77)
Non-Res	0 to 5 MWh	($0.12)	($0.23)	($0.03)	($0.38)
	5 to 10 MWh	($0.45)	($0.36)	($0.04)	($0.85)
	10 to 15 MWh	($0.59)	($0.91)	($0.06)	($1.55)
	15 to 25 MWh	($1.10)	($1.60)	($0.13)	($2.83)
	25 to 35 MWh	($1.12)	($1.50)	($0.19)	($2.82)
	35 to 50 MWh	($1.26)	($1.91)	($0.30)	($3.47)
	50 to 100 MWh	($3.18)	($4.99)	($1.23)	($9.40)
	100 to 500 MWh	($13.17)	($16.61)	($5.63)	($35.41)
	Over 500 MWh	($39.95)	($13.35)	($22.26)	($75.56)
	Average	($60.94)	($41.45)	($29.88)	($132.28)
Overall Average		($193.26)	($121.22)	($73.56)	($388.04)

Table 54: RIM Results by Customer Size, Base Case, 2009 (20-year Annualized $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.32)	($0.09)	($0.18)	($0.59)
	5 to 10 MWh	($1.97)	($0.64)	($0.60)	($3.20)
	10 to 15 MWh	($2.77)	($1.21)	($0.86)	($4.83)
	15 to 25 MWh	($3.45)	($2.48)	($1.16)	($7.09)
	25 to 35 MWh	($1.31)	($1.24)	($0.48)	($3.03)
	35 to 50 MWh	($0.61)	($0.59)	($0.20)	($1.41)
	50 to 100 MWh	($0.34)	($0.36)	($0.14)	($0.84)
	100 to 500 MWh	($0.25)	($0.20)	($0.11)	($0.57)
	Average	($11.29)	($6.81)	($3.73)	($21.83)
Non-Res	0 to 5 MWh	($0.01)	($0.02)	($0.00)	($0.03)
	5 to 10 MWh	($0.04)	($0.03)	($0.00)	($0.07)
	10 to 15 MWh	($0.05)	($0.08)	($0.01)	($0.13)
	15 to 25 MWh	($0.09)	($0.14)	($0.01)	($0.24)
	25 to 35 MWh	($0.10)	($0.13)	($0.02)	($0.24)
	35 to 50 MWh	($0.11)	($0.16)	($0.03)	($0.30)
	50 to 100 MWh	($0.27)	($0.43)	($0.10)	($0.80)
	100 to 500 MWh	($1.12)	($1.42)	($0.48)	($3.02)
	Over 500 MWh	($3.41)	($1.14)	($1.90)	($6.45)
	Average	($5.20)	($3.54)	($2.55)	($11.29)
Overall Average		($16.49)	($10.34)	($6.28)	($33.11)

Table 55: RIM Results by Customer Size, Base Case, 2009 (20-year Annualized $/customer)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($440)	($553)	($780)	($527)
	5 to 10 MWh	($906)	($985)	($960)	($931)
	10 to 15 MWh	($1,597)	($1,665)	($1,759)	($1,641)
	15 to 25 MWh	($2,243)	($2,685)	($2,524)	($2,427)
	25 to 35 MWh	($3,281)	($4,045)	($3,690)	($3,624)
	35 to 50 MWh	($4,229)	($5,202)	($4,522)	($4,636)
	50 to 100 MWh	($6,557)	($8,478)	($7,009)	($7,353)
	100 to 500 MWh	($22,555)	($15,353)	($50,208)	($21,373)
	Average	($1,668)	($2,318)	($1,868)	($1,865)
Non-Res	0 to 5 MWh	($1,184)	($1,152)	($977)	($1,144)
	5 to 10 MWh	($1,342)	($1,301)	($1,154)	($1,314)
	10 to 15 MWh	($1,602)	($1,518)	($1,340)	($1,540)
	15 to 25 MWh	($1,907)	($1,699)	($1,753)	($1,776)
	25 to 35 MWh	($2,407)	($1,953)	($2,370)	($2,139)
	35 to 50 MWh	($3,393)	($2,078)	($3,349)	($2,515)
	50 to 100 MWh	($4,546)	($3,754)	($4,031)	($4,028)
	100 to 500 MWh	($8,621)	($7,074)	($10,164)	($7,994)
	Over 500 MWh	($47,416)	($22,394)	($40,654)	($38,041)
	Average	($11,529)	($5,198)	($16,903)	($8,802)
Overall Average		($2,283)	($2,860)	($2,925)	($2,550)

Table 56: RIM Results by Customer Size, Base Case, 2009 (20-year Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.19)	($0.20)	($0.32)	($0.22)
	5 to 10 MWh	($0.27)	($0.25)	($0.28)	($0.27)
	10 to 15 MWh	($0.36)	($0.31)	($0.36)	($0.34)
	15 to 25 MWh	($0.37)	($0.34)	($0.39)	($0.36)
	25 to 35 MWh	($0.37)	($0.37)	($0.40)	($0.38)
	35 to 50 MWh	($0.37)	($0.37)	($0.40)	($0.37)
	50 to 100 MWh	($0.35)	($0.37)	($0.40)	($0.37)
	100 to 500 MWh	($0.32)	($0.38)	($0.40)	($0.36)
	Average	($0.33)	($0.33)	($0.36)	($0.34)
Non-Res	0 to 5 MWh	($0.37)	($0.53)	($0.15)	($0.39)
	5 to 10 MWh	($0.30)	($0.26)	($0.21)	($0.28)
	10 to 15 MWh	($0.24)	($0.20)	($0.17)	($0.22)
	15 to 25 MWh	($0.21)	($0.19)	($0.20)	($0.20)
	25 to 35 MWh	($0.21)	($0.16)	($0.16)	($0.18)
	35 to 50 MWh	($0.19)	($0.14)	($0.18)	($0.16)
	50 to 100 MWh	($0.17)	($0.13)	($0.16)	($0.14)
	100 to 500 MWh	($0.13)	($0.10)	($0.11)	($0.11)
	Over 500 MWh	($0.12)	($0.09)	($0.15)	($0.12)
	Average	($0.13)	($0.10)	($0.14)	($0.12)
Overall Average		($0.22)	($0.19)	($0.22)	($0.21)

Table 57: RIM Results by Customer Size, Base Case, 2017 (20-year NPV, $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($3.22)	($0.34)	($1.04)	($4.60)
	5 to 10 MWh	($39.64)	($10.63)	($15.24)	($65.51)
	10 to 15 MWh	($68.98)	($29.97)	($32.04)	($130.98)
	15 to 25 MWh	($89.87)	($72.27)	($49.91)	($212.05)
	25 to 35 MWh	($35.62)	($38.47)	($20.82)	($94.91)
	35 to 50 MWh	($17.01)	($18.88)	($9.11)	($45.00)
	50 to 100 MWh	($9.28)	($12.00)	($6.18)	($27.47)
	100 to 500 MWh	($6.70)	($6.68)	($5.00)	($18.39)
	Average	($270.33)	($189.24)	($139.33)	($598.90)
Non-Res	0 to 5 MWh	($0.10)	($0.10)	$0.01	($0.19)
	5 to 10 MWh	($0.40)	($0.02)	($0.04)	($0.46)
	10 to 15 MWh	($0.48)	$0.25	$0.01	($0.22)
	15 to 25 MWh	($0.95)	$0.13	($0.12)	($0.95)
	25 to 35 MWh	($1.13)	$0.74	($0.15)	($0.54)
	35 to 50 MWh	($1.15)	$1.07	($0.36)	($0.44)
	50 to 100 MWh	($2.23)	$4.17	($1.20)	$0.74
	100 to 500 MWh	($1.88)	$32.67	$1.85	$32.64
	Over 500 MWh	($9.38)	$31.15	($27.46)	($5.69)
	Average	($17.71)	$70.05	($27.46)	$24.89
Overall Average		($288.04)	($119.18)	($166.79)	($574.01)

Table 58: RIM Results by Customer Size, Base Case, 2017 (20-year Annualized $M)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.28)	($0.03)	($0.09)	($0.39)
	5 to 10 MWh	($3.38)	($0.91)	($1.30)	($5.59)
	10 to 15 MWh	($5.89)	($2.56)	($2.73)	($11.18)
	15 to 25 MWh	($7.67)	($6.17)	($4.26)	($18.10)
	25 to 35 MWh	($3.04)	($3.28)	($1.78)	($8.10)
	35 to 50 MWh	($1.45)	($1.61)	($0.78)	($3.84)
	50 to 100 MWh	($0.79)	($1.02)	($0.53)	($2.34)
	100 to 500 MWh	($0.57)	($0.57)	($0.43)	($1.57)
	Average	($23.07)	($16.15)	($11.89)	($51.11)
Non-Res	0 to 5 MWh	($0.01)	($0.01)	$0.00	($0.02)
	5 to 10 MWh	($0.03)	($0.00)	($0.00)	($0.04)
	10 to 15 MWh	($0.04)	$0.02	$0.00	($0.02)
	15 to 25 MWh	($0.08)	$0.01	($0.01)	($0.08)
	25 to 35 MWh	($0.10)	$0.06	($0.01)	($0.05)
	35 to 50 MWh	($0.10)	$0.09	($0.03)	($0.04)
	50 to 100 MWh	($0.19)	$0.36	($0.10)	$0.06
	100 to 500 MWh	($0.16)	$2.79	$0.16	$2.78
	Over 500 MWh	($0.80)	$2.66	($2.34)	($0.49)
	Average	($1.51)	$5.98	($2.34)	$2.12
Overall Average		($24.58)	($10.17)	($14.23)	($48.98)

