California Public Utilities Commission

California Net Energy Metering Ratepayer Impacts Evaluation

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Introduction to the California Net Energy Metering Ratepayer Impacts Evaluation

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Technical Report by
Energy and Environmental Economics, Inc.

Introduction to the California Net Energy Metering Ratepayer Impacts Evaluation

The California Public Utilities Commission (CPUC) has contracted with Energy and Environmental Economics, Inc. (E3) to provide an evaluation of the costs and benefits of the net energy metering (NEM) program in California. This study fulfills the requirements of Assembly Bill (AB) 2514 (Bradford, 2012) and Commission Decision (D.) 12-05-036, to study "who benefits, and who bears the economic burden, if any, of the net energy metering program." This study also serves as an update to the CPUC's 2010 NEM Cost-Effectiveness Evaluation.[1]

NEM is an electricity tariff billing mechanism designed to facilitate the installation of renewable customer distributed generation (DG). Under NEM tariffs, customers receive a bill credit for generation that is exported to the electric grid during times when it is not serving onsite load. Bill credits for the excess generation are applied to a customer's bill at the same retail rate (including generation, distribution, and transmission components) that the customer would have paid for energy consumption, according to their otherwise applicable rate schedule. This study also provides a separate evaluation of the NEM fuel cell program, which credits the generation only component of the rate for participating fuel cells that achieve targeted reductions in greenhouse gas emissions.

Role of the CPUC's Energy Division in the Evaluation

The CPUC's Energy Division was responsible for contracting with E3 and overseeing the development of this report. Energy Division initiated the contract process in the spring of 2012, and E3 was selected following a competitive bidding process.

In October 2012, Energy Division hosted a well-attended workshop where E3 consultants previewed the methodology and scope of the cost-benefit analysis, avoided public purpose charges, and income distribution sections of the attached report. Informal comments were solicited from interested parties on November 5, 2012, and reply comments were received on November 15, 2012. E3 provided responses to comments in the December study scope of work. Unfortunately, due to delays in processing the funding needed to conduct the full cost of service analysis, the methodology for the NEM full cost of service calculation was not available for public comment. Utility costs of service were emulated from the methodology filed by each utility in its most recent General Rate Case (GRC).

In September 2013, E3 consultants presented the results of the draft NEM report. The CPUC solicited informal comments from interested parties on 'calculation errors' contained in the draft report, and comments were received by eight parties on October 10, 2013. Based on

[1] http://www.cpuc.ca.gov/NR/rdonlyres/0F42385A-FDBE-4B76-9AB3-E6AD522DB862/0/nem_combined.pdf

these comments, E3 made several modifications to the analysis, clarified several issues in the final report, and responded under separate cover to all of the substantive comments.

The final spreadsheet analysis tools, methodology workshop presentation materials, draft and final scope of work, stakeholder comments on the methodology and draft report, and E3's reply comments are available on the CPUC's NEM study webpage.[2]

Scope of the Evaluation

When the CPUC's Energy Division initiated the contract process for an evaluation of NEM in the spring of 2012, the primary focus of the evaluation was to incorporate an updated and more robust data set to the prior methodologies used in the 2010 NEM Cost-Effectiveness Evaluation. At the time, the analysis was limited to the costs and benefits of generation exports to the electric grid. Following the request for proposals (RFP) for the study, however, two mandates were adopted – Commission D. 12-05-036 in May 2012, and AB 2514 in September 2012 – which added significant breadth and scope to the study. These additional tasks include:

(1) A cost-benefit study of NEM at the capacity needed to reach the solar photovoltaic goals of the California Solar Initiative and the 5% net energy metering program cap. The costs and benefits of NEM should be evaluated relative to energy that is exported to the grid and energy consumed onsite.

(2) An evaluation of the extent to which NEM customers pay their share of utility costs.

(3) An estimate of the reduction in public purpose charges avoided by NEM customer-generators.

(4) An income demographic assessment for residential customers with NEM generation.

Unfortunately, the inclusion of multifaceted analytical approaches, at different penetration levels, precludes a single, simplified answer to the underlying question that we are trying to address: That is, who benefits from, and who bears the economic burden, if any, of the net energy metering program? However, when taken together, the various analyses included in the attached NEM Ratepayer Impacts Evaluation shed new light on the impacts of the NEM program in California, provided that the results are interpreted alongside the metrics used in the evaluation and in the context of current DG policies and utility operations. Two of the more relevant issues included in the report are discussed in more detail below.

Lastly, it is important to note that the attached NEM Report is focused exclusively on the utility ratepayer impacts of NEM, and does not include the overall societal benefits from the deployment of clean energy resources, although significant environmental, public health and other non-energy benefits occur. The importance of the environmental benefits that result from of the deployment of renewable generation is well established within the California

[2] http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm

Energy Action Plan, and is reflected in a number of the state's DG policies, including the Go Solar California campaign, the Commission's Self-Generation Incentive Program, as well as the NEM program.

NEM Cost-Benefit Analysis vs. Cost of Service Analysis

At its most basic level, the attached study employs two separate ratepayer impact measures: A cost-benefit analysis of the NEM program using the traditional California Standard Practices Manual (SPM) Ratepayer Impact (RIM) test, which estimates the net benefits (or costs) of a demand-side resource or program from the perspective of non-participating customers, and a full cost of service assessment, which compares the utility cost of serving NEM customers with their actual bill payments.

In the cost-benefit analysis, E3 evaluates the *change* in utility costs associated with the *change* in usage due to the installation of DG. If the customer bill savings resulting from NEM are greater than the corresponding reduction in utility costs, NEM will create a cost shift from NEM customers to other non-participating customers as utilities adjust their rates to compensate for the shortfall. Alternatively, if the reductions in customer bill savings are less than the reduction in utility costs, non-participating customers experience a net benefit. Note that this approach does not address or reflect any pre-existing cost shift <u>onto</u> NEM customers prior to their installation of customer generation.

In the full cost of service analysis, E3 evaluates the *total cost* to serve the remaining energy usage after accounting for the change in usage due to the installation of DG. The cost of service assessment compares the actual bills that NEM customers pay to the utility costs (including fixed costs) needed to serve the customer. This study evaluates whether customers who install NEM eligible systems pay more or less than the cost of providing them electricity service before and after they install a NEM eligible system. Utility costs of service are emulated from the methodology that each utility used in their most recent GRC.

Despite the use of different metrics, a central driver in both the cost-benefit and cost of service analyses is current retail rate designs. For residential NEM customers, tiered rates (for which a customer's marginal electricity rate increases with cumulative usage) and tiered time-of-use rates are the most commonly subscribed. As described in more detail below, changes to the tiered rates would have a significant impact on the study results. Similarly, differences in retail rates should be an important consideration for policymakers outside of California that are using this study.

Export Only vs. All NEM Generation

One of the key drivers of the magnitude of any cost impacts is what generation is measured. Pursuant to AB 2514, the cost-benefit analysis included in this study considers all NEM generation as well as only the generation that is exported to the grid.

The most explicit impact of NEM is associated with energy exports to the grid; both NEM and non-NEM DG receive bill reductions during hours when generation is offsetting onsite load, but only NEM customers receive bill credit for generation that is exported to the grid.

To the extent that NEM compensation allows a project to be viable, the entire NEM generation is a useful metric. In this instance, an exact measure of the effect of NEM on ratepayers would compare the state of the world with NEM to that without NEM, and calculate the ratepayer costs under both. Unfortunately, the state of the world *in the absence of NEM* is a theoretical and unknown condition, which is further confounded by other incentive programs designed to facilitate the deployment of DG (such as the Federal Income Tax Credit, California Solar Initiative, and Self-Generation Incentive Program). Because it is uncertain how much renewable DG would be installed in California without NEM, or how customers might choose to size DG or change their electricity usage to better align with the DG output, the all generation scenario included in the attached report likely overestimates the costs that are directly associated with NEM.

Solar is Primary Focus of the Report

The attached report focuses exclusively on the NEM program within the territories of the three large investor-owned utilities (IOUs), which had enrolled over 150,000 customers totaling 1,300 MW through the end of 2012. Collectively, these systems generated about 2,400 GWh of annual electricity. The vast majority of customers on NEM tariffs had installed solar PV (99% of accounts, and 96% of capacity). Customers with wind and bioenergy generation make up the remaining 1 percent. A separate evaluation of fuel cell NEM, which provides credits at the generation only component of the rate for fuel cells, including those that are fueled by natural gas, is also included in the report.

Customer-sited solar PV installations that are not enrolled on a NEM tariff are excluded from this report. As of June 2013, 492 installations in IOU service areas representing over 110 MW of generating capacity opted to not take NEM tariffs, presumably because their solar generation was not expected to exceed load at any time, and thus no benefits would be accrued from NEM.[3]

Impact of Possible NEM Policy Modifications and Rate Reform

This report evaluates the ratepayer impacts of the NEM program as it was outlined in 2012, assuming current rate structures. Under its open proceeding on future residential rate designs (R.12-06-013) and its process to implement AB 327 (Perea, 2013), the CPUC is required by statute to adopt a number of changes to the NEM rule and rate design, including modifying the NEM cap and considering reformation of residential rate designs to make rates more accurately

[3] Source: Energy Division Second Quarter 2013 Interconnection Data Request

reflect the true cost of utility service. To the extent that changes are made to the NEM policy and rate designs, the actual impacts of NEM will differ from those estimated in this study. By presenting a picture of the ratepayer impacts under the current NEM policy, this study provides a foundation for this future work and enables well-reasoned changes to NEM and rate design within the CPUC stakeholder process.

A large portion of the cost impacts associated with residential NEM that are identified in this report are the result of the current rate designs. The analysis in this report shows that, on average, residential NEM customers would have paid utility bills that are 54% greater than the utility's cost of providing service if they had not installed a NEM-eligible DG system. This high cost is due to the fact that most residential NEM customers are in the higher tiers. These customers stand to benefit the most by installing NEM eligible DG systems, but as discussed in section 4.5.1 of the report, the higher cost tiers also drive most of the residential cost impacts identified in the report's cost-benefit analysis.

While forecasting the impact of specific changes to the current rate design is beyond the scope of this study, the impact of the larger residential customers on the overall cost-benefit analysis make it clear that changes in the current tiered rate structures will also dramatically improve the cost-benefit results of NEM.

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1 Executive Summary

1.1 Net Energy Metering (NEM) Overview

This study evaluates the ratepayer impacts of the California net energy metering (NEM) program and fulfills the requirements of Assembly Bill (AB) 2514 (Bradford, 2012)[1] and Commission Decision (D.) 12-05-036 to determine "who benefits, and who bears the economic burden, if any, of the net energy metering program."[2]

NEM is an electricity tariff that facilitates the deployment of on-site renewable distributed generation (DG).[3] Under NEM tariffs, customers receive a bill credit for energy that they generate and export to the grid. In this study we evaluate two types of NEM: Renewable NEM, which provides credits at the full retail rate for solar PV, wind, and bioenergy generation; and fuel cell NEM, which provides credits at the generation only component of the rate for fuel cells, including those fueled by natural gas.

The vast majority of NEM customers in California are solar PV (99% of accounts, and 96% of capacity). At the end of 2012, California's three largest investor-

[1] See Appendix G for further information about AB 2514
[2] This study will also serve as an update to the CPUC's 2010 NEM Cost Effectiveness Evaluation (2010 NEM Study) http://www.cpuc.ca.gov/NR/rdonlyres/0F42385A-FDBE-4B76-9AB3-E6AD522DB862/0/nem_combined.pdf
[3] Public Utilities Code 2827 (b) (4)

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owned utilities (IOUs)[4] had approximately 150,000 customers enrolled in NEM, totaling 1,300 MW of installed capacity. Collectively, these systems generated about 2,400 GWh of electricity during 2012.

1.2 Scope of Evaluation

We did four principle analyses in this study to characterize "who benefits from, and who bears the economic burden, if any, of, the net energy metering program"[5] as required in statute:

(1) Cost-benefit analysis of NEM to estimate any cost impacts from NEM customers to other customers,

(2) Cost of service evaluation to estimate the degree NEM customers pay their share of utility costs,

(3) Public purpose charge savings to estimate the reduction in payments of NEM customers toward public purpose programs, and

(4) Income demographic assessment to learn more about the household incomes of residential customers with NEM generation.

The study is based on the current NEM policy in California that is defined by a number of rules, including the 5% NEM cap established by D. 12-05-036, the net surplus compensation rate under AB 920 (Huffman, 2009), and the existing

[4] The IOUs are Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric.
[5] All quotes in this section are from AB 2514, the full text of which is provided in Appendix G.

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retail tariff designs at each utility. Changes to the structure of the NEM policy, or to the retail rate structures, would change the results of this study.

1.2.1 NEM COST-BENEFIT ANALYSIS

In the cost-benefit analysis, we compare the reduction in NEM customer bills to the reduction in utility costs. To the extent that the NEM customer's bill reduction is greater than offsetting utility savings, NEM will create a cost shift from NEM customers to other customers as utilities adjust their rates to compensate for the shortfall. The results of the analysis are disaggregated by a number of dimensions, including by "utility, and customer class," and for "household income groups within the residential class."

One of the key drivers of the magnitude of any cost impact is what generation is measured; all of the NEM generation, or only the electricity generated that is exported to the grid. We recognize that this issue is controversial, and therefore measure the net cost both ways. The net cost of the specific mechanism enabled by NEM, namely the ability to 'export' electricity to the utility at the retail rate, is measured by the 'export only' case in this study. This approach disregards NEM generation consumed on the customer premise. We also calculate the net cost of the entire NEM generator output. To the extent NEM compensation enables the whole DG project to be viable, and the total output of the project results in a cost to non-NEM customers, the entire NEM generation is the appropriate scope to measure the impact on non-NEM customers.

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We analyze the costs and benefits of NEM at three different levels of installed capacity: A forecast from the actual installed capacity at the end of 2012 ('2012 Snapshot' case), totaling approximately 1,305 MW; the capacity needed to reach the goals of the California Solar Initiative (CSI) ('Full CSI Subscription'), totaling 2,916MW[6]; and the capacity needed to reach the 5% net metering cap as defined by D. 12-05-036 ('Full NEM Subscription'), forecast to be reached in 2020 at approximately 5,573 MW.

Other key input assumptions for which there is uncertainty, such as future natural gas prices, CO2 prices, retail rate escalation, cost of interconnecting and integrating NEM generation, and avoidance of transmission and distribution system capacity costs, are considered through sensitivity analyses.

1.2.2 COST OF SERVICE OF NEM

In addition to the cost-benefit analysis, we evaluate "the extent to which each class of ratepayers and each region of the state receiving service under the net energy metering program is paying the full cost of the services provided to them by electrical corporations." In the cost of service assessment we compare the resulting bills of NEM customers to their full cost of service. Full cost of service is a regulated utility term that includes all utility costs, including an appropriate share of utility fixed costs to serve the customer. We emulate the methodology each utility used in their most recent General Rate Case (GRC) cost of service allocations. The cost of service analysis is an indicator of whether NEM customers paid bills equal to their estimated share of the total utility cost of

[6] Includes solar, wind, and other NEM generation

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service prior to installing a NEM eligible system and what impact installing a NEM eligible system has on whether they pay their estimated share of their cost of service after installing the system.

1.2.3 PUBLIC PURPOSE CHARGES

We disaggregate the NEM customer bill savings to estimate their savings in public purpose charges. In addition to public purpose charges, we decompose the bill savings into all of the other subcomponents of the NEM customer bill.

1.2.4 INCOME DISTRIBUTION OF NEM CUSTOMERS

We estimate the distribution of the household income of residential NEM customers based on the median household income by census tract and census block group using 2010 data provided by the IOUs. The current methodology for the publicly reported household income information is based on zip code, which is less granular than census tract and census block group levels. We believe the much smaller geographic areas and more homogenous demographics in census tract provide much better accuracy.

1.3 Summary of Cost-Benefit Analysis Results

1.3.1 NET ENERGY METERING COST-BENEFIT ANALYSIS

We evaluate the costs and benefits of NEM using two metrics: Our primary metric is a '2020 snapshot' of the cost impact from NEM generators to all ratepayers in the year 2020. We chose 2020 because it is the year our forecast of NEM generation reaches the 5% NEM cap. Calculating the annual cost shift

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does not require a forecast of avoided costs and bills beyond 2020, so it involves less uncertainty. In addition to the net cost in 2020, we evaluate the lifecycle costs and benefits of NEM generators installed in 2012 over an assumed 20-year economic life (2012 to 2031). The lifecycle analysis estimates the costs and benefits over the life of NEM generation systems in a single metric. We use the lifecycle results to estimate per unit costs, benefits, and net costs ($/kWh and $/watt installed) over the life of the generator.

Table 1 shows the net cost of NEM exports to the grid by residential and non-residential customers for each of the three penetration levels. In 2020, with a complete build out of systems to the existing NEM cap, the costs associated with NEM electricity exported to the grid under the current NEM tariffs are approximately $370 million per year, or 1.1% of the utility revenue requirement.

Table 1: Net Cost of NEM Generation Exports in 2020 (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$61	$85	$291
Non-Residential	$18	$41	$79
Total	$79	$126	$370
% of Revenue Requirement	0.23%	0.36%	1.06%

Table 2 shows the net cost of all NEM generation by residential and non-residential customers for each of the three penetration levels. The costs associated with all NEM generation are forecast to be approximately $1.1 billion per year in 2020 (in $2012). This is approximately 3.1% of the forecasted utility revenue requirement.

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Table 2: Net Cost of All NEM Generation in 2020 (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$182	$250	$794
Non-Residential	$70	$170	$299
Total	$252	$420	$1,093
% of Revenue Requirement	0.72%	1.20%	3.13%

Approximately 2/3 of the net transfer is from residential NEM systems, with 1/3 of the net transfer from non-residential NEM systems. This is despite non-residential systems accounting for 56% of the installed NEM capacity.

The bill savings for NEM customers are entirely a function of the retail rate designs for each customer class and utility. In particular, there are significant differences between residential and commercial customer rates. For the mix of systems installed in 2012, the cost impact from residential NEM systems is significantly greater (levelized net cost of $0.20/kWh generated) in the All Generation case than the cost impact from non-residential systems (levelized net cost of $0.08/kWh generated) due to the residential inclining block rate design. Relative to the residential rates, the commercial rates generally include lower energy charges as well as demand charges related to the customer peak load. Because NEM systems tend to reduce net energy consumption by a greater percentage than they reduce peak demand, residential NEM customers tend to experience greater bill savings than commercial customers.

Table 3 and Table 4 show the levelized net cost of residential customers broken out by customer size. The larger customers are generally customers in the

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higher inclining block tiers. These results indicate that possible changes to the residential rate structure could have significant impacts on the costs associated with residential NEM generation.

Table 3: Levelized Cost of NEM for Residential Customers by Usage Bin - Export Only (Levelized $/kWh)

Customer Usage	PG&E	SCE	SDG&E	All IOUs	No. of Customers
< 5 MWh	0.01	0.03	0.05	0.03	12,370
5 to 10 MWh	0.08	0.08	0.10	0.09	45,170
10 to 25 MWh	0.21	0.15	0.17	0.17	70,462
25 to 50 MWh	0.29	0.22	0.24	0.25	7,995
50 to 100 MWh	0.27	0.25	-	0.26	354
100 to 500 MWh	0.31	-	-	0.31	18
Average	0.17	0.14	0.14	0.15	-

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Table 4: Levelized Cost of NEM for Residential Customers by Usage Bin - All Generation (Levelized $/kWh)

Customer Usage	PG&E	SCE	SDG&E	All IOUs	No. of Customers
< 5 MWh	0.02	0.03	0.05	0.04	12,370
5 to 10 MWh	0.14	0.11	0.15	0.13	45,170
10 to 25 MWh	0.29	0.18	0.23	0.23	70,462
25 to 50 MWh	0.35	0.23	0.26	0.28	7,995
50 to 100 MWh	0.33	0.25	-	0.28	354
100 to 500 MWh	0.35	-	-	0.35	18
Average	0.26	0.17	0.19	0.20	-

In the remainder of the report we provide significantly more detail and disaggregation of the results for each of the respective analyses, as well as results of sensitivities. In addition, a spreadsheet tool of calculations and results has been made available to enable further disaggregation and testing of additional sensitivities.

1.4 Summary of Cost of Service Results

The full cost of service analysis looks at the degree to which NEM customers pay bills commensurate with their estimated share of the total utility cost of service. In the full cost of service analysis we find that both the residential and non-residential customers look significantly different than typical customers. Residential NEM customers who install renewable DG are larger than the average residential customer. Because of the utility tiered rate structures, residential NEM customer bills were 54% greater than their cost of service, on

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average, before the installation of NEM generation. Non-residential NEM accounts had bills that exceeded their full cost of service by 22%. In the residential class, the differences were largely explained by the customer size and tiered rates. In the non-residential class, the reasons are linked more to an account's usage pattern, rather than total usage.

After the installation of NEM generation, the aggregate gap between bills and the full cost of service shrinks dramatically. Whereas total annual bills were $175 million in excess of the full cost of service before DG, the difference is only $12 million after DG. The relative changes to bills and full cost of service, however, are not uniform across all utilities and customer sectors. Table 5 shows that, with renewable DG, NEM residential customers pay 81% of their full cost of service compared to 154% before DG, and non-residential NEM customers pay 112%, compared to 122% before DG. Overall, based on limited information for a single year, the NEM accounts appear to be paying slightly more than their full cost of service.

Table 5: Percent Cost of Service Recovery from NEM Customers in 2011 With and Without DG Systems (% of Full Cost of Service)

	PG&E		SCE		SDG&E		All IOUs	
	Without DG	With DG	Without DG	With DG	Without DG	With DG	Without DG	With DG
Residential	171%	88%	152%	86%	101%	54%	154%	81%
Non-Residential	128%	106%	110%	105%	124%	122%	122%	112%
Total	146%	99%	122%	100%	119%	111%	133%	103%

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1.5 Public Purpose Charges

In 2020, with a complete deployment of systems to the NEM cap, NEM customers avoid approximately $142 million in public purpose charges, or about 6.3% of the total estimated 2020 public purpose funding.

Table 6: Bill Savings in Public Purpose Charges from NEM in 2020 ($2012 Million/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$15	$21	$66
Non-Residential	$17	$48	$76
Total	$32	$69	$142
Total as % of Total Public Purpose Charges	1.4%	3.1%	6.3%

1.6 Income Distribution of NEM Participants

Within the residential sector, we find that the customers installing NEM systems since 1999 have an average median household income (based on IOU-provided data at the census tract level[7]) of $91,210, compared to the median income in California of $54,283 and in the IOU service territories of $67,821. Figure 1 shows the 2010 household income in the census tract of the customers that installed NEM generation since 1999 and the IOU and California median household incomes overall. The median household income of NEM customers

[7] Some data was provided at the more granular census block group level.

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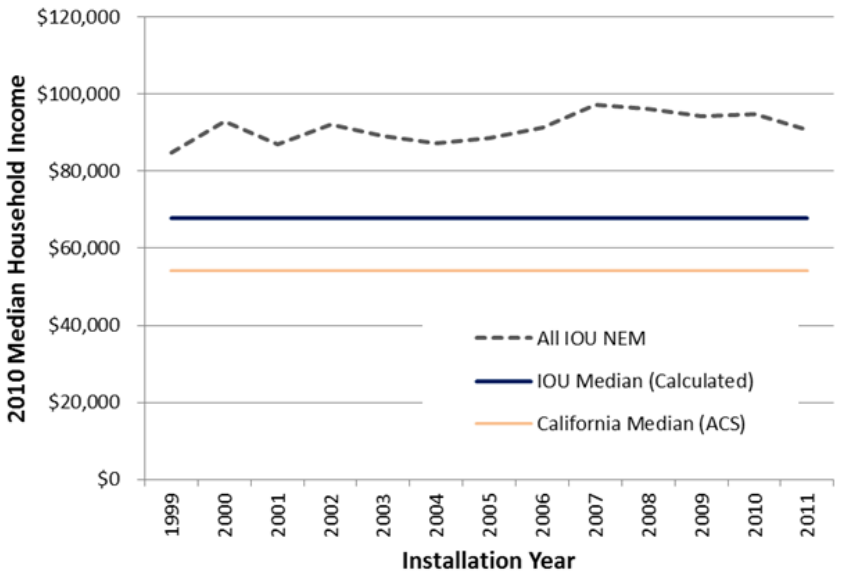
has been relatively consistent since 1999, but peaked in 2007 and has been declining moderately since.

Figure 1: NEM 2010 Household Income by Installation Year Compared to IOU and California Median Income



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2 Introduction

2.1 Net Energy Metering (NEM) Program Overview

Under NEM tariffs,[8] customers with DG receive a bill credit for energy generated in excess of electric load that is exported to the grid. In this study we evaluate both renewable NEM, which provides credits at the full retail rate (including generation, transmission, and distribution rate components) for solar, wind, and technologies using bioenergy, as well as the separate fuel cell NEM program, which provides credits at the generation only component of the rate for fuel cells, including those that operate on natural gas. Bill credits are applied each month against charges for hours when the customer's load exceeds the customer's generation. Any excess bill credits remaining in a billing month are carried forward for up to one year. Eligible customer generators who produce electricity in excess of on-site load over a 12-month period may elect to receive net surplus compensation, or apply the net surplus electricity as a credit toward future consumption.

[8] See Appendix G for P.U. Code 2827 (b) (5)

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2.1.1 CALIFORNIA NEM POLICY AND COORDINATED PROGRAMS

There are a number of rules and decisions that affect the overall compensation under California's NEM policy. This section outlines the key rules and decisions that are accounted for in the analysis.

2.1.1.1 Incentive Programs

Any customer meeting the eligibility requirements may convert to a NEM electric rate. NEM participants may have generation installed through an incentive program, such as the Self-Generation Incentive Program (SGIP) or California Solar Initiative (CSI), or of their own accord.

2.1.1.2 AB 920 and Net Surplus Compensation

In 2009, AB 920 (Huffman) amended the law to allow customers, beginning in January 2011, to receive compensation for annual net excess generation. For any net excess energy exported to the grid at the end of the year, compensation is based on each utility's default load aggregation point (DLAP) price on a 12-month rolling average plus a Renewable Energy Credit (REC) premium (applicable to customers that are in compliance with the Renewables Portfolio Standard (RPS) Guidebook).[9] The DLAP compensation rate fluctuates with market prices, and is currently about $0.04/kWh for net surplus generation.

[9] See Decision (D.) 11-06-016 at http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/137431.htm

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2.1.1.3 Free Interconnection

Pursuant to Commission D.02-03-057, NEM customers are exempt from interconnection application fees, study costs, and distribution upgrade costs.

2.1.1.4 Standby Charge Exemption

California Public Utilities (PU) Code Section 2827 states that eligible customer-generators cannot be assessed standby charges on the electrical generating capacity or the kilowatt-hour production of a renewable electrical generation facility.

2.1.1.5 Non-bypassable Charge Exemption

Pursuant to Commission D.03-04-030, NEM customer generation that is under 1 MW in size and eligible to participate in NEM is exempt from certain non-bypassable charges.

2.1.1.6 Renewable Energy Credits

NEM customers own the renewable energy credits for the generation on their facilities. In practice, most 3rd party solar installers 'purchase' these RECs as part of the contract to install solar. However, due to the relatively high costs associated with tracking and verifying RECs, the ultimate market for these credits associated with NEM generation is uncertain. Therefore, in this study we assume RECs will eventually be retired without transfer, and that renewable NEM generation does not directly reduce the utility RPS obligation through the generation of renewable energy.

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2.2 Analysis Framework

This study evaluates the cost impacts of NEM using two approaches. The first approach compares the bill savings of customers who install NEM systems to the reduction in utility costs attributable to having the NEM system. Throughout the report we refer to this as the NEM 'cost-benefit analysis'. The cost-benefit analysis is based on the change in NEM customers' bills due to NEM generation compared to the associated change in utility costs. If the bill savings of NEM customers are greater than utility avoided costs, this will ultimately result in a cost increase to other utility customers since the utility is allowed to pass those costs on.

This study is the third study by the CPUC to investigate the impacts associated with net energy metering since 2005. The most recent study was completed in 2010 as part of the overall evaluation of the California Solar Initiative.[10] The 2010 study quantified the cost impacts associated with exports from NEM for solar PV systems. The CPUC also conducted a study in 2005.[11]

This study is designed similarly to the 2010 study, but includes a broader scope based on the requirements of AB 2514 and Commission D. 12-05-036. In particular, this study includes an estimate of the cost impacts of all of the output from NEM generation, as well as the proportion attributable to exported energy, for all NEM technology types.

[10] http://www.cpuc.ca.gov/NR/rdonlyres/0F42385A-FDBE-4B76-9AB3-E6AD522DB862/0/nem_combined.pdf
[11] http://docs.cpuc.ca.gov/WORD_PDF/REPORT/45133.PDF

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In the second approach, called 'full cost of service,' we evaluate whether NEM customers are paying their full cost of service as defined by the investor-owned utilities (IOUs). To do this, we compare the actual customer bill with NEM to the full cost of service as calculated by each utility in their General Rate Case (GRC). We are not aware of a prior CPUC analysis (outside of the GRC process) to estimate the full cost of service, so there are some caveats. For example, there are differences in each utility's approach to estimate full cost of service so the results are not perfectly comparable. In addition, it is difficult to exactly replicate the cost of service analysis for a sub-set of customers participating in NEM since the utilities evaluate cost of service at the customer class level.

Figure 2 illustrates the cost-benefit analysis approach. We calculate the NEM bill with and without the NEM generation to estimate savings, then calculate the utility avoided cost. The net cost is the change in customer bills less the utility avoided cost. If the bill savings are greater than the avoided cost then there will be a cost shift to other customers to make up for the shortfall.

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Figure 2: Illustration of the Cost-Benefit Calculation

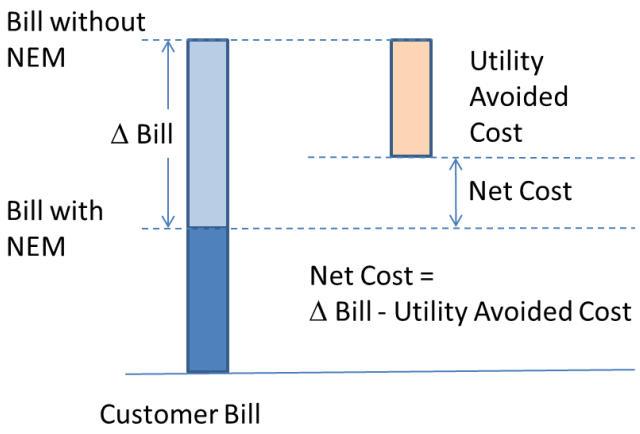

Figure 3, below, illustrates the cost of service approach for NEM customers. First, we compare the bills and the full cost of service of NEM customers without the NEM generation. This provides a customer characterization of the customers who choose to install NEM generation. Then, we compare the customer bills with the NEM generation to the full cost of service with the NEM generation. This comparison shows the contributions of NEM customers to their full cost of service after the installation of NEM generation.

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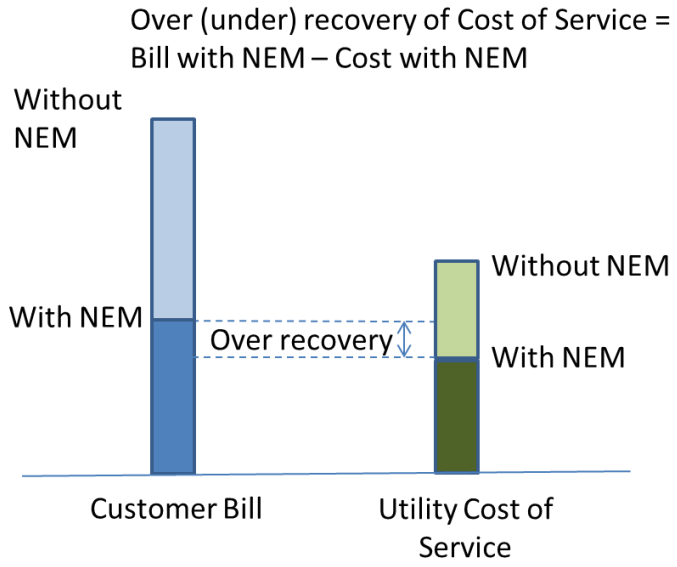
Figure 3: Illustration of the Cost of Service Approach



2.3 Terminology Employed

In this report, descriptions and results are often labeled as pertaining to a certain "sensitivity," "penetration level," or "case. These names are standardized as follows:

2.3.1 SENSITIVITY

In the cost-benefit analysis, we present base case results that reflect our best estimate of the cost and benefits of NEM. The key sensitivity variables are described in Table 7, below.

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Table 7: Sensitivities

Sensitivity	Description
T&D Avoided Costs	This sensitivity calculates results without transmission and distribution (T&D) avoided capacity value.
Natural Gas Prices	We test both high and low alternative natural gas price forecasts as sensitivities. These are based respectively on the Long Term Procurement Plan (LTPP) high gas case and flat real prices. These forecasts use the methodology developed in the CPUC's Market Price Referent (MPR) decisions[12].
CO2 Price	We calculate a low and a high sensitivity with the CO2 price at the CO2 allowance price floor and soft ceiling. Both of these extremes grow at 5% plus inflation through 2030.
Resource Balance Year	We evaluate a sensitivity whereby NEM generation receives the full generation capacity throughout the study horizon rather than a future resource balance year.
Solar Effective Load Carrying Capability	We evaluate a sensitivity whereby the Effective Load Carrying Capability (ELCC) is tied to the vintage of the installation. So, for example, a solar NEM customer installed in 2013 receives the ELCC for 2013 throughout its operating life.
Retail Rate Escalation	We develop high and low electricity retail rate escalation forecasts using the CPUC LTPP model. These forecasts are based on the high and low gas and CO2 price forecasts.
Standby Charges	NEM customers are exempt from standby charges, but we conduct a sensitivity in which non-residential customers would be required to pay standby charges in the absence of NEM.
Metering and Set-up Cost	NEM metering and set-up costs, incremental to standard customer metering and set-up costs, have historically been diminishing each year. We run a low sensitivity wherein these incremental costs are set to zero.
Interconnection Cost	Only limited interconnection cost data on non-reimbursed ratepayer costs were available. We test a range around the data available.
Integration Cost	It is possible that higher penetrations of DG will require higher costs to integrate with the grid. We run a high and low sensitivity of NEM generation integration costs.

[12] See http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr

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To organize all of these sensitivities, we group two opposing sets of decisions across all of these variables that represent a case where NEM is less cost-effective from a ratepayer perspective, or "Low Case," and a more cost-effective case, or "High Case." These cases aim to represent the reasonable bookends that one may consider in the cost-benefit analysis. The assumptions for each of these cases, and for the "Base Case" used in our analysis, are listed in Table 8.

Table 8: Definition of Sensitivities

Component	Base Case	NEM LESS Cost-Effective 'Low Case'	NEM MORE Cost-Effective 'High Case'
T&D Avoided Costs	Included	Excluded	Included
Natural Gas Prices	MPR forecast	Flat in real terms	LTPP high case
CO2 Price	MPR forecast	Cap-and-trade floor price	Cap-and-trade soft ceiling price
Resource Balance Year	2017	2025	2007
Solar Effective Load Carrying Capability	Based on analysis year; 2013 to 2020	Based on analysis year; 2013 to 2020	All systems awarded 2013 ELCC value
Retail Rate Escalation	2.61% average annual increase from 2011 to 2030	2.50% average annual increase from 2011 to 2030	3.02% average annual increase from 2011 to 2030
Standby Charges	Excluded from bill savings	Included in bill savings	Excluded from bill savings
Metering and Set-up Cost	Equal to 2011 values	Equal to 2011 values	No incremental cost assessed to NEM
Interconnection Cost	Equal to 2011 values	150% of 2011 values	50% of 2011 values
Integration Cost	$2.50/MWh	$5.00/MWh	None

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We use "sensitivity" to refer to the Base Case, Low Case, or High Case set of assumptions being used to determine the values of various avoided cost, bill calculation, and program cost parameters.

2.3.2 PENETRATION LEVEL

In this study we investigate the cost-shifting associated with NEM at three penetration levels. The penetration level refers to the total amount of installed NEM generation. The three penetration levels evaluated in this study are: (1) the amount of NEM generation installed at the end of 2012 (1,905 MW), (2) the amount installed at the end of the CSI program for each utility and customer class (2,916 MW), and (3) the amount installed at the 5% NEM cap (5,573 MW).

2.3.3 GENERATION CASES: EXPORT ONLY VS. ALL GENERATION

In this study, we calculate all results considering two generation 'cases.' In the first case, we estimate the cost impact that is attributable to energy that is exported to the grid. This approach disregards NEM generation produced and consumed on the customer premise and captures the specific mechanism that is enabled by NEM. In the second case, we calculate any cost impact attributable to the entire output of the NEM generator, including output that serves load at the NEM customer site and is not exported to the grid. To the extent NEM compensation enables the whole DG project to be viable, and the total output of the project results in a cost to non-NEM customers, the entire NEM generation is the appropriate scope to measure the impact on non-NEM customers. These cases are referred to as either "Export Only,' which includes only the electricity exported to the grid, or 'All Generation,' which includes all of the generation from the NEM generator.

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2.3.4 COST UNITS AND LEVELIZATION

The cost units of this study are primarily dollars per year in 2020 (using $2012). The reason we choose a 'snapshot' in time is that the result is much less dependent on a number of uncertain input assumptions, such as retail rate escalation and the discount rate. In addition, we report two lifecycle values as $/watt installed and levelized $/kWh based on a 20-year economic life from 2012 to 2031.

2.3.4.1 Metric and Unit Definitions

$/year: These units are the cost, benefit, or net cost in a given year in nominal dollars. The majority of the results presented in $/year are the cost, benefit, or net cost in 2020 (in $2012). This metric is used as a primary result because it is much less sensitive to the assumptions on retail rate escalation, and the discount rate.

Levelized $/kWh: The levelized $/kWh is calculated on a nominal levelized basis over a 20-year life. The majority of levelized results are based on the installations in 2012. For example, $0.10/kWh levelized means that the value stream is equivalent to a constant $0.10/kWh every year from 2012 to 2031.

Lifecycle $/W: The lifecycle $/W metric measures the 20-year Net Present Value (NPV) of benefits, costs, or net benefits per installed watt of NEM generation. Again, these metrics are reported for installations in 2012.

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3 Customer Characterization

3.1 Installed NEM Capacity

The vast majority of NEM customers in California are solar PV (99% of accounts, and 96% of capacity). In this study, we used NEM customer information through 2011 to forecast future NEM installation rates and profiles. At the end of 2011, more than 122,000 customer accounts from California's three large IOUs under CPUC jurisdiction were enrolled in NEM. These accounts had approximately 1,110 MW of installed generation and generated about 2,200 GWh of electricity.

For the purposes of our analysis we disaggregated the NEM customers in 2011 by customer class and technology type using lists of NEM customers from each utility, their associated system characteristics (size, technology, orientation of solar, and output), and the associated billing data for each customer. The breakdown of the resulting NEM customers installed through 2011 - including solar, wind, and fuel cells - is shown in Table 9. There were also approximately 20 bioenergy generators installed in California by the end of 2011 and a few NEM generators with unidentified technology type, however, the necessary billing data and customer information was insufficient to characterize them in our analysis.

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Table 9: NEM Customer Information Through 2011

Utility	PG&E		SCE		SDG&E		Total
	Res	Non-Res	Res	Non-Res	Res	Non-Res	All
Solar							
Number of Systems	69,269	4,159	24,080	4,959	17,228	1,895	121,590
MW Installed	289	361	105	233	61	54	1,104
Estimated GWh	544	679	198	439	115	101	2,075
Wind							
Number of Systems	96	53	217	32	30	4	432
MW Installed	1	1	2	0	0	0	4
Estimated GWh	1	2	3.1	0.32	0	0	7
Fuel Cell							
Number of Systems	15	25	19	12	0	5	76
MW Installed	0	8	0	5	0	1	15
Estimated GWh	0.54	58	1	33	0	9	100
All NEM Generators							
Number of Systems	69,380	4,237	24,316	5,004	17,257	1,903	122,098
MW Installed	290	371	107	238	62	55	1,123
Estimated GWh	545	739	202	472	116	110	2,183

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3.2 Forecasted Penetration Levels

We developed a base forecast through 2020 of installed NEM generation based on the historical installation rates by technology type and utility territory through 2011. We then used the historical data and imposed two temporally-dependent capacity limits on the forecast to create three 'penetration levels' of NEM adoption:

1) The installed capacity at the end of 2012 ("2012 Snapshot")

2) The installed NEM capacity when the CSI goals are met ("Full CSI Subscription"), and

3) The capacity needed to reach the 5% net metering cap as defined by D. 12-05-036 (Full NEM Subscription).

The forecasts of future NEM installations used to determine customer distributions for the full CSI and full NEM subscription levels are based on regressions using installation data from 2007 through 2011. Figure 4, below, shows the historical adoption rate from 2007 through 2011 (solid line) and the forecast of each class through 2020. The accuracy of this forecast is not critical for the 2012 'Snapshot' case, for obvious reasons, nor is it critical for the 2020 5% NEM adoption case, since this total is based on the 5% NEM limit. This forecast does affect the Full CSI case to a greater degree. Overall, however, the results in 2020 are not sensitive to the growth forecast so long as the 5% NEM cap is reached by 2020.

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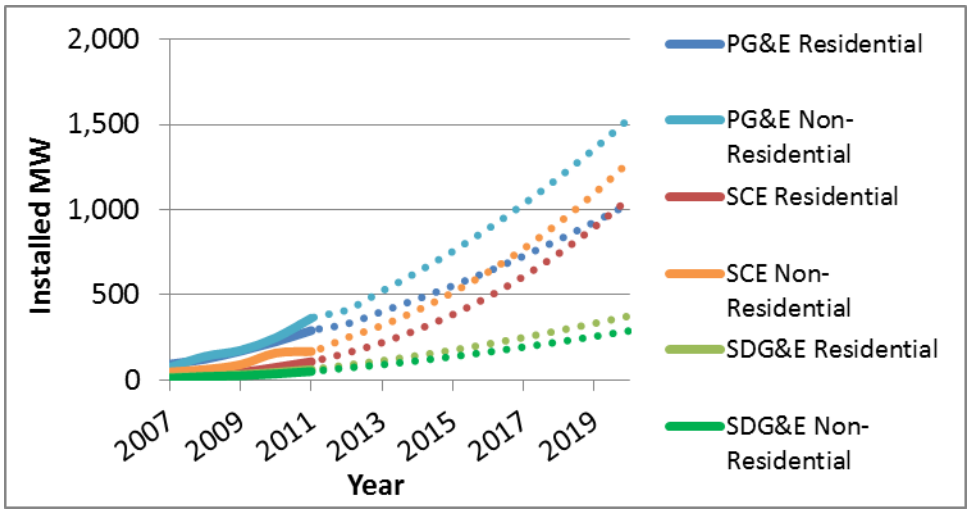
Figure 4: Forecast of NEM Adoption by Utility and Customer Class



Based on this forecast, the CSI tiers are exhausted for each utility and customer class between 2013 and 2019. Table 10, below, shows the year in which the total capacity would be subscribed for each utility and customer class. To develop the penetration level for the Full CSI Subscription scenario we use the installed NEM generation at the end of the year when the last Tier is exhausted for each utility and customer class. In addition to CSI installations, this penetration level also includes all other NEM-eligible technologies, for which we use the total installed generation at the end of the year, even if the tier is reached mid-year.

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Table 10: Projection for Fully Subscribing CSI Tiers

	PG&E		SCE		SDG&E		All IOUs
	Res	Non-Res	Res	Non-Res	Res	Non-Res	Total
Forecast Year CSI Goal Reached	2013	2015	2014	2019	2013	2019	2019
Total CSI MW (At CSI Goal)	252	512	266	539	59	121	1,750
Total Installed NEM MW (At CSI Goal)	402	755	295	1095	113	256	2,916

Based on this forecast, the 5% NEM cap as defined by D. 12-05-036 will be reached in approximately 2020. We calculate the 5% non-coincident cap, defined by the CPUC as a 4-year historical average of non-coincident peak loads, by multiplying the prior four years of historical coincident peak loads by factors developed by the IOUs that reflect diversity of customer loads. The resulting statewide NEM cap in 2020 is approximately 5,573 MW. The load forecast is from the mid-case 2012 California Energy Commission IEPR load forecast[13] and the diversity factors are from utility filings.[14]

Figure 5 displays the total MW of DG installed under each penetration level by customer class and IOU. The number at the top of each bar gives the total terra-watt-hours (TWh) generated by the installed systems, and the parenthetical values in the legend are the average capacity factors of the installed DG.

[13] http://www.energy.ca.gov/2012_energypolicy/documents/demand-forecast/mid_case/

[14] See diversity factors from PUC workshop presentation (http://www.cpuc.ca.gov/NR/rdonlyres/C89C6BF8-9A37-4DF8-BF2E-2A9C8FDD1B8D/0/CPUC_NEM_Workshop_062512C.PPTX)

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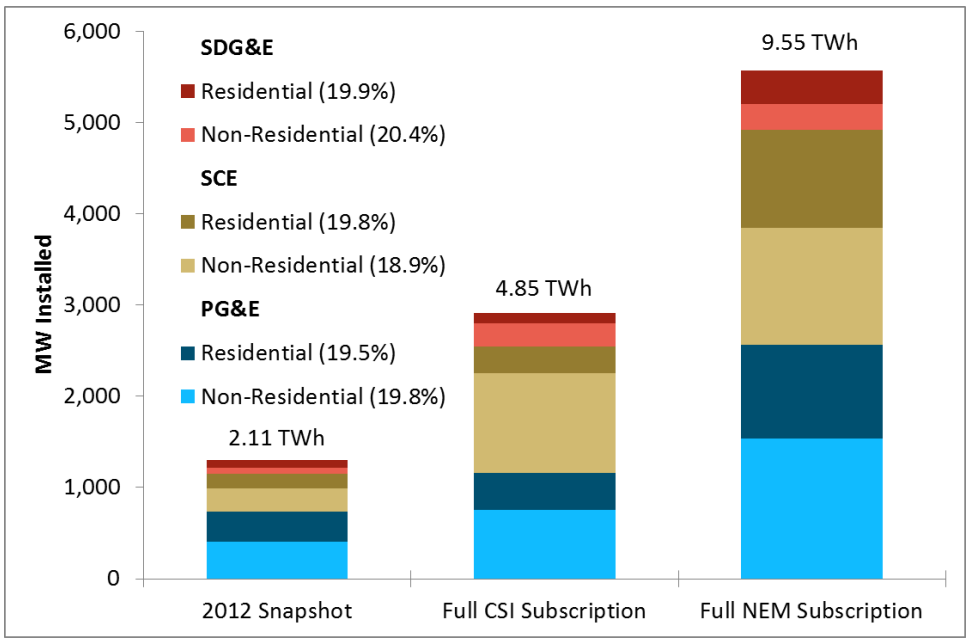
Figure 5: Installed DG Capacity by IOU and Customer Class at Each Penetration Level



3.3 Data and Methodology for Estimating NEM Customer Profiles

In order to develop an accurate assessment of any of our four analyses, we need a detailed view of the consumption and generation characteristics of NEM customers. With this data, it is possible to calculate the *amount* and *timing* of generation serving onsite load and being exported to the grid and, thereby, the associated costs and benefits to the utility and to its customers. Because most of the available data for this study did not provide a precise enough measure of the amount and timing of energy generated and energy consumed onsite, we used metered generation data to simulate missing generation and used

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representative customer usage shapes to convert actual billing data to a more granular level. We then clustered customers into homogenous "groups" and developed representative customer "bins" based on these groups. These customer bins facilitate manageable computations and transparent display of data. They are used throughout the analysis to estimate the costs and benefits of NEM. This section discusses the data we received, our methodology for estimating sub-hourly customer generation and usage data, and the process used to create representative customer profiles.

3.3.1 DATA AVAILABILITY AND ISSUES

To measure the costs and benefits of NEM, as we define them in subsequent chapters, the following data is needed for each customer:

- Hourly or sub-hourly gross consumption (total energy consumed from the grid and from the DG system) for each hour of the year being evaluated
- Hourly or sub-hourly gross generation (total output of the DG system) for each hour of the year being evaluated

E3 requested several large data sets from the utilities that were used to compile a list of all NEM customers, and to create load and generation shapes for them. These data sets include:

1. NEM customer lists
2. Billing data for NEM customers
3. Metered DG output and bidirectional meter data
4. Load research data

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The NEM customer lists provide the installation details of 100,550 NEM systems installed through the end of 2011, representing over 1,040 MW of installed capacity. In addition to providing a nearly comprehensive list of NEM accounts, these data are linked to the billing data to provide DG system size, utility rate and heating code, location, and several other details.

The billing data for NEM customers covered over 85,000 customers during 2011, and provides the annual consumption totals for all NEM customers that we model.

Sub-hourly DG output or bidirectional meter data are available for 6,251 NEM customers. In addition to being used directly in the analysis, these data are utilized to improve simulation of DG output for systems with missing generation data.

The load research data set is comprised of sample sub-hourly usage data of IOU customers. These data are used, along with billing and generation data, to estimate gross usage shaped of NEM customers.

We also received 2011 SolarAnywhere weather data from Clean Power Research to enable us to do simulation of sub-hourly generation for NEM systems for which we did not have metered generation data.

As described in the next section and in Appendix A, we combine all of these data sets to estimate sub-hourly generation and usage for actual NEM customers. We then use these customers to create representative NEM customer profiles (‘bins’).

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3.3.2 METHODOLOGY FOR ESTIMATING SUB-HOURLY NEM GENERATION AND CONSUMPTION FOR REPRESENTATIVE CUSTOMERS

We use the available data to estimate sub-hourly generation and consumption for actual NEM customers and create representative customer 'bins' by means of the following process:

1. Assign 2011 sub-hourly gross generation (total output of the DG system) shapes for each customer

2. Calculate 2011 annual gross consumption for each customer by adding the customer's assigned DG output to the customer's actual billed monthly net load

3. Estimate 2011 sub-hourly gross consumption (total energy consumed onsite from the grid and the DG system) shapes for each customer using load research data

4. Obtain a 2011 sub-hourly net consumption shape for each customer by subtracting assigned DG output from estimated gross consumption

5. Create 'bins' of representative NEM customer profiles, each with one sub-hourly generation and one sub-hourly consumption shape

6. Convert 2011 representative customer generation and usage profiles into typical metrological year (TMY) profiles

Each of the main steps is described in more detail in the subsequent sections.

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3.3.2.1 Sub-Hourly Gross Generation Estimates

We used a combination of actual and simulated generation data to estimate sub-hourly gross generation (total output of the DG system) shapes for each NEM customer over the course of 2011. Metered DG output data provided actual half-hourly DG output for over 7,000 systems over the course of 2011. With the DG system specs contained in the NEM customer lists, and information from the CSI PowerClerk database, we were able to simulate DG output using 2011 SolarAnywhere weather data from Clean Power Research to fill in any gaps in the metered data, and for any systems not contained in the set of metered data.

3.3.2.2 Sub-Hourly Gross Consumption Estimates

Estimating sub-hourly gross consumption profiles for individual NEM customers entailed a two-step process.

First, we developed *annual* gross consumption profiles. Annual *net* consumption (total consumption minus the output of the DG system that served onsite load) for all customers in our analysis was provided by the utility billing data. To estimate annual *gross* consumption, we simply added the estimated annual gross generation to the measured annual net consumption.