Table 59: RIM Results by Customer Size, Base Case, 2017 (20-year Annualized $/customer)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($151)	($52)	($96)	($119)
	5 to 10 MWh	($616)	($422)	($520)	($551)
	10 to 15 MWh	($1,340)	($1,060)	($1,397)	($1,276)
	15 to 25 MWh	($1,970)	($2,007)	($2,302)	($2,053)
	25 to 35 MWh	($2,995)	($3,226)	($3,421)	($3,174)
	35 to 50 MWh	($3,944)	($4,269)	($4,277)	($4,142)
	50 to 100 MWh	($6,065)	($7,234)	($6,605)	($6,658)
	100 to 500 MWh	($20,004)	($13,236)	($47,290)	($19,441)
	Average	($1,379)	($1,654)	($1,482)	($1,479)
Non-Res	0 to 5 MWh	($301)	($153)	$57	($174)
	5 to 10 MWh	($360)	($23)	($290)	($215)
	10 to 15 MWh	($399)	$127	$77	($68)
	15 to 25 MWh	($501)	$43	($445)	($180)
	25 to 35 MWh	($728)	$297	($512)	($124)
	35 to 50 MWh	($930)	$359	($1,102)	($97)
	50 to 100 MWh	($962)	$966	($1,068)	$95
	100 to 500 MWh	($372)	$4,290	$907	$2,218
	Over 500 MWh	($3,360)	$16,106	($13,627)	($844)
	Average	($1,011)	$2,708	($4,221)	$499
Overall Average		($1,349)	($850)	($1,659)	($1,264)

Table 60: RIM Results by Customer Size, Base Case, 2017 (20-year Levelized $/kWh-generated)

	Customer Size	PG&E	SCE	SDG&E	All IOU Average
Residential	0 to 5 MWh	($0.06)	($0.02)	($0.04)	($0.05)
	5 to 10 MWh	($0.19)	($0.11)	($0.15)	($0.16)
	10 to 15 MWh	($0.30)	($0.19)	($0.29)	($0.26)
	15 to 25 MWh	($0.32)	($0.26)	($0.35)	($0.30)
	25 to 35 MWh	($0.34)	($0.29)	($0.37)	($0.33)
	35 to 50 MWh	($0.34)	($0.30)	($0.38)	($0.33)
	50 to 100 MWh	($0.32)	($0.32)	($0.37)	($0.33)
	100 to 500 MWh	($0.29)	($0.32)	($0.38)	($0.32)
	Average	($0.28)	($0.24)	($0.28)	($0.26)
Non-Res	0 to 5 MWh	($0.09)	($0.07)	$0.01	($0.06)
	5 to 10 MWh	($0.08)	($0.00)	($0.05)	($0.05)
	10 to 15 MWh	($0.06)	$0.02	$0.01	($0.01)
	15 to 25 MWh	($0.06)	$0.00	($0.05)	($0.02)
	25 to 35 MWh	($0.06)	$0.02	($0.04)	($0.01)
	35 to 50 MWh	($0.05)	$0.02	($0.06)	($0.01)
	50 to 100 MWh	($0.04)	$0.03	($0.04)	$0.00
	100 to 500 MWh	($0.01)	$0.06	$0.01	$0.03
	Over 500 MWh	($0.01)	$0.06	($0.05)	($0.00)
	Average	($0.01)	$0.05	($0.04)	$0.01
Overall Average		($0.12)	($0.06)	($0.13)	($0.10)

APPENDIX B:

AVOIDED COSTS

1. Methodology for Determining Utility Avoided Cost

1.1. Overview

The avoided cost methodology described below provides a transparent method to value net energy production from distributed generation using a time-differentiated cost-basis. This appendix provides the background and methodology underlying the conclusions in the costs and benefits of net energy metering. The utility avoided costs represent the benefit of the net energy metering program.

The electricity produced by distributed generation has significantly different avoided cost value depending on the time (and location) of delivery to the grid. The value of electricity production varies considerably day to night, and season to season. Furthermore, because of the regional differences in weather and overall energy usage patterns, the relative value of producing energy at different times varies for different regions of the California. The time and location based avoided cost methodology reflects this complexity.

1.2. Approach

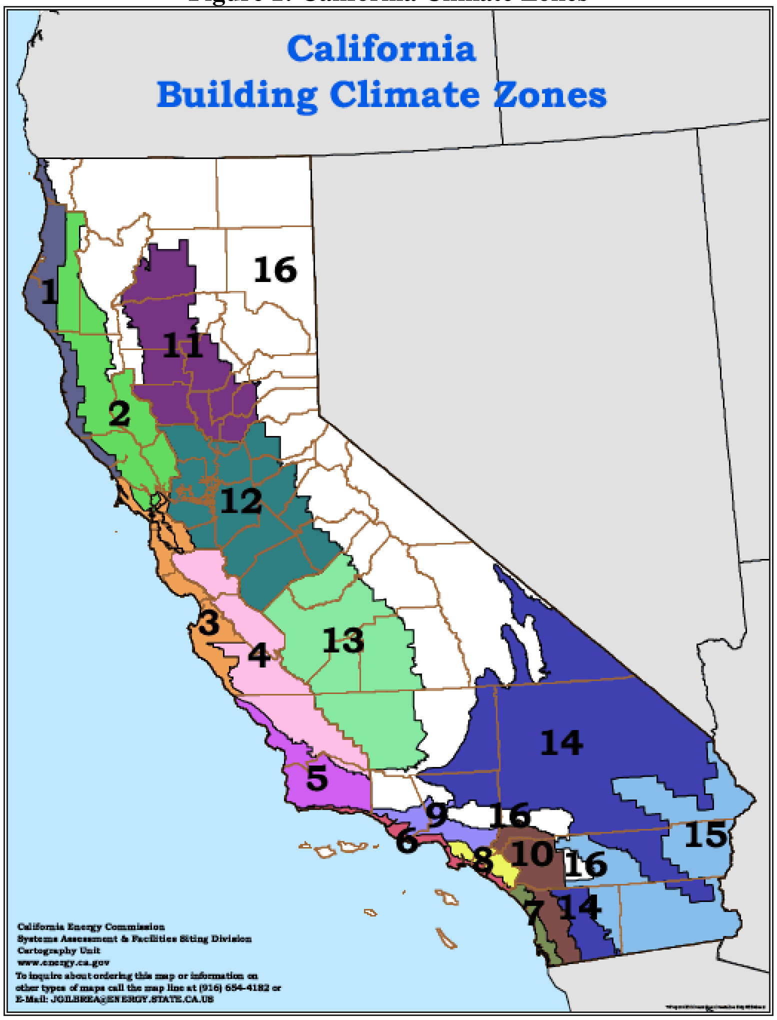
By using a cost-based approach, valuation of net energy production reflects the underlying marginal utility costs. The avoided costs evaluate the total hourly marginal cost of delivering electricity to the grid by adding together seven individual components that contribute to cost of serving load. The cost components include generation energy, losses, ancillary services, generation capacity, transmission and distribution capacity, environmental costs, and avoided renewable purchases. The utility avoided cost value is calculated as the sum in each hour of the seven individual components.

1.3. Methodology

1.3.1. Climate Zones

In each hour, the value of electricity delivered to the grid depends on the point of delivery. The DG Cost-effectiveness Framework adopts the sixteen California climate zones defined by the Title 24 building standards in order to differentiate between the value of electricity in different regions in the California. These climate zones group together areas with similar climates, temperature profiles, and energy use patterns in order to differentiate regions in a manner that captures the effects of weather on energy use. Figure 1 is a map of the climate zones in California.

Figure 1: California Climate Zones



Each climate zone has a single representative city, which is specified by the California Energy Commission. These cities are listed in

Table 1. Hourly avoided costs are calculated for each climate zone.

Table 1: Representative cities for California Climate Zones

Climate Zone	Utility Territory	Representative City
CEC Zone 1	PG&E	Arcata
CEC Zone 2	PG&E	Santa Rosa
CEC Zone 3	PG&E	Oakland
CEC Zone 4	PG&E	Sunnyvale
CEC Zone 5	PG&E/SCE	Santa Maria
CEC Zone 6	SCE	Los Angeles
CEC Zone 7	SDG&E	San Diego
CEC Zone 8	SCE	El Toro
CEC Zone 9	SCE	Pasadena
CEC Zone 10	SCE/SDG&E	Riverside
CEC Zone 11	PG&E	Red Bluff
CEC Zone 12	PG&E	Sacramento
CEC Zone 13	PG&E	Fresno
CEC Zone 14	SCE/SDG&E	China Lake
CEC Zone 15	SCE/SDG&E	El Centro
CEC Zone 16	PG&E/SCE	Mount Shasta

1.3.2. Overview of Avoided Cost Components

For each of the climate zones, E3 estimate the total hourly marginal cost of delivering electricity to the building site as a sum of individual components, which are described in

Table 2.

Table 2: Components of marginal energy cost

Component	Description
Generation Energy	Estimate of hourly wholesale value of energy measured at the point of wholesale energy transaction
Losses	Losses between the delivery location and the point of wholesale energy transaction
Ancillary Services	The costs of providing system operations and reserves for electricity grid reliability
System Capacity	The costs of building new generation capacity to meet system peak loads
T&D Capacity	The costs of expanding transmission and distribution capacity to meet peak loads
Environment	The cost of CO2 associated with electricity generation
Avoided RPS	The cost of purchasing renewable resources to meet an RPS Portfolio that is a percentage of total retail sales

In the value calculation, each of these components is estimated for each hour in a typical year and forecasted into the future for 30 years. The hourly granularity of the avoided costs is obtained by shaping forecasts of the average value of each component with hourly curves meant to replicate actual trends in wholesale energy markets and loads; Table 3 summarizes the methodology applied to each component to develop this level of granularity.

Table 3: Summary of methodology for avoided cost component forecasts

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	Combination of market forwards through 2014 and a long-run forecast of California gas prices through 2040	Hourly curve developed through analysis of historical spot market prices, gas prices, and system loads
Losses	Scales with the value of energy	Scales with value of energy; losses factors also vary by TOU period
System Capacity	Fixed costs of a new simple-cycle combustion turbine, less net revenue from energy and AS markets	Hourly allocation factors calculated as a proxy for rLOLP based on 2008 CAISO hourly system loads
Ancillary Services	Historical prices for A/S products scaled with price of gas	Historical A/S market shapes
T&D Capacity	Survey of utility transmission and distribution deferral values from general rate cases	Hourly allocation factors calculated using hourly temperature data as a proxy for local area load
Environment	Synapse Mid-Level carbon forecast developed for use in electricity sector IRPs	Directly linked with energy shape with bounds on the maximum and minimum hourly value
Avoided RPS	Cost of a marginal renewable resource less the energy and capacity value associated with that resource	Flat across all hours

The hourly time scale used in this approach is an important feature of the avoided costs used in the DG Cost-effectiveness framework for two reasons:

1. Hourly costs capture the extremely high marginal value of electricity during the top several hundred load hours of the year; and

2. Hourly costs can be matched against historical hourly generation data from actual metered PV systems, allowing for a robust analysis of the value of different distributed generation technologies.

Figure 2 shows a three-day snapshot of the components of the hourly avoided costs in the summer in CZ13. As shown, the marginal cost of serving load can be significantly higher in the summer afternoons than in the very early morning hours. This chart also shows the relative magnitude of different components in this region in the summer for these days. The highest peaks of total cost shown in Figure 2 of almost $1,000/MWh are driven by higher energy market costs, higher losses, and allocation of the capacity costs of generation, transmission and distribution to the highest load hours.

Figure 2: Three-day snapshot of energy values in CZ13

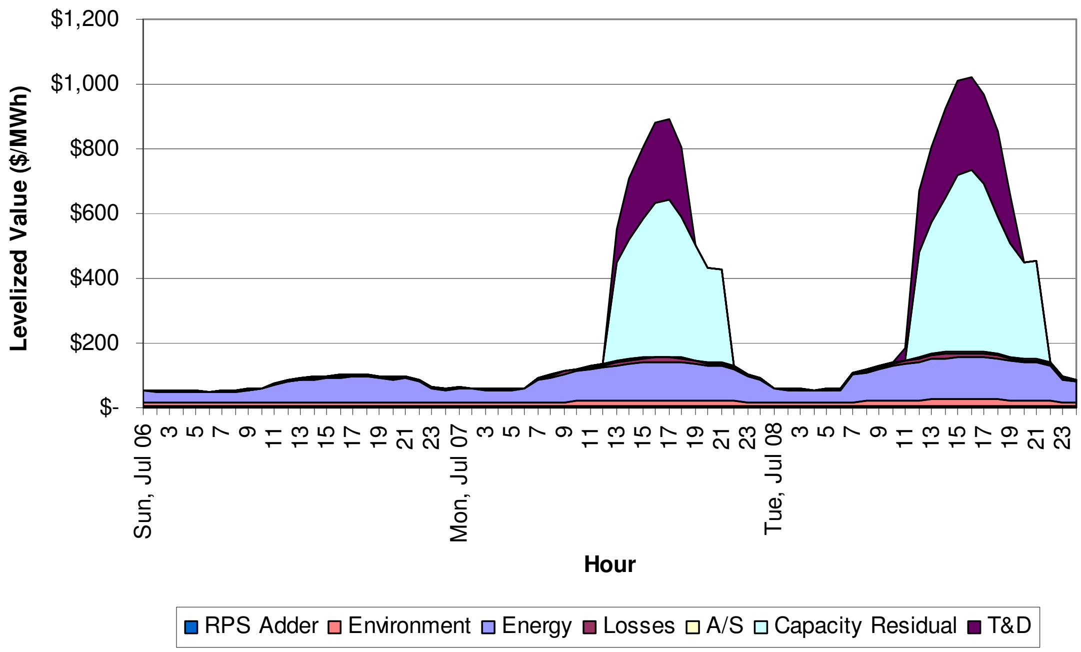


Figure 3 shows the annual chronological set of estimated values for CZ13 for an entire year. The several hundred notable spikes in value align with the hours where CAISO and local loads are expected to peak and are caused by the costs of adding generation and T&D capacity to deliver electricity in these hours.

Figure 3: Annual levelized energy values for CZ13

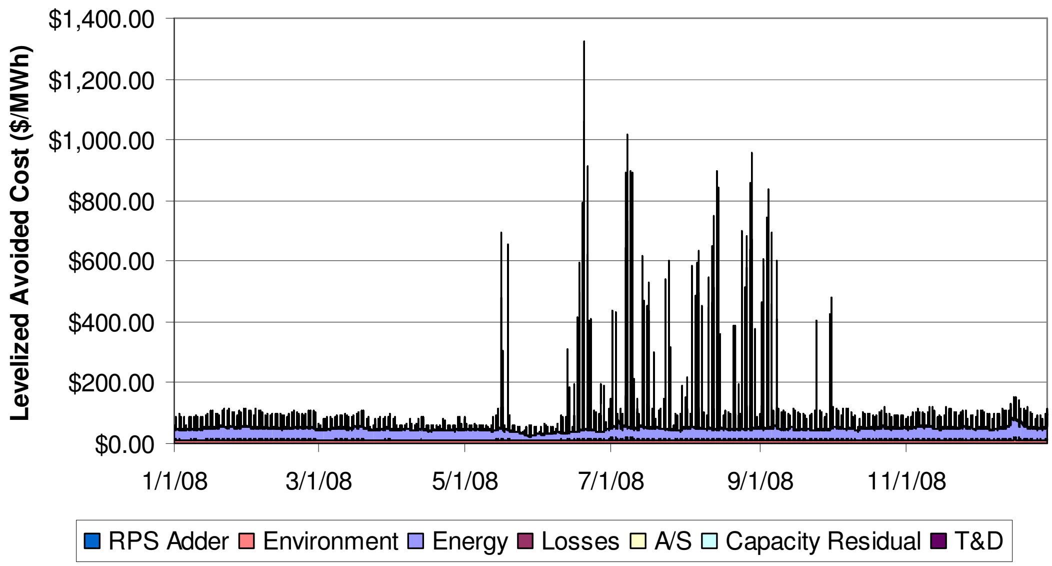
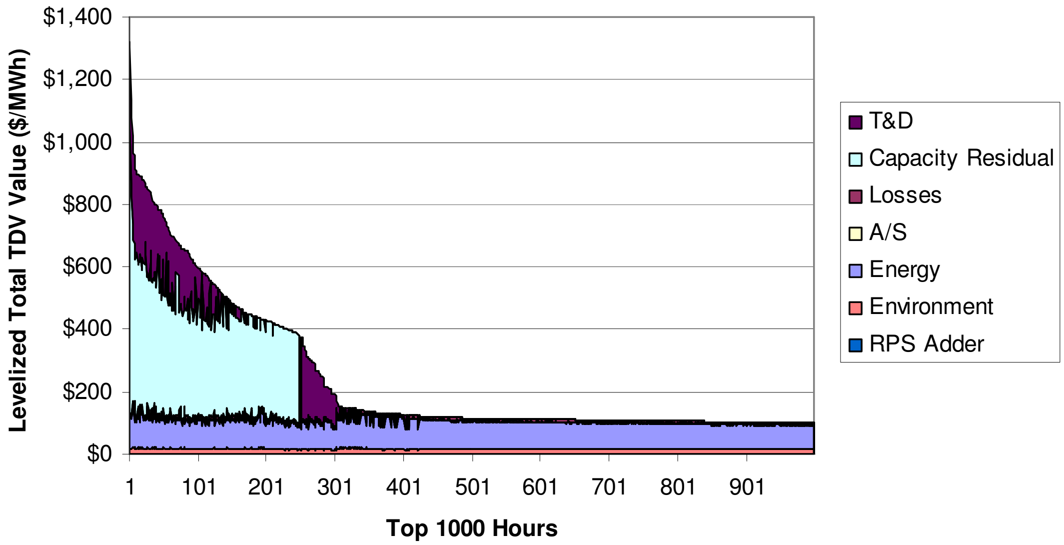


Figure 4 shows the components of value for the highest value hours in descending order of cost. This chart shows the relative contribution to the highest hours of the year by component. Note that most of the high cost hours occur in approximately the top 200 to 400 hours. This is true in all regions in California evaluated due to the allocation of capacity costs to a limited number of hours, though the timing and magnitude vary by location.

Figure 4: Price duration curve showing top 1000 hours for CZ13

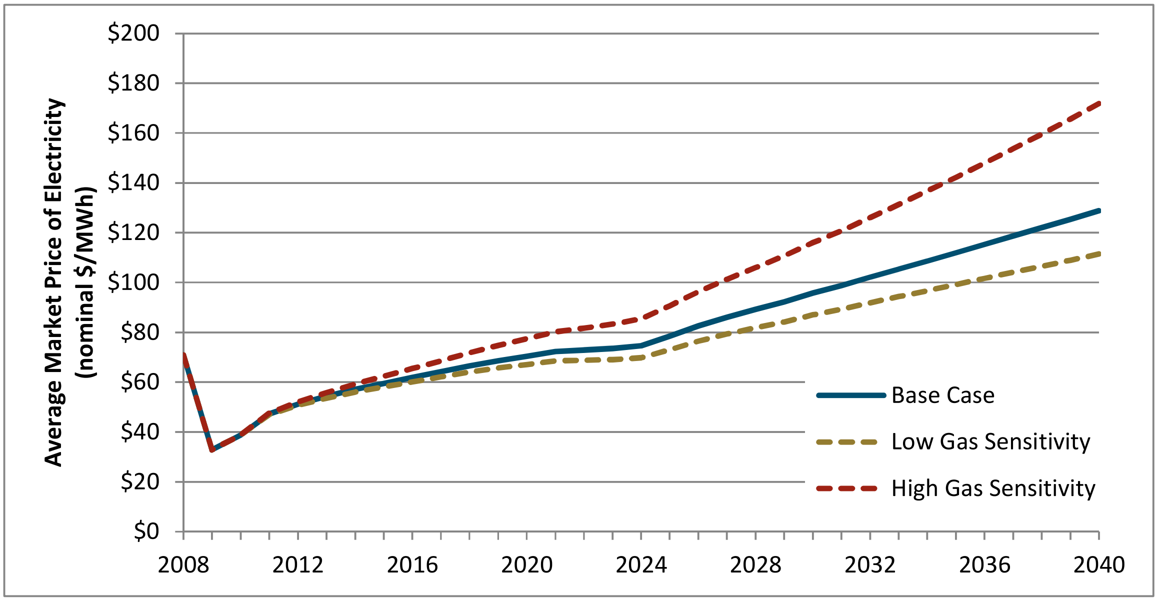


1.3.3. Energy Generation

The forecast of the avoided cost of energy includes both a short-run and a long-run component; the transition between the two occurs in the resource balance year. The short-run forecast is based upon historical market spot prices (2008-2009) and forwards curves (2010-2014) for NP15 and SP15. The long-run forecast, which begins in 2015, is based upon the implied market heat rate of the final year of the electricity forward curve.[1] The resulting forecast of market prices, shown in Figure 5, represents the average value of avoiding a unit of generation in a given year.