In order to get from *annual* gross customer consumption to *sub-hourly* customer consumption estimates, we then scaled load research data, or sub-hourly usage data for non-NEM customers, to match the correct annual gross load of the customer it is being used to represent. Each customer received one load research match based on location, rate, and usage profile, with the

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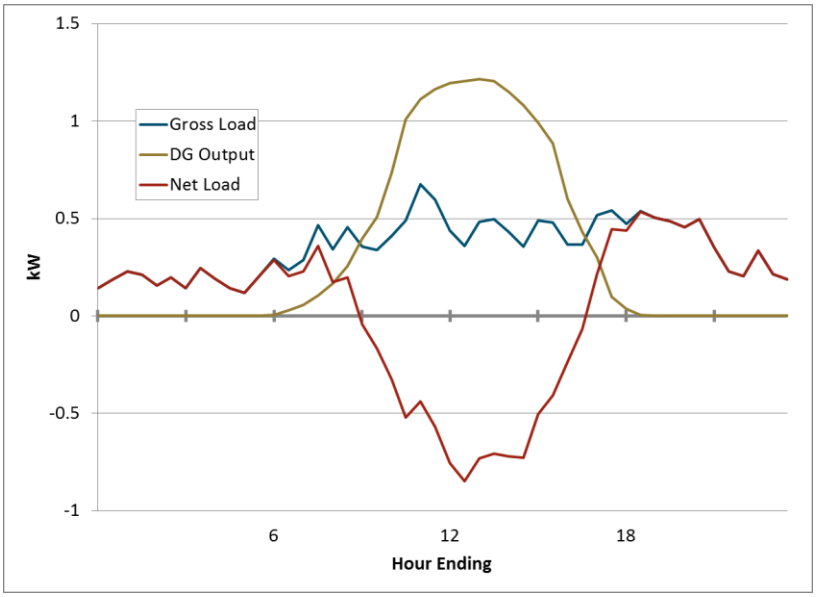
exception of customers for whom no good match could be found (difference in annual consumption of the two profiles was greater than 20%).

3.3.2.3 Sub-Hourly Net Consumption Estimates

Subtracting the metered or simulated DG output for the NEM customer profiles from the gross customer load profiles yields half-hourly net load profiles for individual NEM customers.

Combined, this approach provides estimates of gross load, net load, and generation for any given NEM customer. The net load profile for an example customer on a summer day is shown in Figure 6.

Figure 6: Load and DG Generation for an Example Residential Customer



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3.3.2.4 Representative NEM Customer Bins

To reduce computational requirements, and make the analysis possible to display in the public NEM Summary Tool, we create 'bins' of representative NEM customers. Each bin is depicted by one gross consumption shape, one gross generation shape, and a number of other customer characteristics. These consumption profiles, generation profiles, and customer characteristics are treated in the analysis as the consumption, generation, and customer characteristics of every single NEM customer represented by the bin. The number of NEM customers represented by each bin is scaled up and down according to capacity forecasts, but per-customer generation and usage remain constant throughout the analysis. In all, there are 9,458 bins of representative customers with wind or solar generation and 31 fuel cell bins.

Creating bins involved a two-step process:

1. We divided actual NEM customers into 'groups' that are relatively homogenous in terms of customer characteristics and usage.

2. We created 1-4 customer bins for each customer group. Each bin was assigned a generation and consumption profile of one of the customers in the original group, and then these profiles were scaled to the mean annual generation, annual consumption, and NEM generator capacity of all customers in the group.

In the first step, we grouped customers based on the following customer characteristics:

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- **Utility**: Customers receiving service from each of the three IOUs were grouped separately.

- **Customer class**: The customer classes used were residential, agricultural, and commercial/industrial.

- **Utility territory**: Twenty-three territories across the three IOUs were used to establish customer baselines. Classification by territory captures much of the variation in climate and other geographically-driven customer and building characteristics. Some territories were combined based on geographical proximity and rate baseline similarity.

- **DG technology**: Customers were further divided by generation type; customers with PV and wind generation were grouped separately from customers with only one generation type.

- **Retail rate**: All customers in each group are on the same utility retail rate.

- **Rate baseline**: Customers with electric heating and medical baseline allowances were grouped separately from those without these additional baseline allowances. In a few cases where there were no customers with load research matches on a medical baseline in a given group, customers were grouped with customers that shared every other customer characteristic, as we believe that this was more accurate than excluding these customers from the analysis. This is relevant for tiered rate structures only.

- **Voltage level**: This field denotes the voltage level at which customers receive electricity. Voltage levels comprise basic, primary, secondary, and transmission.

- **Gross annual consumption**: Customers were grouped roughly based on their annual consumption, as calculated from the billing data.

- **Ratio of PV generation to annual gross consumption:** This ratio was calculated for each customer using billing data and actual or simulated

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generation profiles. Customers were grouped based on rough categories of this ratio.

3.3.2.5 Conversion of Customer Profiles to Match Typical Meteorological Year (TMY)

Finally, because these profiles will be used to forecast through the year 2020, we convert from 2011 to a Typical Meteorological Year (TMY) weather profile. This TMY weather is based on the weather files adopted by the California Energy Commission for the Title 24 building standards and represents long-term average weather conditions in California.

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4 Cost-Benefit Analysis

4.1 Cost-Benefit Analysis Approach

In order to evaluate "who benefits from, and who bears the economic burden, if any, of, the net energy metering program"[15] as required in statute we evaluate the costs and benefits of NEM from the perspective of NEM customers (participants) and ratepayers overall. The cost-benefit analysis measures any cost impact of NEM. To the extent that the bill reductions attributed to NEM exceed offsetting benefits, there is a cost shifting from NEM customers to other utility ratepayers. Therefore, the net cost of NEM to ratepayers is the sum of ratepayer costs (bill savings, incremental billing costs, and integration costs) less ratepayer benefits (avoided costs).

This comparison is made considering (1) the exported portion of NEM generation, and (2) the entirety of NEM generation. The calculations for these two generation cases for an example customer on a summer day are shown are shown in Figure 7 and Figure 8.

[15] Quote is from AB 2514, the full text of which is provided in Appendix G.

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Figure 7: Calculation of "Export Only Generation" for an Example Customer and Day

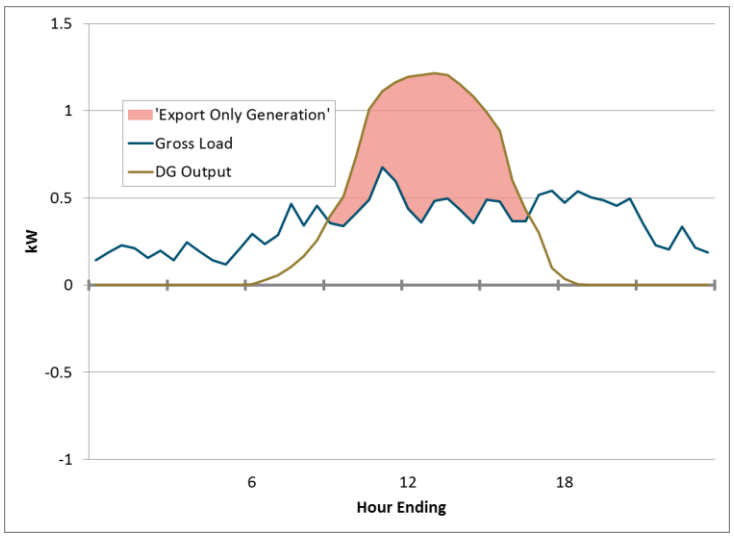
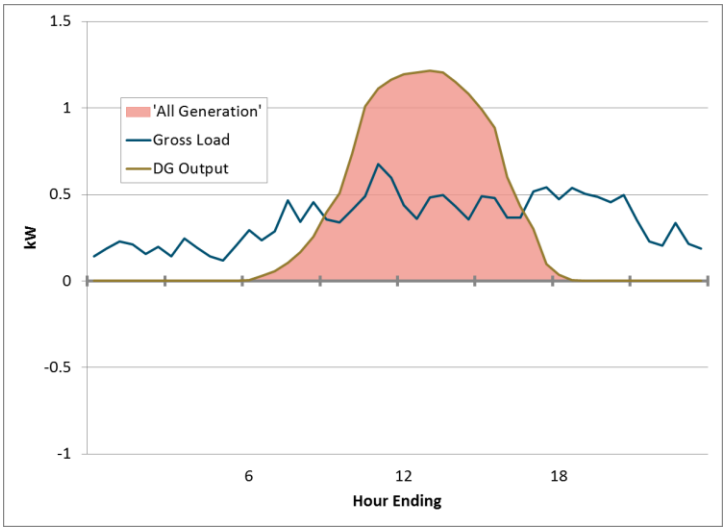


Figure 8: Calculation of "All Generation" for an Example Customer and Day



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In this study, total generation and exported generation is measured on a half-hourly basis. Total monthly exported generation is computed as the sum of each of the half-hourly estimates.

The summary the cost-benefit calculation of each approach is as follows:

1. Export Only Net Cost (Benefit) = Bill Savings of Export Only + Program Costs - Avoided Cost of Export Only

2. All Generation Net Cost (Benefit) = Bill Savings of All Generation + Program Costs - Avoided Cost of All Generation

Figure 9 shows the formulation of the cost-benefit analysis, including the derivations of each of the key calculation components: Bill Savings, Program Costs, and Avoided Costs.

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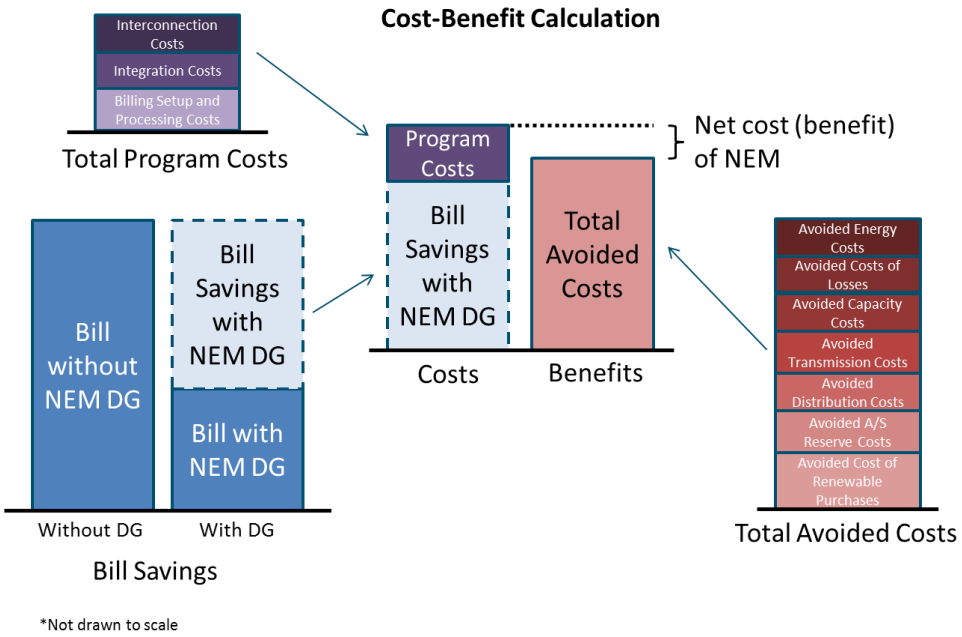
Figure 9: Formulation of the Cost-Benefit Calculation



Bill savings are a cost to ratepayers. NEM customer-generators receive benefits in the form of bill savings, which in our analysis are calculated to include any reduction in bills from exported energy, or arising from AB 920 implementation. Every dollar of bill savings received by NEM customers is a direct reduction in utility revenues. Since rates are adjusted over time such that utilities meet their revenue requirement, this revenue reduction will be made up by ratepayers. The bill savings are thus a direct cost to ratepayers.

Increased operational costs are a cost to ratepayers. Any additional operational costs resulting from NEM, such as incremental billing administration costs, or integration costs, must be covered by the utility, and therefore by ratepayers.

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Avoided costs are a benefit to ratepayers. The energy delivered by the NEM generators offsets purchases of energy and capacity, and other avoided costs. These savings are evaluated consistently with a long history of avoided cost estimates at the CPUC. In addition, sensitivity analysis is used to define high and low ranges of avoided costs.

The remainder of this chapter of the report describes the calculation of the NEM customer bill savings, avoided costs, and program costs and then presents the cost-benefit results. These results are also benchmarked against the CPUC's 2010 NEM study.

4.2 Bill Savings

Bill savings are the difference between what a NEM customer's bill would be without the NEM generation compared to what the bill is with the NEM generation. To calculate bills, we parse the half-hourly load profiles developed for each customer bin into billing determinants. These determinants are then input into the E3 Utility Bill Calculator, which outputs the annual bills for each customer bin based on 2011 rates. The details of this tool are provided in Appendix B.

Three sets of bills are created using the E3 Utility Bill Calculator: A set based on gross load billing determinants, a set based on net load billing determinants, and a set based on positive net load billing determinants (in which all exports are set to zero). To calculate the bill savings of the Export Only case, we subtract the net load bill from the positive net load bill. To calculate the bill savings of the All Generation case, we subtract the net load bill from the gross load bill.

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The results in this section reflect the aggregate bill savings of all NEM customers across various rates, calculated separately for each penetration level. Figure 10 and Figure 11 show the number of customers on each of the top 10 residential and commercial NEM rates calculated for the 2012 Snapshot case. A total of 75 NEM customer rates are included in this analysis.

Figure 10: Number of Customers on the Top 10 Residential NEM Rates

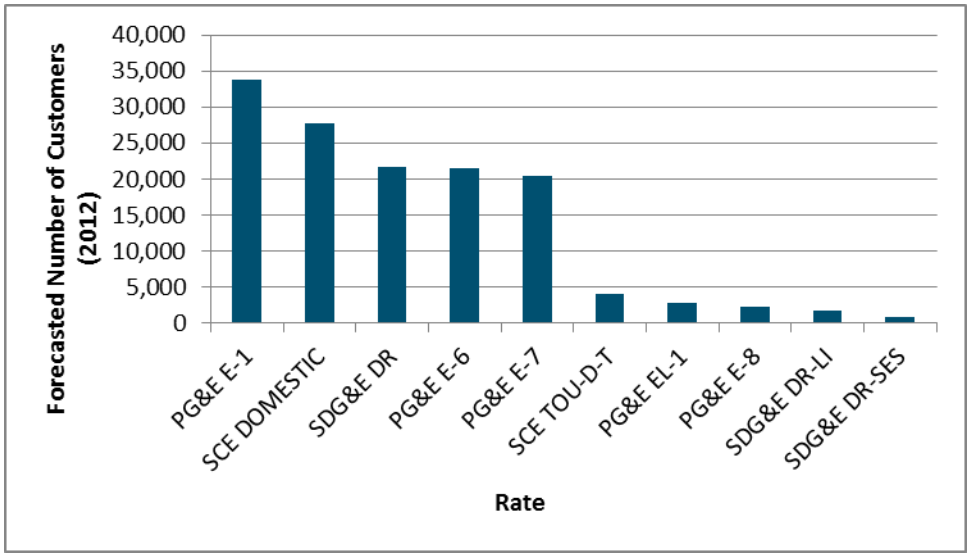

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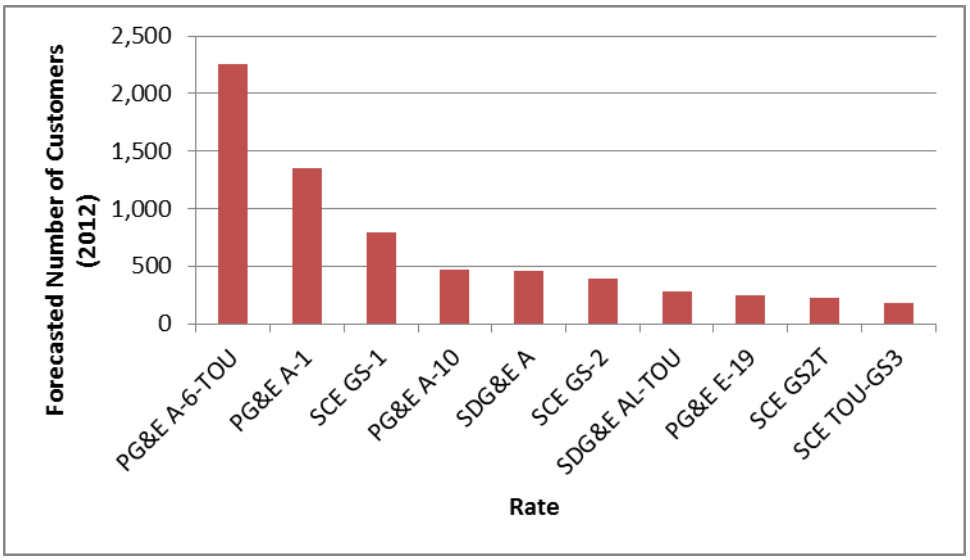
Figure 11: Number of Customers on the Top 10 Commercial NEM Rates



The bill savings for NEM customers are entirely a function of the retail rate designs for each customer class and utility. In particular, there are significant differences between residential and commercial customer rates. The default residential rates and the rates that most NEM customers are on include inclining block rate designs. Under inclining block rate designs, a customer's marginal electricity rate increases with cumulative usage within each billing period. In California, the rate structure is divided into 2-5 tiers where each successive block has a higher rate per kWh of electricity. The commercial rates include generally lower energy charges as well as demand charges related to the customer peak load. Some of the residential and commercial rates vary by time of year and time of day, although more temporal dependency can be found in commercial rates.

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NEM participants are not paid directly for excess generation; instead, they earn credits which can be applied to offset their electricity bills. These credits can be applied only to the energy charge portion of the customers' utility bills. Other charges, including meter charges, demand charges, phase charges, and any other non-energy charges cannot be offset by excess generation credits. However, all charges are calculated based on the customers' net energy usage, so the demand charge portion of the bill can be reduced significantly through NEM participation independent of the value of excess generation. Based on our load research, NEM DG reduces customer billing demand by a substantially smaller percentage amount (approx. 3% of nameplate capacity) than the amount by which it reduces total energy consumption (approx. 20% of nameplate capacity).[16] Therefore, NEM customers on rates with only energy charges experience greater bill reductions, and impose greater costs to their utilities, than customers on rates with demand charges.

Since all of the utilities have tiered residential rates, the amount of consumption relative to generation from residential NEM customers is of critical importance. Figure 12, below, shows the distribution of estimated gross consumption of the residential customers on NEM compared to estimated annual output of the NEM generation. The size of each dot is proportional to the number of customers. A diagonal line is drawn where NEM production equals gross consumption. All customers above this line are net annual exporters. A vertical line is drawn at the approximate average residential consumption in California

[16] Percentage reductions based on 2011 representative customer data. The demand reduction calculation only included representative customers on rates with demand charges.

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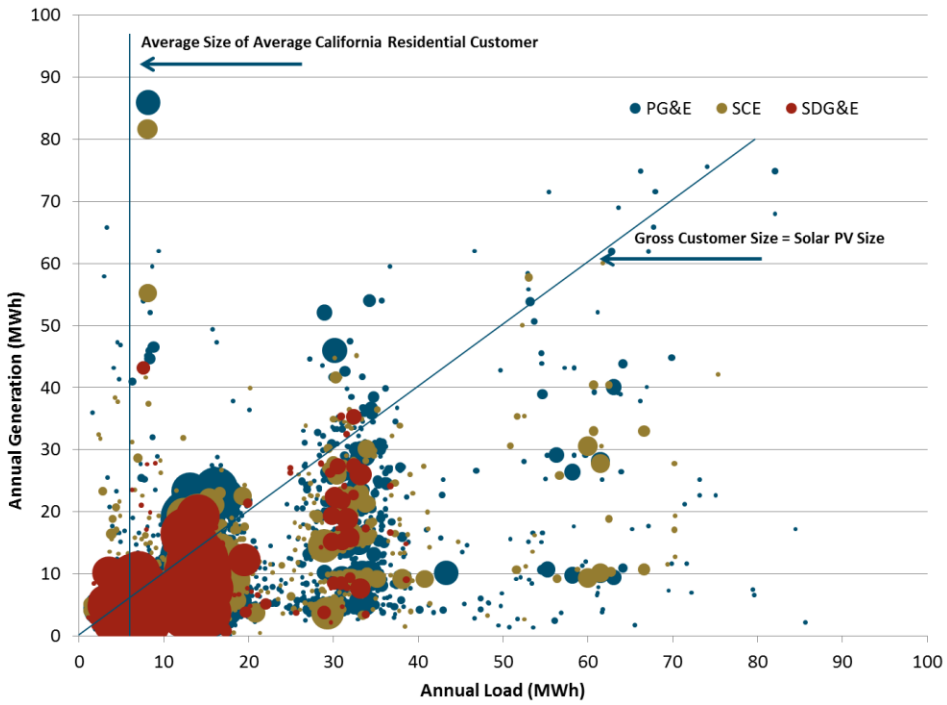
of 6.8MWh per year.[17] This figure shows that the majority of residential NEM customers have greater than average consumption.

Figure 12: Comparison of Gross Residential Load and NEM Generation Size



4.2.1 BILL SAVINGS FROM NEM

Table 11 shows the NEM customer bill savings associated with exports in millions of dollars in the year 2020. These are the savings directly attributable to the NEM incentive mechanism. Because full CSI subscription caps the non-residential class at a higher proportion to total installations than currently

[17] See US EIA http://www.eia.gov/tools/faqs/faq.cfm?id=97&t=3. Note that this includes multifamily consumption, and therefore is approximate. The US average annual electricity consumption is approximately 11MWh.

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exists, the share of bills savings are weighted more heavily towards the non-residential sector. The relatively high share of residential bill savings is a result of residential inclining block rate design and that residential customers export an average of 49% of their total generation, while non-residential customers export an average of 30% of their total generation (based on penetration levels for Full NEM subscription).

Table 11: Total Bill Savings in 2020 by Penetration Level - Export Only (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$108	$153	$489
Non-Residential	$54	$145	$242
Total	$161	$298	$731

Table 12 shows the bill savings of All Generation in millions of dollars in the year 2020. The higher energy charges present in residential rate structures results in larger total residential bill savings between customer classes, despite 57% of all DG generation coming from non-residential systems.

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Table 12: Total Bill Savings in 2020 by Penetration Level - All Generation (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$299	$416	$1,289
Non-Residential	$218	$607	$949
Total	$517	$1,023	$2,238

4.2.2 LEVELIZED BILL SAVINGS

Table 13 displays the levelized bill savings of exports for 2012 DG installations by customer class and utility over the life of the generator. The $/W figure represents the bill savings resulting from exported energy seen by a NEM customer over the DG system's lifetime per watt installed. In a sense, these values can be viewed as the equivalent upfront payment for the exported NEM generation.

Table 13: Total Levelized Bill Savings for Systems Installed in 2012 by Utility - Export Only ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$2.6	$0.29	$2.3	$0.23	$2.1	$0.23	$2.3	$0.25
Non-Residential	$1.2	$0.19	$0.6	$0.13	$0.7	$0.13	$1.0	$0.17
Average	$1.9	$0.24	$1.9	$0.22	$1.5	$0.20	$1.8	$0.22

Table 14 displays the levelized bill savings for 2012 DG installations by customer class and utility over the life of the generator. The higher energy rates of

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residential customers are evidenced by the higher $/kWh values. Additionally, the higher PV capacity factors of Southern California are reflected by the higher $/W values relative to the $/kWh value. In the All Generation case, the $/W figure represents the bill savings resulting from all energy seen by a NEM customer over the DG system's lifetime per watt installed.

Table 14: Total Levelized Bill Savings for Systems Installed in 2012 by Utility - All Generation ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$7.4	$0.39	$5.6	$0.29	$6.0	$0.31	$6.3	$0.33
Non-Residential	$4.4	$0.23	$2.9	$0.16	$4.1	$0.21	$4.1	$0.21
Average	$5.7	$0.30	$5.0	$0.27	$5.3	$0.27	$5.4	$0.28

4.2.3 LEVELIZED RESIDENTIAL BILL SAVINGS BY CUSTOMER SIZE

Table 15 shows the levelized bill savings by customer size for the residential class for exported energy. Here, we see the rate of bill savings increasing steadily as customers are larger. This effect is due to the higher usage tiers associated with inclining block rate structures. Note that these are 'levelized' values assuming escalation of rates over a 20-year period, and are not directly comparable to current rates.[18]

[18] Because there are very few residential NEM customers with load greater than 100 MWh, the data in that row is incongruous due to small sample size.

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Table 15: Residential Levelized Bill Savings for Systems Installed in 2012 by Customer Size and Utility - Export Only ($/W; $/kWh)

Annual Gross Load	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
< 5 MWh	$1.8	$0.13	$1.9	$0.14	$2.0	$0.15	$1.9	$0.14
5 to 10 MWh	$2.1	$0.19	$2.0	$0.18	$2.1	$0.20	$2.1	$0.19
10 to 25 MWh	$2.7	$0.32	$2.3	$0.25	$2.0	$0.26	$2.4	$0.27
25 to 50 MWh	$3.4	$0.40	$2.5	$0.31	$2.4	$0.32	$2.8	$0.35
50 to 100 MWh	$3.4	$0.39	$1.8	$0.32	-	-	$2.4	$0.35
100 to 500 MWh	$1.8	$0.40	-	-	-	-	$1.8	$0.40
Average	$2.6	$0.29	$2.3	$0.23	$2.1	$0.23	$2.3	$0.25

Table 16 shows the levelized bill savings by gross customer size for the residential class for the All Generation case. The results are similar to those of Table 15 in showing larger customers avoiding the higher tiers of residential inclining block rates. The levelized bill savings are greater in the All Generation case compared to the Export Only case due to the tier structure and because much of the NEM generation is consumed on site before it is exported.

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Table 16: Residential Levelized Bill Savings for Systems Installed in 2012 by Customer Size and Utility - All Generation ($/W; $/kWh)

Annual Gross Load	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
< 5 MWh	$2.9	$0.15	$2.9	$0.15	$3.3	$0.17	$3.0	$0.16
5 to 10 MWh	$5.2	$0.27	$4.3	$0.23	$5.1	$0.27	$4.9	$0.25
10 to 25 MWh	$8.1	$0.43	$5.9	$0.31	$6.7	$0.35	$6.8	$0.36
25 to 50 MWh	$9.2	$0.48	$6.8	$0.36	$7.4	$0.38	$7.8	$0.41
50 to 100 MWh	$8.6	$0.47	$7.2	$0.38	-	-	$7.7	$0.41
100 to 500 MWh	$9.3	$0.48	-	-	-	-	$9.3	$0.48
Average	$7.4	$0.39	$5.6	$0.29	$6.0	$0.31	$6.3	$0.33

These levelized bill savings assume continuation of the current retail rate structures. Actual levelized bill savings could be dramatically different if future rate structures differ from the current structures.

4.2.4 SENSITIVITIES

We calculate bill savings with a low sensitivity, in which retail rate escalation follows a lower trajectory than that of the Base Case, and a high sensitivity, in which retail rate escalation follows a higher trajectory than the Base Case. Table 17 shows the results of these sensitivities for the Export Only case and each penetration scenario in millions of dollars in the year 2020. These savings are

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calculated as the difference of the estimated customer bill with and without credit for exports to the grid from the NEM customer.

Table 17: Total Bill Savings in 2020 by Penetration Level - Export Only Sensitivities ($2012/year)

	2012 Snapshot		Full CSI Subscription		Full NEM Subscription	
	High	Low	High	Low	High	Low
Residential	$113	$108	$160	$153	$514	$489
Non-Residential	$56	$54	$153	$146	$254	$242
Total	$170	$161	$313	$298	$768	$731

Table 18, below, shows the bill savings in the All Generation case. In the All Generation case, the bill savings is the difference in the customer bill with and without the NEM generation. Note that since NEM customers are exempt from standby charges, this bill savings is not reduced by a standby charge in the base case and high cases. In the low case sensitivity, we reduce the bill savings for non-residential customers for the standby charges that would be assessed without the exemption.

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Table 18: Total Bill Savings in 2020 by Penetration Level - All Generation Sensitivities ($2012/year)

	2012 Snapshot		Full CSI Subscription		Full NEM Subscription	
	High	Low	High	Low	High	Low
Residential	$315	$299	$438	$417	$1,355	$1,290
Non-Residential	$229	$218	$638	$607	$998	$949
Total	$544	$518	$1,075	$1,023	$2,353	$2,239

4.3 Avoided Costs

Avoided costs are a representation of the value that a resource provides to the electrical system. In the case of NEM, the avoided costs are an estimate of the costs that the IOUs would otherwise have to pay in the absence of NEM generation. We use the avoided cost framework that has been developed in numerous proceedings at the CPUC since it was adopted in 2004. This approach provides a transparent method to value net energy production from distributed generation on a time-differentiated cost-basis. Appendix C describes the avoided cost calculation in detail, and there is a publically available Avoided Cost Model that is used to develop the avoided costs.

We estimate avoided costs in the six component categories described in Table 19. Each of the avoided cost components is a direct cost that would otherwise be borne by the utility or utility customers through their electricity bills in the absence of NEM generation.

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Table 19: Components of Marginal Energy Cost

Component	Description
Generation Energy	Estimate of hourly marginal wholesale value of energy adjusted for losses between the point of the wholesale transaction and the point of delivery
System Capacity	The marginal cost of procuring Resource Adequacy resources in the near term. In the longer term, the additional payments (above energy and ancillary service market revenues) that a generation owner would require to build new generation capacity to meet system peak loads
Ancillary Services	The marginal cost of providing system operations and reserves for electricity grid reliability
T&D Capacity	The costs of expanding transmission and distribution capacity to meet customer peak loads
CO2 Emissions	The cost of carbon dioxide emissions (CO2) associated with the marginal generating resource
Avoided RPS	The cost reductions from being able to procure a lesser amount of renewable resources while meeting the Renewable Portfolio Standard (percentage of retail electricity usage).

We forecast each of the six avoided cost components at the hourly level through the year 2050, although only forecasts through 2031 are used in this analysis. The 2020 avoided costs are used for the 2020 snapshot analysis, and the 2012-2031 avoided costs are used to calculate levelized system benefits. The Commission adopted the use of hourly avoided costs in 2004. In that original application, the hourly costs were developed for use with the predictable load reduction profiles of energy efficiency measures. In the intervening years, E3 has worked with parties to enhance the methodology for distributed generation and other distributed energy resources.

We develop the hourly forecasts using a two-step process, whereby annual avoided costs are first forecast for each component through 2050. E3 then

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disaggregates, or shapes, the annual values to encompass hourly variations and peak timing. Table 20 summarizes the methodology applied to each component to develop the annual and hourly forecasts.

Table 20: Summary of Methodology for Avoided Cost Component Forecasts

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	Forward heat rate projections from 2010 CPUC Long Term Procurement Plan and monthly fuel cost projections	Historical hourly day-ahead market price shapes from MRTU OASIS aligned to a typical meteorological year based on daily system loads
System Capacity	Lower of the residual capacity value a new simple-cycle combustion turbine or combined cycle gas turbine	Hourly allocation factors calculated as a proxy for LOLP based on system loads
Ancillary Services	Percentage of generation energy value	Directly linked with energy shape
T&D Capacity	Marginal transmission and distribution costs from utility ratemaking filings.	Hourly allocation factors calculated using hourly TMY temperature data as a proxy for local area load
Environment	CARB 2013 auction results; 2011 Market Price Referent (MPR)[19]	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

Figure 13 shows average monthly value of load reductions, revealing the seasonal characteristics of the avoided costs. The energy component dips in the spring, reflecting increased hydro supplies and imports from the Northwest, and peaks in

[19] http://www.ethree.com/documents/2011_MPR_E4442_CPUC_Final_Resolution.pdf

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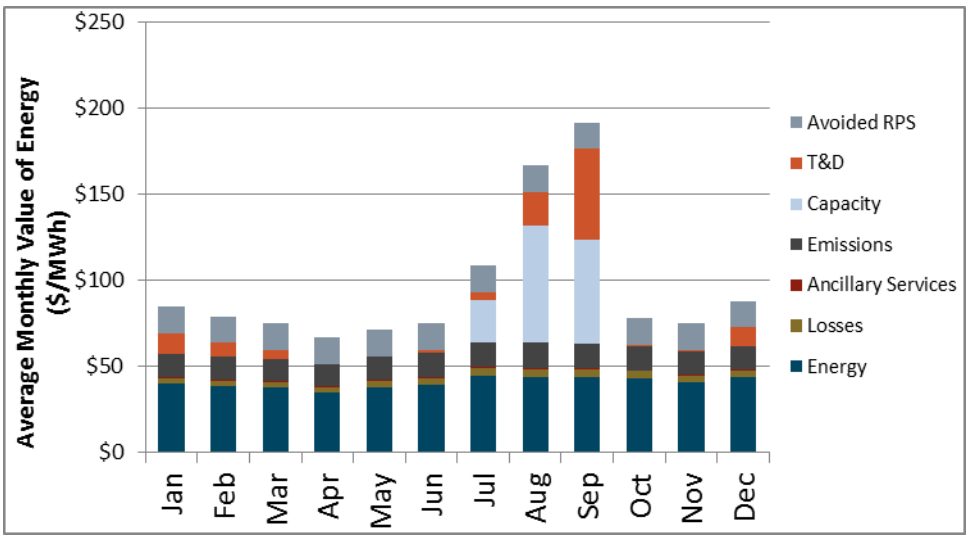
the summer months when demand for electricity is highest. The value of capacity—both generation and T&D—is concentrated in the summer months and results in significantly more value on average during these months.

Figure 13: Average Monthly Avoided Cost (Levelized Value Over 30-yr Horizon)



In order to calculate the total avoided costs, we multiply the half-hourly DG generation profiles (kWh) developed for each customer bin by hourly avoided cost values ($/kWh), which are the output of the Avoided Cost Model. These values are then summed to provide total annual avoided cost results.

When considering the Export Only case, only DG production that is exported onto the grid (negative net load) is valued. When considering the All Generation case, the entire DG generation profile of each customer bin is valued using the avoided costs.

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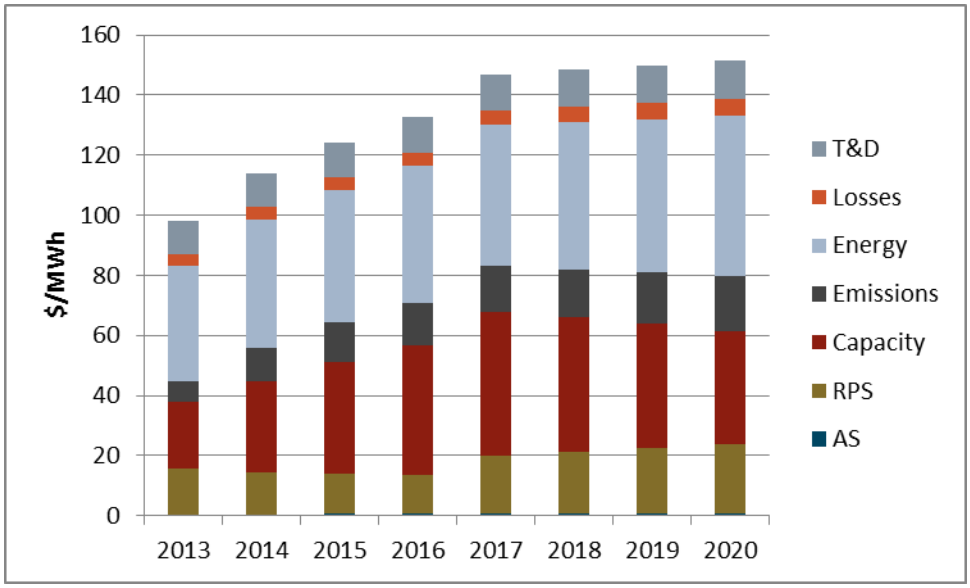
Figure 14, below, shows the value of each component of avoided cost over time for the combined NEM output shape in the Base Case assumptions. Note the evolving relative importance of each component of the avoided costs over time.

Figure 14: Average NEM Avoided Costs by Component



4.3.1 TOTAL AVOIDED COST

Table 21 shows the total avoided cost of the Export Only case in millions of 2012 dollars in the year 2020. As with bill savings, the higher percentage of exported DG generation for the residential class is evident in the class's larger share of total avoided costs relative to the All Generation case.

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Table 21: Total Avoided Cost in 2020 by Penetration Level - Export Only (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$50	$72	$239
Non-Residential	$37	$108	$173
Total	$87	$180	$412

Table 22 shows the avoided cost of All Generation in millions of 2012 dollars in the year 2020. The share of avoided costs between residential and non-residential is almost identical to the split of GWh generated by each customer class in 2020.

Table 22: Total Avoided Cost in 2020 by Penetration Level - All Generation (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$121	$172	$541
Non-Residential	$151	$445	$668
Total	$272	$617	$1,209

4.3.2 LEVELIZED AVOIDED COST

Table 23 displays the levelized avoided cost for 2012 DG installations by customer class and utility over the life of the generator for the Exports Only case.

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Table 23: Total Levelized Avoided Cost for Systems Installed in 2012 by Utility - Export Only ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$1.2	$0.13	$1.1	$0.12	$1.0	$0.11	$1.1	$0.12
Non-Residential	$0.8	$0.12	$0.5	$0.11	$0.6	$0.10	$0.7	$0.11
Average	$0.9	$0.12	$1.0	$0.12	$0.8	$0.11	$0.9	$0.12

Table 24 displays the levelized avoided cost for 2012 DG installations by customer class and utility over the life of the generator for the All Generation case. The consistent $/kWh values suggest similar avoided costs across the three IOUs.

Table 24: Total Levelized Avoided Cost for Systems Installed in 2012 by Utility - All Generation ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$2.7	$0.14	$2.6	$0.14	$2.5	$0.13	$2.6	$0.14
Non-Residential	$2.6	$0.14	$2.5	$0.14	$2.6	$0.13	$2.6	$0.13
Average	$2.7	$0.14	$2.6	$0.14	$2.5	$0.13	$2.6	$0.14

4.3.3 SENSITIVITY ANALYSIS RESULTS

We calculate a high and low sensitivity for avoided costs by grouping assumptions together that increase or decrease the avoided costs as described previously. The low avoided cost sensitivity assumes a lower gas price forecast, a lower CO2 price forecast, no avoided T&D value, and a later resource balance

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year relative to the Base Case. The high avoided cost sensitivity assumes a higher gas price forecast and a higher CO2 price forecast relative to the Base Case, along with a resource balance year that gives full capacity value in every year and a 2013 vintage ELCC.[20] Table 25 shows the results of these sensitivities for each penetration scenario for the Export Only case in millions of dollars in the year 2020.

Table 25: Total Avoided Cost in 2020 by Penetration Level - Export Only (Millions $2012/year)

	2012 Snapshot		Full CSI Subscription		Full NEM Subscription	
	High	Low	High	Low	High	Low
Residential	$61	$42	$89	$61	$296	$203
Non-Residential	$46	$32	$137	$93	$216	$148
Total	$108	$74	$225	$153	$512	$351

Figure 15 shows the breakdown by component of avoided costs in millions of dollars in the year 2020 for each Export Only case sensitivity. Bear in mind that the Low and High sensitivities are named for their effects on total NEM cost-effectiveness from a utility perspective, and not their effects on individual components of the calculation.

[20] Because the high gas price forecast used in the high avoided cost sensitivity results in higher energy market prices, the capacity value in the high avoided cost case is lower than in the base avoided cost case. See Appendix C for a detailed explanation of the relationship between market prices and capacity value.

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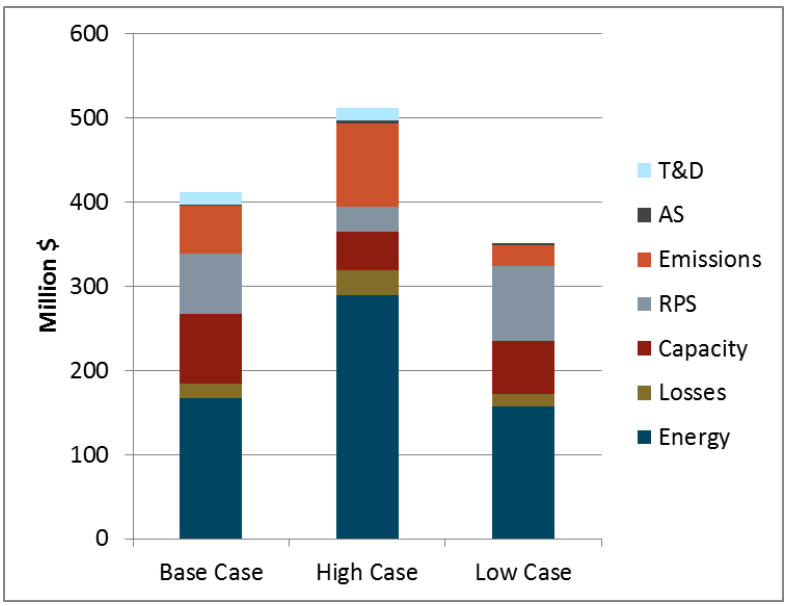
Figure 15: Total Avoided Costs by Component of Export Only in 2020 for Full NEM Cap (Millions $2012/year)



Subject to the same sensitivities, Table 26 shows the high and low avoided cost ranges for the All Generation case at each penetration level.

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Table 26: Total Avoided Cost in 2020 by Penetration Level - All Generation (Millions $2012/year)

	2012 Snapshot		Full CSI Subscription		Full NEM Subscription	
	High	Low	High	Low	High	Low
Residential	$144	$100	$205	$142	$649	$448
Non-Residential	$181	$125	$537	$368	$803	$553
Total	$325	$225	$742	$510	$1,452	$1,001

4.4 Program Costs

Program costs are the costs to the IOUs associated with maintaining the NEM tariff. These include one-time initial set up costs associated with setting up the NEM billing account, recurring incremental metering costs due to the complexity of NEM customers, one time interconnection costs, and recurring integration costs associated with balancing the intermittent DG resources on the system.

Initial set-up costs, metering costs, and interconnection costs are incurred during system installation and do not change based on a customer's usage or DG production profile. Therefore, there are no real differences in program costs between the All Generation and Export Only cases. However, when integration costs are assessed as $/MWh, the denominator used in the Export Only case is equal to only exported MWh, while the denominator used in the All Generation case comprises all generated MWh.

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4.4.1 PROGRAM COST DATA

PG&E and SCE provided program cost data for the year 2011 to E3 in a series of data requests. The following tables present the data that was received, which form the basis for the calculations of program costs presented below. Since no data was received from SDG&E, their program costs are assumed to be an average of the costs of the other IOUs.

Table 27 provides the reported interconnection costs. Our understanding is that this data reflects the costs associated with the application review and site inspection for new DG systems. By NEM statute, these costs are not passed to NEM customers. Estimates of distribution system upgrade costs, if any, were not available from the utilities, and therefore are not included in these estimates.

Table 27: Interconnection Costs ($/customer)

Customer Description	Cost
PG&E	$209
SCE (DG ≤10 kW)	$105
SCE (DG >10 kW)	$524

Table 28, below, provides the reported incremental billing costs of NEM customers. These are the costs above and beyond the regular cost of billing for non-NEM customers. Note that the incremental billing costs, particularly the auto billing costs, are significantly improved from the 2010 NEM Evaluation. For PG&E, these decreased costs are also a reflection of the availability of more granular billing data.

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Table 28: Incremental Billing Cost ($/customer-month)

Customer Description	Cost
PG&E (Auto billing)	$1.35
PG&E (Manual billing)	$4.66
SCE (Auto billing)	$0.69
SCE (Manual billing)	$19.06

Table 29, below, provides the NEM customer setup services. These are the one-time costs to include a customer in the billing system. From the data requests it is clear that PG&E and SCE use different cost attribution for billing and setup of NEM customers. In addition to different formats, there may also be different costs accounted for in the estimates of initial set-up costs provided by the utilities.

Table 29: Initial Set-up Cost ($/customer)

Utility	Cost Component	Cost
PG&E	All	$39.41
SCE	Application Processing	$84.63
SCE	Account Billing Setup	$6.37
SCE	Metering Services Setup (Load 4-6 kW)	$396.22
SCE	Metering Services Setup (Load <20 kW)	$441.59
SCE	Metering Services Setup (Load 130-165 kW)	$1,174.73

4.4.2 PROGRAM COSTS

Using the costs provided above, Table 30 displays the levelized program cost for 2012 DG installations by customer class and utility over the life of the generator. These costs are based on the Export Only case, and are therefore shown per

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kWh exported to the grid. The program costs are higher for residential customers because there are proportionally higher setup costs relative to the amount of energy generated. Overall, however, the magnitude of these costs is insignificant relative to the bill savings and avoided costs.

Table 30: Total Levelized Program Cost for Systems Installed in 2012 by Utility - Export Only ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$0.1	$0.01	$0.2	$0.02	$0.2	$0.02	$0.2	$0.02
Non-Residential	$0.0	$0.00	$0.0	$0.01	$0.1	$0.01	$0.0	$0.01
Average	$0.1	$0.01	$0.2	$0.02	$0.1	$0.02	$0.1	$0.01

The program costs in the All Generation case are lower per kWh. Table 31 displays the levelized program cost for 2012 DG installations by customer class and utility over the life of the generator. Many numbers are unchanged due to rounding from the prior table.

Table 31: Total Levelized Program Cost for Systems Installed in 2012 by Utility - All Generation ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$0.2	$0.01	$0.2	$0.01	$0.2	$0.01	$0.2	$0.01
Non-Residential	$0.1	$0.00	$0.1	$0.00	$0.1	$0.00	$0.1	$0.00
Average	$0.1	$0.01	$0.2	$0.01	$0.2	$0.01	$0.1	$0.01

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4.4.3 SENSITIVITY ANALYSIS

Although small, we do include a sensitivity analysis in which lower metering costs, set-up costs, and interconnection costs are used relative to the Base Case. Similarly, we evaluate a high sensitivity in which higher interconnection and integration costs are used relative to the Base Case. These sensitivities have a relatively small impact on the analysis. Table 32 and Table 33 show levelized program costs for the sensitivity ranges for the Export Only and All Generation cases, respectfully.

Table 32: Levelized Program Cost for Systems Installed in 2012 by Utility - Export Only ($/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	Low	High	Low	High	Low	High	Low	High
Residential	$0.00	$0.02	$0.00	$0.02	$0.00	$0.03	$0.00	$0.02
Non-Residential	$0.00	$0.01	$0.00	$0.01	$0.00	$0.01	$0.00	$0.01
Average	$0.00	$0.01	$0.00	$0.02	$0.00	$0.02	$0.00	$0.02

Table 33: Levelized Program Cost for Systems Installed in 2012 by Utility - All Generation ($/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	Low	High	Low	High	Low	High	Low	High
Residential	$0.0	$0.01	$0.0	$0.01	$0.0	$0.01	$0.0	$0.01
Non-Residential	$0.0	$0.01	$0.0	$0.01	$0.0	$0.01	$0.0	$0.01
Average	$0.0	$0.01	$0.0	$0.01	$0.0	$0.01	$0.0	$0.01

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4.5 Cost-Benefit Analysis Results

The tables and figures within this section present the total NEM cost-benefit analysis results. Results are given first for the Export Only case, and then for the All Generation case. An additional subsection provides the results unique to fuel cell customers, whose differentiated NEM tariff requires them to be analyzed separately.

4.5.1 NEM COST-BENEFIT ANALYSIS

Table 34 shows the total net cost of NEM in millions of dollars in the year 2020 for the Export Only case. Recall that we defined net cost such that a positive value indicates a cost shift from NEM participants to other ratepayers. The total net cost of NEM exports, at full subscription in the year 2020, will be in the range of $370 million dollars per year. This is approximately 1.1% of the combined IOU revenue requirement in that year. The revenue requirement forecast is formed by escalating current IOU revenue requirements at the modeled retail rate escalation.

Table 34: Net Cost of NEM Generation Exports in 2020 (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$61	$85	$291
Non-Residential	$18	$41	$79
Total	$79	$126	$370
% of Revenue Requirement	0.23%	0.36%	1.06%

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Table 35 shows the total net cost in millions of dollars in the year 2020 for all NEM generation. The total net cost of the NEM program, at full subscription in the year 2020, will be in the range of $1,093 million dollars per year. For perspective, this is projected to be about 3.1% of the combined IOU revenue requirement. As we are considering all NEM generation, including generation that meets onsite load and that is exported to the grid, the cost of the NEM program more than doubles that of the Export Only case.

Table 35: Net Cost of All NEM Generation in 2020 (Millions $2012/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$182	$250	$794
Non-Residential	$70	$170	$299
Total	$252	$420	$1,093
% of Revenue Requirement	0.72%	1.20%	3.13%

Table 36 displays the per unit cost impact for the exported energy on a levelized $/kWh and lifecycle $/watt basis for 2012 DG installations by customer class and utility. We find that NEM generation exports have a net cost of 12 ¢/kWh, or a lifecycle net cost of 1.0 $/W installed on average. The residential costs per watt installed are significantly higher than the non-residential costs because more energy is exported, and because the retail rate credit for residential customers is greater.

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Table 36: Levelized Net Cost ($/kWh) and Lifecycle Cost ($/W) of NEM for Systems Installed in 2012 by Utility - Exports Only

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$1.6	$0.17	$1.3	$0.14	$1.2	$0.14	$1.4	$0.15
Non-Residential	$0.5	$0.07	$0.1	$0.03	$0.2	$0.03	$0.4	$0.06
Average	$1.0	$0.13	$1.1	$0.12	$0.8	$0.11	$1.0	$0.12

Table 37 displays the levelized total net cost of all NEM generation for 2012 installations by customer class and utility over the life of the generator per watt installed and per kWh generated. We find that NEM generation creates a levelized cost impact of 15 ¢/kWh generated, or 3.1 $/W installed on average. These numbers are significantly higher for residential customers, who incur bill savings at higher retail rates.

Table 37: Levelized Net Cost ($/kWh) and Lifecycle Cost ($/W) of NEM for Systems Installed in 2012 by Utility - All Generation

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$4.9	$0.26	$3.2	$0.17	$3.7	$0.19	$3.9	$0.20
Non-Residential	$1.8	$0.09	$0.5	$0.03	$1.7	$0.08	$1.5	$0.08
Average	$3.2	$0.17	$2.6	$0.14	$2.9	$0.15	$2.9	$0.15

Figure 16 shows the costs and benefits of exports on a levelized $/kWh exported basis side-by-side for each utility. The difference in height between the cost bars and the benefit bars is the net cost shown in Table 37, above. These levelized

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net costs are per kWh exported. Note that the bill savings are the dominant driver of the results of this analysis. The program costs are a relatively small component.

Figure 16: Levelized Costs and Benefits of NEM for Systems Installed in 2012, Export Only (Levelized $/kWh)

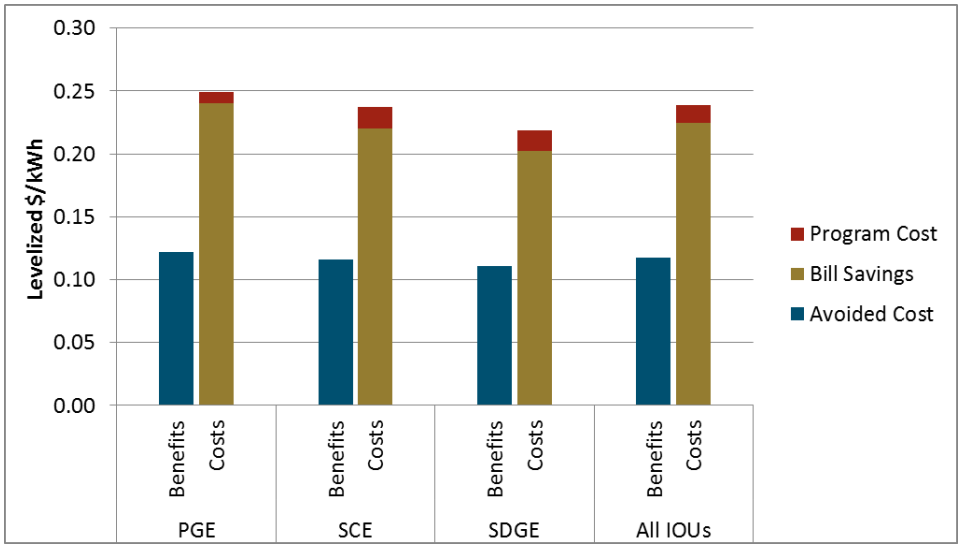

Figure 17 shows the All Generation costs and benefits on a levelized $/kWh basis side-by-side for each utility. Compared to the Export Only case, program costs play a smaller role here. Program costs are relatively equivalent in the two cases, but they are distributed over fewer kWh in the Export Only case.

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Figure 17: Levelized Costs and Benefits of NEM for Systems Installed in 2012 - All Generation (Levelized $/kWh)

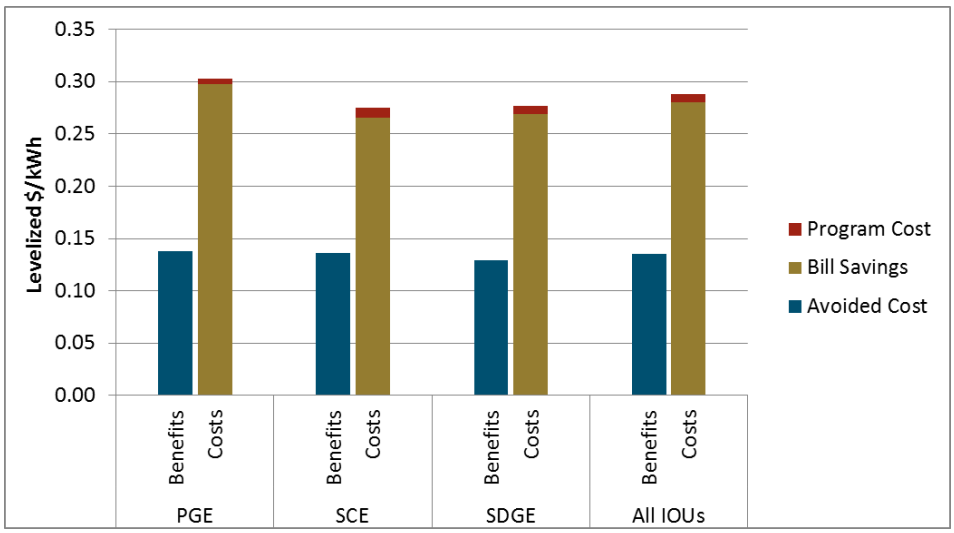

Table 38 shows the levelized net cost of exports from residential NEM systems by customer size. The table shows that larger residential NEM customer impose higher per-kWh costs on the system than smaller customers. This is primarily due to the inclining block residential rate structures. Changes in the current inclining block rate structures would likely impact the overall levelized cost of NEM substantially. Since over half of the customers using NEM have DG systems that produce more than 10 MWh and because larger customers have significantly higher levelized costs than smaller customers, these cost results are especially sensitive to changes in the rates of the higher inclining blocks, with lower rates resulting in lower levelized costs.

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Table 38: Levelized Cost of NEM for Residential Customers by Usage Bin - Export Only (Levelized $/kWh)

Customer Usage	PG&E	SCE	SDG&E	All IOUs	Number of Customers
< 5 MWh	0.01	0.03	0.05	0.03	12,370
5 to 10 MWh	0.08	0.08	0.10	0.09	45,170
10 to 25 MWh	0.21	0.15	0.17	0.17	70.462
25 to 50 MWh	0.29	0.22	0.24	0.25	7,995
50 to 100 MWh	0.27	0.25	-	0.26	354
100 to 500 MWh	0.31	-	-	0.31	18
Average	0.18	0.14	0.14	0.15	136,549

Table 39 displays the levelized net cost of all generation from residential NEM systems by customer size. The per-kWh cost disparity between small and large residential customers is even larger in this case than in the Export Only case. Again, any change in the current inclining block rate structures would affect the overall levelized cost of NEM, with rate decreases for higher tiers reducing the overall net cost shift of NEM.

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Table 39: Levelized Cost of NEM for Residential Customers by Usage Bin - All Generation (Levelized $/kWh)

Customer Usage	PG&E	SCE	SDG&E	All IOUs	Number of Customers
< 5 MWh	0.02	0.03	0.05	0.04	12,370
5 to 10 MWh	0.14	0.11	0.15	0.13	45,170
10 to 25 MWh	0.29	0.18	0.23	0.23	70.462
25 to 50 MWh	0.35	0.23	0.26	0.28	7,995
50 to 100 MWh	0.33	0.25	-	0.28	354
100 to 500 MWh	0.35	-	-	0.35	18
Average	0.26	0.17	0.19	0.20	136,549

While average metrics are useful for understanding the costs and benefits of NEM, there is a significant diversity across different customers. Figure 18 shows the total net cost of NEM of each customer bin modeled for both the Export Only case and the All Generation case. The total net cost is expressed in levelized $/kWh over the lifetime of DG systems installed in 2012 and is plotted as a function of customer size, expressed in annual gross demand (plotted on a log scale). The size of each bubble is proportional to the number of customers represented by each customer bin. As demonstrated in this chart, there is a wide range of cost effectiveness of individual customers and a large number that provide net benefits (customers that provide more benefits than costs to the system), as expressed by the points located below the y-axis.

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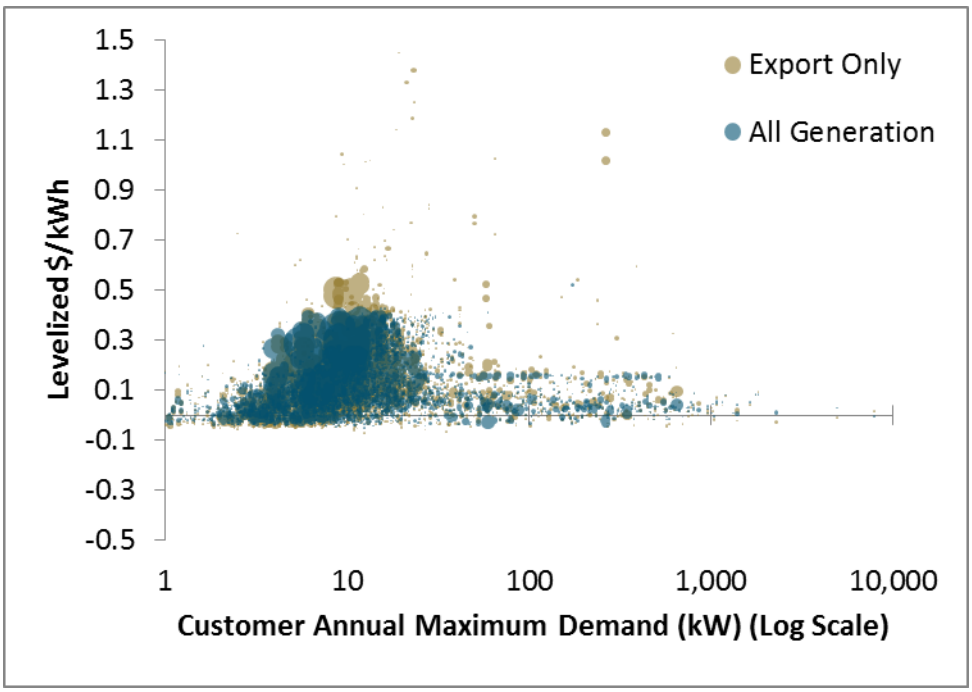
Figure 18: Scatter Plot of Net Levelized Costs and Maximum Demand for NEM Customers by Bin



Note that some points may be excluded due to scale of axes
Size of bubble corresponds to number of customers represented by each point

4.5.2 SENSITIVITY ANALYSIS

Figure 19 shows the range of export net costs in millions of dollars in the year 2020 based on our high and low sensitivities for each penetration level. The range of sensitivity is relatively symmetric above (high case) or below (low case) from the Base Case and is +/- approximately 20%. The non-residential cost-shifting is a relatively larger contributor to the total cost impact in the CSI case because there is relatively more non-residential capacity installed as the non-residential tiers become fully subscribed.

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Figure 19: Sensitivity Results of Net Cost of NEM Exports in 2020 (Millions $2012/year)

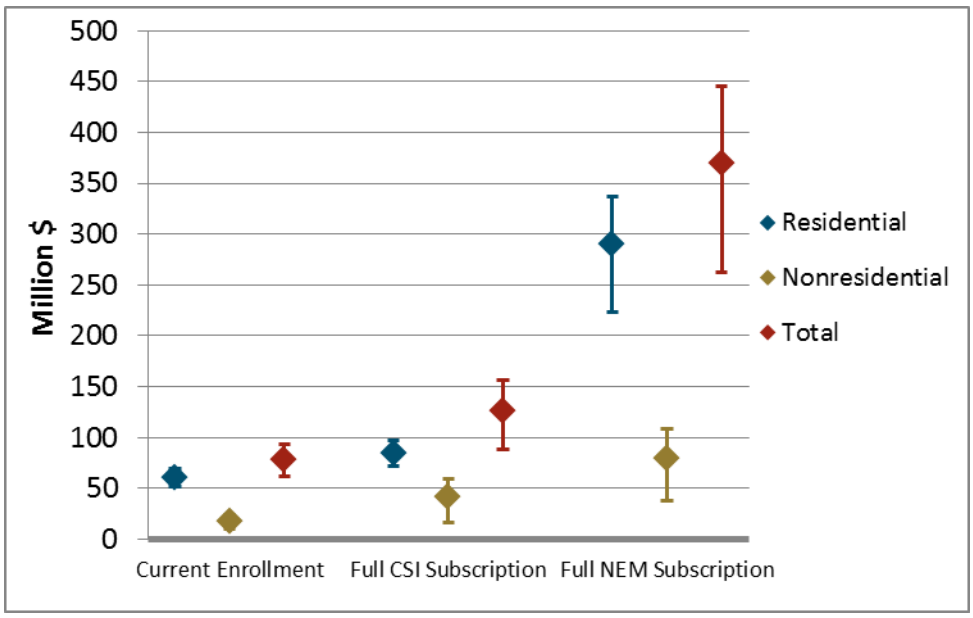

Figure 20 shows the range of All Generation net cost of NEM in millions of dollars in the year 2020 based on the high and low sensitivities for each penetration level. Though the scale of the numbers changes, the relative results are nearly identical to the Export Only case.

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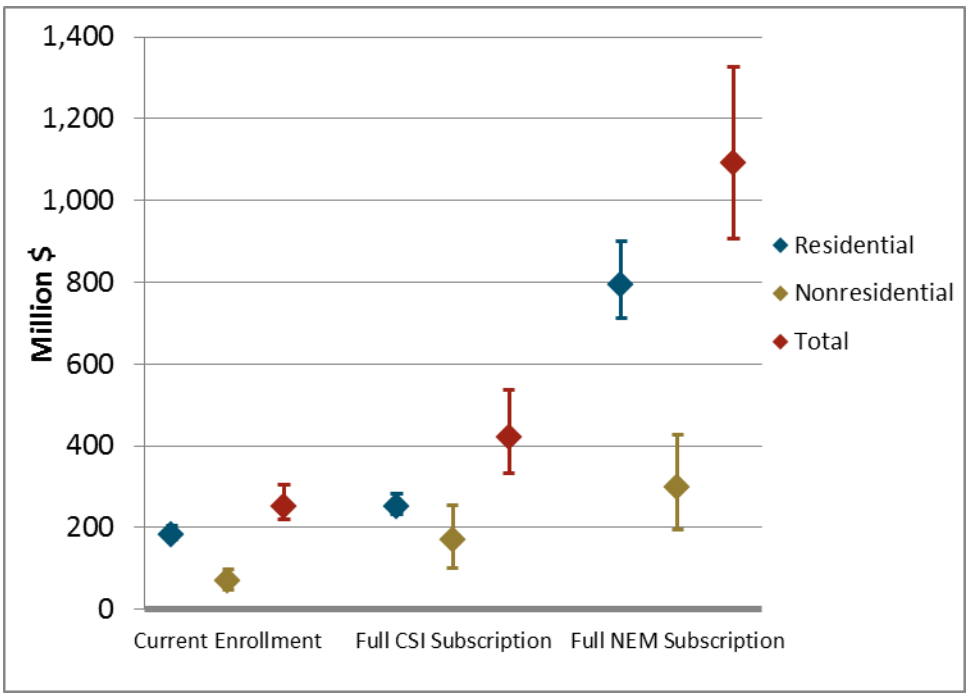
Figure 20: Sensitivity Results of Net Cost of NEM Generation in 2020 (Millions $2012/year)



4.6 Benchmarking to 2010 Study

This study can be readily compared to the prior CPUC analysis of NEM costs and benefits released in 2010.[21] The 2010 study employed a similar methodology, with a few notable exceptions. One difference is that the 2010 study only evaluated the exports associated with NEM. Also, the analysis only included solar

[21] http://www.cpuc.ca.gov/PUC/energy/DistGen/nem_eval.htm

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PV systems that were NEM, and did not include wind or fuel cells. Lastly, the analysis only included systems installed through 2008, and we 'scaled' these systems to estimate 2020 impacts after full CSI implementation at the IOUs. The metrics reported in that study were based on a 20-year NPV and an annualized impact.

Table 40, below, shows the comparison of the lifecycle net cost between the 2010 study and the results of this study on a lifecycle and annualized value basis. To make the comparison, the comparable NPV lifecycle values from this study were calculated. Based on this comparison, the overall net cost per kWh exported is lower, despite the larger overall MW of NEM due to the inclusion of wind and fuel cell generation. This lower net cost is primarily due to retail rate escalation rates being lower than they were forecast to be in 2010. The equivalent upfront incentive of exports is higher now because of a lower discount rate, and an assumption of lower PV system degradation.

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Table 40: Lifecycle Analysis Comparison: Method from 2010 Study (2008 dollars)

Study	Year	Net Cost NPV $MM	Annualized Net Cost $MM/Year	MW Installed	Net Cost Levelized $/kWh Exported	Net Cost NPV $/W
2010 Study	2008	$ 230.6	$ 19.7	365	0.12	1.02
2013 Study	2008	$ 323.6	$ 28.5	391	0.11	1.49
2010 Study	2012	$ 769.6	$ 65.7	1,218	0.12	1.02
2013 Study	2012	$ 1,017.1	$ 89.5	1,305	0.11	1.62
2010 Study	2020	$ 1,611.3	$ 137.5	2,550	0.12	1.02
2013 Study	2020 Full CSI	$ 1,418.5	$ 124.8	2,916	0.07	1.53

In the current study we evaluate different metrics than were previously evaluated in the 2010 study. Rather than lifecycle NPV values, we assess the net cost in specific years. The reason is that the lifecycle results are highly dependent upon the retail rate escalation over the next 20 years, which is uncertain, and the discount rate assumption. Table 41, below, shows the comparison on an annual basis for the key metrics for 2008. All results have been normalized to 2008 dollars for comparison.

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Table 41: Snapshot Analysis Comparison for 2008: Method from 2013 Study ($)

Year	Net Cost $MM/Yr	MW Installed	GWh Generated	GWh Exported	$/kWh Bill Savings	$/kWh Avoided Cost
2010 Study, 2008	$ 11.0	365	625	197	$0.16	$0.11
2013 Study, 2008	$ 12.9	391	700	271	$0.17	$0.12

Comparing the 2008 results of the two studies, there are more MW installed in the current study through the inclusion of wind and fuel cell NEM. There is also more exported electricity per GWh generated. These factors contribute to the net cost estimate being a little higher for 2008 than in the prior study.

4.7 NEMFC Results

NEM customers with fuel cells may be placed on a unique version of the NEM tariff referred to as NEMFC. NEMFC participants receive a credit only for the generation component of their energy exports to the grid, while traditional NEM participants earn credits at their full retail electricity rate. Due to the fact that, through 2012, fewer than 80 fuel cell customers have joined NEMFC, the contribution of NEMFC to the overall NEM costs and benefits is de minimis.

While the NEMFC bill calculations differ from those of other NEM customers, the avoided costs of energy generated or exported are the same, and are estimated using the same methodologies outlined in sections 4.3 and 4.4.

Table 42 displays the levelized total net cost of NEMFC for DG installations through 2012 by customer class and utility over the life of the generator per watt

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installed and per kWh exported. Because most fuel cell customers are large users, the denominators of the levelized costs for the Export Only case are extremely small, making the results somewhat volatile. Overall, the Export Only case represents a very small benefit to ratepayers (1 ¢/kWh). This result is dominated by SDG&E's NEMFC participants: while the utility has a small number of NEMFC customers, they are relatively large exporters, so they have a significant impact on the average statewide Export Only net costs.

Table 42: Net Cost per Watt Installed and Levelized Cost of NEMFC for Systems Installed Through 2012 - Export Only ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$0.2	$0.02	$0.1	$0.01	-	-	$0.2	$0.01
Non-Residential	$0.0	$0.00	$0.0	$0.09	-$0.7	-$0.02	-$0.1	-$0.01
Average	$0.0	$0.00	$0.0	$0.03	-$0.7	-$0.02	-$0.1	-$0.01

Table 43 displays the levelized total net cost of NEMFC for DG installations through 2012 by customer class and utility over the life of the generator and the cost per W installed. In the All Generation case, the NEMFC program represents an overall cost to ratepayers of 5 ¢/kWh or 3.3 $/W installed. The per-unit net cost to ratepayers is much higher for residential NEMFC generators than for non-residential NEMFC generators. However, because non-residential systems are much more common, the overall per-unit program cost is close to the non-residential unit cost and much lower than the residential unit cost. In comparison to the Export Only case results, the All Generation costs are higher because of the relatively low export credits awarded under the NEMFC program.

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Table 43: Net Cost per Watt Installed and Levelized Cost of NEMFC for Systems Installed in 2012 - All Generation ($/W; $/kWh)

	PG&E		SCE		SDG&E		All IOUs	
	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh	$/W	$/kWh
Residential	$24.6	$0.34	$11.8	$0.16	-	-	$17.6	$0.24
Non-Residential	$2.4	$0.03	$1.0	$0.01	$1.7	$0.02	$1.8	$0.03
Average	$2.6	$0.04	$1.2	$0.02	$1.7	$0.02	$2.0	$0.03

Figure 21 shows the total NEMFC costs and benefits on a levelized $/kWh basis side-by-side for the Export Only case and the All Generation case. It is worth noting that, in comparison to the avoided costs of renewable NEM, the avoided costs are lower per kWh generated due to the flat shape of fuel cell output relative to the load-coincident shape of PV output. Furthermore, the bill savings drop significantly due to the specialized rules of the tariff.

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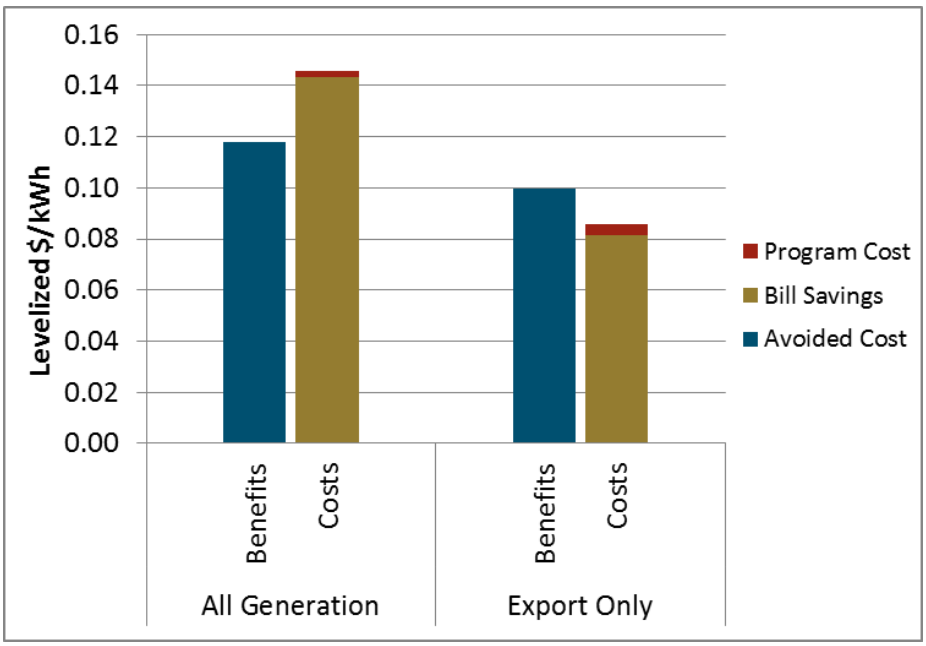
Figure 21: Levelized Cost of NEMFC for Systems Installed in 2012 (Levelized $/kWh)



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5 Full Cost of Service

As required by AB 2514 (Bradford, 2012), we estimate the degree to which NEM customers pay their share of utility costs, or 'full cost of service.' To do this, the following analysis compares NEM customer bills to their share of utility costs as defined by an approximation of NEM customer full cost of service.

Net and gross NEM customer bills are calculated for each customer 'bin' using the E3 Utility Bill Calculator based on 2011 net and gross billing determinants, respectively.

Full cost of service is a regulatory construct that refers to the total amount of revenue that a customer group would pay relative to other customer groups, based on how that group imposes costs on the utility. There are numerous steps in the ratemaking process that result in *all* customers, not just NEM customers, paying bills that differ from their actual full cost of service. Nevertheless, the utility GRC methods to calculate full cost of service method remain the most transparent and straightforward processes for developing an approximation of a customer's share of utility costs.

Full cost of service is generally not a metric that is evaluated when looking at resource options like demand response (DR). As such, it may be unfamiliar to

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readers and confusing when juxtaposed with the traditional avoided cost analysis presented earlier in this report. Despite *full cost of service* and *avoided cost* both having "cost" in their titles, they are actually very different metrics.

As illustrated in Figure 22, the avoided cost approach evaluates the marginal cost change associated with the change in usage due to DG, whereas the full cost approach evaluates the total cost to serve the remaining NEM account usage (net usage). Moreover the full cost of service considers all utility costs, including fixed and historical utility costs, rate surcharges, balancing and memorandum accounts, and costs that are directly attributable to a particular customer or customer group, whereas the avoided cost approach only considers marginal costs.[22]

[22] Another difference is that the NEM full cost of service analysis uses 2011 customer load data and 2011 DG output shapes. E3 uses the 2011 data to be consistent with the full cost of service information that was prepared by the IOUs based on 2011 data. This approach differs from the NEM avoided cost analysis, where E3 uses DG output shapes that are based on Typical Meteorological Year (TMY) data.

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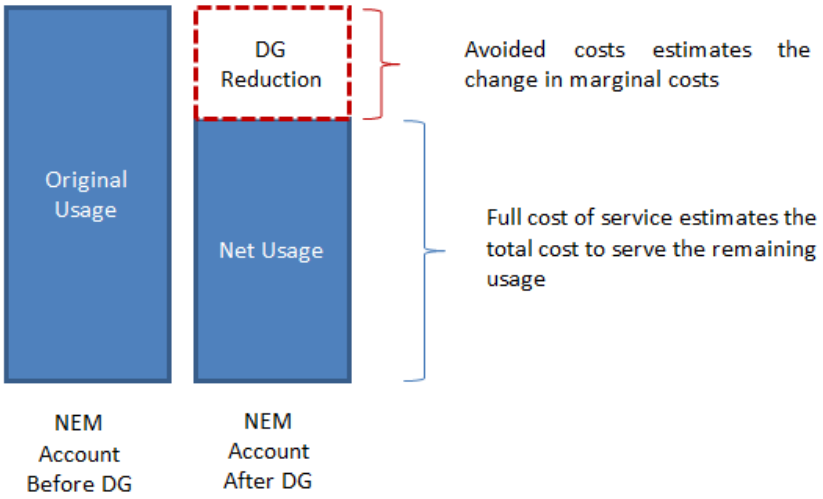
Figure 22: Avoided Cost versus Full Cost of Service Approaches



The avoided cost approach provides the cost information necessary to evaluate the impact of the DG resource. The full cost of service approach, on the other hand, is focused on the cost characteristics of the remaining NEM account usage. As such, the full cost of service analysis provides more of an indication of issues related to utility rate design, rather than issues related to the DG resource itself. While the DG facilitates the characteristics of the "after-DG" NEM accounts, any issues revealed in evaluating the full cost of service for those accounts would also exist for non-NEM accounts with similar usage characteristics.

5.1 Full Cost of Service Approach

The full cost of service is composed of three classes of costs:

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1. **GRC Cost of Service.** Generation, subtransmission, distribution, and customer costs are allocated to customers through utility GRC ratemaking proceedings and comprise the bulk of the full cost of service. SCE's FERC transmission is also allocated to customers via the GRC cost of service methods.

2. **Regulatory Items.** Costs or credits included in customer bills, but not assigned to customers in the GRC cost of service process. These regulatory cost items are generally assigned to customers on an equal cents per kWh basis, and we assume those tariff rates are equal to their cost of service. For PG&E and SDG&E, we also assume that their tariff rates for FERC transmission are equal to their cost of service.

3. **Incremental Costs.** Utility costs that are unique to NEM accounts and are not included in either the GRC Cost of Service or Regulatory Items. Such costs can include items such as interconnection costs, billing setup and processing costs, and integration costs. These costs are incurred because of the DG, and we add these incremental costs directly to the full cost of service for the NEM account.

The full cost of service components are illustrated in Figure 23. The stacked bars on the left represent the NEM account before the installation of DG. The full cost of service is comprised of the cost items assigned in the utility GRC proceedings (generation, transmission for SCE, subtransmission, distribution, and customer service) plus the regulatory amounts that are pass through based on the utility

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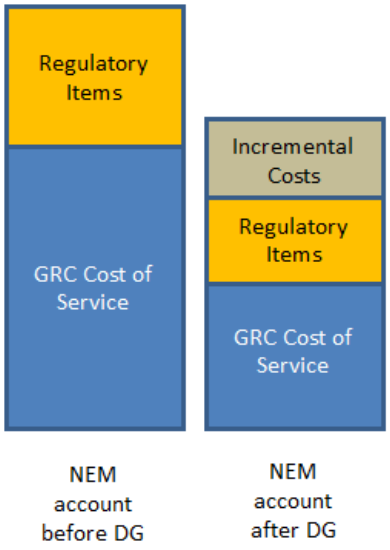
tariffs (rate surcharges, such as transmission for PG&E and SDG&E, etc.). The stacked bar on the right illustrates the full cost of service components after DG is installed. The GRC and regulatory items remain, but in smaller amounts, and there is the new incremental cost category associated with the addition of the DG.

Figure 23: Full Cost of Service Components



5.1.1 GRC COST OF SERVICE

GRC cost of service is the largest component of an account's full cost of service. To estimate the GRC cost of service, E3 estimates the cost that each account would be assigned if the account were treated as its own customer group in the

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utility GRC revenue allocation process.[23] The approach of treating each account as a customer class provides maximum flexibility for evaluating the full cost of service for NEM accounts. While this method is highly precise in calculating customer-specific full cost of service estimates, the estimates are only indicative of what an individual customer might have received in utility ratemaking proceeding.

The fact that these results are only indicative cannot be stressed enough. While the utility cost proposals and methods from their prior GRC proceedings represent the best information currently available, there are numerous caveats to viewing the GRC cost of service as the revenues that NEM accounts would pay. Some of these caveats are listed below.

- Party settlements are often used to resolve ratemaking results. As such, there are disconnects between cost of service and the costs that are actually adopted for a customer group.
- The actual determination of a definitive GRC cost of service study is not possible at this time due to the lack of adopted marginal costs and methods from the GRC proceedings.[24]
- The GRC cost of service analysis is based on 2011 data, whereas utility filings use multiple years of data and perform weather normalizations.

[23] For PG&E and SDG&E, each account is analogous to its own customer class; for SCE, each customer group is analogous to its own rate sub-schedule within the larger SCE rate schedule. This subtle difference exists because the EPMC factors provided by SCE vary by rate schedule and function, whereas the EPMC factors provided by PG&E and SDG&E only vary by function.

[24] In settlement agreements parties often disagree on the unit of marginal costs and calculation methods used to determine the full cost of service. Where there is agreement on a number, such agreement is usually limited to use in the particular case, and its use does not carry any precedence.

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- The GRC cost of service estimates for an individual customer may be abnormally high or low due to vagaries in their 2011 usage. Utility GRC cost of service is conducted at a more aggregate level that may temper such variations.
- The GRC cost of service analysis relies upon utility customer cost information, which is averaged at the class or rate schedule level and masks individual variations in customer costs. For residential sector, in particular, the predominance of single-family detached dwellings among NEM accounts (as opposed to apartments), likely results in an underestimate of the customer costs for the NEM accounts.
- Utility ratemaking would likely result in more uniform cost of service within a customer class since utilities develop costs using aggregated loads.
- SCE's distribution capacity cost allocators for this GRC cost of service analysis are, by necessity, a stylized version of the allocation factors that SCE uses in their ratemaking filings.

5.1.1.1 Relationship between Marginal Cost and GRC Cost of Service

The GRC cost of service assigned to each account starts with estimates of the marginal cost revenue responsibility (MCRR) of serving the account. MCRR is the product of the utility marginal costs multiplied by each account's costing determinants. Costing determinants include an account's hourly energy usage, its peak demand coincident with generation, transmission or distribution peaks, and its maximum demand. E3 worked with each utility to reproduce their GRC methods as closely as possible. Citations of utility data responses used for this analysis are contained in the full cost of service Appendix.

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The larger the MCRR for an account, the larger the share of GRC costs that are assigned to the account, all other things being equal. This is why the costing scenarios discussed in the next section can affect the GRC cost of service and the full cost of service for each account.

The fact that MCRR is only used to determine shares of costs highlights another important caveat with this analysis. The scope of work and budget for the NEM full cost of service analysis only allowed for the data collection and estimation of full cost of service results specific to NEM accounts. To fully understand how NEM customers fit into the GRC revenue allocation process, it would be necessary to calculate the MCRR for all utility accounts, including non-NEM accounts. For this analysis, we are forced to assume that 2011 usage and the proxy methods used herein would have resulted in the exact same MCRR for all other non-NEM accounts.

5.1.1.2 Scenarios

As with the avoided cost analysis, we conducted scenario analyses for the full cost of service comparison to customer bills. Of particular uncertainly was whether certain cost components should reflect the account's gross load (prior to any load reduction from distribution generation) or net load (effective load that reflects lower utility purchases, or even negative usage due to distributed generation). For costs that are incurred when a quantity is used, the net load is appropriate. However, for costs that are incurred based on potential, and not necessarily based on actual usage, then gross loads may be appropriate.

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At the one end of the spectrum, marginal energy costs are a function of the market prices in the aggregate California or wider western markets, and are incurred on an "as used" basis. E3 estimates marginal energy costs for NEM accounts using net loads.

Marginal generation costs are incurred at the aggregate utility net peak demand level. Utilities plan for aggregate net peak loads and E3 believes that the diversity of DG output is sufficient at the system level to warrant use of the net account load for generation capacity cost estimation.

At the other end of the spectrum, secondary distribution equipment is sized for the maximum demand that a customer *could* impose. E3 estimates marginal secondary costs using gross loads for each account.

For the other capacity components (transmission, subtransmission, distribution, primary, and primary-new business), the level of DG diversity and utility planning practices are less clear.

Therefore, we evaluate three cases. The base case reflects the assumptions made by the utilities in their respective GRCs and is therefore called the 'Utility' case. A low case which calculates the cost of service assuming more components full cost of service would be allocated on net consumption, and a high case which calculates the cost of service assuming more components are based on gross consumption. Note that the 'Utility' case is very similar to the high case in this analysis.

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Table 44: Full Cost of Service Scenario use of Net or Gross Loads

Marginal Cost Category	No NEM DG Case	Low Case	Utility Case	High Case
Generation Energy	Gross	Net	Net	Net
Generation Capacity	Gross	Net	Net	Net
Transmission (SCE)	Gross	Net	Net	Gross
Transmission (PG&E and SDG&E)	Gross Bill Pass-Through	Net Bill Pass-Through	Net Bill Pass-Through	Net Bill Pass-Through
Subtransmission (SCE)	Gross	Net	Gross	Gross
Distribution (SCE and SDG&E)	Gross	Net	Gross	Gross
Primary Distribution (PG&E)	Gross	Net	Gross	Gross
Primary New Business (PG&E)	Gross	Net	Gross	Gross
Secondary Distribution (PG&E)	Gross	Gross	Gross	Gross
Customer Cost	Gross	N/A	N/A	N/A

Net load is the account's hourly usage after it has been reduced by the DG output. Gross load is the account's hourly usage absent the DG. Net Load = Gross Load - DG Output.

5.1.1.3 Truing-Up to Utility Revenue Requirements

The revenue allocation process must ultimately reconcile to the utility CPUC jurisdiction revenue requirement. The standard way to achieve that in California is through the use of an Equal Percentage of Marginal Cost (EPMC) multiplier. The EPMC multiplier equals the utility revenue requirement divided by the sum of the MCRRs for all customer groups for the utility.

Each utility has separate EPMC factors for (1) generation (generation energy and capacity), and (2) subtransmission distribution and customer-related costs. Transmission is addressed in separate FERC proceedings, so there is no EPMC factor for transmission. The full cost of service for each customer group starts

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with the sum of the product of the MCRRs for each customer group multiplied by the respective EPMC multiplier.

E3 then adds costs for the bill components that are incremental to the utility revenue allocation process, as well as incremental utility cost associated with providing service to customer with renewable distributed generation. The complete formula for the full cost of service for customer "c" is shown below. Note that not all cost components will apply to all utilities.

$$
\begin{aligned}
\text{Full Cost of Service}_c \;=\; & (\text{Gen Energy MCRR}_c + \text{Gen Capacity MCRR}_c)*\text{EPMC}_{Gen} \\
+\; & \text{Transmission (PG\&E and SDG\&E is in Regulatory Items)} \\
+\; & (\text{SubTran MCRR}_c + \text{Dist MCRR}_c + \text{Primary MCRR}_c + \text{Primary} \\
& \quad \text{New Business MCRR}_c + \text{Customer MCRR}_c) * \text{EPMC}_{Dist} \\
+\; & \text{Regulatory Items}_c \\
+\; & \text{Incremental Utility Costs}_c
\end{aligned}
$$

5.1.2 REGULATORY ITEMS

The rates of each utility also include regulatory-related costs and fees that are not included in the revenue allocation process. The costs are calculated using the 2011 tariff rates and customer loads, and they vary slightly for each IOU. The full list of regulatory items added to the full cost of service is presented below.

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Table 45: Regulatory Items Added to Full Cost of Service

Utility	Regulatory Items
PG&E	• Nuclear Decommissioning, • Public Purpose Programs • Competition Transition Charge • New System Generation Charge • Energy Cost Recovery Amount • Department of Water Resources Bond Charges • Transmission
SCE*	• Transmission non-bypassable • Distribution non-bypassable • New System Generation Charge • Nuclear Decommissioning Charge • Public Purpose Programs • Department of Water Resources Bond Charges • PUC reimbursement Fee
SDG&E	• Public Purpose Programs • Nuclear Decommissioning • Ongoing Competition Transition • Reliability Services • Total Rate Adjustment Component • Department of Water Resources Bond Charges • Transmission

** Some of the SCE items are not shown separately in the SCE tariffs. Those items can be found the full cost of service appendix.*

5.1.3 INCREMENTAL UTILITY COSTS

The installation of renewable generation imposes additional capital and ongoing costs onto the utility that are not paid for by the renewable generation owner. These additional costs are added to the full cost of service estimate for each account. See Section 4.4 for further discussion of these costs.

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5.2 Full Cost of Service Results

5.2.1 FULL COST OF SERVICE AND BILLS, ABSENT DG

Once the full cost of service is calculated for the NEM accounts, the next step is to compare those costs to the utility bills that customers would receive. In order to provide some perspective on the NEM account results, it is useful to first compare bills and full cost of service for those accounts *absent the installation* of DG (Gross usage). By examining the bill and full cost of service results of NEM account gross usage, we can identify the extent to which the accounts would have exhibited differences if the NEM system did not exist. Again, some of the differences will also be due to not being able to calibrate the full cost of service results for all customers using 2011 data.[25] Nevertheless, the starting differences, regardless of their cause, provide important reference points for the evaluation of NEM impacts.

As shown in Figure 24, the full cost of service is composed of the GRC cost of service for the account, based on 2011 gross usage, plus the cost of regulatory items that are included in the tariffs but not allocated in the GRC cost of service process. The bill is simply the product of the tariff rates and the 2011 NEM account gross usage. Regulatory items are already included in the tariff rates, so there is no need to add them separately to the bill.

[25] Because a cost of service study involves the allocation of utility revenue requirements based on customer costs, it is necessary to estimate the costs for all customers (NEM and non-NEM customers) to provide the most accurate results. This type of analysis would have been extensive, and would have required more time and budget than allotted in this study.

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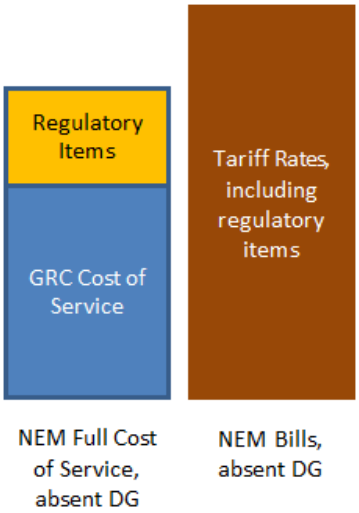
Figure 24: Comparison of Full Cost of Service and Utility Bills (Gross Usage)



Because of the differences between the ways that cost are incurred and assigned in the GRC cost of service process, and the methods by which customers are billed (tiered rates, seasonal demand charges, facilities demand charges, customer charges, etc.), it would only be by coincidence that any account would have a bill that exactly matches its full cost of service.

Comparisons of full cost of service and bills for 2011 NEM account gross usage are shown in Table 46 and Table 47. A positive value in Table 46 indicates that the estimated bills are greater than the estimated full cost of service for that sector in aggregate. The table shows that, absent DG, all of the NEM account sectors would receive bills that exceed their full cost of service.

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Table 46: Aggregate Bill Payments Above Full Cost of Service for NEM Customers– No DG Case (1,000$)

	PG&E	SCE	SDG&E	All IOUs
Residential	$75,368	$19,480	$170	$95,018
Non-Residential	$42,082	$9,358	$28,187	$79,626
Average	$117,449	$28,838	$28,357	$174,644

Table 47 shows the total bills divided by the total full cost of service for each sector. For example, a value of 110% indicates that the sector is estimated to have bills that are 10% greater than the sector's full cost of service. Again, the results indicate that all of the sectors have aggregate total bills in excess of the full cost of service for gross usage. In other words, before installing DG, the NEM participants in aggregate were likely[26] paying bills that exceeded their full cost of service.

Table 47: Percent of Cost of Service Recovery from NEM Customers – No DG Case

	PG&E	SCE	SDG&E	All IOUs
Residential	171%	152%	101%	154%
Non-Residential	128%	110%	124%	122%
Total	146%	122%	119%	133%

The difference between gross bills and full cost of service for SDG&E residential NEM accounts is partly explained by the difference in average rates between the gross NEM accounts and the average SDG&E residential account. Looking at schedule DR Domestic accounts, the gross NEM Accounts have 61% higher

[26] We qualify this statement because of the caveats discussed in section 5.1.1.

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average usage, and a 3% higher average rate than the average SDG&E DR Domestic customer. The higher than average rate is due to the inclining tier residential rates.

Higher average usage also explains part of the PG&E and SCE residential gross NEM account results. For both the PG&E E-1 and SCE Domestic residential NEM account, gross usages are almost twice the schedule average. This higher than average usage translates to PG&E E-1 and SCE Domestic gross NEM account average rates that are 30% and 16% higher than the respective schedule averages.[27] Other differences between the gross bills and cost of service are due to variations between the participants and average customers on the other residential rate schedules, as well as the caveats for the full cost of service estimation process, as discussed in section 5.1.1.

Looking at the non-residential accounts, PG&E and SDG&E have gross bills substantially above the gross full cost of service. As with the residential accounts, some of the differences can be explained by differences between the NEM participants, even before any DG, and average customers. For example, SDG&E AL-TOU NEM accounts have gross usage that is far "peakier" than the average AL-TOU customer. Because there is a substantial non-coincident demand charge for this rate, the poor load factor of the NEM accounts results in average rates for gross usage that are far higher than the average AL-TOU account.

A less extreme example is PG&E's A-6 TOU schedule. Those customers are small commercial accounts that comprise a large portion of the non-residential NEM

[27] PG&E's gross NEM accounts have a higher deviation due to the 40.3 cent per kWh upper tier rate, compared to SCE's 30 cent per kWh upper tier rate.

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population. The PG&E A-6 NEM participants have gross usage that is 11% higher than the schedule average during the most expensive summer peak and partial peak periods. The higher summer use may also result in somewhat higher cost of service, but the example does illustrate the differences between NEM participants and the average customer.

Ultimately, regardless of the reason for the difference between gross bills and gross full cost of service, it is important to keep those starting differences in mind when reviewing the full cost of service Utility Case results that are presented in the next section.

5.2.2 FULL COST OF SERVICE AND BILLS, UTILITY CASE RESULTS

The Utility Case analysis compares 2011 bills for the NEM accounts, net of the DG output (net usage), with the Utility Case full cost of service for the net usage of those accounts. As shown in Figure 25, the NEM account bill is based on the 2011 tariffs that include the regulatory items and NEM account net usage. The full cost of service is comprised of 1) the GRC cost of service, based on a combination of gross and net usage characteristics[28]; 2) the regulatory items based on net usage; and 3) incremental costs. The incremental costs are the additional costs imposed on the utilities to connect, integrate, and bill the NEM accounts.

[28] We refer to the base case as evaluating 2011 NEM account net usage. We use the term net usage (metered usage that is lower or negative because of DG self-generation) to distinguish the analysis from the evaluation of gross usage in the prior section. In performing the GRC cost of service analysis, however, some cost components are more correctly evaluated based on a customer's gross usage. Details on when gross usage and net usage are used in the GRC cost of service analysis are provided in Table 50 in Section 5.2.3 Sensitivity Analysis.

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Figure 25: Comparison of Full Cost of Service and Utility Bills (Utility Case)

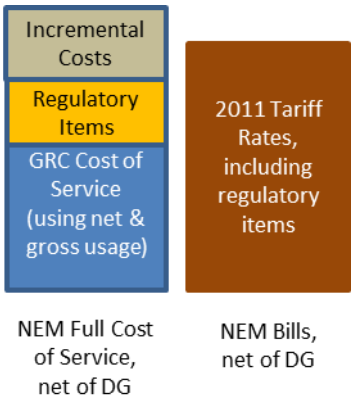

Table 48 shows the Utility Case results by utility and customer class. A positive result indicates that customers' bills are higher than their full cost of service. The full cost of service for PG&E and SDG&E NEM accounts is their estimated share of the total utility cost of service. The full cost of service for SCE NEM accounts is their estimated share of the corresponding class or rate schedule full cost of service.

Table 48: Aggregate Bill Payments above Full Cost of Service for NEM Customers - Utility Case (1,000$)

	PG&E	SCE	SDG&E	All IOUs
Residential	-$7,329	-$3,377	-$8,811	-$19,516
Non-Residential	$5,502	$3,468	$22,418	$31,389
Total	-$1,827	$92	$13,608	$11,872

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The associated full cost of service recovery percentages are shown below. The percentages are aggregate annual customer bills in 2011, divided by the associated aggregate full cost of service.

Table 49: Percent of Cost of Service Recovery from NEM Customers - Utility Case

	PG&E	SCE	SDG&E	All IOUs
Residential	88%	86%	54%	81%
Non-Residential	106%	105%	122%	112%
Total	99%	100%	111%	103%

We find that, in aggregate, NEM customers pay amounts close to their full cost of service. In general, the non-residential accounts continue to see bills that substantially exceed their full cost of service. The percentage of exceedance remains relatively unchanged for SCE and SDG&E, while PG&E accounts see bills 22% closer to the full cost of service compared to the NEM accounts without DG.

The largest changes, however, occur within the residential sector. Just as the residential inclining tier rate structure resulted in NEM accounts paying bills that exceeded their full cost of service when they consumed more than the average residential customer, the same tier structure results in the NEM accounts paying less than their full cost of service when the NEM accounts consume less than the average residential customer. Table 50 summarizes the average monthly usage for the major residential rate schedules, and the corresponding gross and net usage of NEM accounts on those schedules. The table clearly demonstrates how the DG transforms the NEM accounts from larger-than-average to smaller-than-average customers. It should be noted that SCE residential accounts might also be paying less in aggregate than their full cost of service. Even though Table 49

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shows that SCE residential NEM accounts are paying 102% of their full cost of service, because of all of the caveats discussed in section 5.1.1, the true number could easily be less than 100%.

Table 50: Residential Average Monthly Usage for Schedule Average and NEM Accounts (kWh/month)

	PG&E (E-1)	SCE (Domestic)	SDG&E (DR)
Schedule Average	538	522	545
NEM Gross Usage	1,068	1,111	876
NEM Net Usage	435	417	299

Finally, it is important to bear in mind that the comparison results are estimated based on 2011 bills and 2011 full cost of service. Over the life of the DG, however, weather patterns and utility cost causation factors (such as the timing of generation and transmission and distribution peaks, and the hourly pattern of energy prices) would change --- not to mention utility rate designs --- all of which would alter the results. Therefore, caution should be observed in extrapolating the snapshot 2011 results to conclusions regarding over or underpayment by NEM accounts over the lifecycle of the installed renewable distributed generation.

5.2.3 SENSITIVITY ANALYSIS

We perform a 'low case' and a 'high case' sensitivity analysis to capture a range of potential costs of service.

The "low case" sensitivity uses net distribution costs for cost of service calculation for all distribution cost components except for PG&E's secondary distribution cost

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component. The "high case" sensitivity considers more costs fixed, which increases the estimated cost of service of NEM customers. In the high cost sensitivity, we use the gross load profile to estimate the cost of service for transmission. This results in slightly higher full cost of service estimates for SCE.

Table 51: Aggregate Bill Payments Above Full Cost of Service for NEM Customers - Low Case (1,000$)

	PG&E	SCE	SDG&E	All IOUs
Residential	$1,108	-$3,192	-$8,156	-$10,240
Non-Residential	$15,191	$5,170	$25,242	$45,603
Total	$16,299	$1,978	$17,086	$35,363

Table 52: Percent of Cost of Service Recovery from NEM Customers - Low Case

	PG&E	SCE	SDG&E	All IOUs
Residential	102%	86%	56%	89%
Non-Residential	117%	108%	126%	118%
Total	111%	102%	115%	110%

Using this conservative cost of service specification, the SCE percent cost of service recovery increases by about 2 percentage points, SDG&E percent cost of service recovery increases by about 3 percentage points, and PG&E's increases by about 13 percentage points.

The results of the "high case" sensitivity are presented below. For the High Case, the only change in assumptions relative to the Utility Case is the use of gross transmission for determining SCE capacity costs.

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Table 53: Aggregate Bill Payments Above Full Cost of Service for NEM Customers - High Case (1,000$)

	PG&E	SCE	SDG&E	All IOUs
Residential	-$7,329	-$5,198	-$8,811	-$21,337
Non-Residential	$5,502	$129	$22,418	$28,050
Total	-$1,827	-$5,068	$13,608	$6,712

Table 54: Percent of Cost of Service Recovery from NEM Customers - High Case

	PG&E	SCE	SDG&E	All IOUs
Residential	88%	79%	54%	80%
Non-Residential	106%	100%	122%	111%
Total	99%	94%	111%	102%

The change in the treatment of SCE transmission costs reduces the percent cost of service recovery by six percentage points. It is notable that the direction of whether NEM customers pay their full cost of service, on average, reverses with the slight change in the cost of service specification for SCE in the high case.

5.2.4 MEDIAN ANALYSIS

While the aggregate cost of service analysis estimates the mean total cost of service recovery from all NEM customers in 2011, it is important to note that these results may be disproportionately driven by a small number of customers with extreme discrepancies between bills and cost of service. This section explores the cost of service results for the median NEM customer. Combined with the aggregate analysis, the median results provide further insight into the distribution of cost of service recovery by NEM customers.

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Absent NEM generation, the distribution of cost of service recovery is fairly symmetric. The bills of the median NEM customer are about 32% greater than the cost of serving that customer, while the bills of the average (mean) NEM customer are about 33% greater than cost of service. Without NEM generation, approximately 76% of NEM customers are overpaying their cost of service. Table 55 displays the breakdowns of mean and median percentage cost of service recovery by utility and customer class.

Table 55: Percent of Cost of Service Recovery from Mean and Median NEM Customers – No DG Case

	PG&E		SCE		SDG&E		All IOUs	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Residential	171%	124%	152%	127%	101%	157%	154%	131%
Non-Residential	128%	141%	110%	141%	124%	124%	122%	138%
Total	146%	131%	122%	129%	119%	157%	133%	132%

With NEM generation, the distribution of full cost of service recovery from NEM customers differs significantly from the mean, with most customers not recovering their cost of service and a few customers grossly overpaying their cost of service. As shown in Table 56, the median NEM customer's annual bill is only 57% of the cost of serving that customer. Approximately 78% of NEM customers pay less than their cost of service. Nevertheless, as discussed in Section 5.2.2, NEM customers as a group pay their cost of service. This aggregate result is driven by a minority of large, non-residential NEM customers who significantly overpay their cost of service.

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Table 56: Percent of Cost of Service Recovery from Mean and Median NEM Customers – Utility Case[29]

	PG&E		SCE		SDG&E		All IOUs	
	Mean	Median	Mean	Median	Mean	Median	Mean	Median
Residential	88%	57%	86%	57%	54%	53%	81%	57%
Non-Residential	106%	58%	105%	63%	122%	70%	112%	58%
Total	99%	57%	100%	58%	111%	56%	103%	57%

While the average percentage cost of service recovery varies considerably by utility and customer class, the median results remain fairly constant across utilities and customer classes. The median residential customers at the three IOUs pay between 53% and 57% of their cost of service, and the non-residential customers pay between 58% and 70% of their cost of service.

[29] With customers for whom both cost of service estimates and total annual bill estimates are negative, percent cost of service recovery is calculated as the ratio of cost of service to bills.

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6 Avoided Public Purpose and Other Charges

6.1 Methodology

Pursuant to Commission D.03-04-030, NEM customer generation is exempt from certain non-bypassable public purpose charges. In order to calculate the avoided public purpose charges for NEM customers, we simply multiplied the change in customer consumption as a result of NEM generation by the applicable public purpose charge in each rate for all NEM customers. This bill saving is a portion of the total bill savings presented in the cost-benefit analysis section.

6.2 Results

We find that in 2020, with a complete deployment of systems to the NEM cap, NEM customers avoid approximately $142 million in public purpose charges. In comparison, the total public purpose charges for the three IOUs were approximately $2 billion in 2012.[30] Adjusting for escalation (assuming public

[30] SCE 2012 GRC $890 million, PG&E 2011 GRC $936 million, SDG&E 2008 GRC $129 million of public purpose charges.

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purpose charges increase at the same rate as we forecast for retail rates),[31] the reduction in collected public purpose charges is forecast to be approximately 1.4% at current NEM subscription, growing to 6.3% of the total public purpose funding at full subscription to the NEM cap.

Table 57: Bill Savings in Public Purpose Charges from NEM in 2020 ($ Million/year) – All Generation

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Residential	$15	$21	$66
Non-Residential	$17	$48	$76
Total	$32	$69	$142
Total as % of Total Public Purpose Charges	1.4%	3.1%	6.3%

Public Purpose Charges represent a share of the total bill savings. The following tables show the portion of total bill savings by component. Table 58 and Table 59 show the breakdown of bill savings by component for residential and non-residential customers. Both tables show these results for the All Generation case in millions of dollars in 2020.

[31] Public purpose charges forecast to be $2.65 billion in 2020.