[1] Based on the set of forward market data used in this analysis, the average long-run implied market heat rate is 8,025 Btu/kWh.

Figure 5: Forecast of average market electricity prices



To capture the differing marginal costs of generation at different times of day and across different seasons, E3 develops a proxy hourly shape meant to mimic the movements of the wholesale energy market in California. Because the hourly avoided costs are being matched against actual PV output data and both are highly weather-correlated, the hourly price shape preserves the daily and hourly variability of actual historical wholesale markets during the periods for which PV data is available.

The hourly price shape is derived from historical spot prices in the gas and electricity markets, expected monthly trends in the gas forward curve, and hourly loads in the CAISO. Using data from historical spot markets, E3 calculated the average monthly market heat rate for each month from 2003-2008 for both NP15 and SP15 price points. These calculated heat rates were used to derive the monthly heat rate shapes shown in Table 4.

Table 4. Monthly heat rate, gas, and electricity shapes used to derive the hourly price shapes for the wholesale markets.

Month	NP15 Market Heat Rate (% of Annual Average)[2]	SP15 Market Heat Rate (% of Annual Average[3]	Gas Price (% of Annual Average)[4]	NP15 Market Price (% of Annual Average	SP15 Market Price (% of Annual Average
Jan	94.9%	93.6%	106.8%	101.4%	100.0%
Feb	99.0%	96.8%	106.7%	105.7%	103.3%
Mar	92.1%	92.6%	103.7%	95.4%	96.0%
Apr	91.9%	93.2%	94.5%	86.8%	88.0%
May	88.8%	90.2%	93.9%	83.3%	84.7%
Jun	92.0%	91.0%	95.0%	87.4%	86.5%
Jul	117.2%	115.3%	96.4%	113.0%	111.1%
Aug	109.5%	107.3%	97.4%	106.6%	104.5%
Sep	106.5%	106.4%	97.8%	104.1%	104.1%
Oct	104.1%	106.7%	99.0%	103.1%	105.6%
Nov	102.0%	106.6%	102.4%	104.5%	109.2%
Dec	102.1%	100.4%	106.4%	108.7%	106.9%

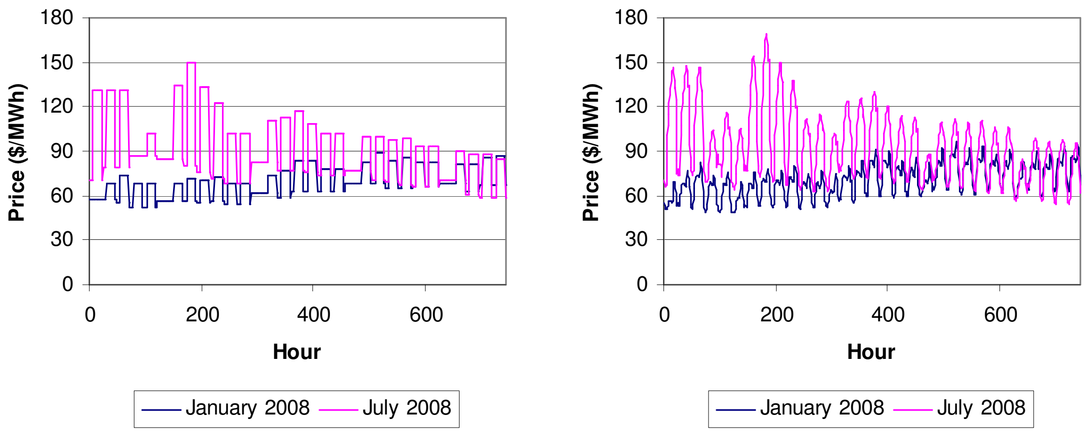
Additionally, E3 has derived a monthly shape for the spot gas market based on monthly NYMEX forward curves for Henry Hub. Combining the expected monthly gas price shape with the market heat rate shape yields an average monthly value (expressed as a percentage of the average annual value) of wholesale energy. This monthly shape captures notable characteristic trends of the California energy markets, including a depression in market prices in the spring due to hydro runoff in the Northwest and high market prices in the summer months when California's system reaches its peak loads.

Within each month, the hourly price shapes are based on the actual peak and off-peak electricity contracts and on system loads: because California did not have a functional hourly day-ahead market in place in 2008, E3 has developed a proxy for such a wholesale market by adjusting these contracts

[2] Based on NP15 peak and off-peak contract prices and natural gas spot prices from 2003 through 2008
[3] Based on SP15 peak and off-peak contract prices and natural gas spot prices from 2003 through 2008
[4] Based on monthly NYMEX Henry Hub forwards from 2010-2021

upward and downward in each hour based on hourly load as shown in Figure 6. The hourly curve is set so that the average price in each month matches the value shown in Table 4.

Figure 6: Diagram of scaling process used to convert daily peak and off-peak prices to hourly prices based on load



This methodology has been benchmarked against the MRTU LMPs during months when both data sources were available, and it results in a relatively close approximation of the actual hourly trends in wholesale markets (the appendix contains several benchmarking charts that compare the two prices series). It is worth noting that many of the spikes in the LMP series are not captured in the scaled market prices—while load is a driver of the market price, is it certainly not the only one. Nonetheless, because general trends are reproduced in the scaled curves and a better data source were not available for this analysis, the scaled curves were used for the hourly shapes of the value of energy.

1.3.4. Losses

The value of both energy and capacity are increased to account for losses. Table 5 shows the loss factor assumptions used in the energy cost value. In the case of energy, the loss factors are differentiated by time of use period broken down into two seasonal categories (May-September and October-March) and three hourly periods (peak, shoulder, and off-peak). The losses for energy are measured from the customer to the wholesale market hub.

For capacity costs, the loss factors are estimates of the losses during the highest load hours, and are measured from the customer to the relevant point on the grid—the distribution and transmission levels and the generator busbar (Table 6).

Table 5: Marginal energy losses by utility and time period

Time Period	PG&E	SCE	SDG&E
Summer Peak	1.109	1.084	1.081
Summer Shoulder	1.073	1.080	1.077
Summer Off-Peak	1.057	1.073	1.068
Winter Peak	-	-	1.083
Winter Shoulder	1.090	1.077	1.076
Winter Off-Peak	1.061	1.070	1.068

Table 6: Losses during peak period for capacity costs

	PG&E	SCE	SDG&E
Distribution	1.048	1.022	1.043
Transmission	1.083	1.054	1.071
Generation	1.109	1.084	1.081

1.3.5. Ancillary Services (A/S)

E3's previous avoided cost analyses have included the value of avoided ancillary services procurement as a flat percentage multiplier on top of the energy value. E3 has updated its handling of ancillary services: instead of bundling the individual ancillary services products into a single multiplier, the updated methodology examines the effect of a load reduction on the procurement of each individual A/S product—regulation up, regulation down, spinning reserves, and non-spinning reserves—and calculates the resulting value.

The procurement of regulation services is generally independent of load—that is, there is no direct link between the two. Small reductions in load are unlikely to affect the procurement of regulation services, so these products are not included in the avoided cost calculator. In accordance with WECC reliability standards, the California ISO maintains an operating reserve equal to 5% of load served by hydro generators and 7% of load served by thermal generators. The reliability standard also states that at least 50% of operating reserves must be spinning reserves. These requirements tie reserves directly to load such that load reductions have a value associated with lower reserves requirements.

The value of the reduced procurement of reserves is calculated in each hour assuming that the average price of reserves scales with the cost of gas. The hourly shape is based on hourly prices from 2008 scaled to match more closely with the price shape for A/S products since the implementation of MRTU.

1.3.6. System Capacity

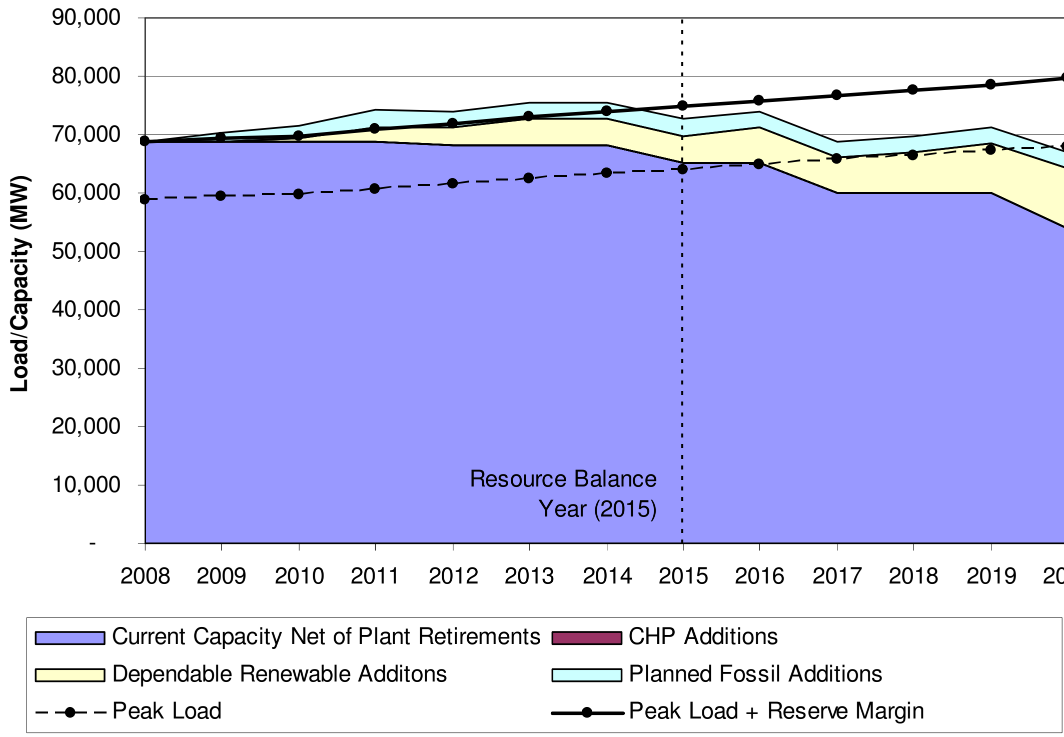
Though such a market does not currently exist in California, the value of capacity is calculated based on expectations of how such a market would perform. As with energy value, the forecast for capacity value has both a short- and long-run component.