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Table 58: Residential Bill Savings in 2020 by Rate Component (M$/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Generation and Other Non-Specified Charges	$143	$202	$631
Transmission	$15	$20	$61
Distribution	$102	$140	$426
Public Purpose Charge	$15	$21	$66
Nuclear Decommissioning Fund	$1	$1	$2
Competitive Transaction Charge	$8	$11	$36
Energy Cost Recovery	$3	$4	$10
DWR Bond Charge	$5	$8	$24
CPUC Surcharge	$0	$0	$1
CEC Surcharge	$0	$0	$1
CARE Surcharge	$7	$9	$27
Net Surplus Compensation	$1	$1	$4
Total	$299	$416	$1,289

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Table 59: Non-Residential Bill Savings in 2020 by Rate Component (Millions $/year)

	2012 Snapshot	Full CSI Subscription	Full NEM Subscription
Generation and Other Non-Specified Charges	$116	$365	$522
Transmission	$11	$28	$45
Distribution	$57	$159	$244
Public Purpose Charge	$18	$53	$80
Nuclear Decommissioning Fund	$1	$1	$2
Competitive Transaction Charge	$8	$23	$35
Energy Cost Recovery	$3	$6	$13
DWR Bond Charge	$7	$23	$34
CPUC Surcharge	$0	$1	$2
CEC Surcharge	$0	$1	$2
CARE Surcharge	$9	$23	$37
Net Surplus Compensation	$1	$4	$7
Total	$232	$688	$1,022

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7 Household Income of NEM Customers

7.1 Methodology

In this analysis, we estimate the household incomes of NEM participants and compare them to non-NEM IOU customers and Californians overall. Income estimates of California Solar Initiative (CSI) participants, which are the vast majority of NEM customers, are currently reported on the Go Solar Website as well as in the California Solar Initiative Annual Report.[32] These estimates are computed using median household incomes by zip code. In this study, we make a significant update to the prior methodology by performing the analysis using census tract and more granular data from the 2010 US Census, rather than zip codes used in the current public reporting. The census tracts are much smaller geographic areas than those represented by zip code, and they are selected to have more homogenous demographics. Therefore, a census tract approach provides a more accurate estimate of NEM customer household income and has significantly different results.

[32] http://www.cpuc.ca.gov/NR/rdonlyres/0C43123F-5924-4DBE-9AD2-8F07710E3850/0/CASolarInitiativeCSIAnnualProgAssessmtJune2012FINAL.pdf

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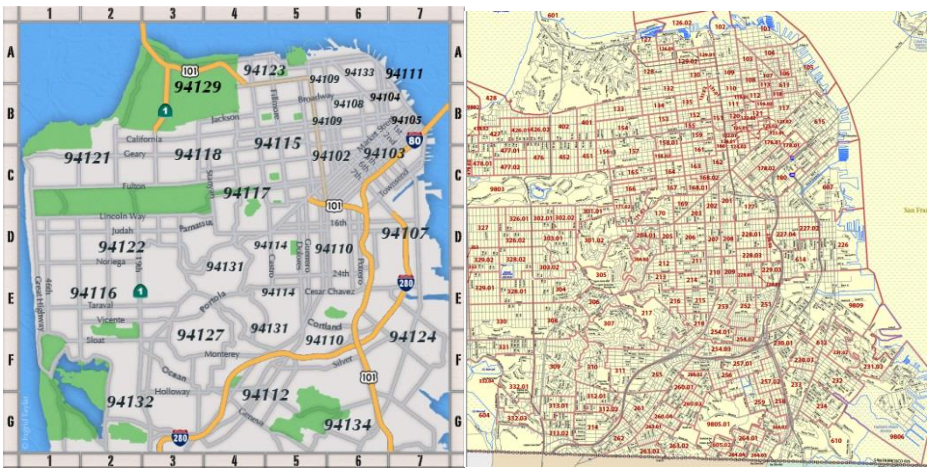
Figure 26: A Map of San Francisco Labeled at the Zip Code Level (left) and Census Tract Level (right)



7.2 Results

For residential sector NEM systems, we find that the customers installing NEM systems system since 1999 have an average household income based on 2010 census tract data of $91,210, compared to the median income in California and in the IOU service territories of $54,283 and $67,821, respectively. The median income of our population of NEM customers is about 68% greater than the median California household income and about 34% greater than the median household income of IOU customers. We find that the relative income gap between those customers that installed NEM generation to those that have not has remained consistent since approximately 2005.

Figure 27 shows the average of 2010 median household incomes for customers who installed NEM generation over time and compares to the median 2010 household income of all IOU customers and statewide. As is portrayed below,

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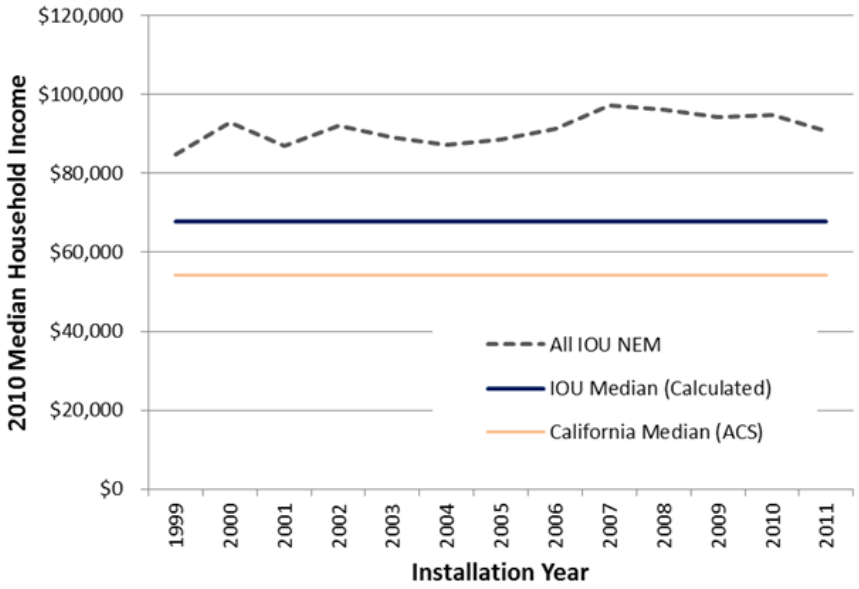
the average median household income of customers installing NEM systems was about 30% to 40% higher than that of the general IOU customer population in 1999. As the NEM program developed and the number of new customers rose, the household income differential income peaked at 43% in 2007, but has shown a gradual decline to around 34% in 2011.

Figure 27: NEM 2010 Household Income by Installation Year Compared to IOU and California Median Income



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APPENDIX A:

Data Collection and Binning Methods

October 28, 2013

Data Collection and Binning Methods

A-1. Overview and Purpose

This section of the report outlines the methods used to amass and estimate net energy metering (NEM) customer usage and generation data and to reduce this data to a manageable number of representative customer profiles. The resulting customer "bins" are used throughout the analysis to estimate the costs and benefits of NEM.

Measuring the costs and benefits of NEM, as we have defined them in Chapter 3, requires hourly or sub-hourly gross consumption and distributed generation (DG) data during the time period being evaluated. With this data, it is possible to calculate the *amount* and *timing* of generation serving onsite load and being exported to the grid and, thereby, the associated costs and benefits to the utility and to its customers.

In reality, hourly or sub-hourly generation and consumption data was available for only a small portion of the total NEM customers included in this study. Generation data was available for only 451 customers, or less than .5% of all NEM customers included in this study, and bidirectional sub-hourly consumption data was available for 5,800 customers, or about 5% of all NEM customers included in this study. The minimal amount of available hourly data is largely a reflection of the fact that hourly data is not required for utility calculations of excess NEM generation customer bill credits or other bill components. As a result, there was limited deployment of advanced metering technologies, such as SmartMeters, that recorded hourly net usage in 2011.

Because we lacked a complete measure of the amount and timing of energy generated and consumed by NEM customers, we used simulation and load research data to estimate the missing data. For customers without complete generation data, we simulated generation data using location-specific parameters. Where net consumption data was missing, we used this simulated generation and gross billing data of non-NEM customers to estimate net consumption. While it would be preferable to have metered hourly or sub-hourly generation and consumption data, we believe that this approach results in sufficient generation and usage estimates based on comparisons with our small sample of sub-hourly generation and consumption data.

To improve transparency and display the analysis in the public tool, we developed "bins" of customers with similar characteristics. We assigned each bin a representative generation and consumption profile based on the generation and consumption profiles that we had estimated for the NEM customers represented by the bin. Bins are homogenous in terms of customer class, rate, service territory, baseline allowance, voltage level, generation technology type, approximate usage, and approximate generation.

A-1.1 DATA RECEIVED

Each investor-owned utility (IOU) provided a list of NEM customers and their DG system characteristics, billing data for a sample of NEM customers, DG output data for a sample of NEM customers, and load research data profiles of non-NEM customers. A description of each data set is given below.

A-1.1.1 NEM Customer Lists

The NEM customer lists include address, DG type (solar, wind, fuel cell, or internal combustion), and installed capacity for each NEM customer. The NEM customer lists are not comprehensive lists of *all* NEM customers, but the combined data set does comprise the vast majority of NEM customers in California IOU service territories (about 93% of installed NEM DG capacity in 2011).

Table 1: NEM Customer Lists

	PG&E	SCE	SDG&E	Total
Solar				
System Count	60,157	24,055	15,707	99,919
MW Installed	628.2	266	108.3	1,002.5
Wind				
System Count	149	224	32	405
MW Installed	4.1	2.8	0.1	7
Fuel Cell				
System Count	40	31	5	76
MW Installed	9.6	5.6	1.5	16.7
Internal Combustion Engine				
System Count	18	-	1	19
MW Installed	12.1	-	0.6	12.7
Misc / Unknown				
System Count	-	-	131	131
MW Installed	-	-	2.4	2.4
Total System Count	60,364	24,310	15,876	100,550
Total MW Installed	654	274.4	112.9	1,041.3

Data from the NEM lists was used to simulate generation from each NEM system. This process is described in detail in section A.2.2.1. The final number of customers in this analysis was grossed up to account for the missing data, the amount of which was estimated based on aggregate forecast penetration levels by utility and customer class (described in Section 3.2 of the main body of this report).

A-1.1.2 Billing Data

Each IOU provided billing data for most (about 90%) of the customers in the NEM lists. Billing data includes monthly net kWh usage (total kWh usage minus kWh generation), interconnection date, rate, and utility territory/climate zone. Table 2 portrays the number of customers for which we received billing data by utility and customer type.

Table 2: 2011 Billing Data

	PG&E	SCE	SDG&E	Total
Residential Customers	47,308	19,225	14,127	80,660
Non-Residential Customers	2,969	1,070	619	4,658
Total	50,277	20,295	14,746	85,318

Although the billing data set does not include hourly data for every NEM customer, the monthly net kWh usage variable could be used along with actual hourly usage shapes to estimate hourly usage and provide a basis for the calculations in this analysis. This data captures approximately 75% of all 2011 NEM customers.

A-1.1.3 Metered DG Output and Bi-Directional Data

The IOUs provided generation data and bidirectional meter data for a subset of the NEM customers. Generation data comprises metered NEM system generation on the 30-minute or 15-minute level. Bidirectional meter data measures net consumption on the 30-minute or 15-minute level.

Table 3: Generation and Bidirectional Data

	PG&E	SCE	SDG&E	Total
Generation Meter Count	330	5	116	451
Bidirectional Meter Count	1,867	3,773	160	5,800

This generation and bidirectional data was used directly in the analysis. It was also used to calibrate generation simulation, which was used to simulate generation for customers lacking generation data. The calibration process is described in section A-2.2.

A-1.1.4 Load Research Data

Load research data includes 30-minute interval load data, customer class, base rate, and utility territory. This data enabled us to estimate gross load data for NEM customers for whom we did not have bidirectional meter data.

Table 4: Load Research Data

	PG&E	SCE	SDG&E	Total
Residential Customers	2,102	367	205	2,674
Non-Residential Customers	10,755	406	146	11,307
Total	12,857	773	351	13,981

Load research shapes are matched to customers without bidirectional meter data based on customers' DG system characteristics, net consumption billing data, and other customer characteristics. This process is described in detail in section A-2.3.

A-2. Hourly Net Load Profiles Estimation

As previously discussed, the ideal data set used to measure the costs and benefits of NEM would include hourly or sub-hourly gross consumption, net consumption, and distributed generation data. Because hourly metered generation data was available for only a small portion of NEM customers in this study, we simulate generation for the remaining customers. Load research data is used along with the generation data to estimate net and gross consumption during each 30-minute time period. The general outline for estimating customer net consumption profiles is as follows:

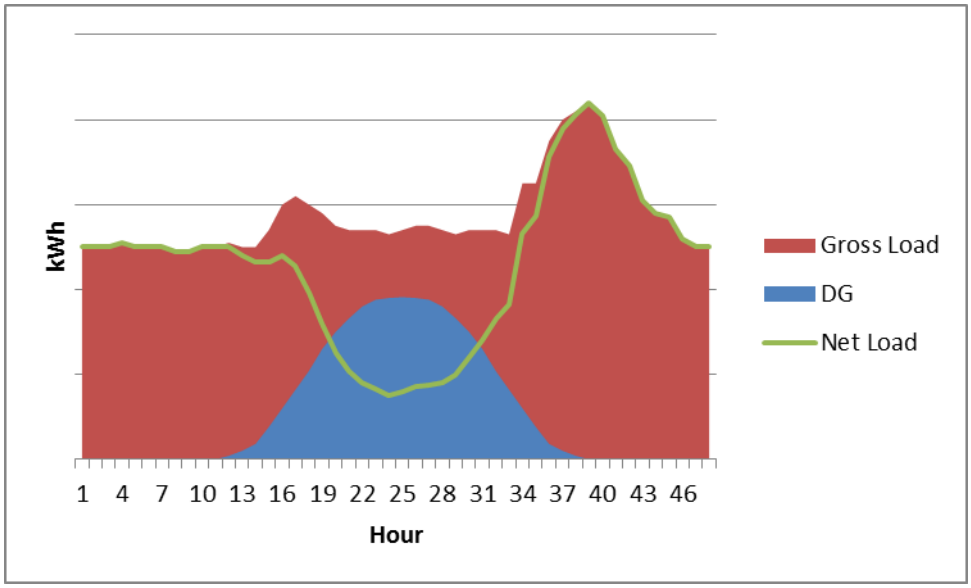
1. Assign a sub-hourly DG output shape (actual or simulated) to each customer

2. Calculate annual gross consumption for each customer by adding the customer's assigned DG output to the customer's actual billed monthly net load

3. Estimate sub-hourly gross consumption for each customer using the load research profile that most closely resembles the customer's location, rate, and usage profile

4. Obtain a sub-hourly net consumption shape for each customer by subtracting assigned DG output from estimated gross consumption (see Figure 1).

Figure 1: Diagram of Net Load Calculation

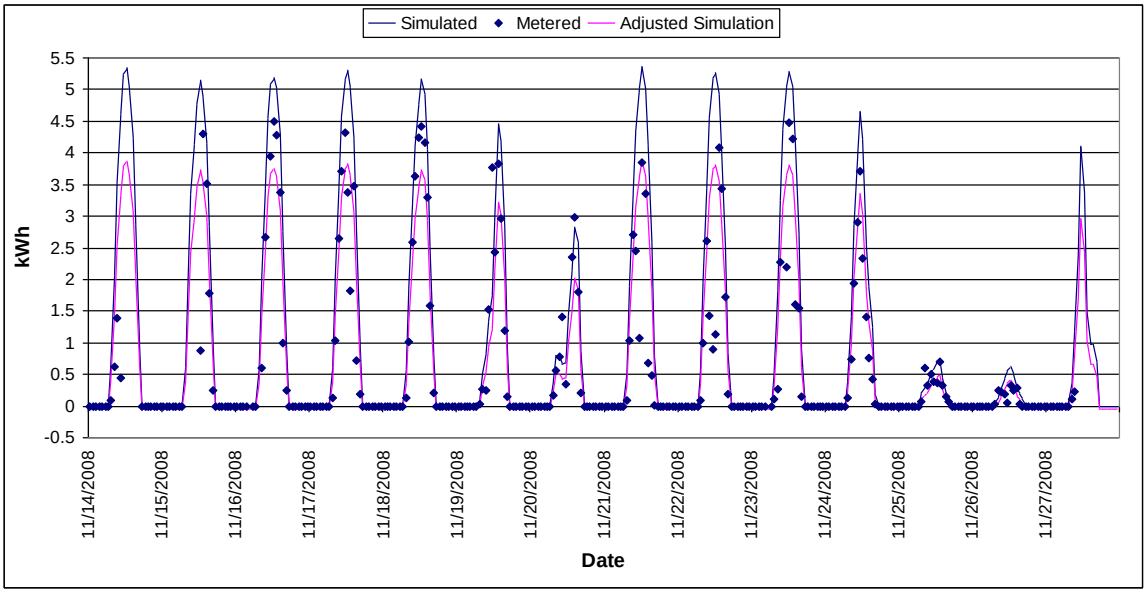


The subsequent sections provide a detailed description of each step of this process.

A-2.1 ANNUAL GROSS GENERATION OUTPUT SHAPES

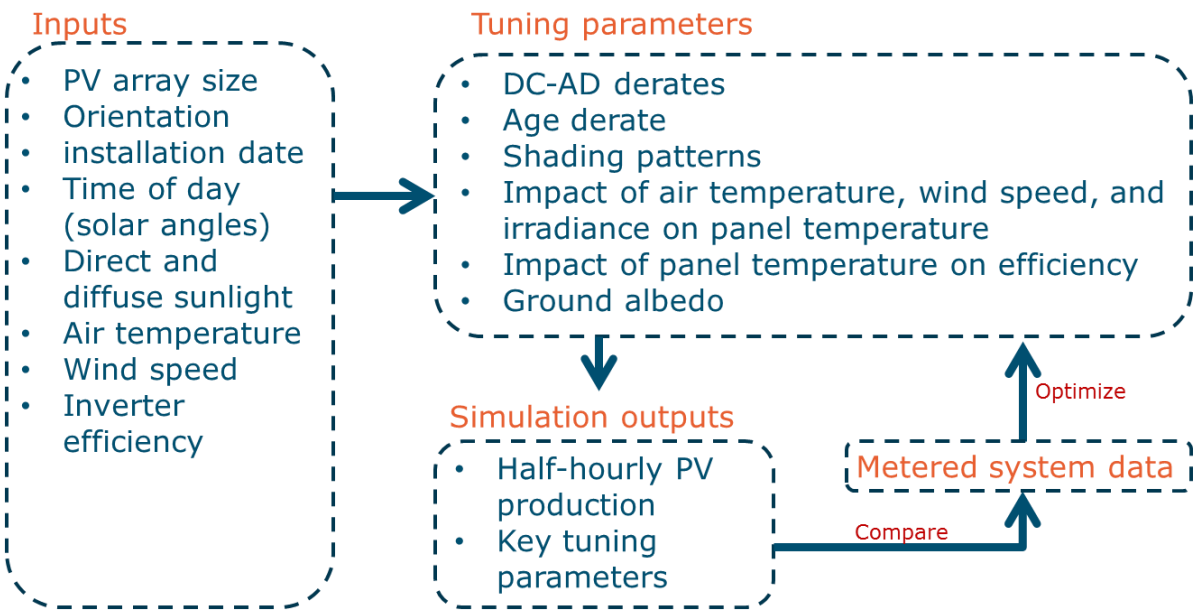
As a first step in the analysis, distributed generation time-series energy production (2011) was produced for every NEM customer in the IOU service territories. For a subset of customers, 15-minute metered data was available from the Power-Clerk database. The metered data was supplemented with simulated wind and solar profiles (described in more detail in the following section) to create a complete data set with an individualized generation profile for each NEM customer. In addition to being used directly as part of the final data set, the metered data served as a reference from which we tuned generation simulation parameters. Simulation parameters include shading profiles, age derate profiles, DC-AC derate profiles, ground albedo, impacts of air temperature and wind speed on panel temperature, and impacts of panel temperature on efficiency. Figure 2 displays a two-week period in which the simulation parameters were optimized by minimizing the sum of the squared errors between the simulated profile and the metered data.

Figure 2: Simulated, Metered, and Adjusted Simulation Output Profiles of a PV Installation



After optimizing the simulated data with respect to metered data, missing meter readings for customers with generation data were estimated using the corrected simulation. The simulation tuning process is presented in Figure 3.

Figure 3: Solar PV Simulation Process



A-2.1.1 Simulated Annual Gross Distributed Generation

A-2.1.1.1 Solar PV

Solar PV was modeled using satellite measured irradiance data provided by Clean Power Research. The data is available online at: https://www.solaranywhere.com/Public/About.aspx. Each irradiance data-point represents a 1 km grid-cell and provided an estimate of solar insolation, temperature, and wind speed every 30 minutes. Clean Power Research also provided these temperature and wind speed estimates.

Solar PV output was simulated using industry standard equations.[1] Key parameters include the amount of global, direct, and diffuse insolation, panel orientation, DC-AC efficiency, temperature, wind speed, and shading. Table 5 shows summary capacity factors from the simulation based on system size and geographic location. The capacity factors for the metered systems only differed from those of the simulated systems by an average of about 0.3%, which indicates that the simulated generation closely matches the metered generation, on average.

[1] Gilbert M. Masters (2004) Renewable and Efficient Electric Power Systems. John Wiley & Sons.

Table 5: Summary of Metered and Simulated Solar PV Capacity Factors

IOU	PV Array Size	Annual Capacity Factor (metered)	Annual Capacity Factor (simulated)
PG&E	0-10 kW	16.9%	16.6%
	10-100 kW	16.9%	16.7%
	100-500 kW	17.1%	16.8%
	500+ kW	17.4%	17.2%
SCE	0-10 kW	18.1%	17.8%
	10-100 kW	18.3%	18.0%
	100-500 kW	18.4%	18.1%
	500+ kW	18.4%	18.2%
SDG&E	0-10 kW	18.3%	17.9%
	10-100 kW	18.3%	18.0%
	100-500 kW	18.4%	18.0%
	500+ kW	18.6%	18.4%

A comparison between actual metered data and final simulated data is shown for a summer week in Figure 4 and for a winter week in Figure 5.

Figure 4: Simulated vs. Metered Solar PV for a Sample System During a Summer Week

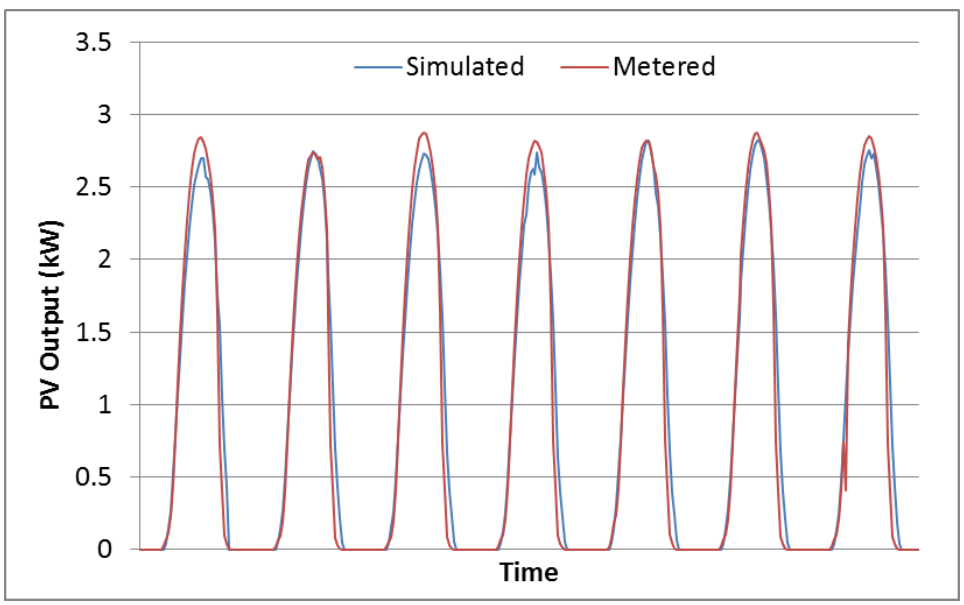
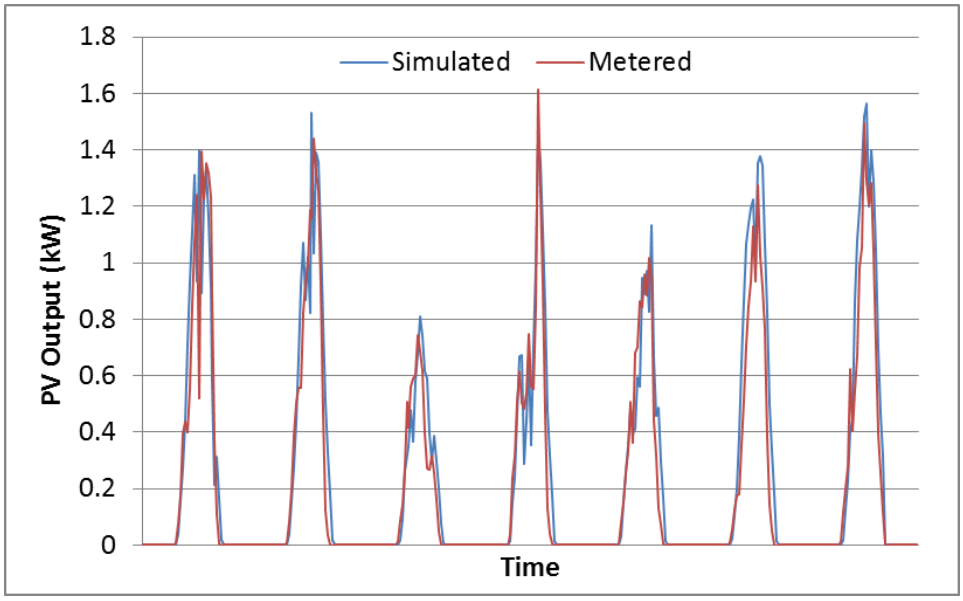


Figure 5: Simulated vs. Metered Solar PV for a Sample System During a Winter Week



The simulation of this particular system agrees well with the metered data, which is not always true due to the particulars of each solar installation. For instance, shading patterns vary considerably across systems and substantially impact the capacity factors of individual systems. The shading parameters used in the simulation are tuned to capture the average shading pattern. It should therefore be expected that the simulation's shading parameters would differ considerably from those of many individual systems, yet the simulation parameters should capture the *aggregate* shading patterns of the systems well. Overall, the solar simulation replicates the *average* system very well, which is the most important factor for ensuring accuracy of the overall analysis.

A-2.1.1.2 Wind

Time series wind production for behind-the-meter wind systems was done using wind speeds from the Clean Power Research data set and wind turbine power curves indicative of the size of the installed wind turbine. As we did not have any metered wind generation, we used power curves for representative wind turbines from an online database, available at: http://www.wind-power-program.com/. The time series wind speed from the Clean Power Research data set was scaled to the appropriate hub height using the 1/7 power law, a common industry equation that relates wind speeds at different heights under neutral atmospheric stability.

Due to the course granularity of the Clean Power Research data set and the highly localized nature of wind resources, wind speeds from neighboring grid cells were sometimes used to simulate system generation when the native grid cell produced an unrealistically low capacity factor. We believe that this technique more accurately estimates local wind speeds at sites with wind generation than would using the unrealistically low average wind speeds of the grid cells that contain the sites.

A-2.1.1.3 Fuel Cells

NEM fuel cell systems were assumed to have a fixed output. The level of output was determined based on nameplate capacity and a capacity factor of .68.[2]

A-2.2 ANNUAL GROSS CONSUMPTION SHAPES

Load research profiles, or sub-hourly usage data for non-NEM customers, were matched to NEM customers based on rate, territory, customer class, and consumption. Each customer received one load research match. Load research shapes were matched to customers in two stages. First, load shapes were matched to customers within a given utility territory, on a given base rate, and having the smallest difference in annual electricity use. Matches were only retained if the difference in usage was less than 20%. If no match was available, a second attempt was made using utility territory, customer class, and difference in annual electricity use only. **Error! Reference source not found.** shows an example of this process.

[2] Estimate from *CPUC Self-Generation Incentive Program—Eleventh Year Impact Evaluation Report*, Appendix A, Table A-10. http://www.cpuc.ca.gov/NR/rdonlyres/EC6C16C5-9285-4424-87CF-4A55B0E9903E/0/SGIP_2011_Impact_Eval_Report.pdf

Figure 6: Example Load Research Matches

Customer Characteristics			
Base Rate	Customer Class	Territory	Annual kWh
E-1	Residential	W	13,303
E-1	Residential	R	46,124
E-1	Residential	X	48,159

Stage 1 Match				
Base Rate	Customer Class	Territory	Annual kWh	Percent Difference
E-1	Residential	W	13,285	0%
E-1	Residential	R	28,599	38%
E-1	Residential	X	35,709	26%

Stage 2 Match				
Base Rate	Customer Class	Territory	Annual kWh	Percent Difference
Matched in Stage 1				
E-8	Residential	R	49,210	7%
E-8	Residential	X	38,202	21%

Results
Use Stage 1 Match
Use Stage 2 Match
No Match

Customers who could not be matched to load research profiles were included in the analysis only if they shared characteristics with at least four customers with load research matches. This process is described more thoroughly in the following section.

A-3. Binning process

A-3.1 BINNING METHOD

Next, to improve transparency and display the analysis in the public tool (See Appendix F), we developed "bins" that represent types of customers. Each bin was assigned one representative generation and consumption profile. These generation and consumption profiles are treated in the remainder of the analysis as the consumption and generation of every single NEM customer represented by the bin. The number of NEM customers represented by each bin is scaled up and down according to capacity forecasts, but per-customer generation and usage remain constant throughout the analysis.

We bin customers based on factors that are likely to result in relative homogeneity in generation and consumption profiles. Customers were first divided into groups based on the following customer characteristics:

- **Utility**: Customers receiving service from each of the three IOUs were grouped separately.
- **Customer class**: As shown in Table 6, the customer classes used were residential, agricultural, and commercial/industrial.
- **Utility territory**: Twenty-three territories across the three IOUs were used to establish customer baselines. These territories are displayed in Table 6. Classification by territory captures much of the variation in climate and other geographically-driven customer and building characteristics. Some territories were combined based on geographical proximity and rate baseline similarity.
- **DG technology**: Customers were further divided by generation type. Customers with PV and wind generation were grouped separately from customers with only one generation type.
- **Retail rate**: Table 7 lists all of the retail rates that were assigned to groups, by utility.
- **Rate baseline**: Customers with electric heating and medical baseline allowances were grouped separately from those without these additional baseline allowances. In a few cases where there were no customers with load research matches on a medical baseline in a given group, customers were grouped with customers that shared every other customer characteristic, as we believe that this was more accurate than excluding these customers from the analysis[3]. This is relevant for tiered rate structures only.
- **Voltage level**: This field denotes the voltage level at which customers receive electricity. Voltage levels comprise basic, primary, secondary, and transmission.
- **Gross annual consumption**: Customers were grouped based on their annual consumption, as calculated from the billing data. Usage categories are shown in Table 8.
- **Ratio of PV generation to annual gross consumption**: This ratio was calculated for each customer using billing data and actual or simulated generation profiles. Table 8 displays the generation categories used.

[3] If these customers were excluded from the analysis, they would be treated as average NEM customers based on our remaining sample. This would underestimate the number of NEM customers in specific rate/territory/voltage/technology/usage/consumption/generation categories and overestimate the number of NEM customers in other categories.

Table 6: Customer Classes and Territories

Customer Classes (All IOUs)	PG&E Territories	SCE Territories	SDG&E Territories
Residential	P, S	5, 6	1
Commercial / Industrial	Q, T, Z	8	2
Agricultural	R	9	3
	V, Y	10	4
	W	13	
	X	14	
		15	
		16	

Maps of each of the utility service territories and climate zones for rates are available at the following web link.

http://www.cpuc.ca.gov/PUC/energy/Electric+Rates/Baseline/mapsNtariffs.htm

Table 7: Retail Rates

Base Rate PG&E		Base Rate SCE	Base Rate SDG&E
A-1	E-19	D-CARE	A
A-10	E-19V	D-FERA	A6-TOU
A-10-TOU	E-19W	DM	AD
A-6-TOU	E-19X	DOMESTIC	AL-TOU
A-6W-TOU	E20	GS-1	DG-R
A-6X-TOU	E37W	GS-2	A-TOU
AG1-A	E37X	GS2T-A	AY-TOU
AG1-B	E-6	GS2T-B	DM
AGR-A	E-7	GS2T-R	DR
AGR-B	E-7W	PA-1	DR-LI
AGV-A	E-8	PA-2	DR-SES
AGV-B	E-A9	TOU-8-B	DR-TOU
AGV-E	E-B9	TOU-8-R	DT
AG4-A	EL-1	TOU-D-1	EV-TOU-2
AG4-B	EL-6	TOU-D-1-CARE	PA
AG4-C	EL-7	TOU-D-2	PA-T-1
AG4-D	EL-8	TOU-D-2-CARE	
AG4-E	EM	TOU-D-T	
AG5-A	EML	TOU-D-TEV	
AG5-B	EML-TOU	TOU-GS-1	
AG5-C	EM-TOU	TOU-GS3-A	
AG5-D	ES	TOU-GS3-CPP	
AG5-E	ETL	TOU-GS3-R	
E-1		TOU-PA-5	
		TOU-PA-B	
		TOU-SOP	

Table 8: Consumption and Generation Categories

Gross Annual Consumption	Ratio of Annual PV Generation to Gross Annual Consumption
0 - 5 MWh	0 to 0.4
5 - 10 MWh	0.4 to 0.6
10 - 25 MWh	0.6 to 0.8
25 - 50 MWh	0.8 to 1
50 - 100 MWh	1 to 1.2
100 - 500 MWh	Over 1.2
Over 500 MWh	

This process resulted in 2,898 unique groups, which became the basis for creating customer bins.

For groups containing fewer than five customers, we use the simulated generation data and load research matches of each customer to calculate individual bins with one representative customer in each. For groups with more than five customers, we selected two load shapes and two generation shapes by taking the 33rd percentile and 67th percentile shapes by load factor and capacity factor, respectively. Consumption and generation shapes are scaled so that the associated annual gross consumption and generation match the average annual gross consumption and generation, respectively, for the original group. NEM generator capacity is scaled along with the generation. Thus, the only variation between bins that originate from the same group is hourly usage and generation shape. This resulted in 9,458 bins of customers with PV and/or wind generation and 31 fuel cell bins. These bins are used in the analysis to calculate avoided cost of generation, bill savings, and cost of service. Figure 7 portrays a fictional example of the binning process.

Figure 7: Example Diagram of Binning Process

Customer ID	Customer Class	Utility Territory	Rate	Baseline	Technology Type	Gross Annual Consumption	Ratio of Annual PV Gen to Consumption	Load Research Match	Generation Match
1	Res	P, S	E-1	B	Solar PV	11 MWh	0.5	1	1
2	Res	P, S	E-1	B	Solar PV	20 MWh	0.45	2	2
3	Res	P, S	E-1	B	Solar PV	14 MWh	0.55	3	3
4	Res	P, S	E-1	B	Solar PV	24 MWh	0.42	4	4
5	Res	P, S	E-1	B	Solar PV	17 MWh	0.57	5	5
6	Res	P,S	E-1	B	Solar PV	22 MWh	0.44	6	6
7	Res	R	E-1	S	Solar PV	6 MWh	0.68	7	7
8	Res	R	E-1	S	Solar PV	9 MWh	0.73	8	8
9	Res	X	E-1	B	Wind	30 MWh	0.94	9	9
10	Res	X	E-1	B	Wind and Solar PV	45 MWh	0.86	10	10

Group	Customer Class	Utility Territory	Rate	Baseline	Technology Type	# of Customers	Gross Annual Consumption	Ratio of Annual PV Gen to Consumption
1	Res	P, S	E-1	B	Solar PV	6	10-25 MWh	0.4-0.6
8	Res	R	E-1	S	Solar PV	2	5-10 MWh	0.6-0.8
9	Res	X	E-1	B	Wind	1	25-50 MWh	0.8-1.0
10	Res	X	E-1	B	Wind and Solar PV	1	25-50 MWh	0.8-1.0

Bin	Group	Cust. Class	Utility Territory	Rate	Base-line	Tech. Type	Load Research Shape	Generation Shape	# of Customers Represented by Bin
1	1	Res	P, S	E-1	B	Solar PV	LR shape with 33rd percentile load factor of LR shapes matched with group 1	Gen shape with 33rd percentile cap factor of gen shapes matched with group 1	1.5
2	1	Res	P, S	E-1	B	Solar PV	LR shape with 33rd percentile load factor of LR shapes matched with group 1	Gen shape with 67th percentile cap factor of gen shapes matched with group 1	1.5
3	1	Res	P, S	E-1	B	Solar PV	LR shape with 67th percentile load factor of LR shapes matched with group 1	Gen shape with 33rd percentile cap factor of gen shapes matched with group 1	1.5
4	1	Res	P,S	E-1	B	Solar PV	LR shape with 67th percentile cap factor of LR shapes matched with group 1	Gen shape with 67th percentile cap factor of gen shapes matched with group 1	1.5
5	2	Res	R	E-1	S	Solar PV	7	7	1
6	2	Res	R	E-1	S	Solar PV	8	8	1
7	3	Res	X	E-1	B	Wind	9	9	1
8	4	Res	X	E-1	B	Wind and Solar PV	10	10	1

Figure 8 portrays an example of bins for one rate class and geographical area. Figure 9 and Figure 10 display two example load shapes of bins in this category, both of which came from the same group and, therefore, have the same annual consumption. These bins are circled in Figure 8.

Figure 8: Bins for PG&E Rate E-1 Customers in Territories Q, T, Z

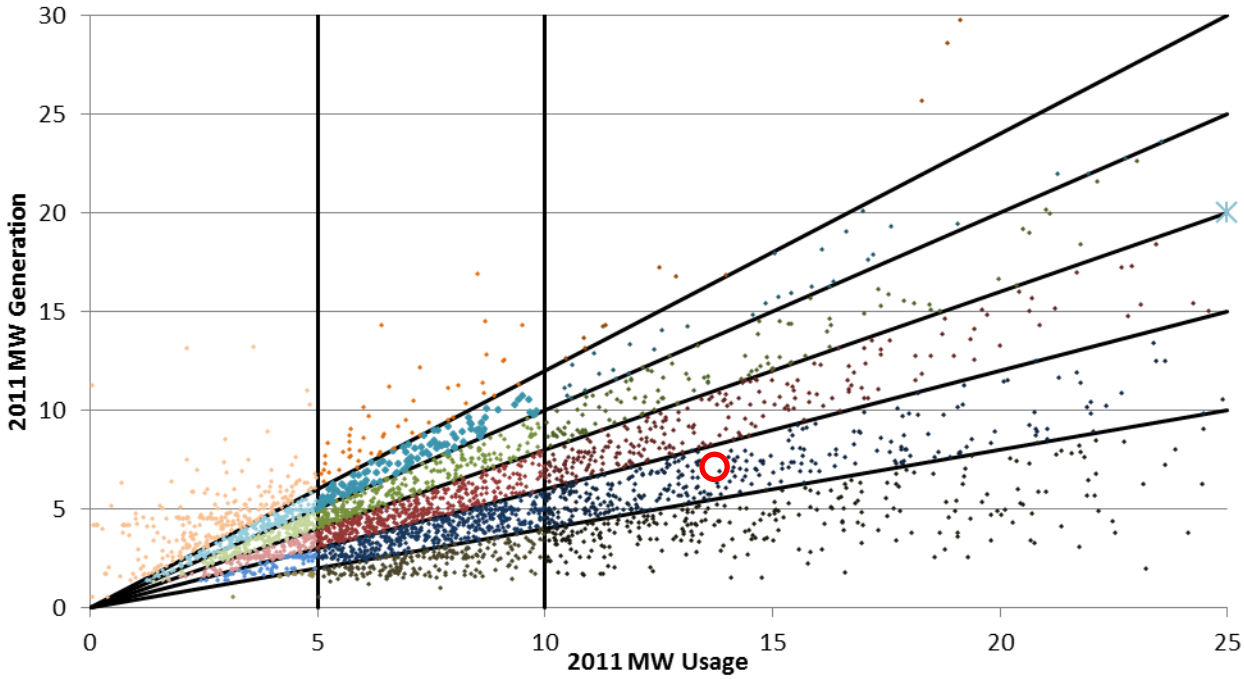


Figure 9: Load Shape Example #1

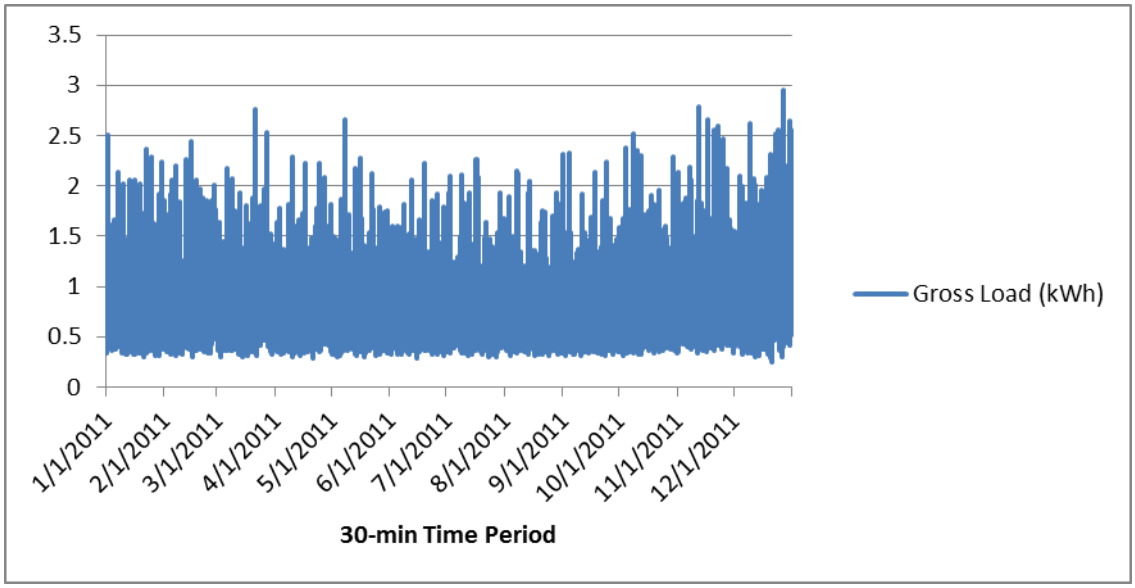
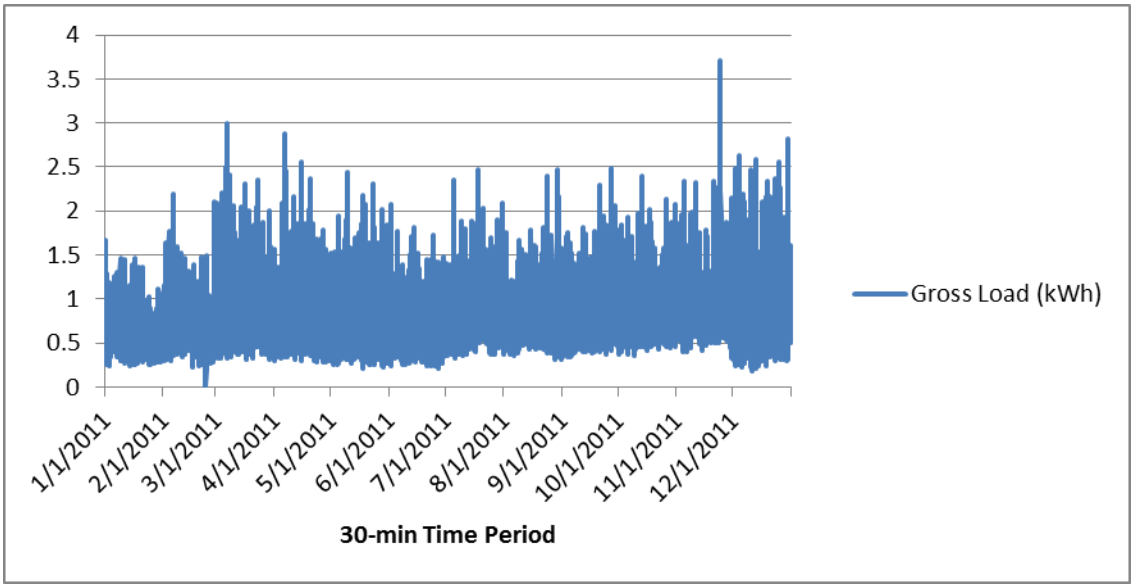


Figure 10: Load Shape Example #2



A-3.2 COMPARISON BETWEEN BINNED AND NEM LISTS

Some customers in the NEM lists are not represented in the final bins because we were unable to match them adequately with a load research profile. The following table presents a comparison of the number and capacity of generation systems in the NEM lists and in the final bins.

Table 9: Comparison of DG Systems in NEM Lists and Bins

	NEM Lists				Bins			
	PG&E	SCE	SDG&E	Total	PG&E	SCE	SDG&E	Total
Solar								
System Count	60,157	24,055	15,707	99,919	49,833	19,634	14,395	83,862
MW Installed	628.2	266.0	108.3	1002.5	539.9	143.6	76.0	759.5
Wind								
System Count	149	224	32	405	102	175	25	302
MW Installed	4.1	2.8	0.1	7.0	1.4	1.3	0.1	2.8
Fuel Cell								
System Count	40	31	5	76	40	31	5	76
MW Installed	9.6	5.6	1.5	16.7	9.6	5.6	1.5	16.7
Internal Combustion Engine								
System Count	18	-	1	19	0	0	0	0
MW Installed	12.1	-	0.6	12.7	0	0	0	0
Misc / Unknown								
System Count	-	-	131	131	0	0	0	0
MW Installed	-	-	2.4	2.4	0	0	0	0
Total System Count	60,364	24,310	15,876	100,550	49,935	19,809	14,420	84,164
Total MW Installed	654	274	112	1041	551	151	78	779

A-4. Conversion to Typical Meteorological Year

Because 2011 substation data was not available for use in the avoided analysis calculations, we had to convert the 2011 load research data associated with each bin to a Typical Meteorological Year (TMY) format. The following steps outline the process used to remap the days of 2011 to a TMY year.

1. Collect hourly load profiles for the entire state from 2011 and based on the TMY data
2. Normalize hourly load profiles by dividing each reading by the average hourly load of the year

3. Classify each day in 2011 and in the TMY as being either weekday or weekend/holiday
    a. The TMY has the weekend/holiday layout of the year 2009
4. For each day of the TMY:
    a. Find, within the nearest 30 days (15 before, 15 after) chronologically, all the 2011 days that are the same day type. As an example, for the TMY day 6/15/2009, all the non-weekend days in June would be in this grouping
    b. Find the mean squared error (MSE) between the normalized hourly load of the TMY day in question and the normalized hourly load of each of the near 2011 days found in the above step
    c. Rank the 2011 days by MSE and assign the top-ranked 2011 day to the TMY day
    d. To avoid overusing certain days, if the top-ranked 2011 day has already been mapped to a TMY day and a latter-ranked 2011 day has not yet been mapped AND has an MSE value within 5% of the top MSE value, then assign the latter-ranked 2011 day to the TMY day
5. Having completed step 4 for each day of the TMY, set each TMY daily load research shape equal to the 2011 daily load research shape indicated by the mapping in step 4.

APPENDIX B:

NEM BILL CALCULATIONS

October 28, 2013

NEM Bill Calculations

B-1. How NEM Billing Works

This appendix describes E3's methodology for determining the total reduction in utility bills attributable to California's Net Energy Metering program. Participants in net energy metering (NEM) are allowed to export excess renewable generation to the electric grid when it is not serving onsite load. Excess generation is purchased by the customer's utility at the exact rate that the customer would have paid for the same amount of consumption, according to their otherwise applicable rate schedule (OAS). This means that customers on time-of-use rates receive different credit amounts depending on when their periods of net generation occur. Similarly, customers on tiered rates are compensated for net exports following the same inverted-block shape that applies to their energy purchases: As the customer generates more and more excess electricity, the utility is required to purchase the generation at an increasing tiered rate.

NEM participants are not paid directly for excess generation; instead, they earn credits which can be applied to offset their electricity bills. These credits can be applied only to the energy charge portion of the customers' utility bills. Other charges, including meter charges, demand charges, phase charges, and any other non-energy charges cannot be offset by excess generation credits. However, all charges are calculated based on the customers' net energy usage, so the demand charge portion of the bill can be reduced significantly through NEM participation independent of the value of excess generation.

Residential and some small commercial customers who participate in NEM have the option to pay the energy portion of their bills on an annual basis, as opposed to a monthly basis. Each month, these customers are billed for non-energy charges such as meter charges or minimum charges. At the end of the year, the customers have a "true-up" period where any excess generation credits that they have earned over the previous twelve-month period are applied to offset any charges they have incurred for net energy consumption. In contrast, large commercial customers pay their full electricity bill every month. In months when they are net exporters, these customers accrue credits that can be applied to offset their energy charges in future months when they are net importers.

B-1.1 Treatment of Excess Credits

Excess generation credits as described above can only be applied to offset customers' incurred energy charges, which means that the lowest possible annual energy charge for any participant is $0.[1] However, customers who generate more electricity than they consume over a full twelve-month period earn a separate credit in accordance with California bill AB 920.[2] This law requires utilities to compensate NEM customers for any annual excess electricity generation using a net surplus compensation (NSC) payment, which occurs during the annual true-up period. The NSC rate is a monthly average of each utility's default load aggregation point (DLAP) price in CAISO's hourly day-ahead market, for the period from 7 AM to 5 PM. In 2011, the NSC rates paid by California's three IOUs ranged from 3.5-4.0 cents per kWh. Under NEM billing policy, the NSC credit can be paid to the customer during the true-up period or rolled over and applied to offset the customer's bills in the following year. In our modeling we assume that the credit is paid out at true-up for all customers.

B-1.2 Billing for NEMFC

NEM participants who install onsite fuel cells pursuant to Public Utilities Code (PUC) 2827.10 are subject to a slightly different set of policies than those who install distributed generation under the regular NEM program otherwise referred to in this report.[3] Like other NEM participants, Fuel Cell NEM (NEMFC) participants are billed on a net basis, but they do not receive a full retail rate credit for their exported energy. Instead, exports are credited at the generation component of the customer's retail rate, excluding any Department of Water Resources (DWR) generation or DWR bond charges. NEMFC participants are not eligible for the NSC payment.

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[1] However, even customers who generate enough energy to completely offset their annual energy charges are responsible for non-energy charges including minimum charges, meter charges and demand charges.

[2] Full text of AB 920 can be found at http://www.leginfo.ca.gov/pub/09-10/bill/asm/ab_0901-0950/ab_920_bill_20091011_chaptered.pdf.

[3] Customers who install renewable-fueled fuel cells can choose to participate in either NEM or NEMFC, while those who install fuel cells powered by fossil fuel are eligible only for NEMFC.

B-1.3 Sample NEM Bill

The following example calculates a sample NEM bill for a commercial PG&E customer for the months of October and November in 2011. In this example, the customer is a net exporter in October and generates a rollover credit that can be used to offset the customer's November energy charge.

Table 1: Sample NEM Bill

CUSTOMER INFORMATION

Customer Class:	Commercial
Utility:	PG&E
Rate:	A-1
Phase:	Three-phase

CUSTOMER BILLING DETERMINANTS

Month:	October	November
Days per month:	31	30
Net kWh usage per month:	-125	200

RATE CHARGES

Month:	October	November
Meter charge ($/day):	$0.44353	$0.44353
Energy charge ($/kWh):	$0.19712 (Summer rate)	$0.14747 (Winter rate)

BILL COMPONENTS

Month:	October	November
Total meter charge:	$0.44353/day x 31 days = **$13.75**	$0.44353/day x 30 days = **$13.31**
Total energy charge:	$0.19719/kWh x -125 kWh = **-$24.64**	$0.14747/kWh x 200 kWh = **$29.49**

FINAL BILL

Month:	October	November
Meter charge:	**$13.75**	**$13.31**
Energy charge:	**$0**	$29.49 - $24.64 = **$4.85**
Amount owed:	**$13.75**	**$18.16**
Rollover credit:	**-$24.64**	**$0**

B-2. Bill Calculation Methodology

E3's bill calculation model calculates total annual electricity bills for NEM participants on a wide variety of investor-owned utility (IOU)[4] rates. Electricity rates consist of a series of charges which are applied to representative measures of a utility customer's electricity consumption. These consumption measures are referred to as billing determinants. Each rate depends on its own set of critical billing determinants; two common determinants that often appear in rates are monthly kWh usage and monthly maximum kW demand. The E3 bill calculator converts a customer's hourly electricity usage shapes into billing determinants based on the applicable rate structure. The model then applies the appropriate rate charges to each billing determinant to calculate monthly charges, and sums those monthly values to determine the total bill. This process can be applied to a customer's gross hourly usage, net hourly usage, or any other hourly consumption shape. The calculator uses 2011 rates; since utilities make small changes to effective tariffs within the year, E3 selected the set of tariffs which applied to the largest portion of 2011 for each utility. Each IOU provided E3 with a list of the utility's NEM customers and each customer's applicable electric rate.