In the long run, E3 values capacity using a new combustion turbine as the proxy resource for capacity, valuing capacity at the net cost of installing a new plant to meet resource adequacy needs. This long-run value is captured fully in each year after the resource balance year: the first year in which system capacity would be insufficient to meet peak system demand plus the planning reserve margin.

The resource balance year is evaluated by comparing the CEC's forecast of peak loads in California with California's expected committed capacity resources. The forecast for expected capacity includes several components: 1) existing system capacity as of 2008, net of expected plant retirements; 2) fossil plants included in the CEC's list of planned projects with statuses of "Operational," "Partially Operational," or " Under Construction"; and 3) a forecast of renewable capacity additions to the system that would be necessary to achieve California's 33% Renewable Portfolio Standard by 2020 based on E3's 33% Model.

The load-resource balance is shown in Figure 7 below; based on this analysis, the resource balance year for California was set at 2015. This represents the first year in which committed capacity resources would be insufficient to meet the expected peak system demand and requirements for the planning reserve margin.

Figure 7: Evaluation of the resource balance year in California



E3 calculates the long-run cost assuming that the marginal capacity resource is a new CT that would operate in the real-time energy and ancillary services markets. Thus, the value of avoided capacity costs are valued at the annual carrying cost of a combustion turbine (CT) less the net revenue the generator can earn in the energy and A/S markets, or 'contribution to fixed costs'. This contribution to fixed costs is calculated by dispatching a representative unit against an hourly real-time market price curve and calculating the revenues the unit would earn. The hourly shape of the real-time market is based on historical real-time data gathered from CAISO's MRTU system[5]; in each year, the level of the curve is adjusted by the average wholesale market price for that year. The CT's net revenues are calculated assuming that the unit dispatches at full capacity in each hour that the real-time price exceeds its operating cost (the sum of fuel costs and variable O&M), earning the difference between its operating cost and the market price. In each hour where the market prices are below the operating cost, the unit is assumed to shut down. The net revenues earned through this economic dispatch are grossed up by 11% to account for profits earned through participation in CAISO's ancillary services markets. The final figure is subtracted from the CT's annualized fixed cost—calculated using a pro-forma tool to amortize capital and fixed operations and maintenance costs—to determine the CT residual in that year.

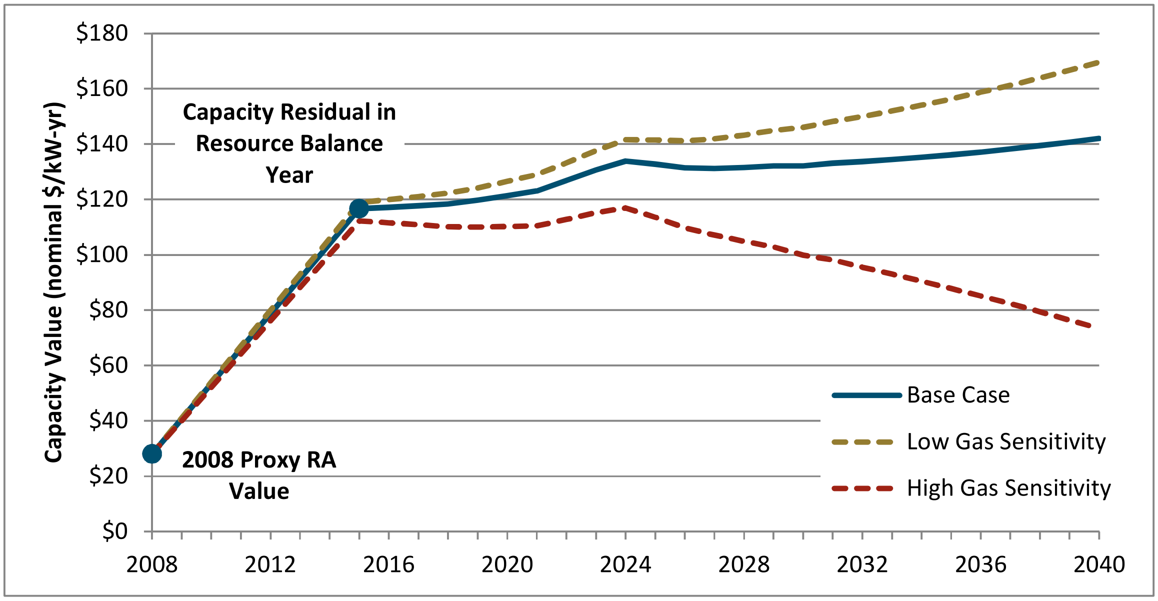
In the short run, the value of capacity is substantially depressed due to the substantial planning reserve margin on the CAISO system. E3 assumes that the value of capacity in 2008 was $28/kW-yr—a proxy value reported for resource adequacy in testimony in the Sunrise case. In the intermediate years between 2008 and the resource balance year, the value of capacity is calculated through a linear interpolation under the assumption that load growth will reduce the reserve margin and result in the escalation of capacity value. This forecast of capacity value is shown in Figure 8.

Figure 8 also shows the value of capacity under the gas sensitivity cases. The low gas sensitivity results in a higher long-run capacity value because lower costs of energy will result in lower energy revenues for the proxy CT, which drives its capacity residual upwards; similar reasoning explains the drop in long-run capacity value associated with high long-run gas costs.

---

[5] While this system was not implemented during 2008, the base year of the avoided costs for CSI, it is expected that the distribution of prices gathered over the first year of MRTU will be representative going forward and is the most appropriate data source to assess future capacity value.

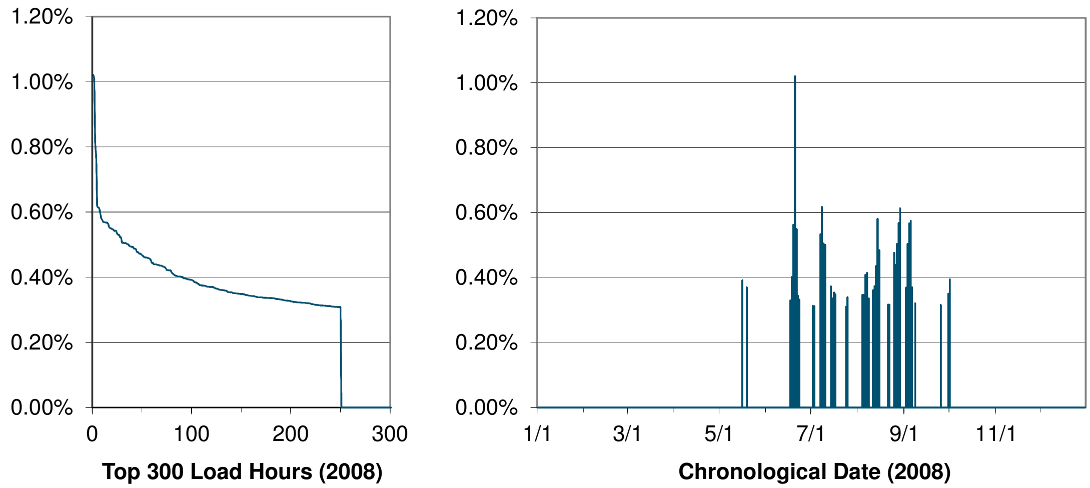
Figure 8: Forecast of system generation capacity value



The value of capacity is allocated among the top 250 hours of CAISO system load of the year based on actual 2008 data under the assumption that these are the hours in which the system is most likely to be constrained (and thus require additional capacity). The allocators developed serve as a simplified and transparent estimation of relative loss of load probabilities (rLOLP) used by utilities to allocate capacity value. The allocator in each of these hours is inversely proportional to the difference between the peak load plus the operating reserve margin (7%) and the load in that hour.[6] Figure 9, below, shows the generation capacity cost allocation factors, which do not vary by climate zone.

[6] The algorithm used to calculate the hourly capacity allocators is described in further depth at the end of this document.

Figure 9: Allocation of generation capacity costs



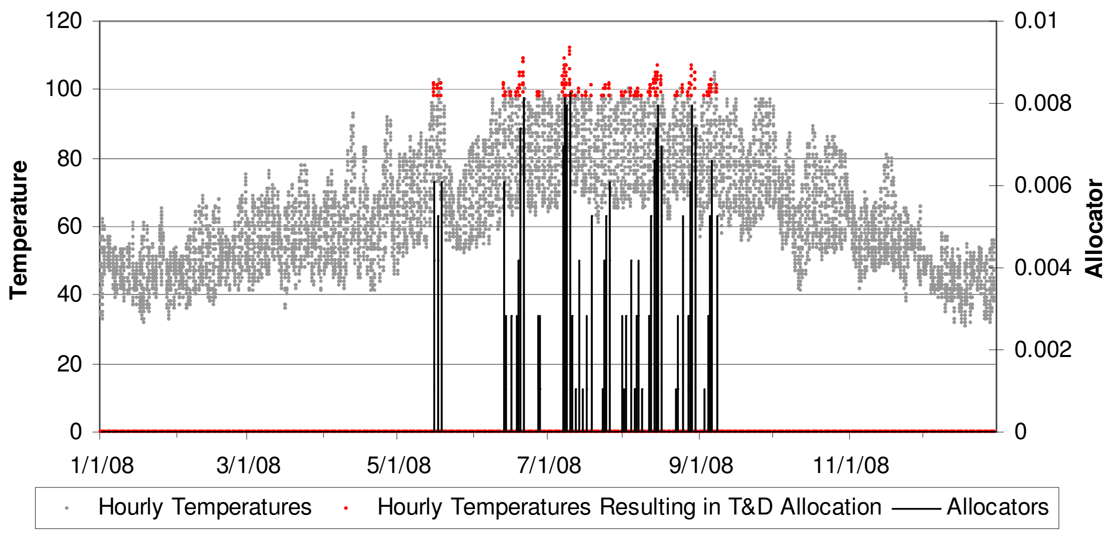
1.3.7. T&D Capacity

The cost of T&D capacity is evaluated in two parts. A forecast of marginal T&D capacity costs is estimated based on GRC data from each of the utilities. This forecast is based on the avoided cost, including reduced O&M costs, of load-related upgrades to the transmission and distribution systems. The avoided cost of T&D capacity varies significantly by location; E3's forecasts of value vary by climate zone.