Both E3's bill calculator and the billing determinants representing the full NEM population will be publicly released upon publication of this report. As described in Appendix A, E3 grouped all NEM customers into a set of "bins" of customers with similar generation and consumption patterns. In the billing determinants developed for E3's bill calculation, each "account" represents one bin. Different files represent billing determinants for gross usage, net usage, and net usage with no export payment. These billing determinants could be used as inputs in future NEM analysis to compare the impacts of various new rate designs on different representative customers' bill savings.

B-2.1 Key Assumptions and Simplifications

Based on the variation in utility rate structures and the data available for our analysis, E3 relies on some simplifying assumptions in our bill calculations, detailed below:

- Bill calculations do not include any minimum charges. Minimum charges are common for residential customers, but their values are small and do not significantly impact the total annual bill amount.

[4] Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)

- Some rates charge customers based on their total connected load. In the absence of connected load data, E3 applies those charges to customers' maximum demand.

- For rates with different TOU options, we select the option with the most favorable alignment to solar PV output (we align the highest charge period with the period of maximum PV generation).

- Customers' real true-up months vary based on when they signed up for NEM. For simplicity, we assume that all customers have a true-up period in December, and we use the December 2011 NSC rate for all annual net exports for the period from January to December 2011.

- We assume that large commercial customers are able to apply all export credits to offset their bills, which may not actually be the case because they can apply excess generation credits only to future bills, not past bills. This assumption is reasonable since large consumers often intentionally align their true-up period to occur after months of net consumption, allowing them to capture the full benefit of their export credits.

- We assume that the California Alternative Rates for Energy (CARE) discount is 20% for all CARE customers, and we apply the discount to the customer's total annual bill value.

- The following charge types are not modeled due to insufficient data:

    - Optional data access charges

    - Power factor adjustments

    - Transmission bus fees

    - Distance fees

    - Peak time rebates

    - Any discounts that are rewarded based on decreases in customers' usage relative to their baseline usage

B-2.2 List of Rates Considered

The table below lists all of the IOU rates included in E3's NEM bill analysis. The table also provides information about each rate's structure, applicable customer class, and the percent of customers assumed to be on that tariff in our analysis. As described in Appendix A, E3's analysis places all NEM participants into bins based on customer characteristics, so the percentages assigned to each rate in the table are calculated based on E3's bins and are representative of, but not exactly equal to, the percent of real NEM participants on each rate.

Table 2: IOU Rates Included in Analysis

Utility	Rate	Rate Structure	Class	Percent of Analyzed Customers
PG&E	A-1	Flat	Commercial/Industrial	0.91%
PG&E	A-10	Flat	Commercial/Industrial	0.32%
PG&E	A-10-TOU	Time-of-use	Commercial/Industrial	0.09%
PG&E	A-6-TOU	Time-of-use	Commercial/Industrial	0.55%
PG&E	A-6W-TOU	Time-of-use	Commercial/Industrial	0.18%
PG&E	A-6X-TOU	Time-of-use	Commercial/Industrial	0.80%
PG&E	AG1-A	Flat	Agricultural	0.10%
PG&E	AG1-B	Flat	Agricultural	0.03%
PG&E	AG4-A	Time-of-use	Agricultural	0.12%
PG&E	AG4-B	Time-of-use	Agricultural	0.07%
PG&E	AG4-C	Time-of-use	Agricultural	0.01%
PG&E	AG5-A	Time-of-use	Agricultural	0.02%
PG&E	AG5-B	Time-of-use	Agricultural	0.03%
PG&E	AG5-C	Time-of-use	Agricultural	0.02%
PG&E	AGR-A	Time-of-use	Agricultural	0.01%
PG&E	AGR-B	Time-of-use	Agricultural	0.01%
PG&E	AGV-A	Time-of-use	Agricultural	0.01%
PG&E	AGV-B	Time-of-use	Agricultural	0.03%
PG&E	E-1	Tiered	Residential	22.86%
PG&E	E-19	Time-of-use	Commercial/Industrial	0.06%
PG&E	E-19V	Time-of-use	Commercial/Industrial	0.02%
PG&E	E-19W	Time-of-use	Commercial/Industrial	0.00%
PG&E	E-19X	Time-of-use	Commercial/Industrial	0.09%
PG&E	E20	Time-of-use	Commercial/Industrial	0.03%
PG&E	E37W	Time-of-use	Commercial/Industrial	0.00%
PG&E	E37X	Time-of-use	Commercial/Industrial	0.00%
PG&E	E-6	Tiered & Time-of-use	Residential	14.54%

PG&E	E-7	Tiered & Time-of-use	Residential	7.21%
PG&E	E-7W	Tiered & Time-of-use	Residential	6.57%
PG&E	E-8	Tiered	Residential	1.50%
PG&E	E-A9	Tiered & Time-of-use	Residential	0.21%
PG&E	E-B9	Tiered & Time-of-use	Residential	0.00%
PG&E	EL-1	Tiered	Residential	1.89%
PG&E	EL-6	Tiered & Time-of-use	Residential	0.35%
PG&E	EL-7	Tiered & Time-of-use	Residential	0.34%
PG&E	EL-8	Tiered	Residential	0.04%
PG&E	EM	Tiered	Residential	0.29%
PG&E	EML	Tiered	Residential	0.00%
PG&E	EML-TOU	Tiered & Time-of-use	Residential	0.01%
PG&E	EM-TOU	Tiered & Time-of-use	Residential	0.02%
PG&E	ES	Tiered	Residential	0.00%
SCE	D-CARE	Tiered	Residential	0.20%
SCE	D-FERA	Tiered	Residential	0.04%
SCE	DM	Tiered	Residential	0.02%
SCE	DOMESTIC	Tiered	Residential	18.72%
SCE	GS-1	Flat	Commercial/Industrial	0.54%
SCE	GS-2	Flat	Commercial/Industrial	0.27%
SCE	GS2T-A	Time-of-use	Commercial/Industrial	0.00%
SCE	GS2T-B	Time-of-use	Commercial/Industrial	0.02%
SCE	GS2T-R	Time-of-use	Commercial/Industrial	0.13%
SCE	TOU-8-B	Time-of-use	Commercial/Industrial	0.00%
SCE	TOU-8-R	Time-of-use	Commercial/Industrial	0.01%
SCE	TOU-D-1	Tiered & Time-of-use	Residential	0.22%
SCE	TOU-D-1-CARE	Tiered & Time-of-use	Residential	0.00%
SCE	TOU-D-2	Time-of-use	Residential	0.21%
SCE	TOU-D-2-CARE	Time-of-use	Residential	0.01%
SCE	TOU-D-T	Tiered & Time-of-use	Residential	2.74%
SCE	TOU-D-T-CARE	Tiered & Time-of-use	Residential	0.11%
SCE	TOU-D-TEV	Tiered & Time-of-use	Residential	0.15%
SCE	TOU-D-TEV-CARE	Tiered & Time-of-use	Residential	0.00%
SCE	TOU-GS-1	Time-of-use	Commercial/Industrial	0.00%
SCE	TOU-GS3-A	Time-of-use	Commercial/Industrial	0.00%
SCE	TOU-GS3-CPP	Time-of-use	Commercial/Industrial	0.05%
SCE	TOU-GS3-R	Time-of-use	Commercial/Industrial	0.07%
SDG&E	A	Flat	Commercial/Industrial	0.31%
SDG&E	AL-TOU	Time-of-use	Commercial/Industrial	0.19%
SDG&E	A-TOU	Time-of-use	Commercial/Industrial	0.00%
SDG&E	AY-TOU	Time-of-use	Commercial/Industrial	0.01%
SDG&E	DG-R	Time-of-use	Commercial/Industrial	0.11%

SDG&E	DM	Tiered	Residential	0.05%
SDG&E	DR	Tiered	Residential	14.67%
SDG&E	DR-LI	Tiered	Residential	1.16%
SDG&E	DR-SES	Time-of-use	Residential	0.51%
SDG&E	DR-TOU	Tiered & Time-of-use	Residential	0.07%
SDG&E	EV-TOU-2	Time-of-use	Residential	0.06%

B-2.3 Comparison to Actual Bills

E3 performed extensive benchmarking of our bill calculations using real utility bills provided by each of the three IOUs for a variety of customers on different rates. We found our bill calculations to be accurate within +/- 10% of the utility reported bill, except for those customers whose bills could not be calculated accurately due to incomplete information. Such missing information included mid-year changes in the customer's tariff, baseline allowance, or direct access status. E3 worked directly with the billing departments of each IOU to assure that our bill calculation methodology was correct and that any discrepancies in benchmarked bills were attributable to lack of account information and not methodological errors.

B-2.4 Rate Component Breakout

In addition to calculating total bills, E3 also calculated a subset of important components of each bill in order to illustrate how participation in NEM impacts customers' contributions to specific funds. Each bill component that was broken out from the total is listed below:

- CARE Surcharge
- California Energy Commission Surcharge
- Competition Transmission Charges
- DWR Bond Charge
- Distribution
- Energy Cost Recovery
- Nuclear Decommissioning
- Public Purpose Programs

- Public Utilities Commission Reimbursement Fee
- Transmission

B-3. Escalation Over Time

E3 initially calculated customer bills for the year 2011, and then used a retail rate escalation forecast to extrapolate those bill values through 2020. We created three rate escalation forecasts: A base case, high case, and low case. Each forecast was generated using E3's 2010 Long Term Procurement Plan (LTPP) model.[5] Historical rate escalations for 2008 through 2012 and forecasts for 2013 through 2020 are shown in the following table:

Table 3: Annual Retail Rate Escalation

Year	Base Case	High Case	Low Case
2008	-2.50%	-2.50%	-2.50%
2009	6.09%	6.09%	6.09%
2010	-1.74%	-1.74%	-1.74%
2011	0.31%	0.31%	0.31%
2012	5.36%	5.36%	5.36%
2013	2.47%	5.16%	2.50%
2014	4.05%	5.10%	4.77%
2015	5.77%	5.47%	5.86%
2016	3.07%	3.03%	2.62%
2017	3.72%	3.93%	3.57%
2018	2.66%	3.04%	2.37%
2019	3.46%	3.91%	3.60%
2020	2.49%	3.21%	2.45%

The key inputs used to develop these rate escalation forecasts in the LTPP model are the gas price forecast and the CO2 price forecast, for which E3 also created base, high and low cases. The

[5] E3's LTPP model is publicly available at in the "E3 workpapers" folder at http://www3.sce.com/law/cpucproceedings.nsf/vwMainPage?OpenView&RestrictToCategory=track%20i%202010%20ltpp&Start=1&Count=25

following table shows the combinations of gas price and CO2 price forecasts used to generate each rate escalation forecast in the LTPP model.

Table 4: Gas and CO2 Price Forecasts Used in Retail Rate Escalation Cases

Gas Price Forecast	CO2 Price Forecast	Resulting Retail Rate Escalation Case
E3 MPR gas forecast	MPR base case forecast	Base Case
CPUC adopted LTPP high gas price forecast	California CO2 price soft cap	High Case
2% nominal annual price increase from historical	California CO2 price floor	Low Case

The gas price and CO2 price forecasts used in our analysis are contained in the table below for the years 2008 through 2020:

Table 5: Gas and CO2 Price Forecasts

	Henry Hub Gas Price Forecast ($/MMBtu)			Carbon Cost Forecast ($/ton)		
Year	Base Case	High Case	Low Case	Base Case	High Case	Low Case
2008	$6.97	$6.97	$6.97	$0	$0	$0
2009	$8.86	$8.86	$8.86	$0	$0	$0
2010	$3.94	$3.94	$3.94	$0	$0	$0
2011	$4.37	$4.37	$4.37	$0	$0	$0
2012	$4.00	$4.00	$4.00	$0	$0	$0
2013	$4.74	$5.85	$4.74	$13.62	$13.62	$13.62
2014	$4.59	$6.31	$4.84	$22.50	$42.80	$10.70
2015	$4.72	$6.82	$4.93	$26.31	$45.80	$11.45
2016	$5.08	$7.36	$5.03	$28.13	$49.00	$12.25
2017	$5.30	$7.95	$5.13	$30.14	$52.43	$13.11
2018	$5.59	$8.58	$5.24	$32.27	$56.10	$14.03
2019	$5.66	$9.26	$5.34	$34.55	$60.03	$15.01
2020	$5.79	$10.00	$5.45	$36.97	$64.23	$16.06

APPENDIX C:

AVOIDED COSTS

October 28, 2013

Avoided Costs

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Avoided Costs

C-1 Overview of Avoided Cost in Net Energy Metering

This appendix describes the avoided cost methodology used to estimate the change in utility costs attributable to net energy metered (NEM) systems. The avoided costs have a 10-year procedural history in evaluating the cost-effectiveness of distributed energy resources at the California Public Utility Commission (CPUC). We use the avoided cost methodology to conduct a cost-benefit study of NEM because it provides a transparent method to value net energy production from distributed generation using a time- and area- differentiated cost-basis. This appendix provides a description of the complete avoided cost methodology, including the methodological updates and new input data, as well as the methodology that has been retained. A spreadsheet accompanies this appendix which performs the avoided cost calculation.

C-1.1 AVOIDED COST UPDATES USED IN THIS STUDY

The existing methodology used in prior studies was largely adopted for the purposes of this study, with new input data to reflect current market additions. Improvements to the avoided cost framework were based on feedback from the NEM stakeholder workshop (October 22, 2012) and subsequent stakeholder comments, and stakeholder reply comments. In addition, the major inputs to natural gas and electricity forward markets were updated. Below is a complete list of the avoided cost updates used in this study:

Updated Methodology

1. Update transmission and distribution (T&D) allocation factors
2. Incorporate ELCC & dynamic capacity value

Updated Data

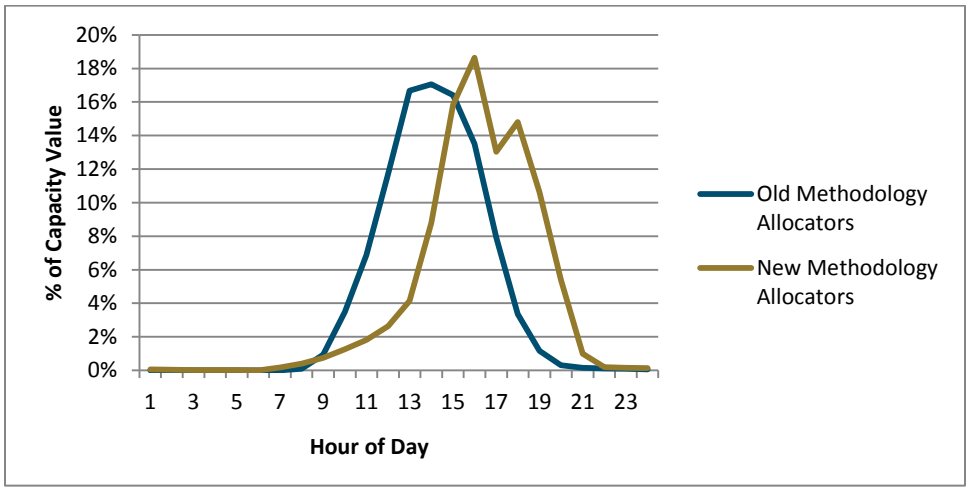
1. Update natural gas prices using MPR methodology
2. Update to new CEC Title 24 Weather Zones
3. Updated avoided RPS purchase calculation

Methodology Change to T&D Allocation Factors

Previous avoided cost methodologies developed by E3 have utilized a temperature based approach to allocate distribution capacity value ($/kW-year) to hours of the year. This approach concentrated capacity value primarily in the hottest hours of the year using weather data as a proxy for substation load. This proxy methodology has been utilized in previous analyses utilizing avoided costs primarily due to a lack of substation level load data. However, for this analysis, the necessary substation load data was

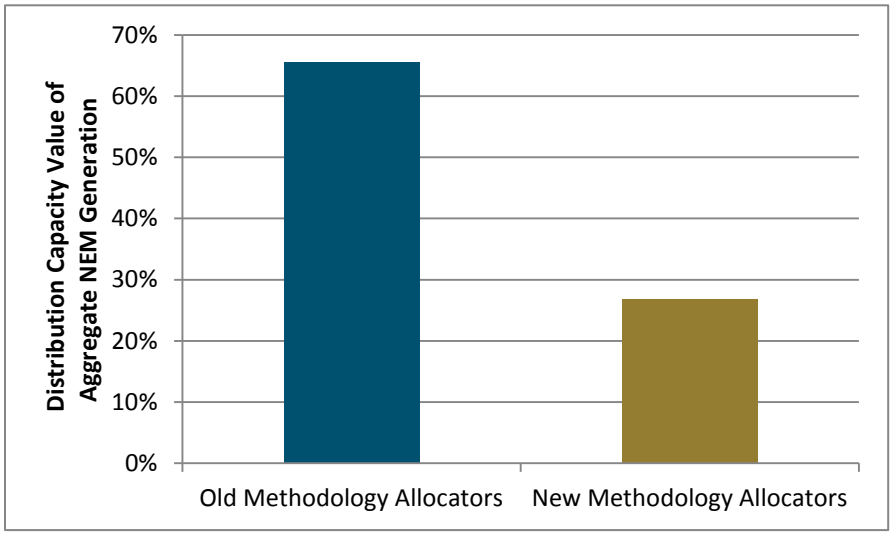
provided by each utility. Allocators were therefore based on actual substation loads. The peak load patterns observed in the actual substation load data tended to be later in the day and "lagged" the hottest temperature hours. This distribution load profile results in more distribution capacity value being allocated to later hours as shown in Figure 1.

Figure 1: Hourly Distribution Capacity Value



This distribution allocation profile reduces the coincidence of solar generation with the distribution load, thereby reducing the average distribution capacity value that the resource provides. Figure 2, below, shows the average value under both allocation methodologies.

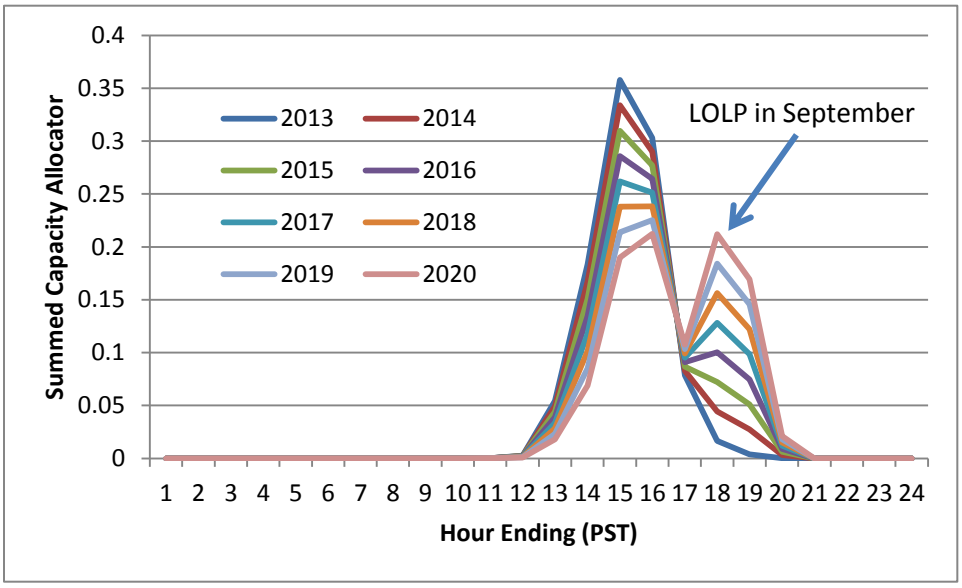
Figure 2: Distribution Capacity Value Comparison



Methodology Change to ELCC Capacity Value

E3 has updated the avoided cost methodology to utilize effective load carrying capability (ELCC) when calculating the capacity value for renewable or thermal generators.[1] The methodology change was made pursuant with Senate Bill (SB) 2 (Simitian, Kehoe, and Steinberg, 2011)[2] due to a general recognition that ELCC is a more appropriate measure of capacity value under quickly changing, high Renewable Portfolio Standard (RPS) scenarios. ELCC is a dynamic assessment of renewable capacity value and captures the relationship between renewable penetration and contribution to system reliability. As penetrations of wind or solar increase, the load carried by additional resources of the same type is reduced due to a gradual shift in the net load peak towards hours during which the resource has lower capacity factors. Capacity allocators by time of day are shown for the new ELCC methodology in Figure 3, below, and the old methodologies are shown in Figure 4, below.

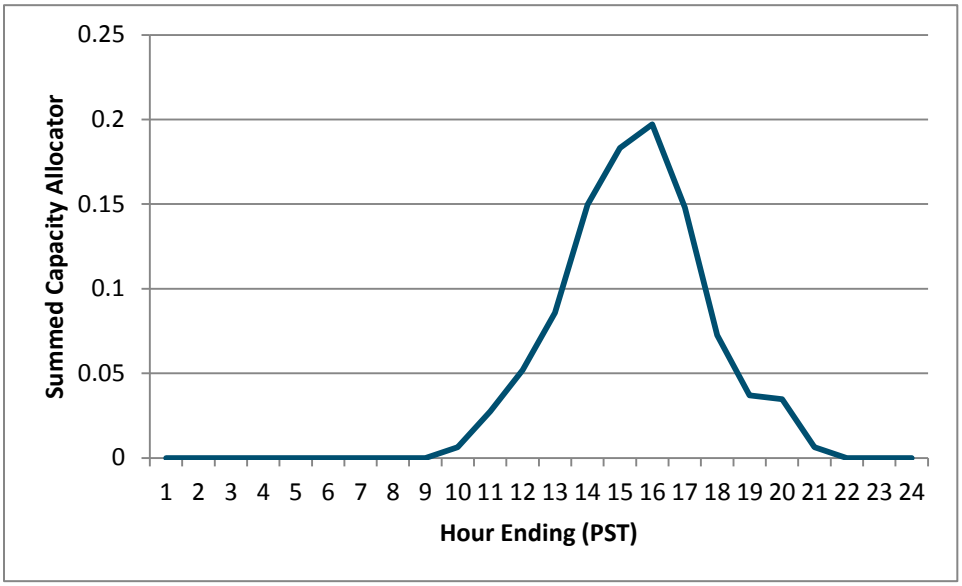
Figure 3: Capacity Allocator by Time of Day for the New Avoided Cost Methodology



[1] ELCC is the additional load met by an incremental generator while maintaining the same level of system reliability

[2] See http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.html

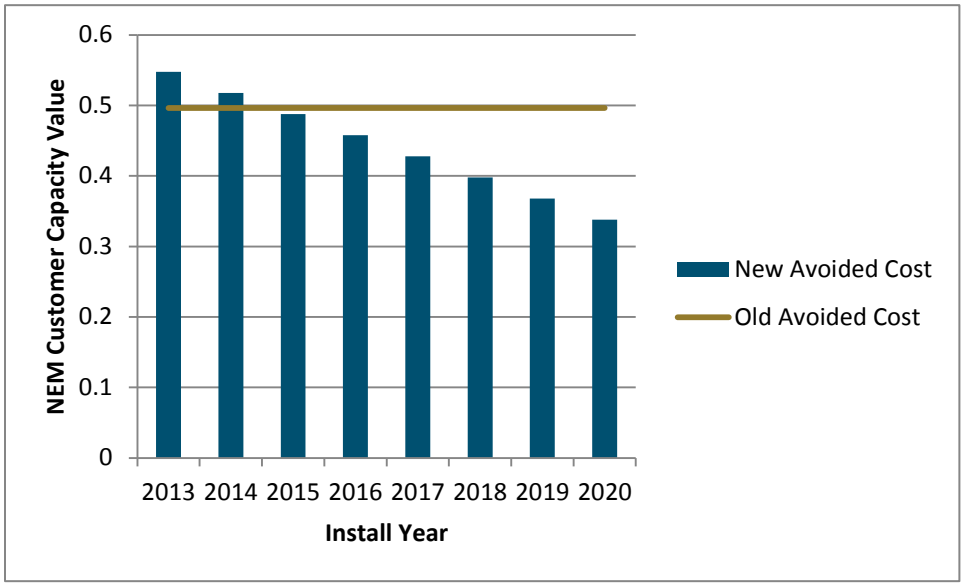
Figure 4: Capacity Allocators Based on the Old Capacity Allocation Methodology



The prior methodology gave weight to a larger number of total hours, which results in a wider distribution of important hours. The prior methodology was also unchanging based on renewable penetration, which is why separate allocation curves are not shown by year.

The impact of the methodology change on the average NEM customer's capacity value is shown in Figure 5, below. In 2013 and 2014 the new methodology results in slightly higher capacity value; however, as additional solar PV is installed in CA, both NEM systems and utility scale PV, the capacity value in 2020 of the next increment of solar PV is decreased by 40%.

Figure 5: Average NEM Customer Capacity Value for the New and Old Methodologies



C-2 History of Avoided Costs at CPUC Since 2004

The avoided cost methodology was originally adopted to evaluate the cost-effectiveness of energy efficiency by the CPUC in Order Instituting Rulemaking 04-04-025 in 2004. The original methodology is described in the report "Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs."[3] Subsequently, a Distributed Generation (DG) Cost-effectiveness Framework was adopted by the Commission in D. 09-08-026. While there are some methodological differences, the avoided cost framework for energy efficiency and distributed generation are similar. Finally, the Demand Response Cost-effectiveness protocols adopted in 2010 largely draw on the avoided costs for energy efficiency, and then adjustments are made based on a series of 'factors' to account for the dispatchability and other considerations for Demand Response (DR). Again, there are some methodological differences, particularly in treatment of the resource balance year. A summary of the most significant updates since 2010 for each of the distributed resource types is provided below.

C-2.1 DISTRIBUTED RESOURCE AVOIDED COST UPDATES SINCE 2010

Energy Efficiency Proceeding

1. Input update with existing methodology (April 2010)[4]
    - Update gas prices
    - Update CO2 price

[3] See website http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.pdf

[4] See website http://www.ethree.com/public_projects/cpuc4.php and http://www.ethree.com/documents/8.13.10/cpucAvoided26-1_update%20MPR%202009%20eac%205-3-10.zip

- Update generator cost and performance based on latest MPR

2. Input update and some methodology update (Sept 2011)[5]
   - Update hourly generation market shapes using 2010 MRTU markets
   - Revise renewable cost adder to quantify costs based on interim (prior to 2020) targets
   - Update emission profiles based on updated market shapes
   - Update T&D capacity costs using utility GRC filings.
3. Input and method update (July 2012)[6]
   - Explicitly calculate capacity value based on CT net capacity cost
   - Set energy price at the "make whole" level for a CCGT unit
   - Replace the use of PX market hourly shapes with 2010 MRTU hourly shapes
   - Move the resource balance year (the year when the avoided costs are based on sustaining new CT and CCGT units in the market) to 2017
   - Update the ancillary service value to reflect 2010 markets
   - Remove the energy market multiplier
   - Update CO2 values to Synapse Consulting mid-case forecast
   - Model generator performance with monthly performance adjustment factors based on weather
   - Adjust avoided capacity value to reflect the $/kW-yr value of produced capacity, rather than nameplate capacity, under hot ambient temperature conditions.
   - Update allocation of capacity value based on 4 years of historical load and temperature data
   - Transmission and Distribution (T&D) method unchanged, but T&D avoided cost levels updated to more recent utility filings
   - Gas forecast lowered to reflect market conditions of Dec 2010 (aligns with DR proceeding)
4. Weather File Update Analysis (January 2013)
   - Update to new CEC T24 Weather Zones, not yet adopted[7]

Distributed Generation

5. NEM Cost-effectiveness (Jan 2010)[8]
   - Updated inputs to cost-effectiveness calculation
   - Revised the capacity allocation method based on top 250 hours and 2008 observed loads
   - Revised residual CT capacity value to look at real-time energy market and ancillary service revenues
   - Added the avoided RPS purchases as a benefit component
6. SGIP Cost-effectiveness by ITRON (Feb 2011)[9]

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[5] See website and http://www.ethree.com/public_projects/cpuc4.php
http://www.ethree.com/documents/E3%20Calculator%2009.20.11/2011_Avoided_Cost_Update.zip
[6] See http://www.ethree.com/public_projects/cpuc5.php and
http://www.ethree.com/documents/DERAvoidedCostModel_v3_9_2011_v4d.xlsm
[7] See http://www.energy.ca.gov/title24/2013standards/prerulemaking/documents/2010-11-16_workshop/presentations/06-Huang-Weather_Data.pdf
[8] See http://www.ethree.com/documents/CSI/Final_NEM-C-E_Evaluation_with_CPUC_Intro.pdf

- Included market transformation effects in assessment

7. CSI Cost-effectiveness (April 2011)[10]
   - Same avoided cost inputs as the NEM cost-effectiveness from January 2010
   - Included market transformation effects in assessment
8. Technical Potential of High Penetration PV (March 2012)[11]
   - Distribution-area specific distribution value
9. NEM Cost-effectiveness (this study 2013)[12]
   - Update natural gas prices using MPR methodology
   - Update T&D allocation factors
   - Incorporate ELCC & dynamic capacity value
   - Updated avoided RPS purchase calculation
   - Update to new CEC T24 Weather Zones[13]

Demand Response

10. DR Avoided Cost (January 2011)
    - Update allocation of capacity value based on 4 years of historical load and temperature data
11. Permanent Load Shifting Analysis and Support (March 2011)[14]
    - Expanded the technology scope to include range of PLS applications
    - Added temperature performance of a CT on capacity value
12. Update to the DR Reporting Template (July 2012)[15]
    - No updates to avoided cost inputs
    - Updated DER Avoided Cost model to provide inputs to DR Reporting Template necessary for PLS
    - Calculated levelized avoided costs by component for 10, 20 & 30 years and created table of average levelized avoided costs by hour and by month
    - Created separate spreadsheet to calculate DR A-factor for PLS
13. Non-proprietary LOLP tool for DR cost-effectiveness (February 2013)[16]
    - Allocates capacity value on the basis of LOLP

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[9] See http://www.cpuc.ca.gov/NR/rdonlyres/2EB97E1C-348C-4CC4-A3A5-D417B4DDD58F/0/SGIP_CE_Report_Final.pdf
[10] See http://www.ethree.com/documents/CSI/CSI%20Report_Complete_E3_Final.pdf
[11] http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf
[12] See Scope and other Material at http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_benefit_evaluation.htm
[13] See http://www.energy.ca.gov/title24/2013standards/prerulemaking/documents/2010-11-16_workshop/presentations/06-Huang-Weather_Data.pdf
[14] See http://www.ethree.com/documents/SCEPLS/PLS%20Final%20Report%20with%20Errata%203.30.11.pdf
[15] See http://www.ethree.com/public_projects/cpucdr.php
[16] See https://e3.sharefile.com/d/s78313505eea47ffb

Other / Cross-Cutting Projects

14. Straw-proposal for Water Efficiency Avoided Cost Framework (March 2013 workshop)[17]
15. Discount Rate Discussion (June 2012 and On-going)[18]

[17] See http://www.cpuc.ca.gov/NR/rdonlyres/41982C8B-F72A-402C-9E9D-007EDAACE028/0/E3EnergyWaterAvoidedCosts032113.pdf
[18] See http://www.cpuc.ca.gov/NR/rdonlyres/D401E61F-F2CD-46EA-98D8-2D7AD8DA8C2E/0/E3AnalysisWACC.pdf

C-3 Methodology Overview

This section describes the electricity avoided costs that are intended for the evaluation of energy efficiency, demand response, permanent load shifting, and distributed generation programs. The avoided costs reflect expected monetary impacts of electricity consumption, and are appropriate for use in the California Standard Practice Manual Total Resource Cost (TRC), Program Administrator Cost (PAC), Participant, and Ratepayer Impact Measure (RIM) tests. This section does not include retail rate forecasts that would also be needed for the Participant and RIM tests, nor does it include non-energy benefits that are often considered in social cost test evaluations.

C-3.1 OVERVIEW OF AVOIDED COST COMPONENTS

E3 forecasts electricity avoided costs in the six component categories described in Table 1. Each of the avoided cost components is a direct dollar cost that would be borne by the utility or utility customers through their electricity bills.

Table 1: Components of Marginal Energy Cost

Component	Description
Generation Energy	Estimate of hourly marginal wholesale value of energy adjusted for losses between the point of the wholesale transaction and the point of delivery
System Capacity	The marginal cost of procuring Resource Adequacy resources in the near term. In the longer term, the additional payments (above energy and ancillary service market revenues) that a generation owner would require to build new generation capacity to meet system peak loads
Ancillary Services	The marginal cost of providing system operations and reserves for electricity grid reliability
T&D Capacity	The costs of expanding transmission and distribution capacity to meet customer peak loads
CO2 Emissions	The cost of carbon dioxide emissions (CO2) associated with the marginal generating resource
Avoided RPS	The cost reductions from being able to procure a lesser amount of renewable resources while meeting the Renewable Portfolio Standard (percentage of retail electricity usage).

E3 forecasts each of the six avoided cost components at the hourly level through the year 2050. The Commission adopted the use of hourly avoided costs in 2004. In that original application, the hourly costs were developed for use with the predictable load reduction profiles of energy efficiency measures. In the intervening years, E3 has worked with parties to enhance the methodology to make the hourly avoided costs more appropriate for the evaluation of resources such as dispatchable DR programs. The hourly costs have been refined to better reflect the extremely high marginal value of electricity during the top hours of the year.

E3 develops the hourly forecasts using a two-step process, whereby annual avoided costs are first forecast for each component through 2050. E3 then disaggregates or shapes the annual values to encompass hourly variations and peak timing. Table 2 summarizes the methodology applied to each component to develop the annual and hourly forecasts.

Table 2: Summary of Methodology for Avoided Cost Component Forecasts

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	Forward heat rate projections from 2010 CPUC Long Term Procurement Plan and monthly fuel cost projections	Historical hourly day-ahead market price shapes from MRTU OASIS aligned to a typical meteorological year based on daily system loads
System Capacity	Lower of the residual capacity value a new simple-cycle combustion turbine or combined cycle gas turbine	Hourly allocation factors calculated as a proxy for LOLP based on system loads
Ancillary Services	Percentage of generation energy value	Directly linked with energy shape
T&D Capacity	Marginal transmission and distribution costs from utility ratemaking filings.	Hourly allocation factors calculated using hourly TMY temperature data as a proxy for local area load
Environment	CARB 2013 auction results; 2011 Market Price Referent[19] (MPR)	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

Figure 6, below, shows a three-day snapshot of the avoided costs, broken out by component, in Climate Zone 2. As shown, the cost of providing an additional unit of electricity is 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 over $1,000/MWh shown in Figure 6 are driven primarily by the allocation of generation and T&D capacity to the highest load hours, but also by higher wholesale energy prices during the middle of the day.

[19]See http://www.ethree.com/documents/2011_MPR_E4442_CPUC_Final_Resolution.pdf

Figure 6: Three-Day Snapshot of Energy Values in CZ2

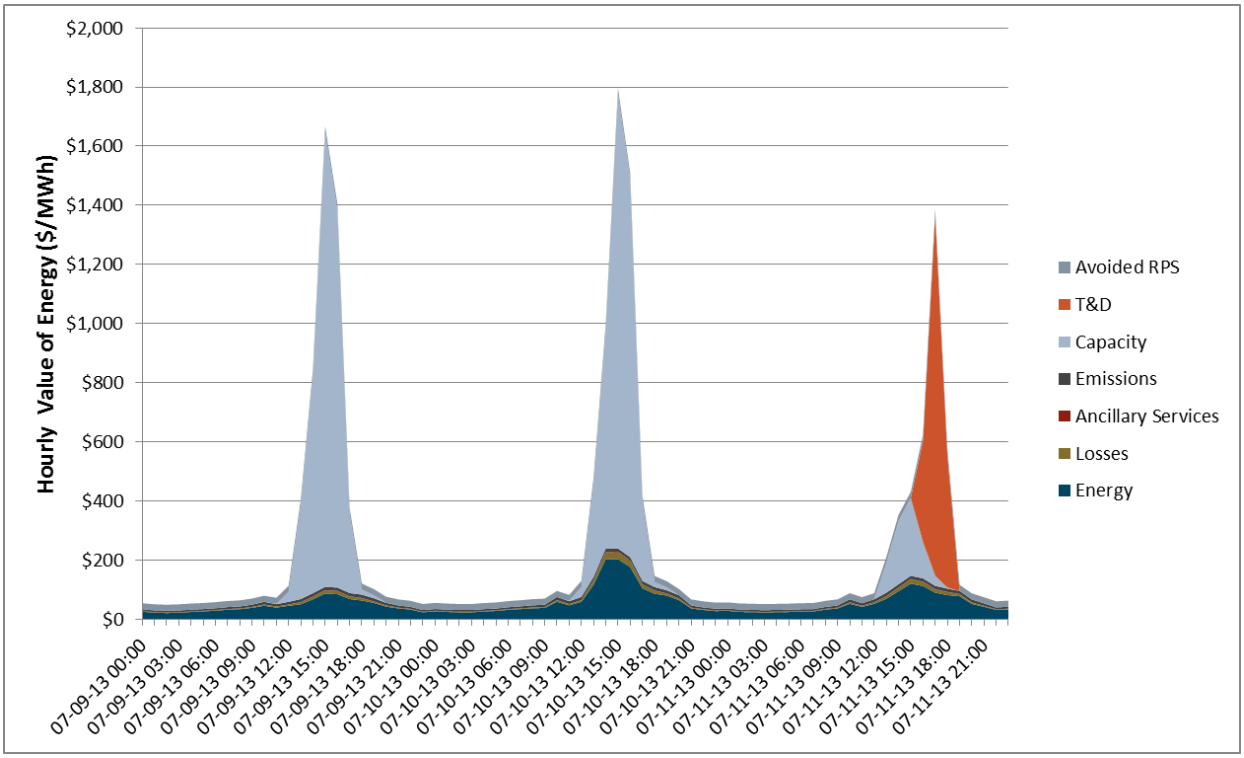


Figure 7 shows average monthly value of load reductions, revealing the seasonal characteristics of the avoided costs. The energy component dips in the spring, reflecting increased hydro supplies and imports from the Northwest, and peaks in the summer months when demand for electricity is highest. The value of capacity—both generation and T&D—is concentrated in the summer months and results in significantly more value on average in these months.

Figure 7: Average Monthly Avoided Cost (Levelized Value Over 30-yr Horizon)

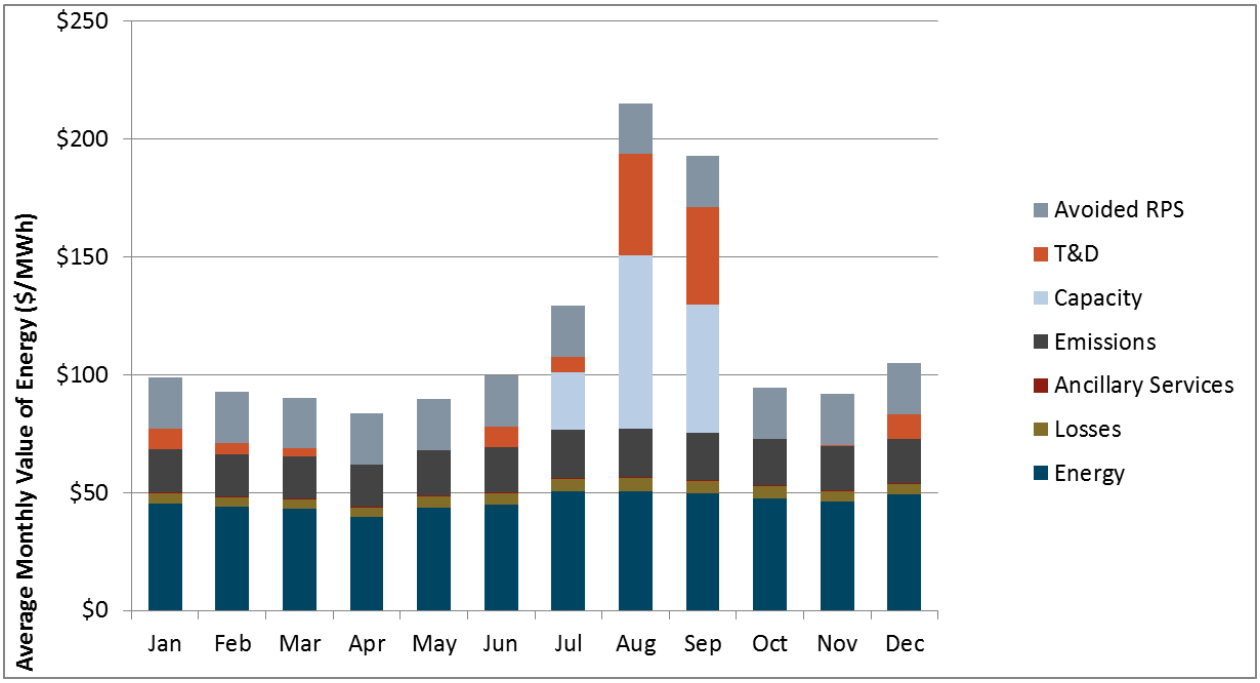
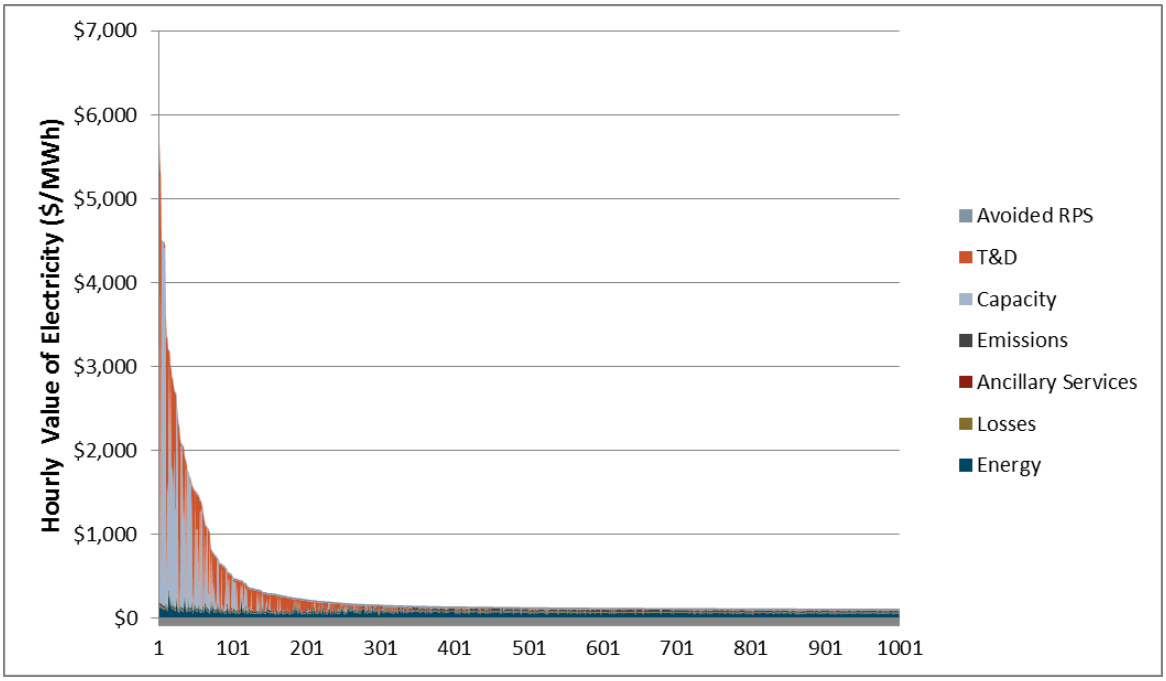


Figure 8 shows the components of value for the highest value hours in sorted order of cost. Note that most of the high cost hours occur in approximately the top 200 to 400 hours—this is because most of the value associated with capacity is concentrated in a limited number of hours. While the timing and magnitude of these high costs differ by climate zone (described below), the concentration of value in the high load hours is a characteristic of the avoided costs in all of California.

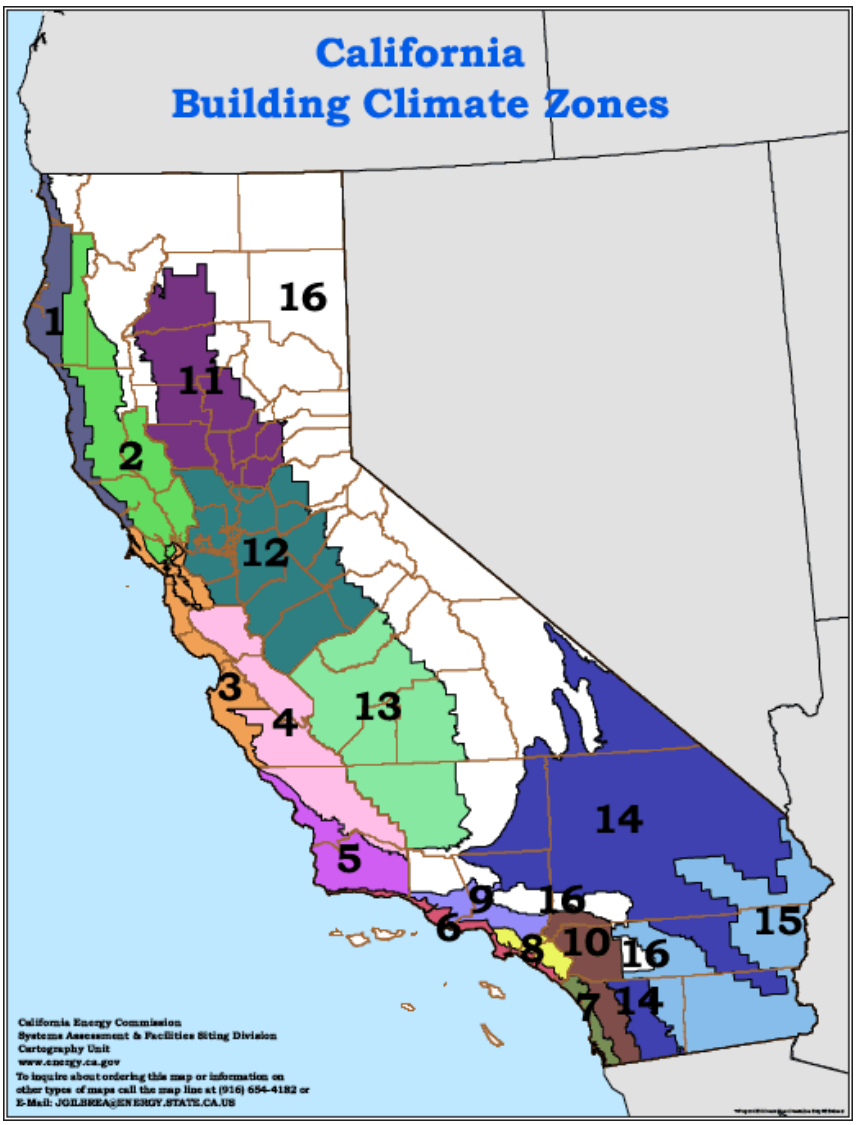
Figure 8: Price Duration Curve Showing Top 1,000 Hours for CZ2



C-3.2 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 9 is a map of the climate zones in California. Each climate zone has an adopted 'Typical Meteorological Year' (TMY) weather file. TMY weather files are assemblages of hourly climate data into annual files meant to represent typical climate conditions at a specified location. We use the most recent weather files that were adopted by the CEC for the 2013 Title 24 building code.

Figure 9: 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 3. Hourly avoided costs are calculated for each climate zone.

Table 3: Representative Cities and Utilities for the California Climate Zones

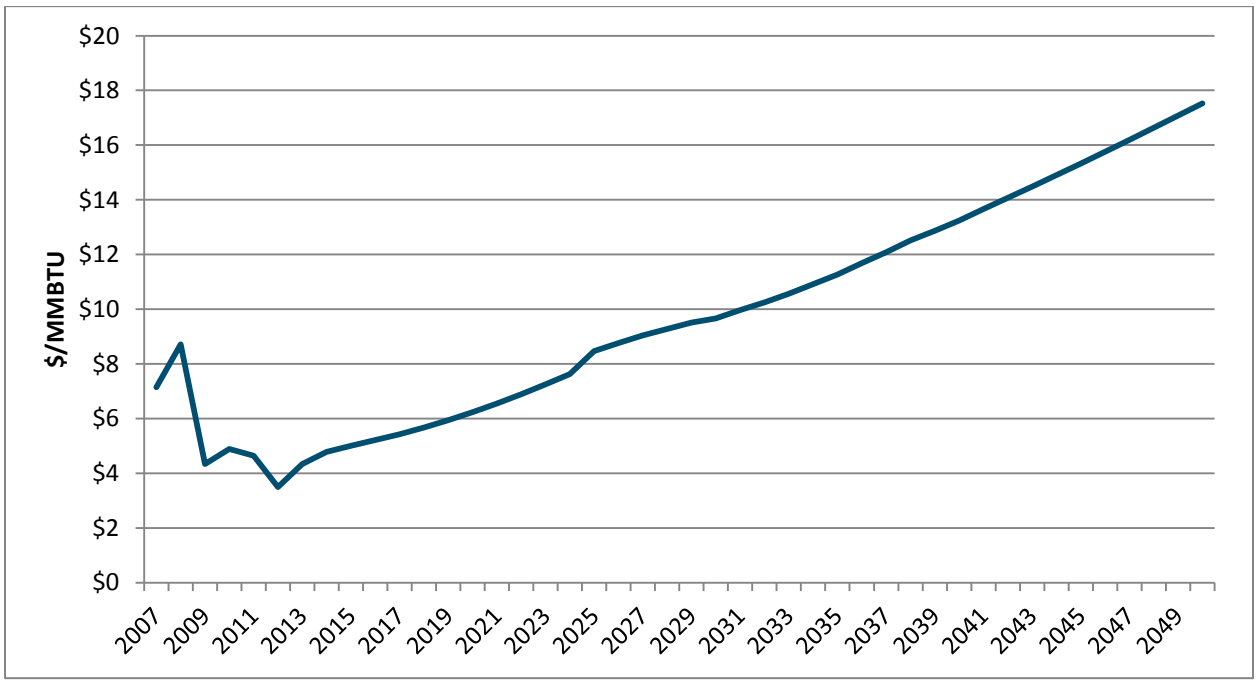
Climate Zone	Utility Territory	Representative City
CEC Zone 1	PG&E	Arcata
CEC Zone 2	PG&E	Santa Rosa
CEC Zone 3	PG&E	Oakland
CEC Zone 4	PG&E	Sunnyvale
CEC Zone 5	PG&E/SCE	Santa Maria
CEC Zone 6	SCE	Los Angeles
CEC Zone 7	SDG&E	San Diego
CEC Zone 8	SCE	El Toro
CEC Zone 9	SCE	Pasadena
CEC Zone 10	SCE/SDG&E	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

C-4 Natural Gas Price Forecast

This section presents the forecast of the market procurement, transportation, and delivery costs for natural gas delivered to California electricity generators. The natural gas price forecast is a major driver of forecast electricity energy and generation capacity avoided costs. The natural gas price forecast can also be used to derive natural gas avoided costs that can be used to evaluate programs that alter consumer natural gas consumption --- but that is not the focus of this report. This report focuses on natural gas a feedstock to electricity generators.