Like the cost of generation capacity, the avoided cost of T&D capacity is allocated over a limited number of hours in the year in which the transmission or distribution system would be likely to experience constraints. Ideally, the allocators developed for T&D would be based on local loads within each climate zone, which would serve as the best indicator of when the T&D system is most stressed. However, due to the lack of publicly available data at the necessary granularity (local loads for each climate zone), E3 has developed a proxy methodology by allocating T&D capacity based on temperature, a parameter with which local loads have a very strong correlation. The T&D allocators are calculated using a triangular hour weighting algorithm that is described in further detail in the appendix. Figure

10 shows the resulting allocators in chronological order as well as the hourly annual temperature profile from which they were derived for CZ13.

Figure 10: Development of T&D allocators for CZ13



1.3.8. Environment

The environmental component is an estimate of the value of the avoided CO2 emissions. While there is not yet a CO2 market established in the US, it is included in the forecast of the future. While there is some probability that there will not be any cost of CO2, that the likelihood of federal legislation establishing a cost of CO2 is high Since a forecast should be based on expected value, the avoided costs forecast includes the value of CO2.

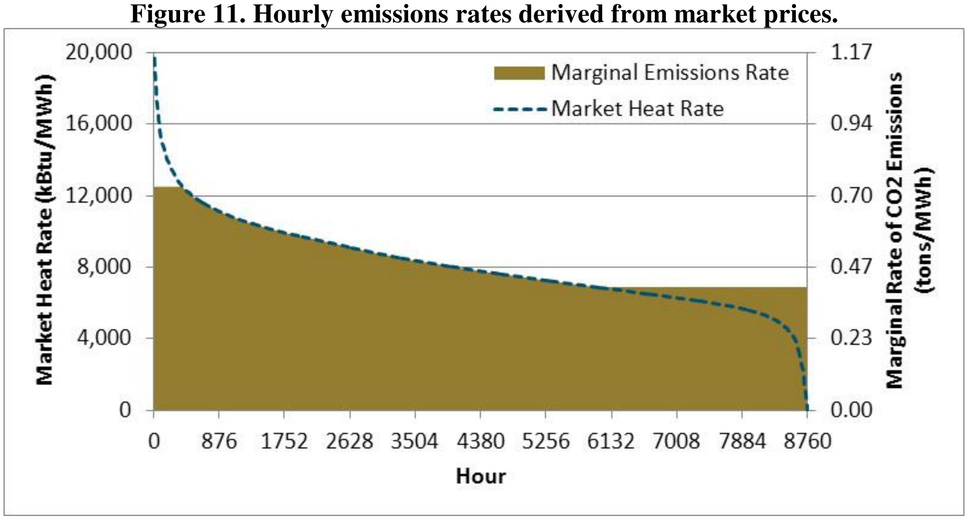
More challenging for CO2 is estimating what the market price is likely to be, given a market for CO2 allowances is established. The price of CO2 will be affected by many factors including market rules, the stringency of the cap set on CO2 allowances, and other elements. The avoided cost of emissions is based on a forecast developed by Synapse Consulting through a meta-analysis of various studies of proposed climate legislation. The mid-level forecast included in this report was developed explicitly for use in electricity sector integrated resource planning and so serves as an appropriate applied value for the cost of carbon dioxide emissions in the future.

Assuming that natural gas is the marginal fuel in all hours, the hourly emissions rate of the marginal generator is calculated based on the day-ahead market price curve. The link between higher market prices and higher emissions rates is intuitive: higher market prices enable lower-efficiency generators to operate, resulting in increased rates of emissions at the margin. Of course, this relationship holds for a reasonable range of prices but breaks down when prices are extremely high or low. For this reason, the avoided cost methodology bounds the maximum and minimum emissions rates based on the range of heat rates of gas turbine technologies. The maximum and minimum emissions rates are bounded by a range of heat rates for proxy natural gas plants shown in Table 7; the hourly emissions rates derived from this process are shown in Figure 11.

Table 7: Bounds on electric sector carbon emissions.

	Proxy Low Efficiency Plant	Proxy High Efficiency Plant
Heat Rate (Btu/kWh)	12,500	6,900
Emissions Rate (tons/MWh)	0.731	0.404

Figure 11. Hourly emissions rates derived from market prices.



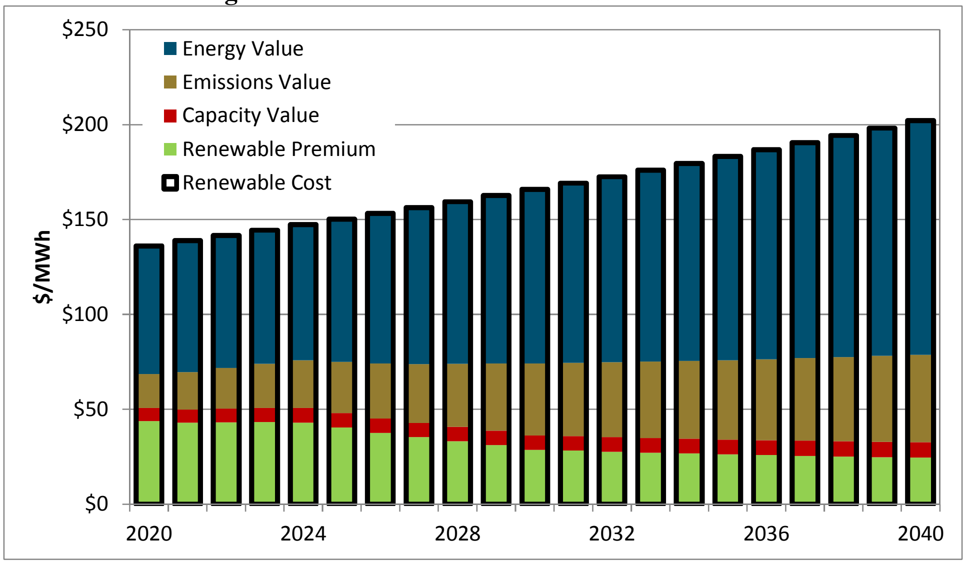
1.3.9. Avoided Renewable Purchases

The avoided costs also include the value of avoided renewable purchases. Because of California's commitment to reach a RPS portfolio of 33% of total retail sales by 2020, any reductions to total retail sales will result in an additional benefit by reducing the required procurement of renewable energy to achieve RPS compliance. This benefit is captured in the avoided costs through the RPS Adder.

The calculation of benefits resulting from avoided purchases of renewables begins in 2020. Because of the large gap between existing renewable resources and the 33% target in 2020, the rate of renewable procurement up until this year is unlikely to change with small reductions to the total retail load. However, after 2020, any reduction to retail sales will reduce requirements to obtain additional resources to continue compliance with the 33% case. As a result, the value of avoided renewable purchases is considered a benefit associated with load reductions beyond 2020.

The RPS Adder is a function of the Renewable Premium, the incremental cost of the marginal renewable resource above the cost of conventional generation. The marginal renewable resource is based upon the Fairmont CREZ, the most expensive resource bundle that is included in the renewable portfolio in E3's 33% Model 33% Reference Case. The Renewable Premium is calculated by subtracting the market energy and capacity value associated with this bundle, as well as the average CO2 emissions from a CCGT, from its levelized cost of energy as shown in Figure 12. The RPS Adder is calculated directly from the Renewable Premium by multiplying by 33%, as, for each 1 kWh of avoided retail sales, 0.33 kWh of renewable purchases are avoided.

Figure 12: Evaluation of the Renewable Premium



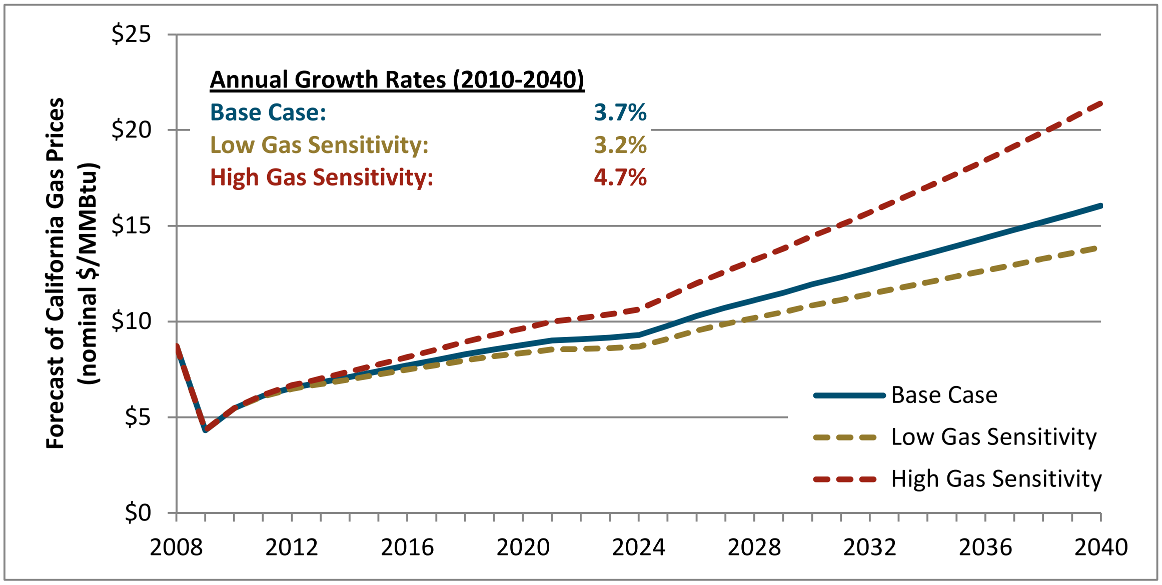
1.4. Key Data Sources and Specific Methodology

This section provides further discussion of data sources and methods used in the calculation of the hourly avoided costs.

1.4.1. Natural gas forecast

The natural gas price forecast, which is the basis for the calculation of the average annual value of energy, is taken from the CPUC MPR 2009 Update (historic data is used for 2008 and 2009). This forecast, shown in Figure 13, is based upon NYMEX Henry Hub futures, average basis differentials, and delivery charges to utilities. E3's avoided costs include several sensitivities on price of natural gas, which are developed by adjusting the annual rate of escalation for natural gas. The low cost sensitivity decrements the annual growth rate by 0.5%; the high cost sensitivity adds 1.0% to the annual growth rate.

Figure 13: Natural gas price forecast used in calculation of electricity value



1.4.2. Power plant cost assumptions

Cost assumptions and operating parameters for the CT are based on the CEC's Cost of Generation report.

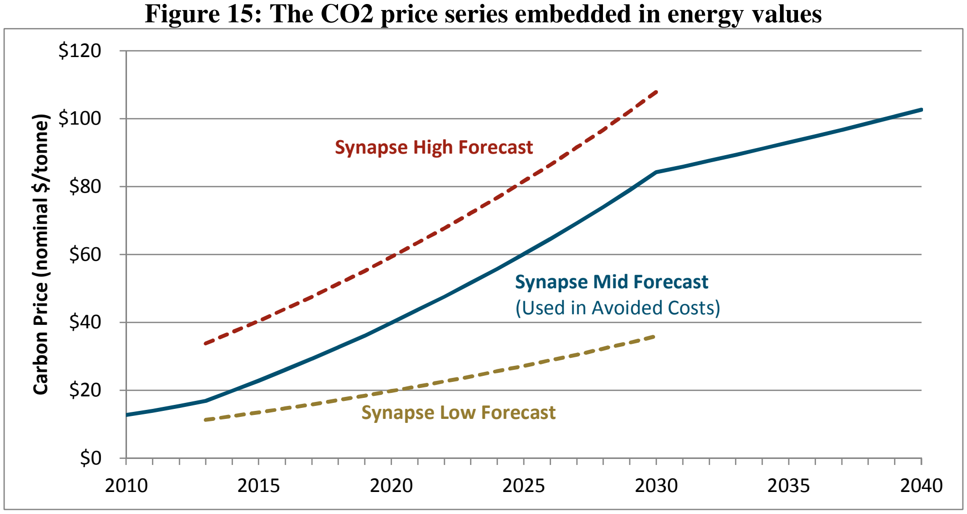
Figure 14: Cost and performance for a new CT

Central Station Plant Assumptions	CT
Operating Data	
Heat rate (BTU/kWh)	9,300
Lifetime (yrs)	20
Plant Costs	
In-Service Cost ($/kW)	$1,380
Fixed O&M ($/kW-yr.)	$17.40
Variable O&M ($/MWh)	$4.17
Cost Basis Year for Plant Costs	2009
Financing	
Debt-to-Equity	50%
Debt Cost	7.7%
Equity Cost	12.0%
Marginal Tax Rate	40.7%

1.4.3. Cost of CO2 Emissions

The CO2 cost projection is taken from a meta-analysis of CO2 price forecasts. Figure 17 summarizes the Synapse price forecasts; the mid-level forecast is used in the calculation of avoided costs.

Figure 15: The CO2 price series embedded in energy values



1.4.4. Benchmarking of Load-Shaped Price Curve Against MRTU LMPs

The hourly market price curves resulting from scaling peak and off-peak prices in proportion to load during those periods were benchmarked against MRTU Locational Marginal Prices when both series were available (between April and June 2009). Figure 16 and Figure 17 show two ten-day snapshots that compare the two series. As earlier discussed, the load-shaped prices follow general trends that are similar to the LMPs but neglect to capture many of the hourly price spikes. Nonetheless, the load-shaped prices were chosen as the best available data for this analysis.

Figure 16: Benchmarking of load-shaped prices against LMPs, 4/1/09-4/10/09

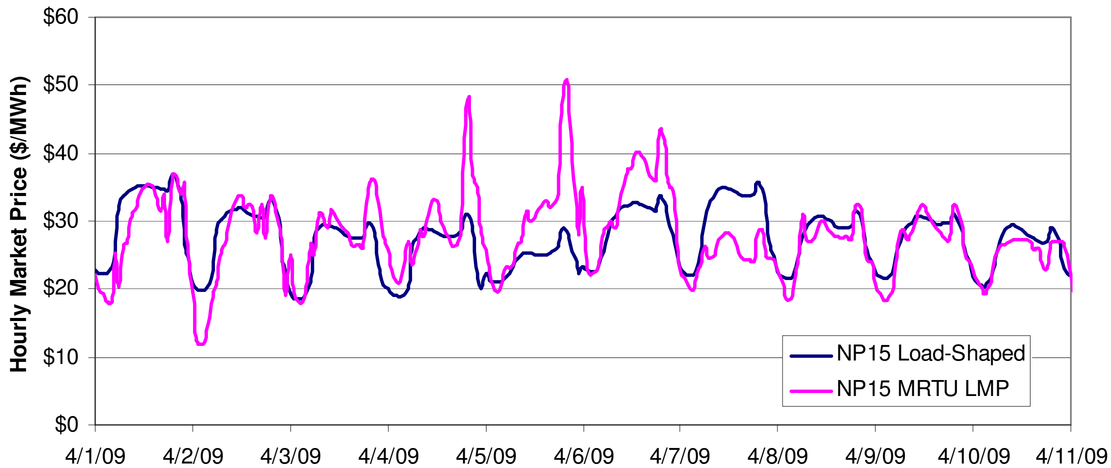
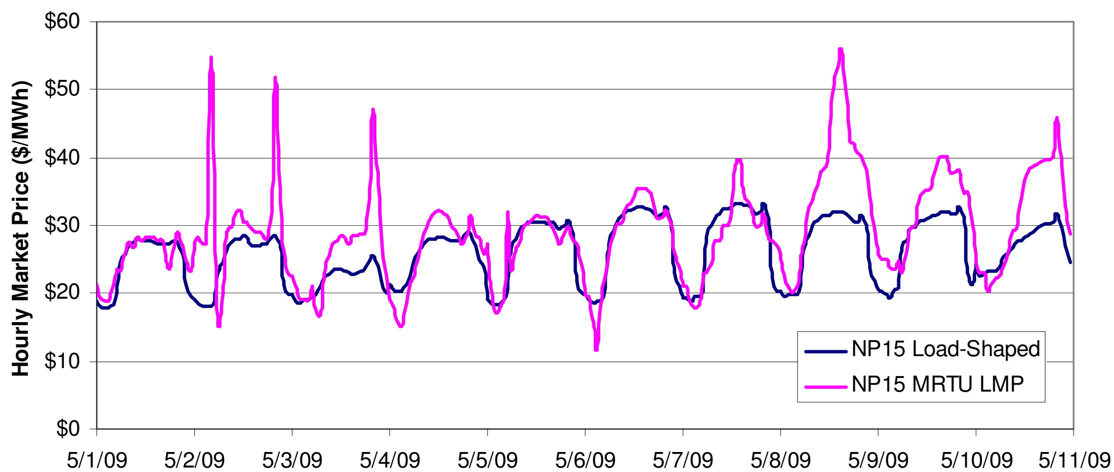


Figure 17: Benchmarking of load-shaped prices against LMPs, 5/1/09-5/10/09



1.4.5. Calculation of the System Capacity Allocators

The following calculation sequence is used to compute a capacity cost allocation factor in each of the top 250 system load hours. This methodology is applied in the calculation of the hourly avoided cost of electricity:

1. Compute the system capacity that provides 7% operating reserves = peak load * 107%

2. Compute a relative weight in each hour as the reciprocal of the difference between the load in each of the top 250 hours and the planned system capacity

3. Normalize the weights in each hour to sum to 100%

1.4.6. Calculation of the T&D Capacity Allocators

The following is a brief description of the algorithm used to allocated T&D capacity value. T&D capacity value is allocated to all hours with temperatures within 15ºF of the peak annual temperature.

1. Select all hours with temperatures within 15ºF of the peak annual temperature (excluding hours on Sundays and holidays) and order them in descending order

2. Assign each hour an initial weight using a triangular algorithm, such that the first hour (with the highest temperature) has a weight of 2/(n+1) and the weight assigned to each subsequent hour decreases by 2/[n*(n+1)], where n is the number of hours that have a temperature above the threshold established in the first step

3. Average the initial weights among all hours with identical temperatures so that hours with the same temperature receive the same weight

Appendix C:

Individual Installation Tool User Guide

CSI Individual Installation Tool User Guide

The CSI Individual Installation Tool is a non-proprietary, open-source tool developed by E3 in support of the cost-effectiveness evaluation of the California Solar Initiative (CSI) for the California Public Utilities Commission. The tool analyzes the cost-effectiveness of a user-specified, individual CSI solar PV project and calculates a project financial *pro forma* based on specified financing assumptions.

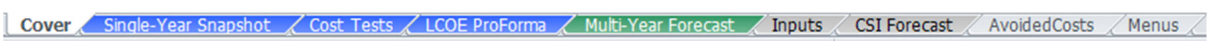
E3 has made the tool publicly available for two reasons. The first is to provide clarity to interested parties regarding the calculations underlying E3's cost-effectiveness results. Interested parties may "audit" the calculations in the tool, get a complete understanding of input assumptions, and test how changes to input assumptions impact results.

The second goal of making the tool public is to enhance discussion regarding the Levelized Cost of Energy (LCOE). LCOE is a common way to discuss the cost of solar, but input and calculation assumptions driving LCOE calculations are not always transparent. A transparent method of LCOE calculation may help illuminate underlying assumptions leading to stated LCOE values.

This user guide is intended to help users understand and use the Individual Installation Tool by providing general information on some of the key features of the tool.

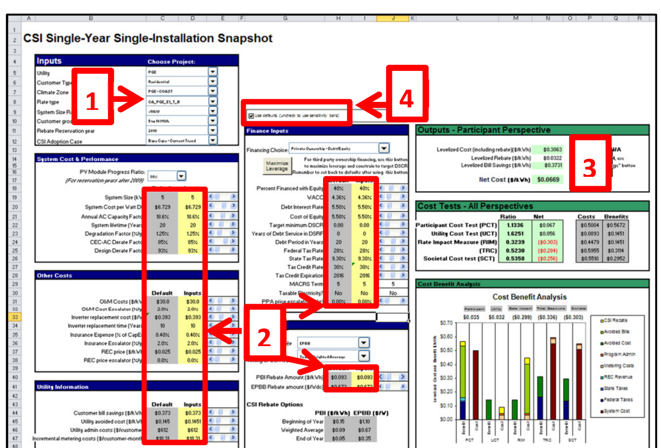
Contents

The CSI Individual Installation Tool is divided into the following tabs:



Single-Year Snapshot	Allows user to specify a system and displays a summary of the cost-effectiveness results
Cost Tests	Detailed cost test outputs for installation selected in 'Single-Year Snapshot' worksheet
LCOE ProForma	Annual cash flows for installation selected in 'Single-Year Snapshot' worksheet
Multi-Year Forecast	Computes the cost effectiveness of one system if it were installed in different years
Inputs	System performance, costs and financing inputs
CSI Forecast	CSI program adoption forecast
AvoidedCosts	Avoided bills and avoided cost inputs
Menus	Active menus

Single-Year Snapshot



To select a specific project, use the dropdown menus in the main inputs block (1). The dropdown menu selections automatically adjust depending on previous menu choices. For example, the menu labeled "Rate type" will provide rate options for the utility and customer type that the user has already chosen.