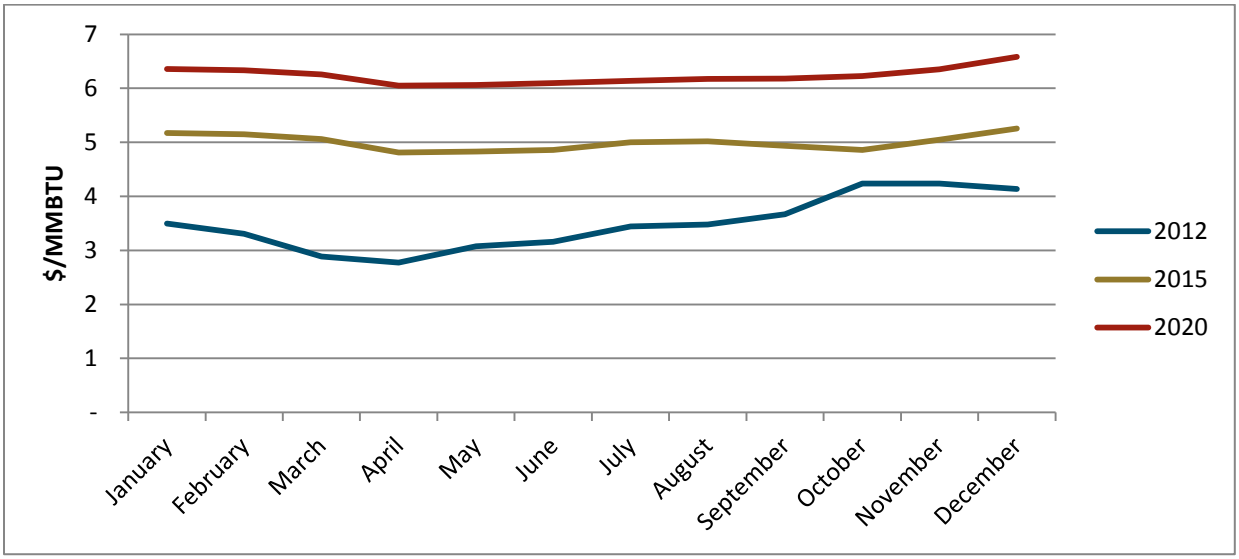
The natural gas price forecast is derived from the CPUC MPR 2011 Update.[20] The commodity forecast is based upon NYMEX Henry Hub futures for the first twelve years before transitioning to a long-term fundamentals forecast based on an average of three out of four private natural gas forecasts from Cambridge Energy Research Associates, PIRA Energy Group, Global Insight, or Wood MacKenzie. The natural gas forecast used in this avoided cost analysis also includes average basis differentials and delivery charges to utilities. The annual forecast is shown in Figure 10**.** The MPR's forecast methodology also incorporates monthly patterns of gas prices—commodity prices tend to rise in the winter when demand for gas as a heating fuel increases. Figure 11 shows three snapshots of the forecast monthly prices of the natural gas in 2012, 2015, and 2020.

Figure 10: Natural Gas Price Forecast Used in Calculation of Electricity Value (Nominal Dollars, Delivered to Generators)



[20] See http://docs.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/154753.PDF

Figure 11: Snapshot of Monthly Gas Price Forecast Shapes for 2012, 2015, and 2020 (Delivered to Generators)



C-5 Avoided Cost of Energy

The avoided cost of energy is the market clearing price of the last resource needed to meet load in each hour. The forecast of the annual wholesale value of energy is based on a projection of annual marginal heat rates in California multiplied by monthly projected natural gas prices.

The basic formula used to calculate the avoided cost of energy is the following:

$ACE_{y,h} = ACE_y * PriceShape_h * LossFctr_{TOU,V}$

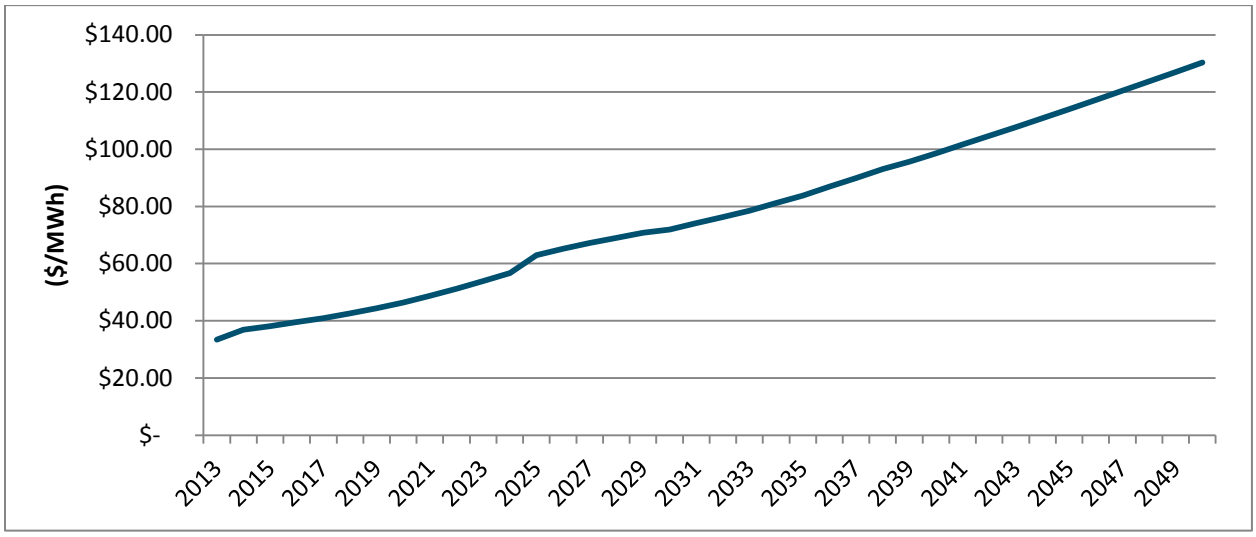
where

$ACE_{y,h}$	=	Hourly avoided cost of energy in year *y* and hour *h*
ACE_y	=	Annual average avoided cost of energy for year *y*
	=	$AvgHeatRate_y * GasPrice_y$
$AvgHeatRate_y$	=	average implied market heat rate in year *y*, adjusted to exclude the effects of carbon costs
$GasPrice_y$	=	annual average price of natural gas delivered to electricity generators in year *y*
$PriceShape_h$	=	Implied hourly heat rates from Northern or Southern California day ahead markets in 2012
$LossFctr_{TOU,V}$	=	Loss factor from the market delivery points to the customer meter voltage level *v*, during the time of use period *TOU*.

C-5.1 ANNUAL AVERAGE COST OF ENERGY

The avoided cost of energy is calculated by first estimating the annual average market price of energy and then applying an hourly shape to that average price to reintroduce the hourly price patterns and volatility observed in recent day-ahead markets. With the introduction of the Carbon Cap and Trade program in California, the recent and future market energy prices will include some price premium for carbon costs. E3 removes these price premiums from the forecasts of avoided energy costs to avoid double counting with the emissions costs that are tracked as a separate component in the avoided cost framework. Figure 12 shows the annual average forecast of market energy prices (net of the effects of carbon prices).

Figure 12: Forecast of Average Wholesale Energy Price (Does not Include Carbon Costs)



The annual average energy avoided cost is the product of natural gas prices and annual average implied market heat rates. Market heat rates are the market clearing price divided by the cost of natural gas. As discussed below, while the composition of the generation fleet may change due to increased renewable energy injected into the grid, we do not expect the heat rates of the dispatch units on the margin to change substantially. Accordingly, the rate of increase after 2013 is driven almost exclusively by the forecast change in natural gas prices (see Figure 10).

C-5.2 IMPLIED MARKET HEAT RATES

The implied market heat rates are the annual average market clearing prices divided by annual average natural gas prices. Figure 13 shows the projection of annual marginal market heat rates for California to 2050. Implied market heat rate projections from 2013-2020 are an interpolation from the six-year historical average (2007-2012) to a 2020 projection from the CPUC's 2010 LTPP Trajectory case, which projected a renewable buildout to meet the 33% RPS that was composed primarily of signed utility contracts with renewable generators. The CPUC 2010 LTPP Trajectory case calculates a decline in the annual average implied marginal heat rate largely due to the addition of wind and solar resources to support the 33% renewable portfolio standard. The increase in non-dispatchable resources changes the

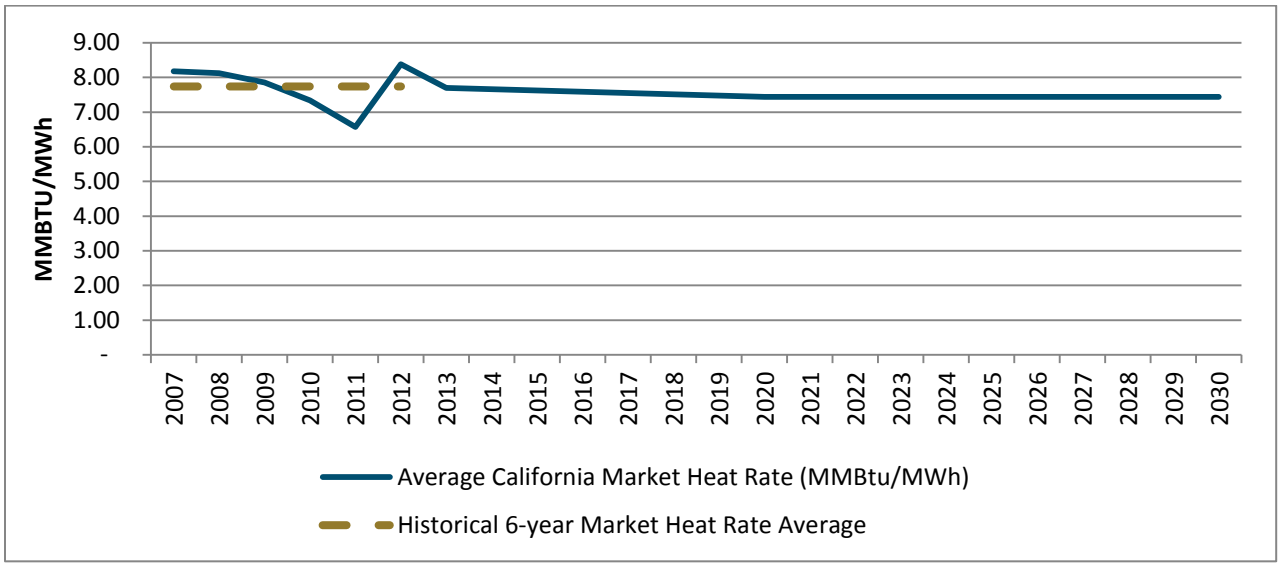
resource stack and places more efficient natural gas units at the margin (even after retirement of once-through cooling units that are forecast to cease operation by 2020). We hold the market heat rate constant from 2020 forward.

$AvgHeatRate_y$ = Energy Market $Price_{,y}$/(Natural Gas $Costs_y$+(CO2 $Cost_y$* CO2Content))

Where

Energy Market $Price_y$	=	The annual average energy market price ($/Mwh)
Natural Gas $Costs_y$	=	Annual average natural gas costs ($/MMBTU)
$CO2Cost_y$	=	Cost of CO2 emissions $/ton in year *y*
CO2Content	=	Natural gas carbon content (0.0585 tons per MMBtu)

Figure 13: Projected Annual Marginal Market Heat Rate



C-5.3 HOURLY PRICE SHAPE

An hourly series of price factors based on the California day-ahead market for wholesale energy is used to estimate hourly energy values. Because the hourly avoided costs are being matched against loads and distributed generation, all of which are highly weather-correlated, the hourly price shape needs to maintain consistency with the weather files used to develop the fixed profile shapes.

The initial hourly shape is derived from 2012 day-ahead LMPs at load-aggregation points in northern (NP15) and southern California (SP15) obtained from the California Independent System Operator's (CAISO) MRTU OASIS system. In order to account for the effects of historical volatility in the spot market for natural gas, the hourly market prices are adjusted by the average daily gas price in California. This yields hourly values as a percentage of the annual average market heat rate. This methodology yields

different hourly shapes for energy prices in Northern and Southern California based on the same California-wide annual average.

C-5.4 ALIGNING MARKET DATA TO MATCH TMY WEATHER DATA

The linkage between weather and California electricity market prices is well known. While market peak prices can occur for non-weather reasons such as generation or transmission outages, high market prices in California are generally driven by statewide hot weather that drives up electricity demand and forces the least efficient fossil generation into the dispatch.

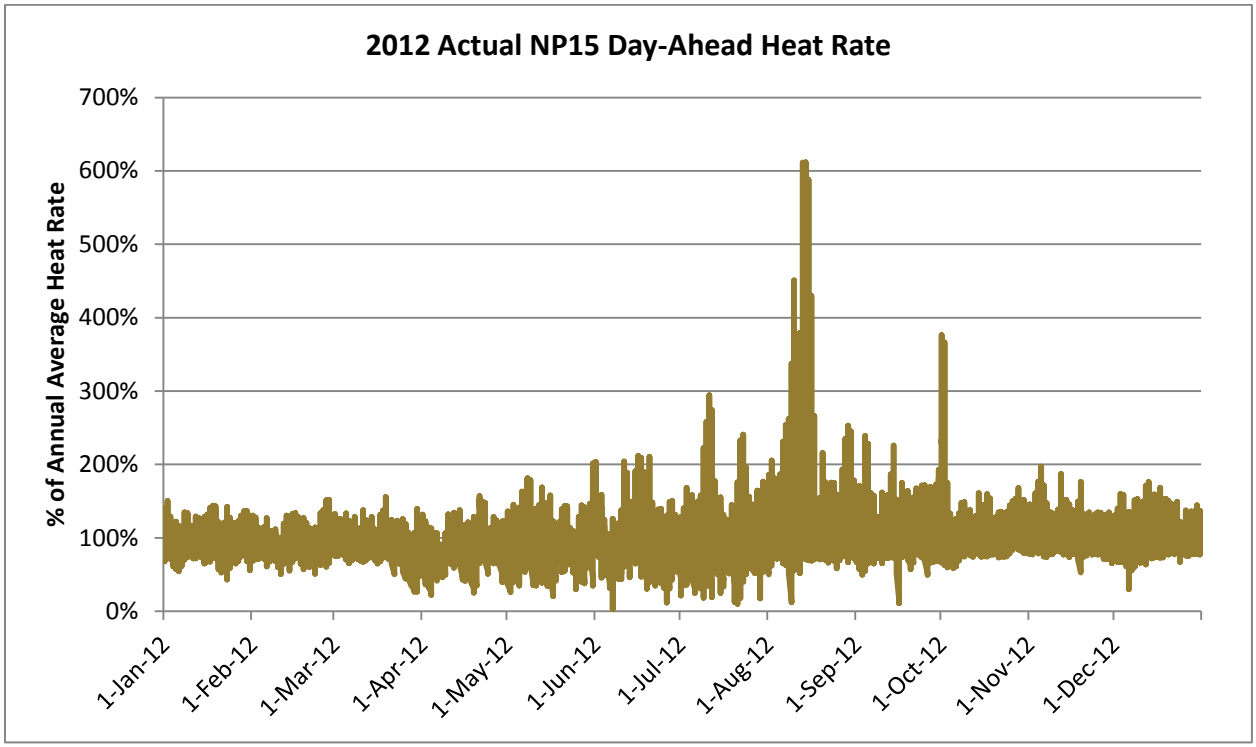
The generation energy prices use an hourly shape from 2012. The simulated output profiles from Distributed Energy Resources (DER) like energy efficiency and solar PV, however, are based on TMY weather files. In order to make the two sets of data compatible, we remap the chronology of the 2012 days to match the TMY data based on a day-matching between simulated and actual CAISO load.

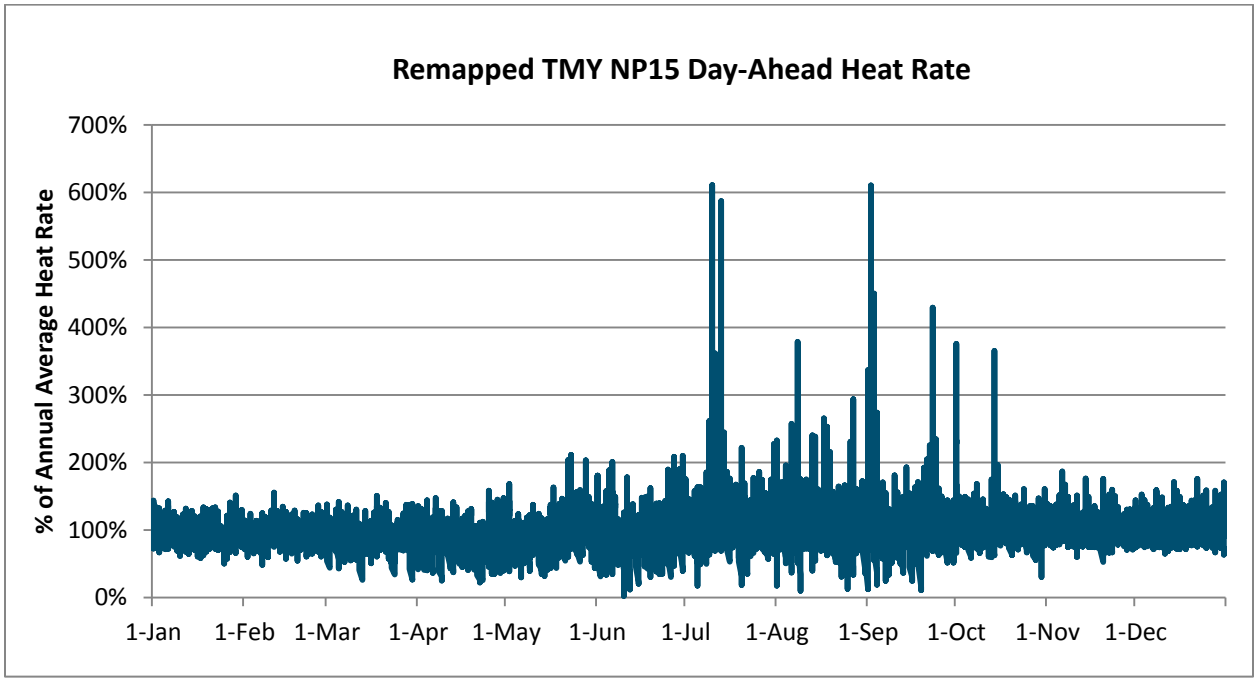
For example, hourly market heat rates associated with the peak summer load day in 2012 would be remapped to the peak summer load day in the TMY. E3 estimates California system loads under TMY weather conditions using an 18-zone regression model.

C-5.4.1 Calculation of the Hourly Energy Market Avoided Costs

The remapped hourly implied market heat rate curve is multiplied by the monthly natural gas price forecast and a calibration factor so that the product is a set of hourly market clearing prices in California that average over the year to the same annual average energy avoided cost shown in Figure 12. In the TMY price shape, the price spikes from August 2012 are spread out more broadly as the TMY has less concentrated peak load events.

Figure 14: Day-Ahead Heat Rate Shape Comparison





C-5.5 ENERGY LOSS FACTORS

The annual avoided energy costs are estimated at the wholesale generation market delivery point. Energy loss factors are applied to those avoided energy costs to convert them to the cost of energy at the customer meter. The loss factors vary by utility, customer voltage level, and time-of-use (TOU) period. The secondary loss factors for each utility are shown in Table 4, and the loss factors for Primary voltage customers are shown in Table 5.

Table 4: Marginal Energy Loss Factors by Time-of-Use Period and Utility (At Secondary Voltage)

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 5: Marginal Energy Loss Factors by Time-of-Use Period and Utility (At Primary Voltage)

Time Period	PG&E	SCE	SDG&E
Summer Peak	1.058	1.061	1.036
Summer Shoulder	1.042	1.057	1.034
Summer Off-Peak	1.036	1.050	1.027
Winter Peak	-	-	1.038
Winter Shoulder	1.039	1.054	1.033
Winter Off-Peak	1.040	1.047	1.027

C-6 Generation Capacity

The generation capacity value captures the reliability-related cost of maintaining a generator fleet with enough capacity to meet each year's peak loads and the planning reserve margin. The generation capacity cost is based on the utility resource adequacy cost in the near term (i.e., before the resource balance year, see Section C.6.1.3 below). In the long term (i.e., after the resource balance year), the generation capacity cost is the annualized cost of a new simple cycle combustion turbine (CT) less the margins that such a generator could earn from energy and ancillary service markets. This difference is referred to as the residual capacity value and represents the level of capacity payments that a new generator would require to supplement its market margins and cover the return on and of its capital. Use of the residual capacity value to estimate generation capacity costs is the common practice in California.[21]

The basic formula used to calculate the avoided cost of capacity is the following:

$$ACV_{u,v,h} = GenCap_y * GenWt_h * CapLF_{U,V}$$

where

$GenCap_y$ = Generation Capacity Cost in year *y*.

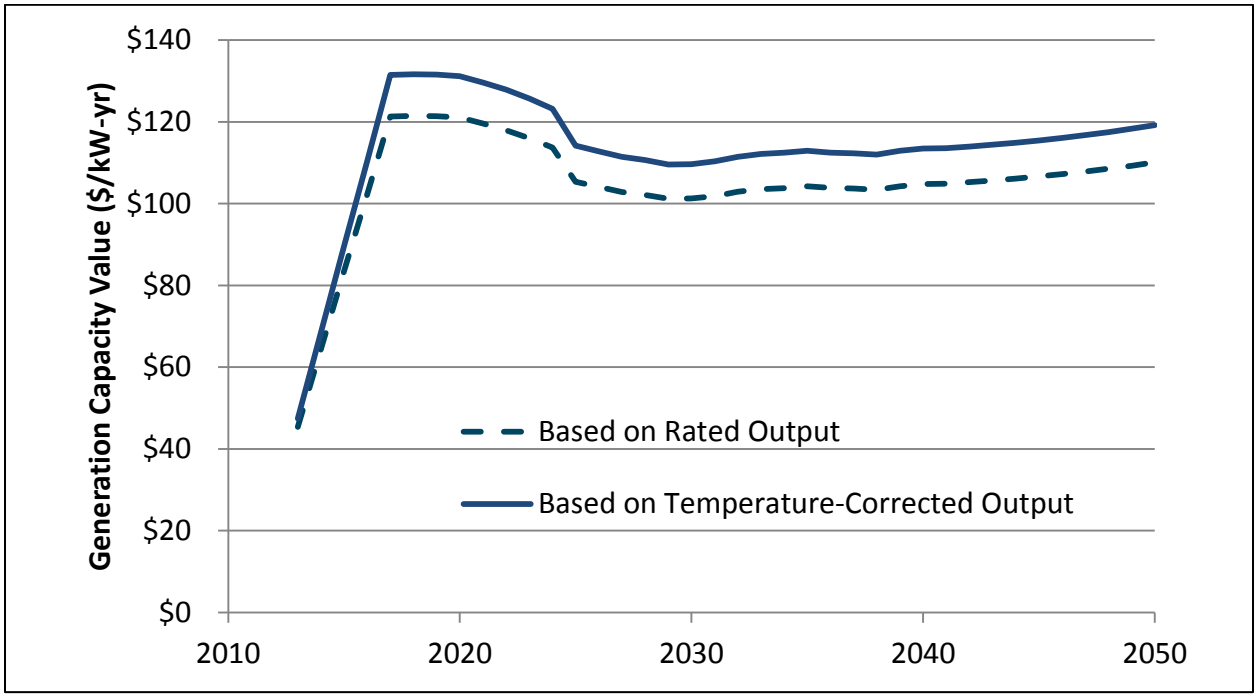
$GenWt_h$ = Generation capacity allocation factors for hour *h*

$CapLF_{u,v}$ = Peak capacity loss factors for utility *u* and customer voltage level *v*

Figure 15 shows E3's forecast generation capacity cost through 2050. The figure shows the capacity cost increasing as surplus capacity diminishes until resource balance is reached in 2017. After 2017, the generation capacity cost declines because increased revenues earned by a new CT in the real-time energy and ancillary service markets reduce the level of contract payments that would be needed to attract a new entrant.

[21] See SCE Phase 2 of 2012 General Rate case Marginal Cost and Sales Forecast proposals (A.11-06-007, pp. 16-19)

Figure 15: Generation Capacity Cost (Nominal Dollars, at the Wholesale Market Delivery Point)



C-6.1.1 Near-Term Resource Adequacy Value

The generation capacity value in 2012 is the median value for resource adequacy capacity in the CPUC's 2013 report on 2011 resource adequacy costs.[22] Values for years prior to 2012, used for historical analysis, are taken from previous CPUC Resource Adequacy reports.[23] Under the Resource Adequacy (RA) program, Load Serving Entities (LSEs) are required to file with the CPUC demonstrating that they have procured sufficient capacity resources including reserves needed to serve their aggregate system load plus 15% reserve margin on a monthly basis. In addition, each LSE is required to file with the CPUC demonstrating procurement of sufficient Local RA resources to meet their RA obligations in transmission constrained Local Areas. The generation capacity value is based on the procurement of capacity resources for aggregate system loads, and do not include any incremental costs for local RA obligations.

[22] See www.cpuc.ca.gov/NR/rdonlyres/58DCCE4F-4096-42A9-BFDC-EC891129E8D9/0/2011RAreportFinal252012.docx

[23] See http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/

C-6.1.2 Transition From Near-Term to Long-Term Values

The historical RA value is relatively low because of excess supply of generation capacity deliverable to the CAISO. The CEC 2013 outlook is not yet published, but the CEC's *Summer 2012 Electricity and Supply and Demand Outlook*, showed that under normal conditions, the minimum reserve margin for 2012 was forecast at 30%—well above the required planning reserve margin of 15% (see Table 6). Even in a 1-in-10 year weather case, the minimum reserve margin was still forecast to be 21%.

Table 6: Expected Reserve Margins for the Summer of 2012[24]

	June	July	August	September
Total Net Supply (MW)	77,399	77,971	78,374	78,363
1-in-2 Peak Demand (MW)	53,811	58,086	60,343	54,922
1-in-10 Peak Demand (MW)	57,944	62,557	64,936	59,173
Reserve Margin (1-in-2 Demand)	44%	34%	30%	43%
Reserve Margin (1-in-10 Demand)	34%	25%	21%	32%

As economic growth increases peak demand, the excess generation capacity supply condition will lessen unless new generation is constructed. As reserve margins approach the required 15% minimum, we expect that the marginal cost of RA procurement would increase as LSEs would need to procure system RA from higher priced resources.

This marginal RA market price should increase annually until the year in which supply is equal to peak demand plus the planning reserve margin—this is known as the resource balance year. Once the resource balance is reached, there is no longer excess generation capacity supply in the market, and new generation would need to be built to meet peak demand growth plus reserve margins. The introduction of new generation would serve as a constraint on the upper limit prices that generators could command for system RA capacity.

In the resource balance year and each year thereafter, the value of capacity is set equal to the residual capacity cost of new generation (see section *Long-term CT Residual Capacity*). Between 2012 and the resource balance year, E3 uses a linear interpolation to calculate the annual increases in capacity value.

C-6.1.3 Resource Balance Year

E3 uses a default resource balance year of 2017, but such a value may change depending on the DER being evaluated. The resource balance year is derived from the Joint IOU July 1, 2011 filing in the LTPP proceeding (R.10-05-006 track 1). 2017 reflects the middle load trajectory with 10,000 MW of imports, no demand response, and no incremental EE or combined heat and power after 2013. The 10,000 MW

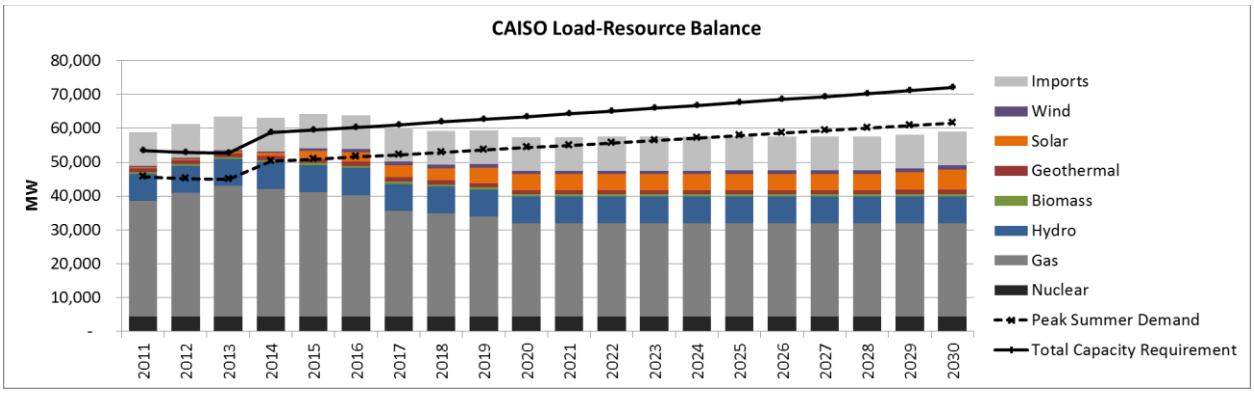
[24] Table reproduced from the California Energy Commission Summer 2012 Electricity Supply and Demand Outlook. See http://www.energy.ca.gov/2012publications/CEC-200-2012-003/CEC-200-2012-003.pdf

import assumption is lower than the CPUC's recommended value of 17,000 MW. However, E3 believes that 10,000 MW is a more appropriate value to use for this analysis as it is more consistent with actual import amounts at the time of the California system peak conditions.

Table 7: Middle Trajectory Resource Balance excluding Demand Response, and Incremental EE and CHP after 2013

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Summary Results										
CAISO Reserve Margin Calculation										
Available Capacity	67,122	69,598	71,779	71,378	72,376	72,147	68,342	67,467	67,704	65,704
Net System Peak	45,710	45,190	45,029	50,259	50,888	51,530	52,222	52,880	53,546	54,273
Reserve Margin Requirement	53,481	52,872	52,683	58,803	59,539	60,290	61,099	61,870	62,649	63,500
Surplus (Shortfall)	**13,641**	**16,726**	**19,095**	**12,576**	**12,837**	**11,857**	**7,242**	**5,597**	**5,055**	**2,204**
Reserve Margin	**47%**	**54%**	**59%**	**42%**	**42%**	**40%**	**31%**	**28%**	**26%**	**21%**
Capacity Resources by Type (MW)										
Nuclear	4,486	4,486	4,486	4,486	4,486	4,486	4,486	4,486	4,486	4,486
Gas	34,056	36,451	38,435	37,502	36,707	35,832	31,176	30,301	29,426	27,426
Various	1,268	1,268	1,268	1,268	1,268	1,268	1,268	1,268	1,268	1,268
Hydro	7,975	7,975	7,975	7,975	7,975	7,975	7,975	7,975	7,975	7,975
Biomass	580	580	609	656	656	656	656	656	656	656
Geothermal	1,079	1,079	1,079	1,177	1,205	1,205	1,205	1,205	1,241	1,241
Solar	384	458	626	1,001	2,272	2,892	3,570	3,570	4,644	4,644
Wind	339	346	346	359	852	877	1,050	1,050	1,053	1,053
Imports	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Total Resources	**60,167**	**62,643**	**64,824**	**64,424**	**65,422**	**65,192**	**61,387**	**60,512**	**60,749**	**58,749**

Figure 16: Resource Balance Year



C-6.2 LONG-TERM CT RESIDUAL CAPACITY COST

The long-run basis for the value of generation capacity is the levelized cost of a new simple cycle CT less the net margin earned during operations in CAISO's energy and ancillary services markets. This framework for capacity valuation assumes that CAISO has reached resource balance: The net available supply is just enough to meet expected peak demands plus the planning reserve margin. Under such

circumstances, a new generator would receive the full capacity residual as a capacity payment, earning just enough revenue to cover its fixed costs (there would be neither an incentive to enter the market nor an incentive to exit). The capacity residual cost is then adjusted to convert the values, which are on a $ per kW of nameplate capacity basis to a $ per kW of delivered capacity basis. This adjustment is necessary to reflect the degraded thermal plant output at high temperatures that are likely to coincide with system peak demands.

$$GenCapCost_y = (CT_y - (EMargin_y + ASMargin_y))*TempFctr$$

where

CT_y = Levelized cost of a simple cycle combustion turbine installed in year *y*

$EMargin_y$ = Margins earned by the new CT in the real-time energy market in year *y*

$AMargin_y$ = Margins earned by the new CT from the ancillary service markets.

TempFctr = CT nameplate rating / CT output at system peak temperatures[25]

C-6.2.1 CT cost and performance assumptions

The cost and performance assumptions for the new simple cycle plants are based on the 100 MW simple cycle turbine included in the California Energy Commission's Cost of Generation report.[26]

Table 8: Power Plant Cost and Performance Assumptions at ISO Conditions[27] (all costs in $2009)

	Simple Cycle Gas Turbine
Heat Rate (Btu/kWh)	9,300
Plant Lifetime (yrs)	20
Instant Cost ($/kW)	$1,230
Fixed O&M ($/kW-yr)	$17.40
Variable O&M ($/kW-yr)	$4.17
Debt-Equity Ratio	60%
Debt Cost	7.70%
Equity Cost	11.96%

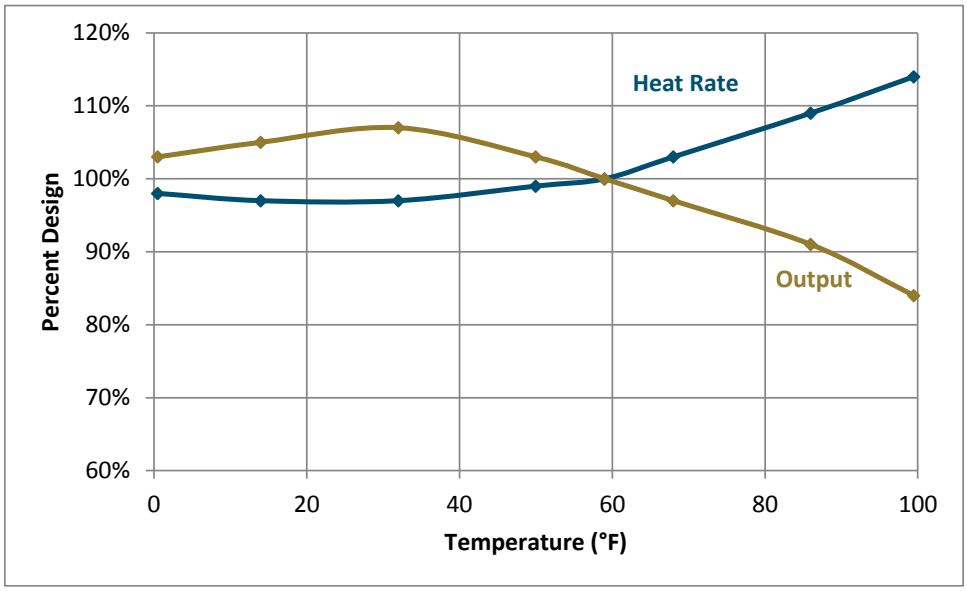
[25] This is calculated on regional (SP15 and NP15) basis using hourly temperatures weighted by hourly LOLP described in the section *Allocation of Avoided Generation Capacity Cost.*

[26]See http://www.energy.ca.gov/publications/displayOneReport.php?pubNum=CEC-200-2009-017-SF

[27] ISO conditions assume 59ºF, 60% relative humidity, and elevation at sea level.

The CT's rated heat rate and nameplate capacity characterize the unit's performance at ISO conditions, but the unit's actual performance deviates substantially from these ratings throughout the year. In California, deviations from rated performance are due primarily to hourly variations in temperature. Figure 17 shows the relationship between temperature and performance for a GE LM6000 SPRINT gas turbine, a reasonable proxy for current CT technology.

Figure 17: Temperature-Performance Curve for a GE LM6000 SPRINT Combustion Turbine



The effect of temperature on performance is incorporated into the calculation of the avoided cost of generation capacity in three ways:

1. In the calculation of the CT's dispatch, the heat rate is assumed to vary on a monthly basis. In each month, E3 calculates an average day-time temperature based on hourly temperature data throughout the state and uses this value to adjust the heat rate—and thereby the operating cost—within that month.
2. Plant output is also assumed to vary on a monthly basis; the same average day-time temperature is used to determine the correct adjustment. This adjustment affects the revenue collected by the plant in the real-time market. For instance, if the plant's output is 90% of nameplate capacity in a given month, its net revenues will equal 90% of what it would have received had it been able to operate at nameplate capacity.
3. The resulting capacity residual is originally calculated as the value per nameplate kilowatt—however, during the peak periods during which a CT is necessary for resource adequacy, high temperatures will result in a significant capacity derate. Consequently, the value of capacity is increased by approximately 9% to reflect the plant's reduced output during the peak hours of the year.

C-6.2.2 Levelized Cost of a New CT

E3 uses a standard Pro forma financial model to estimate the levelized cost of a new CT unit, assuming the instant costs, lifetime, and independent power producer financing shown in Table 8. The pro forma analysis also includes 2 percent per year escalation for fixed and variable O&M costs, 0.6% /yr insurance costs, 7.94% sales tax rate on the system cost, and 1.1%/yr property taxes. Table 9 shows the levelized cost of a new CT. The cost is constant in real terms, and escalates 2% per year in nominal terms.

Table 9: Real Levelized Cost of a New CT

Cost Item	Amount ($/Nameplate kW-yr)
Capital Cost w/Taxes	$145.42
Fixed O&M	$17.40
Insurance	$8.03
Property Tax	$10.16
Total Annualized Fixed Cost	$181.01

C-6.2.3 Calculation of the Capacity Residual

The next step in determining the avoided cost of generation capacity is the estimation of margins that the new CT could earn from energy and ancillary service markets. E3 dispatches the new CT unit against an hourly real-time market price forecast and subtracts the fuel cost and variable O&M from the market revenues to estimate the market margins. The CT's net margin is 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) plus a bid adder of 10%; in each hour that it operates, the unit earns the difference between the market price and its operating costs. In each hour where the market prices are below the operating cost, the unit is assumed to shut down.

$EMargin_y = RTMargin_y + ASMargin_y$

Where

$RTMargin_y$ = Margin from Real-time energy market in year *y*

= Sum of $[(RTMkt_{y,h} - CT_VC_{y,h})*OutFctr_m]$ for all hours where $RTMkt_{y,h} > (1+BidFctr)* CT_VC_{y,h}$

$ASMargin_y$ = 7.8% * $RTMargin_y$

$RTMkt_{y,h}$ = Real-time market price for hour *h* in year *y*

$CT_VC_{y,h}$ = Full variable cost of CT operation for hour *h* in year *y.*

= $HeatRate * GasPrice_m * HRFctr_h + VarOM_y + CO2Cost_y * CO2Content * HRFctr_h$

$OutFctr_m$	=	Output performance adjustment factor, based on average daytime (9am to 10pm) temperatures during each month *m*. Factor is a percentage relative to nameplate capacity under ISO conditions.
BidFctr	=	10%. Assumed profit margin included in CT bid prices.
HeatRate	=	HeatRate under ISO conditions
$GasPrice_m$	=	Natural gas price for month *m*
$HRFctr_h$	=	Heat rate adjustment factor, based on average daytime (9am to 10pm) temperatures during each month. Factor is a percentage relative to heat rate under ISO conditions.
$VarOM_y$	=	Variable cost of O&M escalated to year *y* by 2% per year (2009 base year)
$CO2Cost_y$	=	Cost of CO2 emissions $/ton in year *y*
CO2Content	=	Natural gas carbon content (0.0585 tons per MMBtu)

Note that in an avoided cost scenario with high real-time energy prices, a new CT's net margin increases, which in turn decreases the new CT's capacity residual. So for example, in an avoided cost case where high natural gas prices drive up energy prices, energy avoided costs will be higher and capacity avoided costs will be lower than in a comparable scenario with low natural gas prices.

Hourly Real-Time Market Prices

Real-time market prices are based on historical real-time data gathered from CAISO's MRTU system aligned to a TMY.[28] The historical market prices for NP15 and SP15 are converted to implied heat rates by dividing by the historical California average daily natural gas prices. The remapped implied heat rates are then multiplied by the forecast monthly natural gas prices to form the remapped real time market price curve. In each year, the level of the real-time market price curve is adjusted to match the average wholesale market price for that year.[29]

Ancillary Service Margins for a New CT

E3 adds an additional 7.8% of the real-time market revenues as ancillary service margins that the CT could also earn through participation in CAISO's ancillary services markets. This figure is based on an analysis of new combustion turbine operations presented in the CAISO (2013), *2012 Annual Report*

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[28] See *Aligning Market Data to Match TMY Weather Data* for a discussion of remapping historical data to TMY weather files.

[29] Many real-time market prices reflect ramping capacity constraints or congestion issues present on the CAISO system. The highest prices are actually the penalty prices associated with relaxing supply and demand balance constraint in the CAISO's market optimization. Real-time prices for both NP15 and SP15 were slightly higher than day-ahead prices in 2012. We would expect convergence between those prices in the long-term, reflecting an absence of arbitrage opportunities. So that we do not overestimate the potential real-time market revenues for a CT, we converge historical real-time prices to day-ahead prices by reducing the highest real-time price peaks.

on Market Issues and Performance.[30] 7.8% represents the four-year average of ancillary service revenues/energy revenues from 2009-2012.

C-6.2.4 Allocation of Avoided Generation Capacity Cost

Once the residual capacity cost of a CT has been determined, the next step is to allocate those costs to hours. Combining the hourly allocation factors with the annual capacity residual produces a stream of hourly $/MWh avoided generation capacity costs. These hourly capacity costs can then be multiplied by a resource's hourly load shape to calculate the avoided capacity value provided by the resource.

Previously, capacity value was allocated over the top 250 load hours of the year, using load level to determine the weighting of this capacity value. E3 has refined the methodology to move away from using the load proxy and instead use calculated LOLP values.

The proprietary nature of utility LOLP models and results has historically been a hindrance to the incorporation of LOLP into this avoided cost framework. To solve this problem E3 has developed a non-proprietary LOLP model that uses publically available information.

The E3 Capacity Planning Model[31] estimates LOLP for each month/hour/day-type combination during the year based on net load (gross load net of non-dispatchable renewable resources). These values directly express the likelihood of lost load, and therefore give a more accurate relative weighting among hours. These tables have been calculated using the E3 Capacity Planning Model for the present day as well as a 2020 case representing the RPS buildout from the 2010 LTPP Trajectory Case.

Figure 18: 2013 LOLP Table

Weekday

Hour \ Month												
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	6E-15	0	0	0	0	0
	0	0	0	0	0	0	7E-11	2E-13	4E-15	0	0	0
	0	0	0	0	0	0	2E-08	5E-09	2E-11	0	0	0
	0	0	0	0	0	5E-15	3E-06	3E-06	7E-08	0	0	0
	0	0	0	0	2E-15	2E-13	9E-05	3E-05	1E-05	0	0	0
	0	0	0	0	2E-14	1E-09	8E-04	4E-04	5E-04	3E-15	0	0
	0	0	0	0	5E-12	3E-07	0.002	0.003	0.001	7E-13	0	0
	0	0	0	0	8E-11	6E-06	0.004	0.006	0.002	3E-11	0	0
	0	0	0	0	4E-11	9E-06	0.003	0.006	0.002	3E-13	0	0
	0	0	0	0	1E-12	9E-07	7E-04	0.002	3E-04	4E-15	0	0
	0	0	0	0	2E-15	6E-09	4E-05	3E-04	1E-04	0	0	0
	0	0	0	0	0	7E-11	3E-05	2E-05	5E-05	0	0	0
	0	0	0	0	0	1E-11	3E-07	3E-06	4E-07	0	0	0
	0	0	0	0	0	0	3E-11	6E-10	2E-14	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0

Weekend

Hour \ Month												
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	8E-15	4E-15	2E-15	0	0	0
	0	0	0	0	0	2E-15	9E-12	4E-13	8E-13	0	0	0
	0	0	0	0	0	1E-13	3E-04	3E-10	4E-10	0	0	0
	0	0	0	0	0	2E-13	6E-04	1E-08	1E-08	0	0	0
	0	0	0	0	0	2E-12	7E-04	3E-07	7E-08	0	0	0
	0	0	0	0	0	2E-12	3E-04	2E-07	8E-08	0	0	0
	0	0	0	0	0	3E-13	9E-05	1E-08	2E-08	0	0	0
	0	0	0	0	0	3E-15	1E-05	9E-10	4E-10	0	0	0
	0	0	0	0	0	0	7E-08	1E-11	5E-09	0	0	0
	0	0	0	0	0	0	5E-14	7E-13	2E-12	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0

[30] See http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf

[31] The E3 Capacity Planning Model and the Dispatchability Factor Calculator, including user's manuals, are available online at https://e3.sharefile.com/d/s78313505eea47ffb.

Figure 19: 2020 LOLP Table

Weekday

Hour \ Month											
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	2E-15	0	0	0	0
	0	0	0	0	0	0	5E-11	1E-13	8E-16	0	0
	0	0	0	0	0	0	1E-08	8E-09	5E-12	0	0
	0	0	0	0	0	0	1E-06	1E-06	1E-07	0	0
	0	0	0	0	3E-16	1E-15	3E-05	7E-06	9E-06	0	0
	0	0	0	0	7E-16	6E-11	4E-04	2E-04	2E-04	8E-16	0
	0	0	0	0	1E-12	2E-07	9E-04	0.001	6E-04	6E-12	0
	0	0	0	0	1E-10	4E-06	0.003	0.004	0.001	7E-10	0
	0	0	0	0	2E-10	7E-06	0.002	0.005	0.001	2E-12	0
	0	0	0	0	4E-12	2E-06	8E-04	0.003	9E-04	7E-15	0
	0	0	0	0	1E-15	3E-08	2E-04	0.002	0.003	0	0
	0	0	0	0	0	2E-08	5E-04	1E-03	0.003	0	0
	0	0	0	0	0	7E-09	1E-04	4E-04	2E-04	0	0
	0	0	0	0	0	7E-15	2E-08	2E-07	1E-12	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0

Weekend

Hour \ Month											
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	9E-16	8E-16	3E-16	0	0
	0	0	0	0	0	2E-16	1E-13	2E-15	6E-14	0	0
	0	0	0	0	0	5E-16	9E-05	4E-11	1E-10	0	0
	0	0	0	0	0	5E-16	2E-04	3E-09	2E-08	0	0
	0	0	0	0	0	3E-14	4E-04	5E-07	2E-07	0	0
	0	0	0	0	0	7E-14	3E-04	7E-07	6E-07	0	0
	0	0	0	0	0	2E-14	1E-04	4E-08	1E-07	0	0
	0	0	0	0	0	8E-16	5E-05	1E-08	8E-08	0	0
	0	0	0	0	0	0	2E-05	1E-09	4E-06	0	0
	0	0	0	0	0	0	3E-12	3E-11	4E-10	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0

These likelihoods are then adjusted to reflect expected variations within each month/hour/day-type. The LOLP table provides a single value for a weekday in July at 4 PM. However, spreading that value uniformly over every 4 PM during a July weekday, and following suit with each other month/hour/day-type, would distribute the capacity value over some 500 hours of the year. The adjustment step described herein recognizes that some weekdays are hotter than others, which naturally leads to higher loads and higher probability of lost load on those days. Given this, we use a temperature threshold to label certain days of the year as high load days, and distributed the LOLP from the above tables to only the high load days. The result is a set of capacity allocation factors that distributes value to between 150 and 250 hours of the year.

Allocation Methodology

The following section details the steps used to distribute calculated LOLP values for each month/hour/day-type to statistically determined "hot days" based on TMY weather data.

1. **Use TMY weather data to calculate lagged max daily temperature for each weather region**
   The highest load events that typically result in loss of load are caused by several consecutive hot days. As a result, we create a lagged temperature variable that captures this effect. In the formula, LT_i is the lagged maximum temperature for day i, and T_i is the maximum temperature for day i.
   $LT_i = T_i/2 + T_{i-1}/4 + T_{i-2}/6 + T_{i-3}/12$
   This is calculated for the 18 different regions used to develop the TMY load shapes used in the CEC building codes, listed below, which are intended to represent the major load pockets throughout California.

Table 10: List of Weather Stations Used by Region

Load Region	Associated Weather Station
Anaheim	LOS-ALAMITOS_722975
Burbank	BURBANK-GLENDALE_722880
CFE	IMPERIAL-BEACH_722909
Glendale	BURBANK-GLENDALE_722880
IID	IMPERIAL_747185
LADWP	BURBANK-GLENDALE_722880
MID	MODESTO_724926
NCPA	SACRAMENTO-METRO_724839
Pasadena	BURBANK-GLENDALE_722880
PG&E NP15	SAN-FRANCISCO-INTL_724940
PG&E ZP26	FRESNO_723890
Redding	REDDING_725920
Riverside	RIVERSIDE_722869
SCE	BURBANK-GLENDALE_722880
SDG&E	SAN-DIEGO-LINDBERGH_722900
SMUD	SACRAMENTO-EXECUTIVE_724830
SVP	SAN-JOSE-INTL_724945
TID	MODESTO_724926

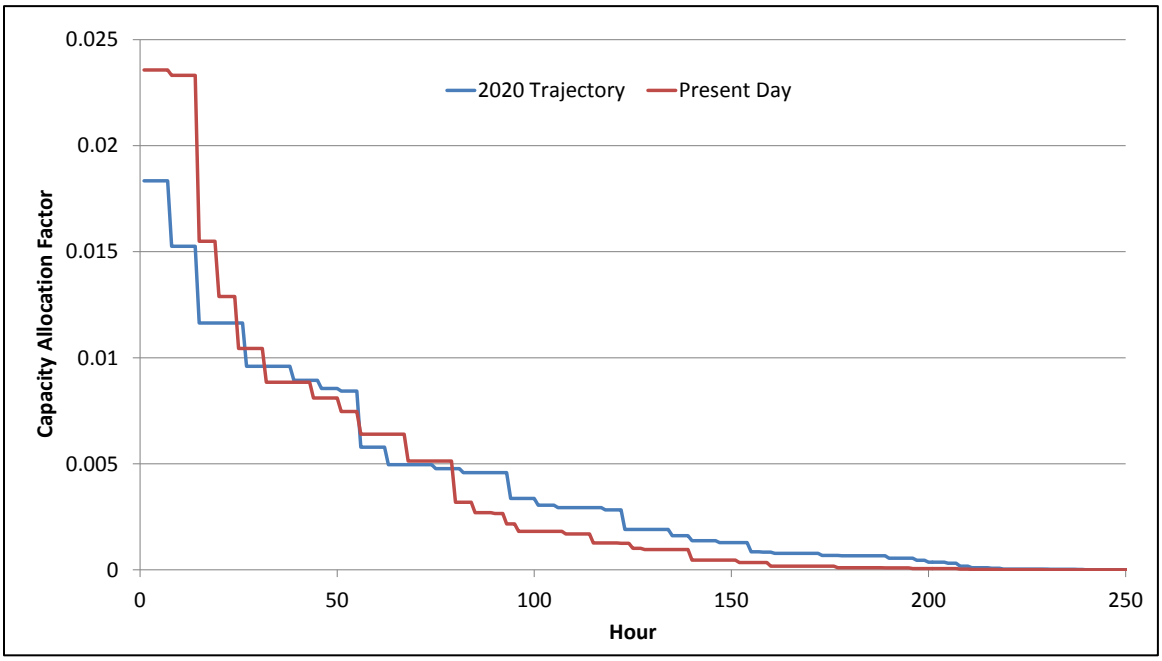
2. **Combine load-weighted regional temperatures to develop a single statewide representative temperature**
   Each of the regions in Step 1 is given a weight based on historical peak load relative to statewide peak load. These weights are multiplied by each region's stream of daily lagged maximum temperatures, and combined, across all regions, to create a statewide lagged maximum temperature for each day of the TMY.

3. **Find the threshold temperature representative of 1 in 10 load**
   Using the methodology described in Steps 1 and 2, and the same weather stations identified in Step 1, a stream of statewide daily lagged maximum temperatures is created for each historical year for which sufficient data is available. The 90th percentile of this set of lagged temperatures is then established as the threshold temperature for high load days. Days with lagged maximum temperature less than this value are deemed to not result in lost load. Meanwhile days with lagged maximum temperature greater than this value are labeled as high load days.

4. **Distribute LOLP across days that classify as high load days**
   Days having a lagged maximum temperature (found in Step 2) that exceeds the high load temperature threshold (found in Step 3) are labeled as high load days within the TMY. Then, the previously calculated LOLP values are distributed across hours that occur on high load days. Hours on non-high load days receive no allocation. Finally, the annual stream of hourly values is normalized to sum to 1. The resulting normalized values are the hourly capacity allocation factors for the TMY.

Two example capacity allocation duration curves are shown below. The two curves shown use the same set of TMY weather data to determine high load days across which LOLP values are distributed, but use two separate sets of annual LOLP values. These two sets represent LOLP conditions in 2013 and under a 2020 Trajectory scenario. Note that the higher concentration of solar resources in the 2020 Trajectory case suppresses the LOLP values in the highest hours, thereby flattening the entire curve. Values for the years between 2013-2020 are interpolated. Capacity allocators after 2020 are held constant.

Figure 20: Resulting Capacity Allocation Duration Curves



C-6.2.5 Generation Capacity Losses

The valuation of capacity includes an adjustment for losses between the point of generation and delivery similar to energy. In order to account for losses, the annual capacity value is multiplied by the utility-specific losses factor applicable to the summer peak period, as this is the period during which system capacity is likely to be constrained.

C-7 Ancillary Services (A/S)

Besides reducing the cost of wholesale purchases, reductions in demand at the meter result in additional value from the associated reduction in required procurement of ancillary services.

The CAISO MRTU markets include four types of ancillary services: regulation up and down, spinning reserves, and non-spinning reserves. Both spinning and non-spinning reserves are directly linked to load—in accordance with Western Electricity Coordinating Council (WECC) reliability standards, the California ISO must maintain an operating reserve equal to 5% of load served by hydro generators and 7% of load served by thermal generators. Regulating reserves are not procured as a percentage of load and so we don't consider these costs.

The value of this avoided reserves procurement scales with the value of energy in each hour throughout the year. According to the CAISO's *2012 Annual Report on Market Issues and Performance*, total spending on reserves in 2012 amounted to $84 million or 1% of the value of wholesale energy costs.[32] Of this, approximately $48 million, or .57%, were spinning and non-spinning reserves. This .57% figure is used to assess the value of avoided reserves procurement in each hour. The wholesale energy costs referred to by the CAISO would reflect the combined energy and carbon avoided costs in this model. The formula for the avoided cost of ancillary services is shown below.

$$ASValue_{y,h} = (ACE_{y,h} + ACC_{y,h}) * 1\%$$

where

$ACE_{y,h}$ = Hourly avoided cost of energy in year *y* and hour *h* (unadjusted for losses)

$ACE_{y,h}$ = Hourly avoided cost of carbon in year *y* and hour *h* (unadjusted for losses)

1% = Total A/S spending on reserves / total wholesale energy costs

[32] Note that this Ancillary Service percentage is not the same as the A/S value used in the calculation of market revenues for a new CT. That A/S value was calculated relative to the real-time energy market for a peaking CT unit. The A/S value described in this section is a percentage of wholesale costs over the entire year.

C-8 T&D Capacity

C-8.1 DISTRIBUTION AVOIDED COSTS

Distribution avoided costs are estimated based on capacity-related project lists provided by the IOUs. Using the project costs and forecast load growth and deficiencies for the project areas, E3 calculated the cost savings that could result from deferral of those projects. This method is referred to as the "Present Worth" method in the literature and is well suited for the evaluation of the value of reducing loads in specific project areas. The deferral value is the present value of the extant project less the present value cost of the deferred project. Dividing by the amount of load reduction needed to attain the deferral yields the $/kW avoided cost, and applying a capital recovery factor that is constant in real dollars provides the $/kW-yr avoided cost.

DCost[p] = PV(Invest[p][y] * (1-((1+i)/(1+r))^deltaT)/deltaL * CRFR

Where

DCost[p] = distribution avoided cost for project p
PV indicates a present value calculation over the utility planning horizon
Invest[p][y] = distribution capacity-related project cost in year y
i = equipment inflation rate
r = utility discount rate
deltaT = deferral length in years
deltaL = load reduction needed to attain deltaT deferral
CRFR = capital recovery factor that is constant in real dollars

This method is used by E3 and numerous utilities for conducting local integrated resource planning studies and estimating project specific avoided cost estimates. The resulting avoided costs developed at a more granular level than typical utility avoided costs developed for revenue allocation and rate design purposes.

The project cost lists provided by utilities reflect investments five to ten years into the future. However, as the PV installations have substantially longer useful lives, it is likely that using such truncated project forecasts would underestimate the distribution value that could be provided by distributed PV. To correct for this potential underestimation, we assume that the project costs of the same real level would recur once after 15 years of normal load growth.[33]

C-8.1.1 PG&E Distribution Costs

PG&E's distribution costs are developed as two separate components. There are (a) project-specific costs related to jobs with total costs over $1 million, and there are (b) more generic division-level costs for smaller projects that PG&E does not forecast on an individual job basis.

[33] Adjustment factor = 1 + ((1+inflation)/(1+discount rate))^15 years

The PG&E avoided costs are based on data that PG&E developed in support of their General Rate Case proceeding (but not utilized in the same granular fashion as done herein). The PG&E information consists of forecast investments and deficiencies for the years 2009 through 2013.[34] While the information is dated, we believe that it is representative of the spread of PG&E distribution costs and sufficient for the purposes of this NEM study. Figure 21 shows PG&E's project-related distribution avoided costs for projects over $1 million. Each column represents the costs associated with a particular forecast project.

Figure 21: PG&E Distribution Avoided Costs (Project)

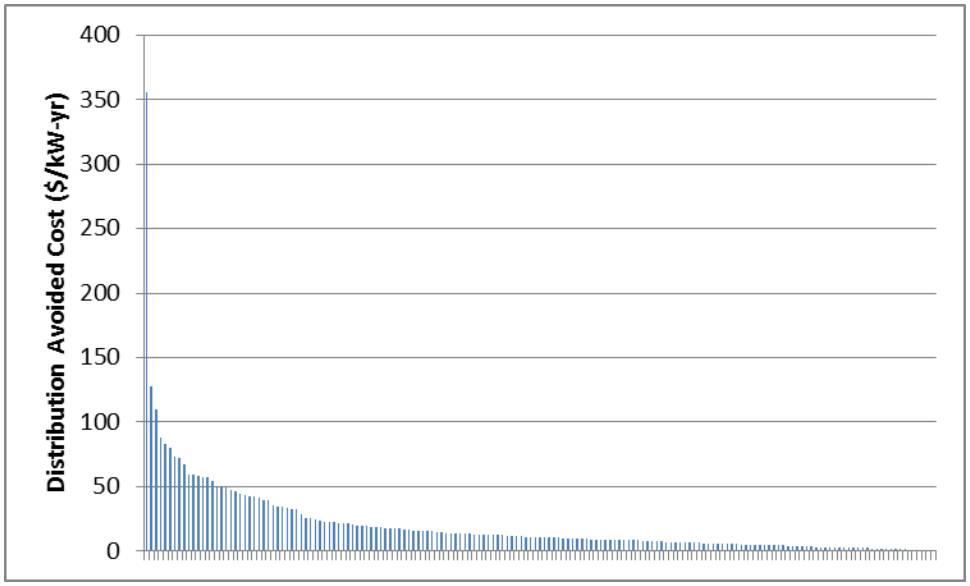


Table 11 shows PG&E's distribution capacity-related costs associated with projects under $1 million. We directly use PG&E's GRC forecast avoided cost for that class of projects and apply it to all areas in PG&E's service territory. The cost is additive with the distribution avoided cost developed from the PG&E's project list Neither SCE nor SDG&E have a similar class of costs in their GRC proceedings, so no adjustment is needed for those utility service territories.

[34] If no deficiency was provided, then the average load growth in the corresponding distribution planning area is used.

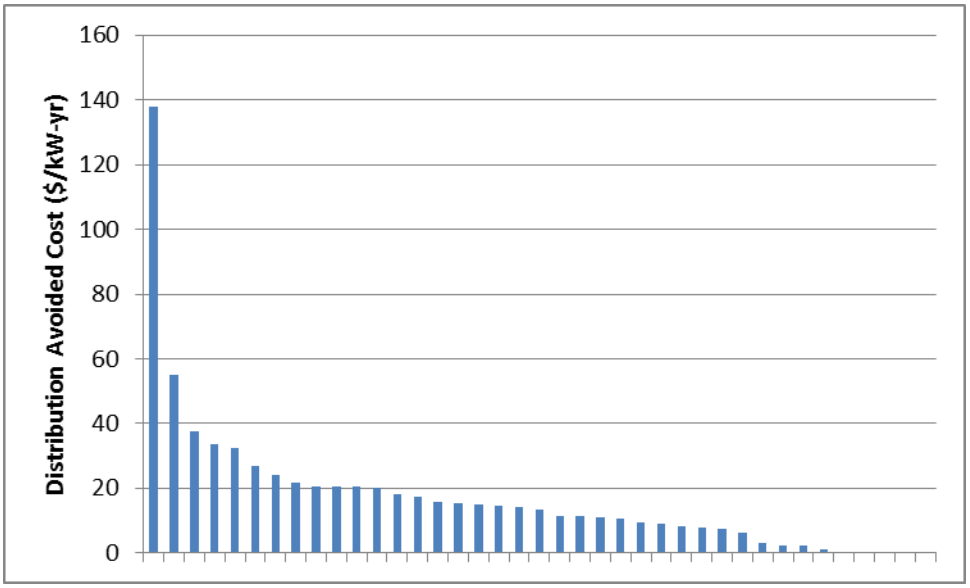
Table 11: PG&E Avoided Costs for Small Distribution Projects

Line No.	DIVISION	PROJECTS UNDER $1 MILLION ($/PCAF-kW-yr)
1	CENTRAL COAST	$ 37.08
2	DE ANZA	$ 11.63
3	DIABLO	$ 40.50
4	EAST BAY	$ 26.74
5	FRESNO	$ 26.43
6	KERN	$ 19.49
7	LOS PADRES	$ 28.98
8	MISSION	$ 23.99
9	NORTH BAY	$ 25.54
10	NORTH COAST	$ 22.57
11	NORTH VALLEY	$ 38.44
12	PENINSULA	$ 28.54
13	SACRAMENTO	$ 25.30
14	SAN FRANCISCO	$ 12.95
15	SAN JOSE	$ 23.74
16	SIERRA	$ 47.25
17	STOCKTON	$ 25.83
18	YOSEMITE	$ 38.97

C-8.1.2 SCE Distribution Avoided Costs

As opposed to PG&E where project capacity costs were developed on at the project level of granularity, the SCE distribution capacity costs are estimated at the SYS ID level. The SYS ID level of granularity is used because SCE's distribution system is more flexible and interconnected than a typical radial system. Because of the flexibility in system reconfiguration, the need for distribution system capacity is driven by load growth over wide geographic areas. Accordingly, the SCE distribution avoided cost values are based on aggregate investments from 2012 through 2018 and forecast growth within SCE SYS ID areas. For each SYS ID area, the total growth-related investments are summed for the year, and the PW method is applied using the average load growth projected for the SYS ID from 2011 through 2018. Figure 22 shows SCE's distribution avoided costs. Each column represents the distribution avoided cost for an SCE SYS ID area.

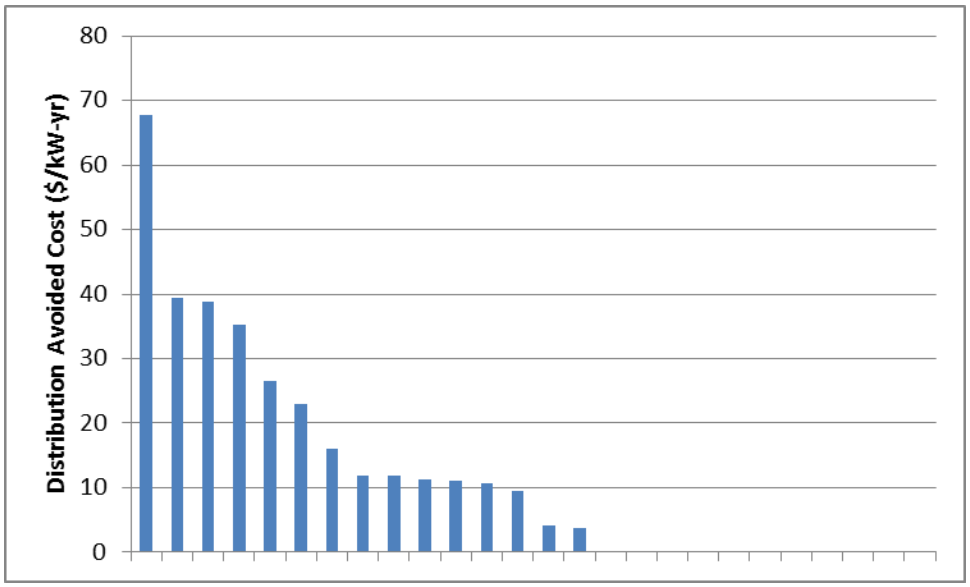
Figure 22: SCE Distribution Avoided Costs (SYS ID area)



C-8.1.3 SDG&E Distribution Avoided Costs

SDG&E's avoided costs are developed at the substation level. Forecast investment costs for 2011 through 2014 are combined with average forecast substation growth over the same period to determine SDG&E's distribution avoided cost. Figure 23 shows SDG&E's distribution avoided costs, with each column representing the avoided costs for a particular substation.

Figure 23: SDG&E Distribution Avoided Costs (Substation)



C-8.1.4 Distribution Avoided Cost Allocators

The avoided distribution costs are allocated to hours of the year based on substation load shapes provided by the IOUs.[35] These shapes are converted to TMY shapes. The peak capacity allocation factor (PCAF) assigns higher value to those hours when the substation loads are highest. All loads within one standard deviation of the station peak load are allocated distribution capacity values, with the peak hour receiving the highest allocation, and the loads near the one standard deviation threshold receiving near zero allocation.

PCAF[s][h] = (Load[s][h] – Threshold[s])/Sum[h](Load[s][h] – Threshold[s])

Where

PCAF[s][h] = peak capacity allocation factor for substation s, hour h.
Load[s][h] = the hourly substation load
Threshold[s] = substation peak load – one standard deviation of substation loads over the year
Sum[h] indicates the summation of all hourly load increments above the threshold
All hours where Load[s][h] are below Threshold[s] are excluded from the calculation.

C-8.2 TRANSMISSION AVOIDED COSTS

Transmission avoided costs are for subtransmission or area transmission assets "downstream" of the CAISO. The costs are from the California Energy Commission's *2013 Time Dependent Valuation of Energy for Development of Building Efficiency Standards* and the CPUC's valuation of Demand Response (DR) in 2010, and have not been re-estimated herein. The sources of the transmission avoided costs are summarized below. The 2011 Transmission Avoided Costs are shown in 2011 dollars.

- PG&E's avoided cost is from PG&E's 2011 GRC Phase II Proceeding, A.10-03-014, Exhibit (PG&E-2), p. 4-3.
- SCE's avoided cost is from the spreadsheet SCE provided to E3 for the DER proceeding. That spreadsheet is *TD Avoided Costs (march 2008)_v2.xls*. Note that SCE's recommended value in that spreadsheet was adjusted to reflect SCE's position on the benefits provided by DR. To be consistent with avoided costs used for ratemaking and energy efficiency evaluation, E3 restored the General Plant Loaders and O&M costs removed from SCE's DR-specific values. E3 used SCE's General Plant Loading Factor of 5.9% (on capital) and a fixed O&M cost of $16.52/kW-yr. To adjust for inflation, E3 used SCE's escalation factors to convert the values to 2011 dollars. The escalation factors are shown in the figure below.
- SDG&E stated that their transmission investments are at the CAISO grid level, and that SDG&E does not have subtransmission investments for inclusion herein. Accordingly, the SDG&E value for subtransmssion or area transmission is zero.

[35] In the avoided cost spreadsheet distributed with the NEM analysis, allocators are calculated by climate zone instead of individual substation load. The same methodology detailed here for individual substation loads is also applied to the aggregated climate zone loads. T&D avoided costs provided for the NEM report are not included in the updated avoided cost spreadsheet tool.

Table 12: Transmission Avoided Costs ($/kW-yr)

IOU	2011 Avoided Costs
PG&E	19.9
SCE	23.39
SDG&E	0

C-8.2.1 Transmission Avoided Cost Allocators

Like the cost of generation capacity, the avoided cost of transmission capacity is allocated over a limited number of hours in the year in which the transmission system would be likely to experience constraints. For the NEM analysis, the transmission avoided costs are allocated 50% based on system peak demands and 50% based on distribution substation demands.

Figure 24: 2010 T&D Allocation Factors

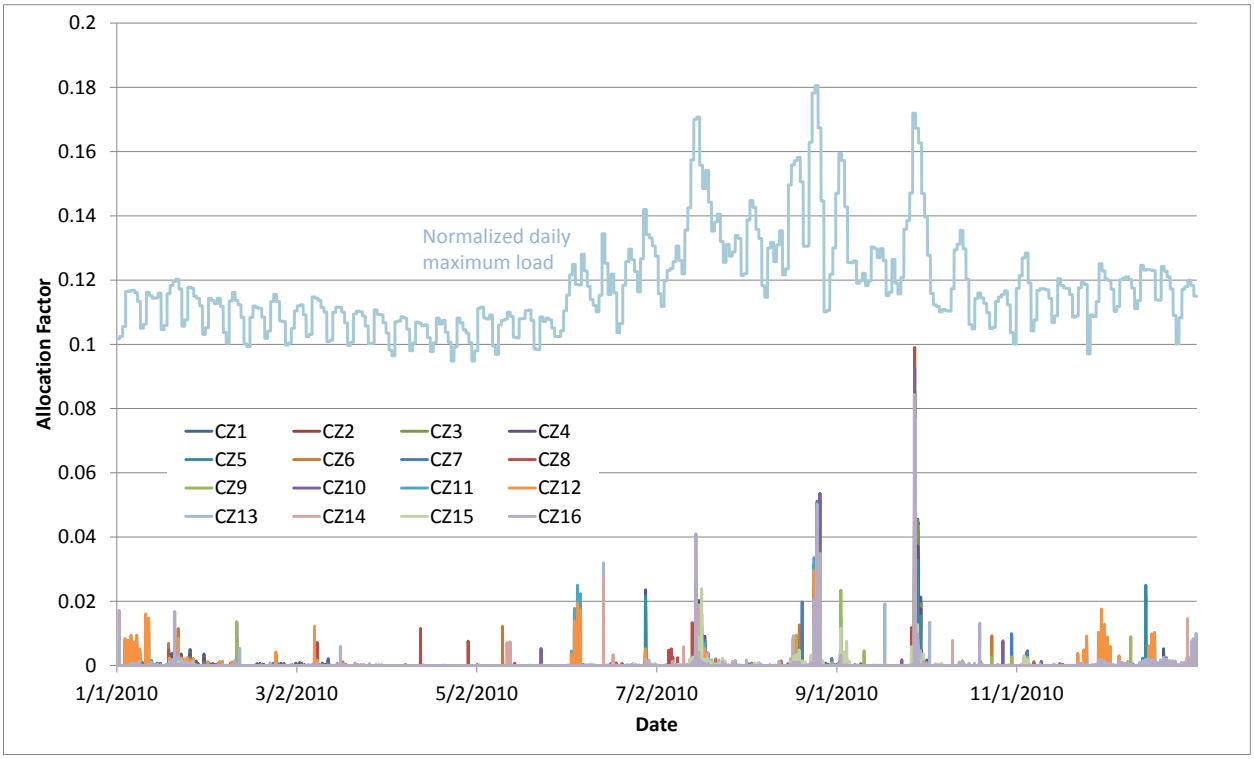
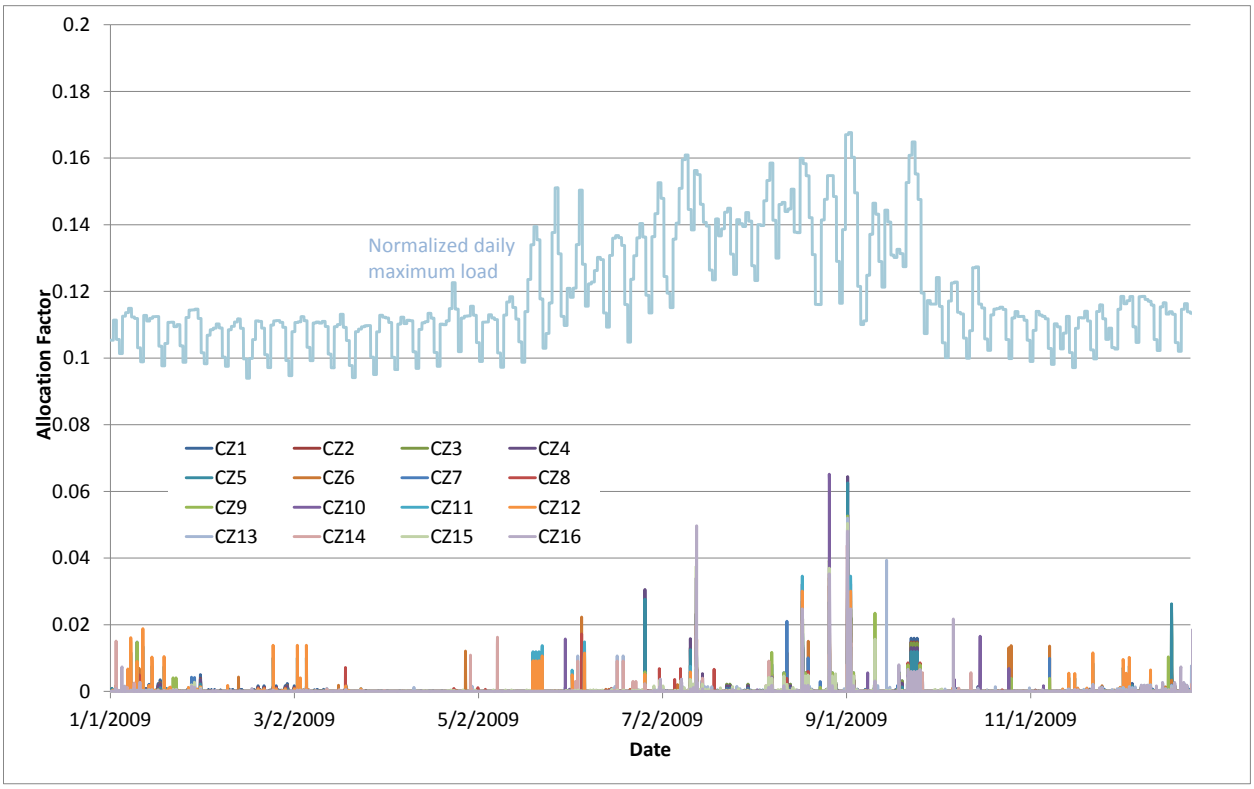


Figure 25: TMY T&D Allocation Factors



C-8.2.2 T&D Capacity Loss Factors

The avoided cost of capacity is increased to account for losses. The capacity 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 13).

Table 13: Capacity Loss Factors

	PG&E	SCE	SDG&E
Distribution	See below	1.022	1.043
Transmission	See below	1.054	1.071
Generation	1.109	1.084	1.081

PG&E's loss factors are from their 2011 GRC Application, and vary by Division. Those loss factors are shown below.

Table 14: PG&E T&D Loss Factors

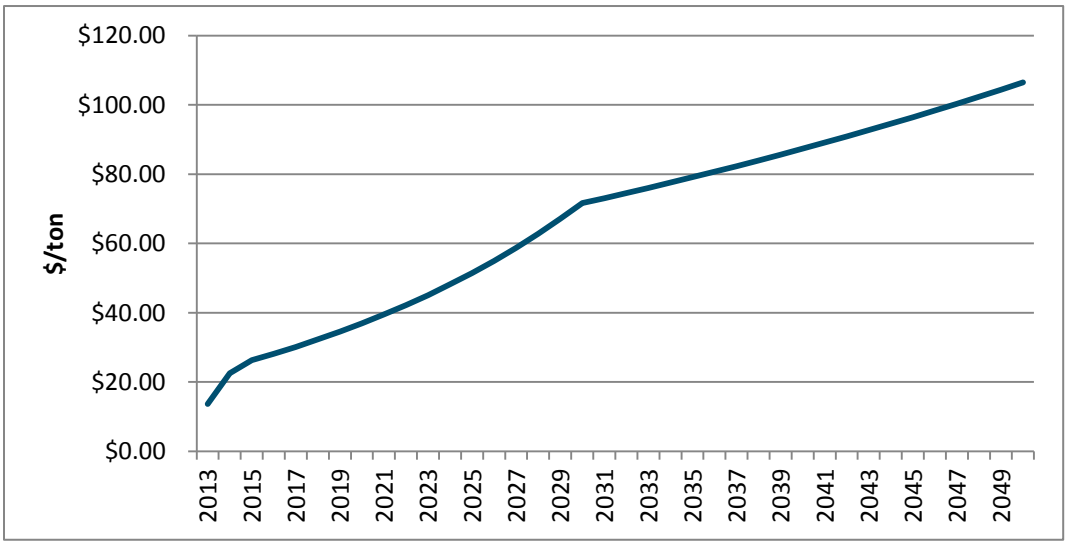
DIVISION	Mtr to Trans	Mtr to Primary	Mtr to Secondary
CENTRAL COAST	1.053	1.019	1.000
DE ANZA	1.050	1.019	1.000
DIABLO	1.045	1.020	1.000
EAST BAY	1.042	1.020	1.000
FRESNO	1.076	1.020	1.000
KERN	1.065	1.023	1.000
LOS PADRES	1.060	1.019	1.000
MISSION	1.047	1.019	1.000
NORTH BAY	1.053	1.019	1.000
NORTH COAST	1.060	1.019	1.000
NORTH VALLEY	1.073	1.021	1.000
PENINSULA	1.050	1.019	1.000
SACRAMENTO	1.052	1.019	1.000
SAN FRANCISCO	1.045	1.020	1.000
SAN JOSE	1.052	1.018	1.000
SIERRA	1.054	1.020	1.000
STOCKTON	1.066	1.019	1.000
YOSEMITE	1.067	1.019	1.000

C-9 Avoided Cost of Emissions

The avoided costs explicitly track the estimated value of avoided CO2 emissions. The avoided costs are the cap and trade costs of CO2 compliance that are embedded in the energy market. The avoided costs of CO2 emissions are intended for use in TRC, or PAC analyses. Other CO2-related costs such as damage or health impacts are not included in the avoided costs produced herein. Costs related to PM-10 and NOx emission compliance are embedded in the cost of new generation (through permitting and offset purchases, etc.) and are not tracked separately. Also, health impacts of PM-2.5 are not included in these avoided costs that are focused on direct costs for use in TRC and PAC evaluations.

E3 bases the avoided cost of CO2 emissions on the results of the February 2013 CARB GHG auction for 2013 vintage allowances.[36] To project future market prices of CO2, E3 applies the CPUC MPR emissions cost forecast which calculates the implicit cost of carbon emissions through an analysis of California energy market forwards.[37]

Figure 26: The CO2 Price Series Embedded in the Avoided Cost Values (Nominal $)



As discussed in section *Annual Average Cost of Energy*, these CO2 costs are converted into an implied Carbon Price ($/MWh) based on the annual average market heat rate for each corresponding year. The implied Carbon Price is then subtracted from the annual energy cost forecast to prevent double counting.

[36] See http://www.arb.ca.gov/cc/capandtrade/auction/february_2013/auction2_feb2013_summary_results_report.pdf.

[37] See http://www.ethree.com/documents/2011_MPR_Public_E4442.xlsm.

C-9.1 HOURLY AVOIDED EMISSION COSTS

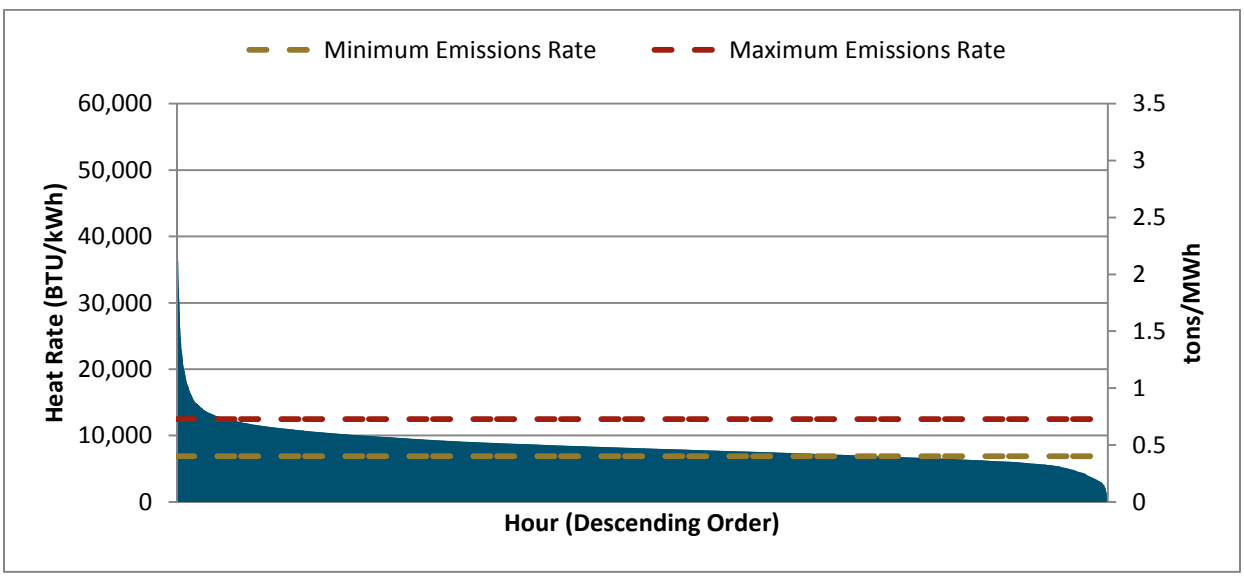
E3 constructs the hourly avoided emission costs from the day-ahead market price curve. Given the assumption that natural gas is the marginal fuel in all hours, the link between higher market prices and higher emissions rates is intuitive: higher market prices enable lower-efficiency generators to operate, 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 15; the hourly emissions rates derived from this process are shown in Figure 27.

Table 15: 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 27: Hourly Emissions Rates Derived from Market Prices (Hourly Values Shown in Descending Order)



Once the bounded implied market heat rates are determined, E3 calculates the hourly avoided emission costs using the formula below.

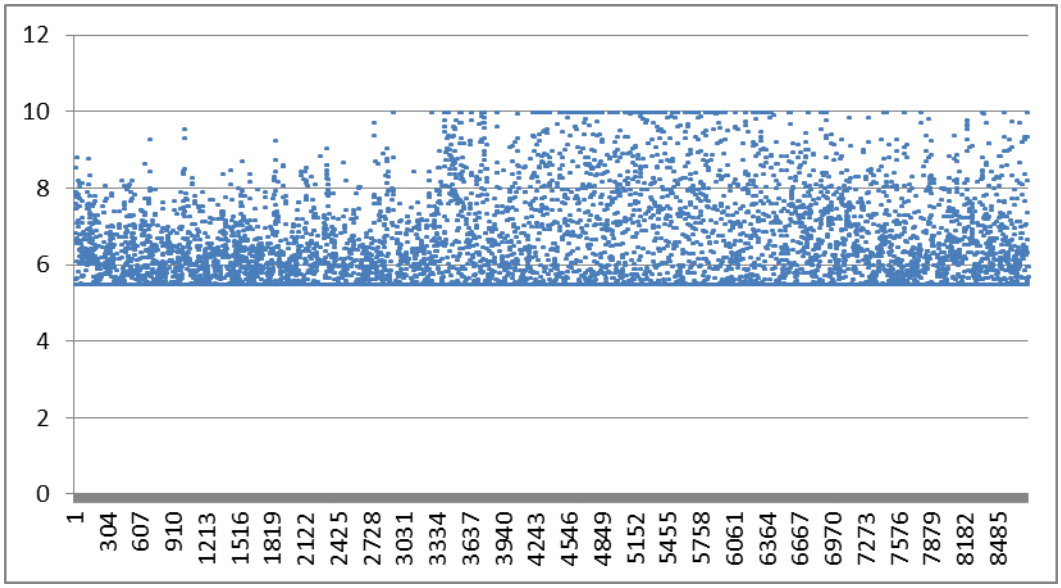
The hourly avoided emission cost formula is shown below.

$$CO2Cost_{y,h} = CO2Cost_{y} * HeatRate_{y,h} \text{ st boundaries} * CO2Content / 1000$$

Where

$CO2Cost_{y,h}$	=	Hourly CO2 cost in hour h and year y ($/MWh)
$CO2Cost_y$	=	CO2 Cost in year y ($/ton)
$HeatRate_{y,h}$	=	Implied market heat rate for hour h in year y, subject to a minimum of 6900 and a maximum of 12500 (Btu/kWh)
CO2Content	=	Natural gas CO2 content (.0585 tons per MMBTU)
1000	=	Factor to convert results to $/MWh

Figure 28: Constrained Market Heat Rates (000 BTUs/kWh)



C-10 Avoided Renewable Purchases

An addition benefit of electricity usage reduction is the avoided cost of 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 basic formula used to calculate the avoided cost of energy is the following:

EQ 5. $\text{RPS Adder}_y = \text{RPS Premium}_y * \text{Compliance Obligation}_y$

RPS Premium_y = Annual above-market costs of renewable generation

$\text{Compliance Obligation}_y$ = Annual % of retail sales required to be met with renewable generation

The RPS Adder captures the value that a reduction in load brings to ratepayers through a reduction in required procurement to comply with the state's Renewable Portfolio Standard. Because the state's current RPS policy requires each utility procure renewable generation equivalent to 33% of its retail sales in 2020, each 1 MWh reduction in load in 2020 reduces a utility's compliance obligation by 0.33

MWh. This reduction in a utility's compliance obligation translates directly to a ratepayer benefit through a reduction in the above-market cost of resources used to serve load.

The first step to calculate the RPS Adder is to evaluate the RPS Premium, a measure of the above-market cost of the assumed marginal renewable resource. The RPS Premium is a function of assumed PPA cost of the marginal resource as well as the incremental costs of transmission and integration and the energy, capacity, and emissions reduction value provided by that resource:

Figure 29. Components of the RPS Premium

	PPA Price
+	Incremental Transmission Cost
+	Integration Cost
-	Energy Value_y
-	Emissions Value_y
-	Capacity Value_y
=	RPS Premium_y

For this analysis, E3 has assumed that the marginal renewable resource is solar PV, the resource with the highest net cost that utilities are currently procuring in large quantities. Data sources and calculation methodologies for each of the components of the RPS Premium are:

- The **PPA Price** of the marginal renewable resource is based on the CPUC's 2012 *Padilla Report to the Legislature: The Cost of Renewables in Compliance with Senate Bill 836.*[38] The marginal cost for 2012 is based on the average cost of all solar PV projects approved in 2012 ($98/MWh). This average cost is assumed to decline over time due to technological learning but increases sharply in 2017 due to the sunset of the ITC. The trend of assumed PV prices over time is based on a review of technology capital costs that E3 completed as an input to WECC's 10- and 20-year transmission planning studies.[39]
- The **Incremental Transmission Cost** associated with the marginal resource is assumed to be $54/kW-yr.[40] This is based on the standardized planning assumption used by the CPUC as an input to its 2010 LTPP. This cost is converted to a $/MWh basis assuming a 27% capacity factor.

[38] See http://www.cpuc.ca.gov/NR/rdonlyres/F0F6E15A-6A04-41C3-ACBA-8C13726FB5CB/0/PadillaReport2012Final.pdf

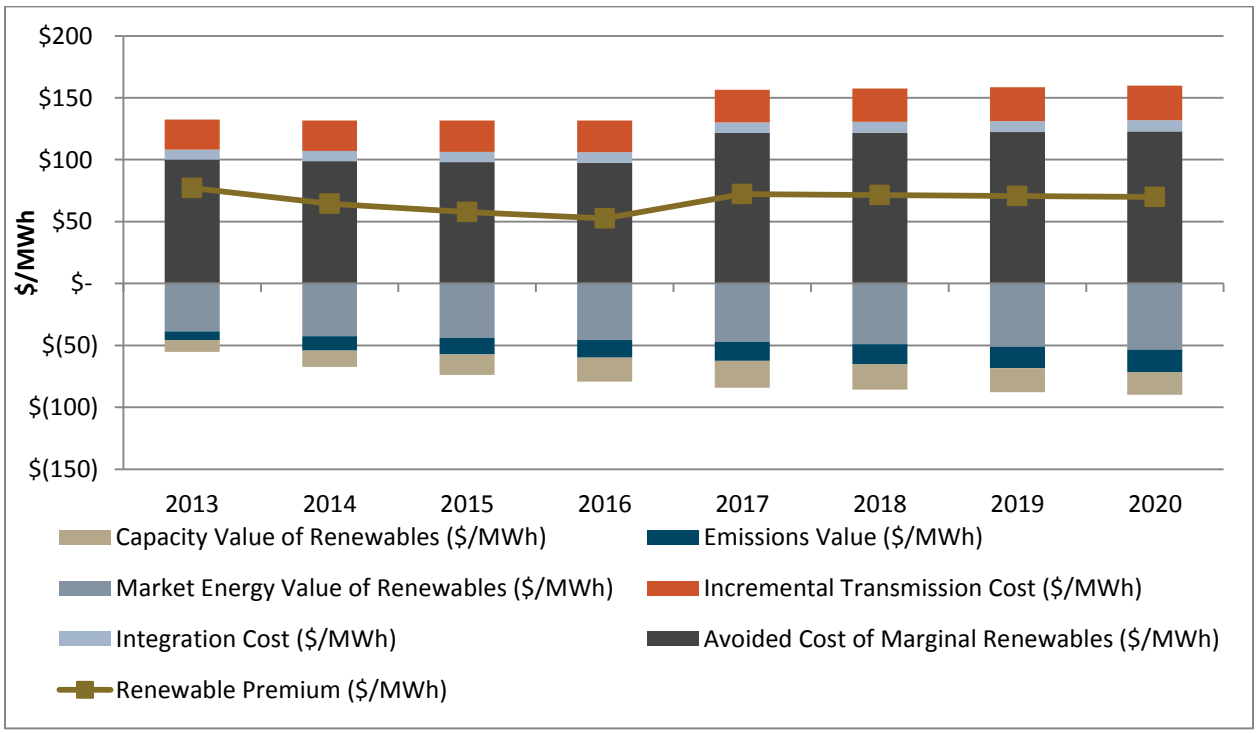
[39] See http://www.wecc.biz/committees/BOD/TEPPC/TAS/121012/Lists/Minutes/1/%20121005_GenCapCostReport_finaldraft.pdf

[40] See http://docs.cpuc.ca.gov/efile/RULC/127544.pdf

- The **Integration Cost** is assumed to be $7.50/MWh for solar PV, reflecting the increased costs of carrying reserves to balance the intermittency of central station solar PV output.[41]
- The **Energy Value** associated with solar PV is calculated endogenously in the avoided cost model based on an assumed hourly PV production profile and the hourly cost of energy in each year.
- The **Emissions Value** is calculated endogenously based on the same PV production profile used to determine the energy value, hourly marginal emissions rates, and the annual cost of carbon.
- The **Capacity Value** is determined based on an assumed marginal ELCC and the endogenous capacity value determined by the avoided cost model. The marginal ELCC is assumed to decline from 53% to 40% between 2013 and 2020 reflecting increasing solar penetrations as the state approaches 33%; thereafter, the marginal ELCC is assumed to remain constant as the compliance requirement remains at 33%.

The magnitude of each of these components and the resulting RPS premium are summarized in Figure 30.

Figure 30: Annual Formulation of the RPS Premium

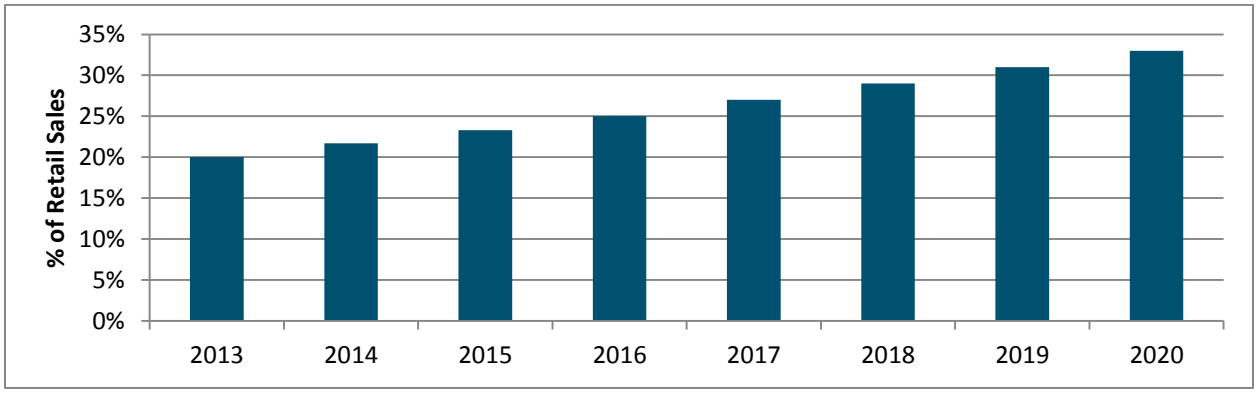


The RPS Adder is calculated by multiplying the RPS Premium by the statutory compliance obligation for the specified year. Current policy requires that utilities meet an RPS target that increases from 20% in 2011 to 33% by 2020. After 2020, E3 assumes that the compliance obligation remains at 33% of retail

[41] Ibid.

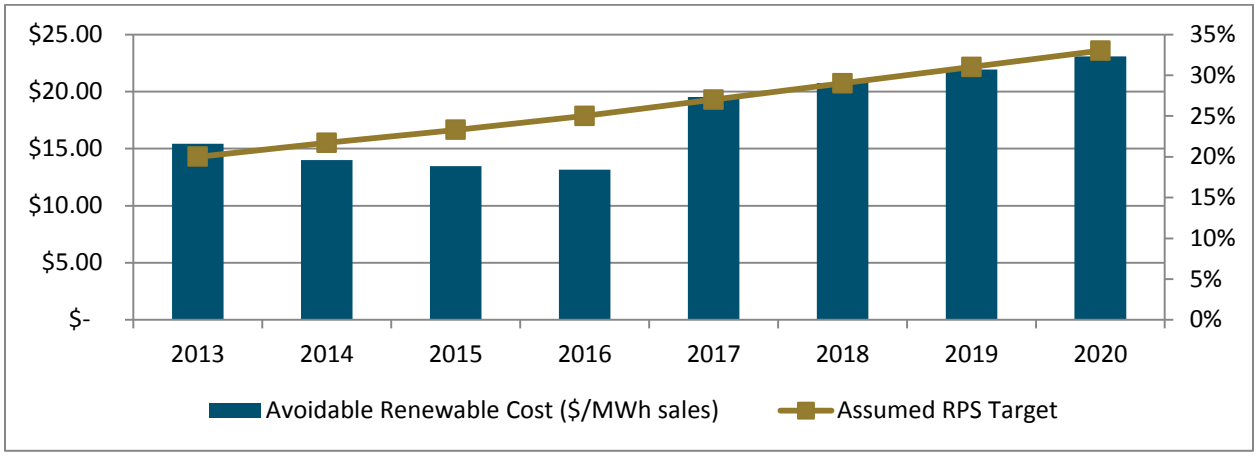
sales. For years before 2020, this compliance obligation is less than 33%. The schedule of interim compliance targets is shown below in Figure 31. The annual RPS Adder resulting from this calculation is shown in Figure 32.

Figure 31: Interim RPS Compliance Targets



CPUC Procurement Targets[42]

Figure 32: RPS Adder Calculated Based on the RPS Premium



[42] See http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33RPSProcurementRules.htm

APPENDIX D:

FULL COST OF SERVICE

October 28, 2013

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1 Full Cost of Service Approach

1.1 Introduction

The full cost of service analysis compares how much net energy metering (NEM) customers are *actually* paying (i.e. their total bills) to how much they *would* be paying (i.e. their full cost of service) based on their use of the grid and an allocation of fixed costs. The full cost of service analysis differs from the avoided cost approach in two fundamental ways:

1) The avoided cost approach evaluates the *change* in usage due to renewable generation, whereas the full cost approach evaluates *total usage net* of the renewable generation.

2) The avoided cost approach looks at changes in future costs, whereas the full cost approach includes fixed and historical utility costs.

1.1.1 METHODOLOGY FOR FULL COST OF SERVICE CALCULATION

To understand full cost of service, it is useful to begin with an overview of the investor-owned utility (IOU)[1] ratemaking process as it is filed through General Rate Case (GRC) proceedings at the CPUC. The ratemaking process starts with a calculation of the revenue requirement (Phase 1), which is the total amount of

[1] The IOUs include Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas and Electric (SDG&E)

money that the utility is authorized to collect from customers. Phase 2 is the cost of service and revenue allocation process, which determines how much of the revenue requirement should be borne by each customer group based on the costs that each group imposes on the utility. Finally, the utility determines how to collect each customer group's allocated revenue using energy, demand, and customer charges, and files these retail rates with the CPUC. The actual tariff rates that customers see on their bill are adopted through a rate hearing process held before a CPUC Administrative Law Judge that involves various ratepayer advocate and industry groups. Often, many or all issues are negotiated and agreed to by the parties through a settlement process. For various reasons, the tariff rates do not perfectly match how customers impose costs on the utility. Therefore, tariff rates are not an appropriate indicator of the 'full cost of service.'

In order to estimate the utility 'full cost of service' we emulate to the degree possible each utilities revenue allocation (Phase 2) from their most recent GRC. We believe this provides a transparent and appropriate approach for calculating the full cost of service. Our rationale is that the utility revenue allocation process has long been the method used to determine cost-based revenue targets. By treating each NEM account as if it were its own customer group in the revenue allocation process, we can estimate account-specific full cost of service values that allow for the evaluation of subgroups within the NEM population.

Not all costs are assigned to utility customers through the revenue allocation process. Examples include Public Purpose Program and Nuclear Decomissioning charges. We add these charges to each NEM account along with estimates of additional costs that are unique to NEM interconnection and billing.

Since the full cost of service values would be compared to bills under the 2011 tariffs, we strove to make the two as comparable as possible as we applied the utility cost of service and revenue allocation methodologies. However, there are differences between our cost of service methods and those of the utilities that will likely result in discrepancies between the full cost of service values and the bills used in this analysis.[2] Another caution noted above is that, while the utilities file retail rates based on the cost of service in their GRC, the final rates are adopted through a settlement process, in which rates are often adjusted based on input from ratepayer and industry groups. This can introduce further deviations between cost of service and bills. Ideally, we would have calibrated the full cost of service results using the entire utility customer population. However, project scope budget and timelines did not allow for such work at this time. This is certainly an area where further work could be pursued with the utilities to refine results. Despite these limitations, we believe that the full cost of service estimates and 2011 rates are sufficiently comparable to support the findings outlined in this section.

1.2 Full Cost of Service Calculation Approach

The full cost of service is composed of GRC cost-based components, unallocated regulatory items, and incremental utility costs. The marginal cost based components are determined through utility GRC ratemaking proceedings and

[2] For example, we use 2011 usage and generation patterns to determine an account's full cost of service, whereas each utility uses a different year, or combination of years, in performing their own cost of service and rate design. Also, SCE uses a complex circuit-specific analysis for their cost of service analysis that they needed to simplify and approximate for our NEM analysis.

comprise the bulk of the full cost of service. Regulatory costs are items that are added to customer bills, but are not included in the GRC process. These regulatory cost items are generally assigned to customers on an equal cents per kWh basis, and we assume those tariff rates are equal to their cost of service. Finally, the incremental utility costs are unique to NEM accounts, and we add those to the full cost of service for each NEM account. Each of these components is discussed in more detail below.

1.2.1 MARGINAL COST-BASED COMPONENTS

The marginal cost-based components are the revenue requirements that each customer or customer group would be assigned as part of the utility GRC ratemaking process. We estimate the marginal cost-based components for each NEM account as the total annual bill that each account would receive if the account were treated as its own customer group in the utility revenue allocation process.[3] This method provides maximum flexibility and disaggregation for evaluating the full cost of service for NEM accounts. While this method is highly precise in calculating customer-specific full cost of service estimates, the estimates are only indicative of what an individual customer might have received in utility ratemaking proceeding. Some limitations of the full cost of service estimates are listed below.

- The full cost of service analysis is based on 2011 data, whereas utility filings use multiple years of data and perform weather normalizations.

[3] For PG&E and SDG&E, each account is analogous to its own customer class; for SCE each customer group is analogous to its own rate sub-schedule within the larger SCE rate schedule. This subtle difference exists because the EPMC factors provided by SCE vary by rate schedule, whereas the EPMC factors provided by PG&E and SDG&E only vary by function.

- The full cost of service estimates for an individual customer may be abnormally high or low because of vagaries in their 2011 usage. Utility full cost of service is conducted at a more aggregate level that may temper such variations.
- The full cost of service analysis relies upon utility customer cost information, which is averaged at the class or rate schedule level and masks individual variations in customer costs. For residential accounts, in particular, the predominance of single family detached dwellings (as opposed to apartments) among NEM accounts, likely results in an underestimate of the customer costs for the NEM accounts.
- Utility ratemaking would likely result in more uniform full cost of service within a customer class because utilities develop costs using aggregated loads.
- SCE's distribution capacity cost allocators for this full cost of service analysis are, by necessity, a stylized version of the allocation factors that SCE uses in their ratemaking filings.

In general terms, the marginal cost components for the full cost of service study are listed in the table below.

Table 1: Full Cost of Service Marginal Cost Components

Marginal Cost Category	PG&E	SCE	SDG&E
Generation Energy	2011 GRC	2009 GRC	2012 GRC
Generation Capacity	2011 GRC	2009 GRC	2012 GRC
Transmission	Tariff Pass Through	FERC Docket No. ER11-3697	Tariff Pass Through
Subtransmission		2009 GRC	
Distribution		2009 GRC	2012 GRC
Primary Distribution	2011 GRC		
Primary New Business	2011 GRC		
Secondary	2011 GRC		
Customer	2011 GRC	2009 GRC	2012 GRC

In the case of transmission costs, tariff charges were used as stand-ins for PG&E and SDG&E because neither utility includes transmission in their revenue allocation process. For SCE, we used the transmission capacity cost from their FERC proceeding to allow the use of SCE's recommended "12 CP" method.

As indicated in Table 1, the marginal cost categories that each utility uses vary substantially. Moreover, the form of the marginal costs and how these costs are attributed to customers varies even more widely. Table 2 lists the marginal cost determinant method by component for each utility.