Not all combinations of menu selections are allowed. If the user has entered an invalid selection, a warning sign will be displayed along with a list of suggested similar options. Users should change their menu selections until a valid combination of inputs has been selected. Once a valid system choice is selected, the model will populate all of the input categories with the corresponding default values (2). A summary of the main outputs is displayed in the output blocks (3).

To override the default inputs, users must uncheck the checkbox labeled "Use defaults" (4). Once this checkbox is unchecked, users can enter their own inputs by using the sensitivity bars next to the input fields.

Cost Tests

The "Cost Tests" tab contains a more detailed version of the results that were summarized in the "Single-Year Snapshot" tab. The cost tests shown in this tool use the cost-benefit methodology for distributed generation as per CPUC Decision 09-08-026. The "Standard Practice Manual" describes four cost-benefit tests that are presented in the CSI Individual Installation Tool:

- Participant Cost Test (PCT)
    - Economic viability to developer or customer
    - Helps determine if incentive is appropriate to drive participation while preventing "free riders"
- Total Resource Cost Test (TRC) (and Societal)
    - Costs and benefits to society at large
- Program Administrator Cost Test (PAC)
    - Measures change to utility revenue requirement (but not revenues)
    - Compares utilities' costs incurred to avoided costs
- Ratepayer Impact Measure (RIM)
    - Indicates the direction and magnitude of any changes in customer bills

A visual representation of the costs and benefits considered for each of these perspectives is shown below:

	PCT	TRC	PAC	RIM
System Cost	Cost	Cost		
Utility Avoided Cost		Benefit	Benefit	Benefit
CSI Rebate	Benefit		Cost	Cost
Bill Changes	Benefit			Cost
Program Administration		Cost	Cost	Cost
REC Value	Benefit			
State Taxes	Benefit			
Federal Taxes	Benefit	Benefit		

LCOE Proforma

The "LCOE Proforma" tab computes the different cost components in the cost benefit analysis. A pro forma cash flow model is used to calculate the levelized nominal cost of each cost component for all PV systems. The same pro forma model is used for the four ownership scenarios allowed: residential, commercial, government, or non-profit. PV system characteristics (capacity factor, costs) and avoided costs vary depending on whether ownership is residential, commercial, or government, or non-profit.

For each ownership scenario, there are two principal financing choices: private or third party. Private ownership assumes the customer finances the PV system. Three financing scenarios are available under private ownership:

100% cash, a mixture of cash & debt, and 100% debt. Third party financing assumes the PV system is developed by a commercial entity that is repaid via a 20-year PPA.

The following assumptions are common across all four scenarios:

- All tax benefits (i.e., accelerated depreciation, investment tax credit) can be fully utilized in the year they become available.
- Scenarios financed partly or entirely with debt assume tax-deductible interest payments. The cost of equity is not tax deductible.
- REC revenue is assumed to be taxable.
- An inverter replacement occurs in year 11 and is financed mortgage-style over 10 years at after-tax WACC.
- A PBI rebate is taxable at the federal level but not taxable at the state level.

Under a third party financing scenario, the PPA price reflects taxable revenues and tax deductible expenses, including 5-yr MACRS tax depreciation. Debt is obtained through a project financing. A one-year debt service reserve is funded at commercial operations. The amount of debt in the capital structure can be maximized to achieve a target average debt service coverage ratio (DSCR). Tax rates of 35% federal and 8.84% state reflect corporate taxation. WACC equals 8.25%. Debt interest is costed at 7.67%. The after-tax ROE is a function of the amount of leverage in the capital structure.

The following assumptions apply to the residential ownership scenarios:

- Private ownership debt and equity capital are costed at the same 5.5% rate. The debt cost reflects a home equity loan; the equity cost reflects a similar opportunity cost.
- Tax rates reflect individual (versus corporate) taxation. The 28% federal and 9.3% state tax rates (34.7% total) assume a higher income homeowner.
- A homeowner may not claim PV system depreciation or a deduction for PV system operating costs on its tax return.
- A homeowner’s avoided electricity bill is not tax adjusted because it cannot be deducted for tax purposes.
- An EPBB rebate is not taxable for federal purposes.
- An EPBB rebate is fully utilized upfront to offset the capital cost of the system.

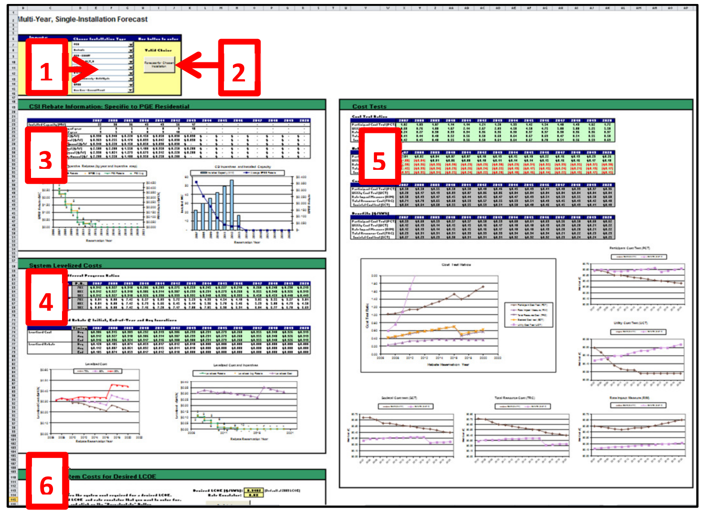
The following assumptions apply to the commercial ownership scenarios:

- Tax rates of 35% federal and 8.84% state reflect corporate taxation.
- WACC equals 8.25%. Debt interest is costed at 7.67%. The after-tax ROE is a function of the amount of leverage in the capital structure.
- Operating costs and depreciation are tax deductible. A PV system qualifies for 5-year MACRS treatment.
- A commercial entity’s electric bill is tax deductible, therefore its avoided electricity bill is tax adjusted. This is accomplished via a (1 – tax rate) multiplier. Similarly, in the case of a PV system owned by a third party, a commercial entity’s PPA payments are an operating expense and are thus tax-adjusted via a (1-tax rate) multiplier.
- A CSI rebate incurs federal tax.
- An EPBB rebate is received in the first year of operation.

The following assumptions apply to the government and non-profit ownership scenarios:

- Government/non-profit entities do not pay taxes and therefore cannot access tax benefits.
- The cost of all capital is 4.21%.
- A government or non-profit entity’s avoided electricity bill is not tax adjusted because it cannot be deducted for tax purposes.
- An EPBB rebate is fully utilized upfront to offset the capital cost of the system.

Multi-Year Forecast



The "Multi-Year Forecast" tab allows users to track the cost effectiveness of a specific system for different installation years. To select a specific project, use the dropdown menus in the main inputs block (1). If the user has entered an invalid selection, a warning sign will be displayed along with a list of suggested similar options. Once a valid system is chosen, use the button labeled "Forecast" (2) to compute the results and populate the multiple output blocks.

The rebate schedule for the selected utility and customer type is shown (3). The results show the installed capacity, incentive steps and rebate amounts by year based on the selected adoption forecast.

The system's nominal levelized cost by year is displayed in another output block (4). Nominal levelized costs are presented at different progress ratios to demonstrate the effects of the assumed costs for rooftop solar PV. To illustrate the effect of the CSI rebate on the levelized cost, the amount of the rebate and the levelized costs are shown side-by-side.

In another output block (5) the results of the cost benefit tests are shown by year. A table summarizes the resulting cost benefit ratios and net costs for different rebate reservation years. The results are also displayed graphically for each of the cost-benefit test perspectives.

Two more output blocks (6) allow users to solve for the system cost in $/kW that would be necessary to achieve a desired participant cost test (PCT) ratio or levelized cost. To do so, the model modifies the system cost in $/kW until attaining the desired PCT ratio, or levelized cost for every year. The progress ratio necessary to reach that system cost is also shown. The model defaults to solving for a desired PCT ratio of 1 and a desired levelized cost equal to the levelized cost result for 2009 from the previous outputs(4). The user can also modify the desired PCT ratio or the desired levelized cost to solve for and recalculate the results using the button labeled "Recalculate".

Inputs

The "Inputs" tab contains a list of all of the system performance, cost, and financing inputs that serve as defaults to the model. An explanation of the individual inputs and their source is mentioned next to each of the input blocks.

CSI Forecast

The "CSI Forecast" tab is used to compute the CSI rebate amounts by year based on the selected adoption forecast. The calculation is based on the incentive steps and the respective rebate amount that vary by customer type and utility. The model uses actual MW adoption data by utility and customer type for years 2007-2009. Starting in 2010 onwards, three different adoption forecasts are allowed. The base case adoption forecast is based on the actual adoption trend by utility and customer type. The high adoption forecast assumes a 50% increase in annual adoption capacity. The low adoption forecast assumes constant annual capacity additions equivalent to the average of the actual annual capacity additions.

Avoided Costs

The "Avoided Costs" tab contains a lookup table of levelized avoided bills and avoided costs for each system type. Once a valid system is chosen using the dropdowns in any of the tabs in the spreadsheet, the corresponding row containing the system's avoided costs and avoided bills will be highlighted in this tab. Because calculating the levelized values for each system in the lookup table is computationally intensive, the values were calculated outside of the spreadsheet model. The values were derived from E3's "Avoided Cost Calculator" and the "Retail Rate Calculator" developed by Clean Power Research (CPR). The Avoided Cost Calculator and a spreadsheet that provides access to CPR's retail rate calculation tool are available on E3's web site at http://ethree.com/public_projects/cpuc.html.