Table 2: Full Cost of Service Marginal Cost Determinant Methods

Marginal Cost Category	PG&E	SCE	SDG&E
Generation Energy	Hourly	Hourly	Monthly Weekday and Weekend Day types
Generation Capacity	Hourly factors	Top 100 system hours	Hourly factors based on peak system loads
Transmission	Tariff Pass Through	12 Monthly Coincident Peaks	Tariff Pass Through
Subtransmission		Circuit-based hourly factors for Res and Non-Res. Plus separate $/customer component	
Distribution		Circuit-based hourly allocation factors for Res and Non-Res.	Maximum Demand
Primary Distribution	Hourly allocation factors by Division		
Primary New Business	Maximum Demand		
Secondary	Maximum Demand		
Customer	$ per Customer	$ per Customer	$ per Customer

1.2.2 REGULATORY ITEMS

The rates of each utility also include regulatory-related costs and fees that are not included in the revenue allocation process. These costs are calculated using the 2011 tariff rates and net loads, and the values are included in the bill *and* full cost of service calculations. Bill components vary slightly for each IOU, and are listed below

Utility	Bill Components added to Full Cost of Service
PG&E	• Nuclear Decommissioning Charge (NGC), • Public Purpose Programs (PPP) rates, • Ongoing Competition Transition (CTC), • New System Generation Charge (NSGC), • Energy Cost Recovery Amount, • Department of Water Resources (DWR) Bond Charge, • Transmission.
SCE	• Transmission Non-Bypassable, • Distribution Non-Bypassable, • NSGC, • NGC, • PPP Charge, • DWR Bond Charge, • PUC Reimbursement Fee (PUCFR).
SDG&E	• Public Purpose Programs (PPP), • Nuclear Decommissioning (ND), • Ongoing Competition Transition (CTC), • Reliability Services (RS), • Total Rate Adjustment Component (TRAC), • DWR Bond Charge, Transmission.

The installation of renewable generation imposes additional capital and ongoing costs onto the utility that are not paid for by the renewable generation owner. These additional costs are added to the full cost of service estimate for each account. See Appendix C for a discussion of these costs.

The full specification for calculating the full cost of service for each utility is presented in the remainder of this Appendix.

2 Pacific Gas & Electric (PG&E) Full Cost of Service

The full cost of service for PG&E accounts is based on the marginal cost and revenue requirements from PG&E's 2011 GRC. The formulas and data inputs are described below.

FullCost = Cost[E]*EPMC[E] + Cost[G]*EPMC[G] + Cost[T]*EPMC[T] +Cost[D]*EPMC[D] + Cust*EPMC[C] + RegItems[] + IncrCost[]

Where

Cost[E] = 2011 marginal energy cost for the account.

Cost[G] = 2011 marginal generation capacity cost for the account.

Cost[T] = 2011 transmission tariff, treated like regulatory item.

Cost[D] = 2011 marginal primary and secondary (if applicable) cost for the account.

Cust = 2011 marginal customer cost for the account.

EPMC[] = Factors to scale the respective marginal costs to full embedded cost revenue responsibility levels. Acronym stands for Equal Percent of Marginal Cost.

Regitems[] = Costs for regulatory items not included in the marginal cost-based revenue allocation process. Those items for PG&E are comprised of the following components from each account's bill (using net load):

1) Nuclear Decommissioning
2) PPP rates
3) CTC
4) NSGC (New System Generation Charge)
5) Energy Cost Recovery Amount
6) DWR Bond

IncrCost[] = Incremental costs borne by the utility to connect and serve NEM customers. Composed of amortized initial setup and interconnection costs plus annual metering and grid interconnection cost increases. See the avoided cost section for further discussion of these costs.

2.1 PG&E Marginal Energy Cost

Cost[E] = MktPrice[V][h] * Load[h]

Where

MktPrice[V][h]	=	Hourly market price of energy adjusted for losses in delivering to service voltage V. Generation system allocation factors provided for 2011 in *DistributedGenerationV_DR_ED_003-Q01_5th-addendum_Attach-1.xls*, Table 2—marginal energy cost tab, columns D and E.
Load[h]	=	Account demand at the meter in hour h. Net Load.

2.2 PG&E Generation Capacity Costs

PG&E's estimate of marginal generation costs is based on a six year average of the going forward cost of an existing CCGT unit for 2011-2013 and the total cost less market revenues of a new CCGT in 2014-2016.

Cost[G] = CapCost[G] * Alloc[G][h] * Load[h] * LossFctr[G][V]

where

CapCost[G]	=	PG&E marginal cost of generation capacity. Real levelized value, delivered to transmission.
Alloc[G][h]	=	Hourly allocation factor for generation (G) at hour h. Generation system allocation factors provided for 2011 in *DistributedGenerationV_DR_ED_003-Q01_5th-addendum_Attach-3.xls*, Summary tab.
Load[h]	=	Account demand at the meter in hour h. Net load.
LossFctr[G][V]	=	Peak demand loss factor from transmission system to the meter served at voltage level V. Loss Factor for Primary voltage accounts . Loss Factor for Secondary voltage accounts.

2.3 PG&E Transmission Capacity Costs

PG&E's transmission tariff rates are used to represent the full cost of service for each account. This use of transmission tariffs, rather than marginal costs and a

marginal cost scaling factor, was recommended by a PG&E rates expert due to: 1) the lack of a marginal cost scaling factor for transmission, and 2) the fact that the evolution of the revenue allocation and rate design process have minimized the need for the PG&E to calculate transmission marginal costs. Net account loads are used for the utility case, and gross loads are used for the high cost case.

2.4 PG&E Distribution Capacity Costs

PG&E provided distribution capacity costs in three categories: Primary, New Business Primary, and Secondary. All costs are by the 18 PG&E Divisions.[4] Accounts served at primary voltage are assigned Primary and New Business Primary costs. Accounts served at secondary voltage are assigned Primary, New Business Primary, and Secondary costs. The formulas for calculating the distribution marginal cost for an account are shown below.

Cost[D] = Cost[P] + Cost[NB-P] + Cost[S]

Where

Cost[P]	=	Primary marginal cost for the account.
Cost[NB-P]	=	New Business Primary marginal cost for the account.
Cost[S]	=	Secondary marginal cost, which is zero for accounts taking service at primary or higher service voltages.

[4] From PG&E January 7, 2011 Update in its 2011 GRC Phase 2 proceeding.

Cost[P] = CapCost[P] * Alloc[P][h] * Load[][h] * LossFctr[P][V]

Where

Cost[P] = Primary marginal cost.

CapCost[P] = PG&E primary marginal cost of distribution capacity (see Table 3).

Alloc[P][h] = Hourly allocation factor for primary distribution (P) at hour h. Primary distribution allocation factors provided by Division in *DistributedGenerationV_DR_ED_003-Q01_5th-addendum_Attach-5.xls,* Summary tab. We normalize the factors from the Summary tab so they sum to 1.0 for each division.

Load[h] = Account demand at the meter in hour h. The analysis is done for two scenarios: 1) net loads and 2) gross loads.

LossFctr[P][V] = Loss factor from the meter to the primary distribution system (see Table 4).

Cost[NB-P] = CapCost[NB-P] * MaxDmd[]* LossFctr[P][V]

Where

CapCost[NB-P] = PG&E new business primary marginal cost of distribution capacity (see Table 3).

MaxDmd[]	=	Maximum annual demand for the account. The analysis is done for two scenarios: 1) net loads and 2) gross loads.
LossFctr[P][V]	=	Loss factor from the meter to the primary distribution system (see Table 4).

Cost[S] = CapCost[S] * MaxDmd[Gr]* LossFctr[S][V]

Where

CapCost[S]	=	PG&E Secondary marginal cost of distribution capacity (see Table 3).
MaxDmd[Gr]	=	Maximum annual gross demand for the account. Load is reconstituted to the level it would have been absent the distributed generation, ceteris paribus.
LossFctr[S][V]	=	Loss factor from the secondary meter to the secondary system (see Table 4).

Account demand for Primary costs is calculated using substation Peak Capacity Allocation Factors (PCAFs). Demand for the New Business Primary and Secondary costs are based on each account's maximum demand. The New Business Primary and Secondary costs are also differentiated by 1) residential, 2) small commercial, and 3) all others. The reason for the differentiation is that those costs are largely driven by customer demand at the final line transformer. Residential and small commercial customers generally share final line transformers, so there is some diversity of demand on the final line transformers serving those accounts. The lower avoided costs per kW of

maximum demand for the residential and small commercial classes reflect that diversity.

Table 3: PG&E Primary Distribution Capacity Cost

	Primary Distribution				Secondary Dist (S Volt only)		
	Applies to all	New Business Primary One of three categories applies			One of three categories applies		
Division	Primary ($/PCAF kW-yr)	NB Primary - Non-Res, Non-Sml ($/Max kW-yr)	NB Primary - Res ($/Max kW-yr)	NB Primary - Small Com ($/Max kW-yr)	Non-Res, Non-Sml ($/Max kW-yr)	Res ($/Max kW-yr)	Small Com ($/Max kW-yr)
Central Coast	$80.22	$13.20	$6.27	$10.10	$1.85	$0.88	$1.42
De Anza	$32.53	$6.35	$3.02	$4.86	$0.51	$0.24	$0.39
Diablo	$80.27	$12.20	$5.42	$9.05	$1.00	$0.44	$0.74
East Bay	$41.15	$15.44	$6.86	$11.46	$0.80	$0.36	$0.59
Fresno	$58.09	$7.86	$4.98	$6.61	$0.61	$0.39	$0.51
Kern	$47.72	$7.38	$4.68	$6.21	$0.66	$0.42	$0.56
Los Padres	$94.39	$13.17	$6.26	$10.08	$0.70	$0.33	$0.54
Mission	$40.62	$14.24	$6.32	$10.57	$0.69	$0.31	$0.51
North Bay	$66.52	$18.25	$10.17	$15.09	$0.70	$0.39	$0.58
North Coast	$60.84	$15.45	$8.61	$12.78	$0.84	$0.47	$0.69
North Valley	$49.24	$15.35	$8.55	$12.69	$0.61	$0.34	$0.50
Peninsula	$54.16	$5.82	$2.58	$4.32	$0.83	$0.37	$0.62
Sacramento	$59.20	$10.23	$5.70	$8.46	$0.63	$0.35	$0.52
San Francisco	$23.32	$7.92	$3.52	$5.88	$0.39	$0.17	$0.29
San Jose	$50.66	$8.21	$3.90	$6.28	$0.64	$0.30	$0.49
Sierra	$77.22	$11.22	$6.25	$9.28	$1.52	$0.85	$1.26
Stockton	$47.94	$10.35	$6.56	$8.70	$0.55	$0.35	$0.46
Yosemite	$55.50	$11.67	$7.40	$9.81	$0.91	$0.58	$0.77

Source: PG&E January 7, 2011 Update in 2011 GRC Phase 2. Costs do not include losses. Max = Annual maximum demand at the account level

North Coast Division was subsequently divided into the new Humboldt and Sonoma Divisions

Table 4: PG&E Distribution Loss Factors

Division	Primary Cost Primary Meter	Primary Cost Secondary Meter	Secondary Cost Secondary Meter
Central Coast	1.03	1.05	1.02
De Anza	1.03	1.05	1.02
Diablo	1.03	1.05	1.02
East Bay	1.02	1.04	1.02
Fresno	1.06	1.08	1.02
Kern	1.04	1.07	1.03
Los Padres	1.04	1.06	1.02
Mission	1.03	1.05	1.02
North Bay	1.03	1.05	1.02
North Coast	1.04	1.06	1.02
North Valley	1.05	1.07	1.02
Peninsula	1.03	1.05	1.02
Sacramento	1.03	1.05	1.02
San Francisco	1.03	1.05	1.02
San Jose	1.03	1.05	1.02
Sierra	1.03	1.05	1.02
Stockton	1.05	1.07	1.02
Yosemite	1.05	1.07	1.02

Loss factors from PG&E 2011 GRC Phase 2 (PG&E-15), WP 6-70. Secondary Cost-Secondary meter loss factor = Secondary Cost Loss Factor / Primary Cost Loss Factor

Table 5: PG&E Marginal Customer Costs ($ per customer-year)

Line No.	Customer Class	Subclass or Rate Schedule	Values
1	Residential		$ 91.72
2	Agricultural Small Ag.	Small Ag.	$ 505.69
3		Large Ag.	$ 822.68
4	Small Commercial		$ 397.37
5	Medium Commercial	A10-S	$ 962.37
6		A10-P	$ 1,642.34
7	Large Light & Power	E19-S	$ 9,251.70
8		E19-P	$ 10,077.26
9		E19-T	$ 16,023.11
10		E20-S	$ 10,139.85
11		E20-P	$ 11,921.28
12		E20-T	$ 23,991.51
13	Streetlights		$ 139.06

Source: January 7, 2011 Update in 2011 GRC Phase 2.

Table 6: PG&E Equal Percent of Marginal Cost (EPMC) Factors

Marginal Cost	EPMC Factor
Energy [E]	0.9623
Generation Capacity [G]	0.9623
Transmission [T]	n/a
Primary [D]	1.4119
New Business Primary and Secondary [D]	1.4119
Customer Cost [C]	1.4119

EPMC factors are from PG&E's January 7, 2011, Update in its 2011 GRC Phase 2 proceeding. Separate marginal cost revenue was not determined for transmission and is not available.

3 Southern California Edison (SCE) Full Cost of Service

The full cost of service for SCE accounts is based on the 2009 GRC marginal cost and 2011 Energy Resource Recovery Account (ERRA) revenue requirements. The formulas and data inputs are described below.

FullCost = Cost[E]*EPMC[E][S] + Cost[G]*EPMC[G][S]]+Cost[T]*EPMC[T][S] +Cost[ST]*EPMC[ST][S] +Cost[D]*EPMC[D][S] + Cust*EPMC[C][S] + RegItems[]+ IncrCost[]

Where

Cost[E] = 2009 marginal energy cost for the account.

Cost[G] = 2009 marginal generation capacity cost for the account.

Cost[T] = 2009 marginal transmission capacity cost for the account.

Cost[ST] = 2009 marginal sub transmission capacity cost for the account.

Cost[D] = 2009 marginal distribution cost for the account.

Cust	=	2009 marginal customer cost for the account (See Table 13).
EPMC[]	=	Factors to scale the respective marginal costs to full embedded cost revenue responsibility levels. The factors vary by cost component and by rate schedule *S* (See Table 14).
RegItems[]	=	Costs associated with items not included in the marginal cost-based revenue allocation process. Those items for SCE are comprised of the following components from each account's bill (using net load). See Table 15. 1) Trans non-bypassable 2) Dist non-bypassable 3) New System Generation Charge (NSGC) 4) Nuclear Decommissioning Charge (NGC) 5) PPP charge (PPPC), 6) DWR Bond charge (DWRBC) 7) PUC reimbursement Fee (PUCFR)
IncrCost[]	=	Incremental costs borne by the utility to connect and serve NEM customers. Composed of amortized initial setup and interconnection costs plus annual metering and grid interconnection cost increases. See the avoided cost section for further discussion of these costs.

3.1 SCE Marginal Energy Cost

Cost[E] = MktPrice[V][h] * Load[h]

Where

MktPrice[V][h] = Hourly market price of energy are provided for 2011. SCE provided energy marginal costs at the meter.

Load[h] = Account demand (net load) at the meter in hour h.

3.2 SCE Generation Capacity Costs

Cost[G] = CapCost[G][V] * Alloc[G][h] * Load[h]

where

CapCost[G] = SCE marginal cost of generation capacity, by voltage level.

Alloc[G][h] = Hourly allocation factor for generation (G) at hour h. Each of the System Top 100 hours is assigned a value of 1%. Each account receives a varying generation cost based on its consumption during the System Top 100 hours.

Load[h] = Account demand (net load) at the meter in hour h.

Table 7: SCE Generation Capacity Cost ($2009/kW-yr)

Class or Voltage	Generation Capacity Value ($/kW-yr)
Residential (Secondary)	125.27
TOU 8 Pri (Primary)	122.59
TOU 8 SUB (Subtransmission)	117.89

Provided by SCE in Data Response Attachment: E3 Data request Q1-final.xlsx.

Table 8: SCE Generation Capacity Top 100 Hours (Hour Ending PST)

Date	Ending Hour (PST)	Date	Ending Hour (PST)	Date	Ending Hour (PST)	Date	Ending Hour (PST)
7/5/2011	13	8/1/2011	16	8/26/2011	13	9/6/2011	13
7/5/2011	14	8/1/2011	17	8/26/2011	14	9/6/2011	14
7/5/2011	15	8/2/2011	13	8/26/2011	15	9/6/2011	15
7/5/2011	16	8/2/2011	14	8/26/2011	16	9/6/2011	16
7/5/2011	17	8/2/2011	15	8/26/2011	17	9/6/2011	17
7/6/2011	12	8/2/2011	16	8/26/2011	18	9/6/2011	18
7/6/2011	13	8/2/2011	17	8/26/2011	19	9/6/2011	19
7/6/2011	14	8/3/2011	15	8/27/2011	12	9/6/2011	20
7/6/2011	15	8/3/2011	16	8/27/2011	13	9/7/2011	11
7/6/2011	16	8/18/2011	16	8/27/2011	14	9/7/2011	12
7/6/2011	17	8/23/2011	15	8/27/2011	15	9/7/2011	13
7/6/2011	18	8/23/2011	16	8/27/2011	16	9/7/2011	14
7/7/2011	12	8/23/2011	17	8/27/2011	17	9/7/2011	15
7/7/2011	13	8/24/2011	14	8/28/2011	14	9/7/2011	16
7/7/2011	14	8/24/2011	15	8/28/2011	15	9/7/2011	17
7/7/2011	15	8/24/2011	16	8/28/2011	16	9/7/2011	18
7/7/2011	16	8/24/2011	17	8/28/2011	17	9/7/2011	19
7/7/2011	17	8/25/2011	13	8/29/2011	12	9/7/2011	20
7/8/2011	14	8/25/2011	14	8/29/2011	13	9/8/2011	12
7/8/2011	15	8/25/2011	15	8/29/2011	14	9/8/2011	13
7/8/2011	16	8/25/2011	16	8/29/2011	15	9/8/2011	14
7/8/2011	17	8/25/2011	17	8/29/2011	16	9/8/2011	15
8/1/2011	13	8/25/2011	18	8/29/2011	17	9/8/2011	16
8/1/2011	14	8/25/2011	19	8/29/2011	18	9/8/2011	17
8/1/2011	15	8/26/2011	12	9/6/2011	12	9/8/2011	18

Provided by SCE in Data Response Attachment: Q.02 2011 E3 monthly CPs and Top 100 Hrs Allocators.xlsx.

3.3 SCE Transmission Capacity Costs

We replaced the marginal transmission capacity costs provided by SCE with data that we obtained from SCE's FERC filings. The replacement was needed because the SCE-provided values produced transmission full costs far below the transmission tariff revenues.

Cost[T] = CapCost[T] * LossFctr[V] * Alloc[T][h] * Load[][h]

where

CapCost[T] = Marginal cost of transmission capacity from SCE FERC Filing in Docket No. ER11-3697 (See Table 9 for derivation).

LossFctr[V] = Loss factor by voltage level. From SCE FERC Filing in Docket No. ER11-3697, p. 78, schedules TOU-8

Transmsision = 1.0335

Primary = 1.0688

Secondary = 1.0979

Alloc[T][h] = Hourly allocation factor for transmission (T) at hour h. Each of the "12 CP" hours identified in Table 10 receives an allocation weight of 1/12.

Load[h] = Account demand at the meter in hour h. The analysis is done for two scenarios: 1) net loads and 2) gross loads.

Table 9: Transmission Capacity Cost ($2009/kW-yr)

Line	Item	Value	Comment
1	12 CP MW at Transmission	186,201	3 Yr Avg for 2008-2010, FERC filing p. 78
2	Transmission Revenue Requirement prior to 2012 ($ million)	722	From FERC filing, p. 1
3	Average Cost per CP each month ($/CP)	$3.88	Line 2 * 1000 / Line 1
4	Cost per average CP for the year ($/kW-yr)	$46.53	Line 3 * 12

Table 10: SCE 12 CP Hours for Transmission

Date	Ending Hour (PST)
1/3/2011	19
2/2/2011	19
3/31/2011	15
4/1/2011	15
5/4/2011	15
6/22/2011	16
7/6/2011	14
8/26/2011	15
9/7/2011	15
10/13/2011	16
11/29/2011	18
12/12/2011	18

Provided by SCE in Data Response Attachment: E3 Data request Q1-final.xlsx, 12 CP tab.

3.4 SCE Sub Transmission Capacity Costs

SCE marginal sub transmission capacity costs are separated into demand-related and connection-related components. The demand-related portion is allocated based on hourly allocation factors from an SCE circuit data study. The connection-related portion is assigned to each account based on rate class and voltage.

Cost[ST] = CapCost[ST][S] * Alloc[D][S][h] * Load[][h] +GridCost[ST][S]

where

CapCost[ST][S] = Marginal cost of sub transmission capacity for rate schedule S (See Table 11).

Alloc[D][S][h] = Hourly allocation factors for sub transmission and distribution, varied by Schedule S.

Load[][h] = Account demand at the meter in hour h. The analysis is done for two scenarios: 1) net loads and 2) gross loads.

GridCost[ST][S] = Grid-related marginal sub transmission capacity cost for rate schedule S.

Table 11: SCE Sub Transmission Marginal Capacity Costs

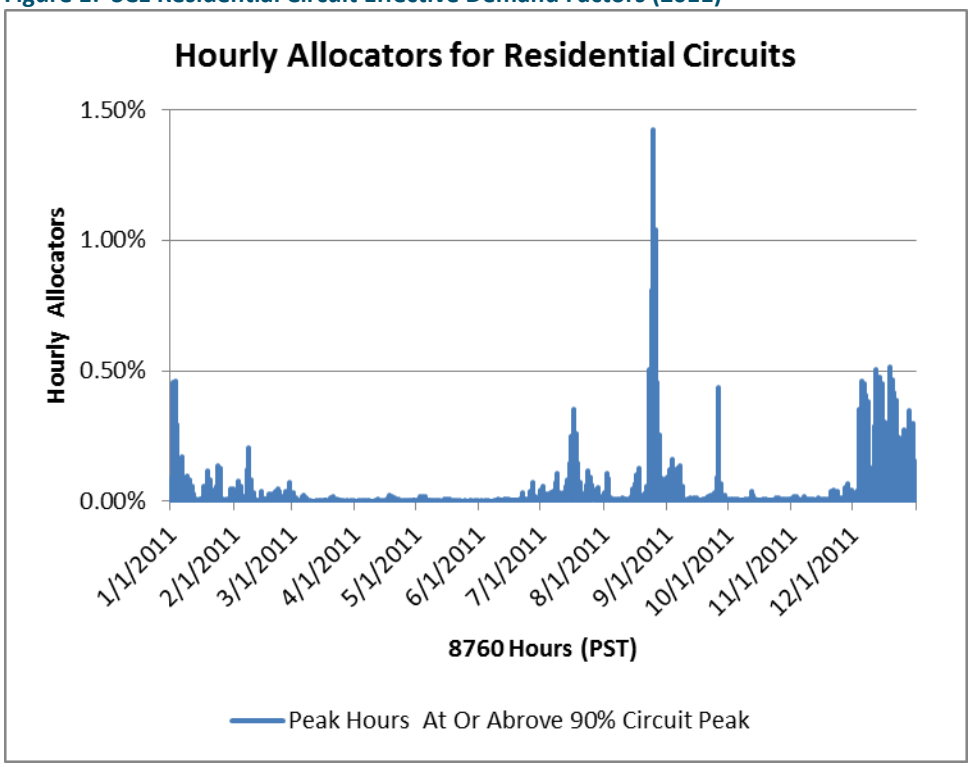
Rate Schedule	Demand-Related Capacity Cost ($/kW-yr)	Grid-Related Cost ($/Account-yr)
Domestic	5.15	32.75
GS-1 (Secondary)	5.3	33.65
GS-2 (Primary)	8.93	393.03
GS-3 (Primary)	10.44	3704.20
TOU-8 (Secondary)	9.99	8704.53
TOU-8 (Primary)	8.58	17251.43
TOU-8 (Sub Trans)	7.82	70830.16
PA-1	4.09	80.74
PA-2	6.05	266.94
AG TOU	4.54	608.17
TOU PA5	8.62	1611.10

Provided by SCE in Data Response Attachment: E3 Data request Q1-final.xlsx.

3.5 SCE Sub Transmission and Distribution Allocation Factors

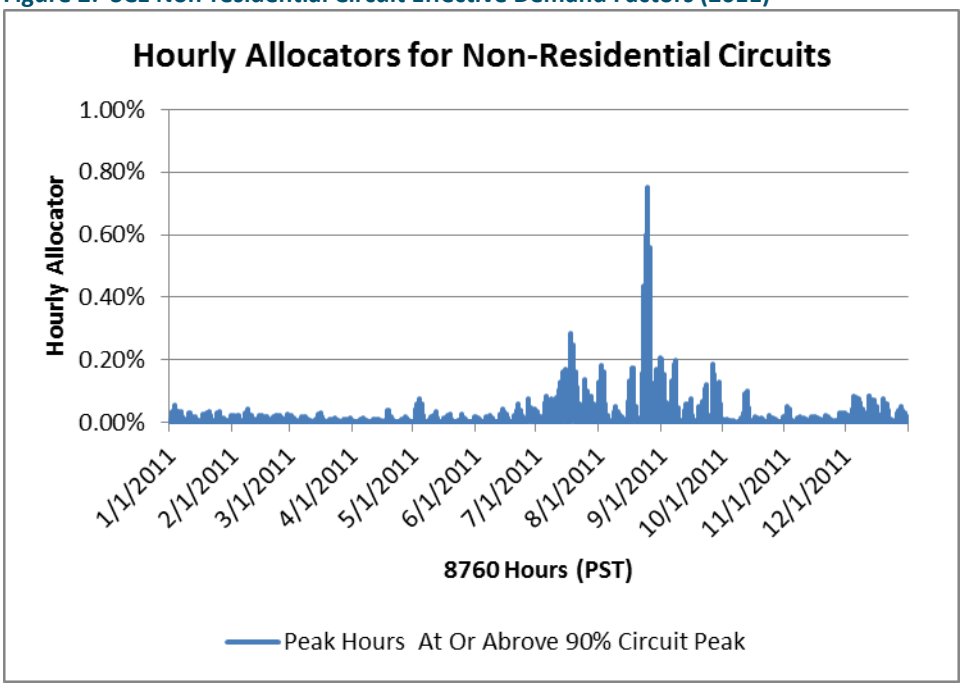
SCE developed hourly allocators for effective demand factors for residential and non-residential circuits. We apply the residential circuit allocation factors to domestic accounts, and the non-residential allocation factors to all other accounts. The residential allocation factors are from the *E3 Data request Q1-final.xlsx* spreadsheet, *Domestic* tab, column *M*. Non-residential allocation factors are from the *TOU 8 SEC* tab.

Figure 1: SCE Residential Circuit Effective Demand Factors (2011)



Note that the large peaks in September 2011 are atypical. Los Angeles experienced a record setting heat wave in early September 2011, with temperatures of 113 degrees Fahrenheit reported widely in the media. The other classes use the allocation factors from *TOU 8 SEC*, shown below for 2011.

Figure 2: SCE Non-residential Circuit Effective Demand Factors (2011)



3.6 SCE Distribution Capacity Costs

Like sub transmission, SCE marginal distribution capacity costs are separated into demand-related and connection-related components. The demand-related portion is allocated based on hourly allocation factors from an SCE circuit data study. The connection-related portion is assigned to each account based on rate class and voltage.

Cost[D] = CapCost[D][S] * Alloc[D][S][h] * Load[][h]
+GridCost[D][S]

where

CapCost[D][S] = Marginal cost of distribution capacity for rate schedule S (See Table 12).

Alloc[D][S][h] = Hourly allocation factors for sub transmission and distribution, varied by Schedule S.

Load[][h] = Account demand at the meter in hour h. The analysis is done for two scenarios: 1) net loads and 2) gross loads.

GridCost[D][S] = Grid-related marginal distribution capacity cost for rate schedule S.

Table 12: SCE Distribution Marginal Capacity Costs

Rate Schedule	Demand-Related Capacity Cost ($/kW-yr)	Grid-Related Cost ($/Account-yr)
Domestic	4.08	121.87
GS-1 (Secondary)	4.2	125.22
GS-2 (Primary)	7.08	1462.11
GS-3 (Primary)	8.88	14776.96
TOU-8 (Secondary)	8.88	36314.19
TOU-8 (Primary)	8.09	76294.23
TOU-8 (Sub Trans)	0	0
PA-1	2.88	267.03
PA-2	4.92	1018.02
AG TOU	4.44	2790.79
TOU PA5	7.32	6415.19

Provided by SCE in Data Response Attachment: E3 Data Request Q1 - Final.xlsx.

Table 13: SCE Marginal Customer Cost

Rate Schedule	Customer Cost ($/Account-yr)
Domestic	117.90
GS-1 (Secondary)	226.81
GS-2 (Primary)	1691.49
GS-3 (Primary)	3978.84
TOU-8 (Secondary)	4049.32
TOU-8 (Primary)	2303.68
TOU-8 (Sub Trans)	14488.51
PA-1	681.99
PA-2	1087.92
AG TOU	1771.44
TOU PA5	2013.72

Provided by SCE in Data Response Attachment: E3 Data Request Q1 - Final.xlsx.

Table 14: SCE EPMC Factors

Rate Schedule	Energy & Gen Capacity	Transmission	SubTrans, Dist & Customer
Domestic	0.782	1	1.3539
GS-1 (Secondary)	0.9001	1	1.3679
GS-2 (Primary)	0.7781	1	1.3782
GS-3 (Primary)	0.6979	1	1.2893
TOU-8 (Secondary)	0.7076	1	1.3158
TOU-8 (Primary)	0.7968	1	1.4125
TOU-8 (Sub Trans)	0.7814	1	1.2639
PA-1	0.7372	1	1.1579
PA-2	0.7069	1	1.2467
AG TOU	1.0918	1	2.1071
TOU PA5	0.1393	1	0.3358

Provided by SCE in Data Response Attachment: E3 Data Request Q1 - Final.xlsx.

Table 15: SCE Non-Bypassable Charges ($/kWh)

Schedule	Trans	Dist	NSGC	NDC	PPPC	DWRBC	PUCRF
Domestic	0.00059	.00340	0.00218	0.00009	0.01488	0.00505	0.00024
GS-1	0.00060	.00329	0.00240	0.00009	0.01342	0.00505	0.00024
GS-2	0.00060	.00308	0.00226	0.00009	0.01211	0.00505	0.00024
GS-3	0.00060	.00242	0.00203	0.00009	0.01138	0.00505	0.00024
TOU 8 Sec	0.00061	.00250	0.00192	0.00009	0.01071	0.00505	0.00024
TOU 8 Pri	0.00061	.00227	0.00169	0.00009	0.01036	0.00505	0.00024
TOU 8 Sub	0.00061	.00177	0.00139	0.00009	0.00831	0.00505	0.00024
PA-1	0.00060	.00395	0.00235	0.00009	0.01431	0.00505	0.00024
PA-2	0.00060	.00310	0.00198	0.00009	0.01118	0.00505	0.00024
AG TOU	0.00061	.00199	0.00104	0.00009	0.00931	0.00505	0.00024
TOU PA5	0.00061	.00579	0.00635	0.00009	0.00901	0.00505	0.00024

Component Charges June 2011 ERRA filing, Provided by SCE in Data Response Attachment: E3 Data request Q1-includes Non Bypassables 5.24.13.xlsx

4 San Diego Gas & Electric (SDG&E) Full Cost of Service

The full cost of service for SDG&E accounts is based on the marginal cost and revenue requirements from SDG&E's 2012 GRC. The formulas and data inputs are described below.

FullCost = {Cost[E]*EPMC[E] + Cost[G]*EPMC[G] +Cost[D]*EPMC[D] + Cust*EPMC[C] + RegItems[]} / (1+ 2012Chg[c]) + IncrCost[]

Where

Cost[E] = 2012 marginal energy cost for the account.

Cost[G] = 2012 marginal generation capacity cost for the account.

Cost[D] = 2012 marginal distribution cost for the account.

Cust = 2012 marginal customer cost for the account (See Table 13).

EPMC[] = Factors to scale the respective marginal costs to full embedded cost revenue responsibility levels (See Table 14).

RegItems[]	=	Costs associated with items not included in the marginal cost-based revenue allocation process. Those items for SDG&E are comprised of the following components from each account's bill (using net load). (a) Transmission (b) Public Purpose Programs (PPP) (c) Nuclear Decommissioning (ND) (d) Ongoing Competition Transition (CTC) (e) Reliability Services (RS) (f) Total Rate Adjustment Component (TRAC) (g) Department of Water Resources Bond Charges (DWR-BC)
2012Chg[]	=	2012 rate change over 2011 levels for rate class c. This adjustment is needed to align the 2012 full cost of service values to the 2011 customer bill calculations. Values are shown in Table 24.
IncrCost[]	=	Incremental costs borne by the utility to connect and serve NEM customers. Composed of amortized initial setup and interconnection costs plus annual metering and grid interconnection cost increases. See the avoided cost section for further discussion of these costs.

4.1 SDG&E Marginal Energy Cost

Cost[E] = MktPrice[h] * Load[h]*ELossFctr[V,h]

Where

MktPrice[h] = Hourly market price of energy are provided for 2012. Marginal energy costs and marginal generation capacity cost allocators are in actual clock time; essentially PST for November – March, PDT for April – October.

Load[h] = Account demand at the meter in hour h. Net Load.

ELossFctr[V,h] = Energy loss factor for delivery of power to the customer meter at service voltage V.

Table 16: SDG&E Marginal Energy Costs - Weekday

	AVERAGE WEEKDAY												
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
1	4.008	3.950	3.734	2.581	2.117	1.996	3.510	3.669	3.397	3.398	3.983	4.171	3.376
2	3.848	3.784	3.472	2.338	1.867	1.274	3.060	3.370	3.053	3.087	3.724	3.920	3.066
3	3.757	3.699	3.353	2.249	1.759	0.972	2.844	3.229	2.904	2.963	3.582	3.787	2.925
4	3.760	3.707	3.424	2.367	1.858	1.223	2.939	3.284	3.004	3.119	3.589	3.780	3.004
5	3.919	3.892	3.835	2.804	2.257	2.230	3.402	3.654	3.540	3.766	3.844	3.968	3.426
6	4.290	4.330	4.693	3.596	2.960	4.000	4.143	4.276	4.549	5.140	4.439	4.409	4.236
7	5.138	5.064	4.869	3.990	3.779	2.994	3.046	3.614	3.711	4.841	4.915	5.153	4.260
8	5.455	5.366	5.152	4.368	4.197	3.882	4.218	4.473	4.385	5.163	5.253	5.457	4.781
9	5.645	5.523	5.323	4.716	4.635	4.667	5.357	5.329	5.104	5.487	5.496	5.678	5.247
10	5.768	5.654	5.479	5.061	5.032	5.423	6.578	6.202	5.873	5.842	5.708	5.853	5.706
11	5.831	5.737	5.590	5.273	5.289	5.920	7.480	6.915	6.505	6.089	5.874	5.921	6.035
12	5.827	5.759	5.625	5.392	5.420	6.200	8.091	7.455	6.986	6.256	5.958	5.908	6.240
13	5.789	5.735	5.622	5.451	5.489	6.349	8.528	7.867	7.379	6.373	5.983	5.846	6.368
14	5.741	5.685	5.597	5.453	5.508	6.473	8.833	8.163	7.638	6.422	5.989	5.788	6.441
15	5.664	5.614	5.544	5.413	5.496	6.514	9.007	8.348	7.779	6.428	5.941	5.710	6.455
16	5.630	5.564	5.493	5.353	5.453	6.464	8.980	8.329	7.718	6.369	5.888	5.711	6.413
17	5.808	5.627	5.480	5.259	5.350	6.223	8.550	7.945	7.327	6.307	6.088	6.200	6.347
18	6.706	6.152	5.641	5.153	5.140	5.690	7.558	7.122	6.774	6.638	6.819	7.561	6.413
19	6.972	6.693	6.311	5.643	5.252	5.426	6.746	6.792	7.182	6.743	6.800	7.607	6.514
20	6.796	6.563	6.295	5.928	5.828	6.305	7.418	7.154	6.878	6.447	6.588	7.392	6.633
21	6.448	6.224	5.914	5.381	5.328	5.744	6.672	6.288	5.917	5.890	6.243	7.031	6.090
22	5.897	5.661	5.323	4.509	4.400	4.311	5.080	5.015	4.682	5.152	5.710	6.380	5.177
23	4.846	4.829	5.088	3.868	3.456	5.871	5.678	5.125	5.051	5.074	5.245	5.395	4.961
24	4.381	4.362	4.307	3.084	2.638	3.522	4.377	4.241	4.033	4.050	4.585	4.757	4.028
Avg	5.330	5.216	5.048	4.385	4.188	4.570	5.921	5.744	5.474	5.293	5.343	5.558	5.172

Provided by SDG&E in Data Response Attachment: SDG&E NEM Cost-Benefit Study Data Request.xlsx, Marg Hourly Gen Energy Costs tab.

Table 17: SDG&E Marginal Energy Costs - Weekend

	AVERAGE WEEKEND												
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
1	4.068	4.003	3.874	2.705	2.243	2.345	3.493	3.646	3.507	3.631	4.072	4.225	3.484
2	3.872	3.800	3.544	2.396	1.923	1.427	2.978	3.304	3.093	3.217	3.758	3.948	3.105
3	3.753	3.682	3.366	2.249	1.755	0.955	2.697	3.119	2.882	3.005	3.562	3.788	2.901
4	3.691	3.619	3.310	2.245	1.729	0.854	2.650	3.079	2.854	2.979	3.460	3.716	2.849
5	3.678	3.616	3.393	2.361	1.804	0.947	2.686	3.159	3.030	3.169	3.435	3.732	2.917
6	3.716	3.689	3.604	2.523	1.875	0.939	2.592	3.216	3.318	3.650	3.487	3.821	3.036
7	3.921	4.050	3.871	2.932	2.693	0.849	0.864	1.872	2.251	3.796	3.770	4.271	2.928
8	4.255	4.326	4.153	3.283	3.103	1.762	1.984	2.677	2.934	4.142	4.113	4.561	3.441
9	4.582	4.576	4.431	3.664	3.571	2.791	3.191	3.617	3.787	4.607	4.521	4.837	4.015
10	4.788	4.753	4.641	3.975	3.964	3.675	4.308	4.496	4.575	5.029	4.831	5.026	4.505
11	4.887	4.849	4.762	4.136	4.213	4.229	5.058	5.125	5.170	5.305	5.044	5.106	4.824
12	4.888	4.875	4.792	4.212	4.346	4.546	5.566	5.572	5.618	5.490	5.146	5.112	5.014
13	4.817	4.829	4.755	4.203	4.386	4.660	5.869	5.873	5.930	5.589	5.145	5.051	5.092
14	4.738	4.762	4.697	4.152	4.380	4.749	6.071	6.081	6.130	5.618	5.124	4.988	5.124
15	4.667	4.708	4.652	4.118	4.391	4.827	6.251	6.256	6.282	5.641	5.079	4.944	5.151
16	4.698	4.719	4.662	4.136	4.426	4.909	6.373	6.337	6.323	5.644	5.084	5.005	5.193
17	5.040	4.895	4.785	4.223	4.481	4.924	6.295	6.209	6.159	5.699	5.447	5.533	5.308
18	6.125	5.530	5.095	4.333	4.452	4.658	5.745	5.713	5.811	6.141	6.342	6.969	5.576
19	6.424	6.133	5.821	4.912	4.610	4.453	5.199	5.567	6.237	6.272	6.354	7.046	5.752
20	6.271	6.042	5.836	5.240	5.217	5.362	5.936	5.983	6.059	5.999	6.163	6.874	5.915
21	6.000	5.775	5.527	4.803	4.809	4.958	5.455	5.349	5.284	5.531	5.878	6.567	5.495
22	5.587	5.336	5.059	4.185	4.113	3.798	4.296	4.376	4.296	4.927	5.450	6.016	4.786
23	4.723	4.681	4.888	3.641	3.257	5.350	5.173	4.772	4.807	4.868	5.063	5.231	4.705
24	4.303	4.264	4.189	2.944	2.514	3.204	4.017	3.989	3.881	3.945	4.467	4.658	3.865
Avg	4.729	4.646	4.488	3.649	3.511	3.382	4.364	4.558	4.592	4.746	4.783	5.043	4.374

Provided by SDG&E in Data Response Attachment: SDG&E NEM Cost-Benefit Study Data Request.xlsx, Marg Hourly Gen Energy Costs tab.

Table 18: SDG&E Generation Loss Factors

SDG&E 2012 GRC Phase 2 Application (A.11-10-002) Generation Capacity and Energy Loss Factors by Rate Schedule & Service Voltage Level Standard TOU Period: A-TOU, AL-TOU, AY-TOU, A6-TOU, DG-R, PA-T-1, OL-TOU and DR-TOD-C:					
Line No.	Description (A)	Secondary (B)	Primary (C)	Transmission (D)	Line No.
3	Summer (May 1 - October 31)				3
4	On-Peak: 11 a.m. to 6 p.m. Weekdays	1.063	1.058	1.011	4
5	Semi-Peak: 6 a.m. to 11 a.m. and 6 p.m. to 10 p.m.	1.060	1.055	1.010	5
6	Off-Peak: All Other Hours incl Weekends & Holidays	1.054	1.051	1.008	6
7					7
8	Winter (November 1 - April 30)				8
9	On-Peak: 5 p.m. to 8 p.m. Weekdays	1.061	1.056	1.011	9
10	Semi-Peak: 6 a.m. to 5 p.m. and 8 p.m. to 10 p.m.	1.058	1.054	1.010	10
11	Off-Peak: All Other Hours incl Weekends & Holidays	1.054	1.050	1.008	11

Provided by SDG&E in Data Response Attachment: SDG&E 2012 GRC Phase 2 Loss Factors.xlsx

4.2 SDG&E Generation Capacity Costs

Cost[G] = CapCost[G] * Alloc[G][h] * Load[h] * LossFctr[G][V]

where

CapCost[G]	=	SDG&E marginal cost of generation capacity. Real levelized value, in 2012 dollars.
Alloc[G][h]	=	Hourly allocation factor for generation (G) at hour h. E3 maps the factors to match the top SDG&E peak demand days in each respective month. The allocation factors are also adjusted to reflect the PST time standard used throughout the analyses.
Load[h]	=	Account demand (net load) at the meter in hour h.
LossFctr[G][V]	=	Peak demand loss factor from transmission system to the meter served at voltage level V. Peak values from Table 18 are used for the corresponding season.

Table 19: SDG&E Generation Capacity Hourly Allocation Factors (Hour Ending PDT)

		Hour Ending																							
Month	Days	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
May	1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.30%	0.31%	0.30%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
June	1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.32%	0.62%	0.65%	0.69%	0.70%	0.40%	0.35%	0.00%	0.00%	0.00%	0.00%	0.00%
	2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.31%	0.34%	0.65%	0.70%	0.70%	0.37%	0.32%	0.00%	0.00%	0.00%	0.00%	0.00%
	3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.29%	0.31%	0.62%	0.62%	0.33%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.29%	0.31%	0.30%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
July	1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.29%	0.37%	0.46%	0.79%	0.75%	0.43%	0.40%	0.35%	0.31%	0.31%	0.00%	0.00%	0.00%
	2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.35%	0.44%	0.48%	0.51%	0.45%	0.38%	0.34%	0.30%	0.00%	0.00%	0.00%	0.00%	0.00%
	3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.30%	0.33%	0.36%	0.37%	0.39%	0.39%	0.34%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%
	4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.30%	0.33%	0.35%	0.36%	0.35%	0.31%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.30%	0.32%	0.34%	0.35%	0.35%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.30%	0.31%	0.32%	0.31%	0.31%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.28%	0.31%	0.32%	0.32%	0.32%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	8	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.28%	0.30%	0.31%	0.32%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	9	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.28%	0.29%	0.29%	0.28%	0.28%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	10	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.28%	0.30%	0.30%	0.30%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	11	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.30%	0.31%	0.30%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	12	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.28%	0.29%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	13	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.28%	0.29%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
August	1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.28%	0.33%	0.68%	0.74%	1.06%	1.07%	1.05%	0.65%	0.28%	0.27%	0.00%	0.00%	0.00%	0.00%
	2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.58%	0.63%	0.66%	0.67%	0.65%	0.32%	0.27%	0.00%	0.00%	0.00%	0.00%	0.00%
	3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.27%	0.59%	0.63%	0.66%	0.68%	0.64%	0.28%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.28%	0.60%	0.63%	0.64%	0.63%	0.58%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.27%	0.59%	0.61%	0.63%	0.62%	0.28%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.28%	0.30%	0.60%	0.61%	0.60%	0.28%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	7	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.28%	0.30%	0.30%	0.60%	0.60%	0.27%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	8	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.27%	0.29%	0.30%	0.30%	0.30%	0.27%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	9	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.27%	0.29%	0.29%	0.29%	0.27%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	10	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.27%	0.27%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
September	1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.30%	0.75%	0.89%	1.29%	1.38%	1.41%	1.35%	1.16%	0.95%	0.98%	0.35%	0.00%	0.00%	0.00%
	2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.33%	0.39%	1.04%	1.13%	1.18%	1.19%	1.13%	0.96%	0.29%	0.28%	0.00%	0.00%	0.00%	0.00%
	3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.32%	0.68%	0.72%	0.71%	0.67%	0.61%	0.28%	0.28%	0.27%	0.00%	0.00%	0.00%
	4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.30%	0.64%	0.68%	0.68%	0.65%	0.31%	0.27%	0.00%	0.00%	0.00%	0.00%	0.00%
	5	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.30%	0.31%	0.30%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
October	1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.34%	0.41%	0.47%	0.55%	0.54%	0.50%	0.41%	0.35%	0.36%	0.30%	0.00%	0.00%	0.00%
	2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.31%	0.32%	0.34%	0.32%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	3	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.29%	0.32%	0.33%	0.31%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

From SDG&E 2012 GRC Phase 2 (A.11-10.002), Provided by SDG&E in Data Response Attachment: SDG&E NEM Cost-Benefit Study data Request.xlsx, Marg Hourly Gen Capacity Costs tab.

4.3 SDG&E Distribution Capacity Costs

The formulas for calculating the distribution marginal cost for an account are shown below.

Cost[D] = CapCost[D] * MaxDmd[]* LossFctr[P][V]

Where

CapCost[D]	=	SDG&E marginal cost of distribution capacity (see Table 3).
MaxDmd[]	=	Maximum annual demand for the account. The analysis is done for two scenarios: 1) net loads and 2) gross loads.
LossFctr[P][V]	=	Loss factor from the meter to the primary distribution system (see Table 4).

Table 20: SDG&E Primary Distribution Capacity Cost ($2012/kW-yr)

Customer Group	Distribution[1]
Residential Class	$101.87
Small Commercial Class (< 20 kW)	$101.87
Medium/Large C&I Class (≥ 20 kW)	
Secondary	
< 500 kW	$101.87
500 - 12 MW	$101.87
> 12 MW	NA
Primary	
< 500 kW	$101.87
500 - 12 MW	$101.87
> 12 MW	NA
Transmission	
< 500 kW	$101.87
500 - 12 MW	$101.87
> 12 MW	NA
Agricultural Class	$101.87
Lighting Class	$101.87
(1) Marginal Distribution Capacity Costs reflect the sum of the Feeder & Local Distribution and Substation costs.	

Provided by SDG&E in Data Response Attachment: SDG&E NEM Cost-Benefit Study data Request.xlsx.

Table 21: SDG&E Distribution Loss Factors

SDG&E 2012 GRC Phase 2 Application (A.11-10-002) Distribution Loss Factors by Service Voltage Level	
Secondary	1.0632
Primary	1.0578
Note: Loss Factors used for allocating SDG&E distribution costs.	

Provided by SDG&E in Data Response Attachment: SDGE 2012 GRC Phase 2 Loss Factors.xlsx

Table 22: SDG&E Marginal Customer Cost

Customer Group	($2012/Meter-yr)[2]
Residential Class	$139.75
Small Commercial Class (< 20 kW)	$455.98
Medium/Large C&I Class (≥ 20 kW)	
Secondary	
< 500 kW	$1,945.26
500 - 12 MW	$5,747.81
> 12 MW	NA
Primary	
< 500 kW	$331.11
500 - 12 MW	$395.65
> 12 MW	$2,850.64
Transmission	
< 500 kW	$6,876.52
500 - 12 MW	$12,783.75
> 12 MW	NA
Agricultural Class	$574.07
Lighting Class	$16.73
(2) Marginal Customer Costs for the Lighting Class reflects a dollar per lamp per year.	

Provided by SDG&E in Data Response Attachment: SDG&E NEM Cost-Benefit Study data Request.xlsx.

Table 23: SDG&E EPMC Factors

Marginal Cost	EPMC Factor
Energy [E]	0.9349
Generation Capacity [G]	0.9349
Primary [D]	0.9132
Customer Cost [C]	0.9132

Provided by SDG&E in Data Response Attachment: SDG&E NEM Cost-Benefit Study data Request.xlsx.

Table 24: SDG&E 2012 Rate Increases over 2011

SDG&E Class Average Electric Rate Percentage Change			
Based on 1/01/12 Average Electric Rates Compared to 1/01/11 Average Electric Rates			
Customer Classes	Class Average 1/01/11 Electric Rates[1] (cents/kWh)	Class Average 1/01/12 Electric Rates[2] (cents/kWh)	Percentage Change (%)
Residential	18.365	17.612	-4.1%
Small Commercial	17.647	17.045	-3.4%
Medium/Large C&I	13.936	13.645	-2.1%
Agricultural	17.200	16.563	-3.7%
Lighting	15.387	14.653	-4.8%
System	15.957	15.449	-3.2%

Note:
(1) 1/01/11 electric rates adopted in SDG&E's Advice Letter 2222-E Consolidated Filing to Implement January 1, 2011 Electric Rates, as adopted by Energy Division letter dated February 9, 2011.
(2) 1/01/12 electric rates adopted in SDG&E's Advice Letter 2323-E Consolidated Filing to Implement January 1, 2012 Electric Rates, as adopted by Energy Division letter dated January 31, 2012.

Provided by SDG&E in Data Response Attachment: SDGE Response – NEM Cost Effectiveness DR – Sixth Addendum.doc. Response 01.

5 Utility Case Full Cost of Service Intraclass Results

In this section, we analyze annual bills and cost of service recovery by utility and customer type to better understand what may be driving the variation in cost of service recovery results across customer groups. There is strong evidence that rate design is a significant driver of the variation.

Figure 3 plots the average annual bills and average full cost of service for PG&E residential E-1 through E-9 NEM accounts. Each plot point is an account bin that can represent between 1 and 569 accounts. The figure shows that bills increase more rapidly per kWh of usage than does the full cost of service. This is a result of the tiered rate structure.

Figure 3: PG&E E-1, E-6, E-7, E-8, E-A9 NEM Accounts – Bill Comparison with Utility Case Full Cost of Service

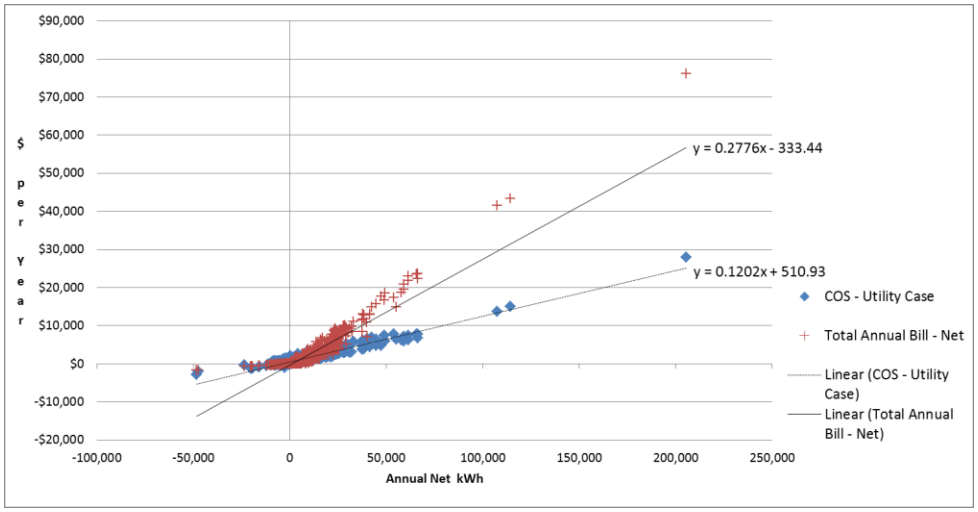
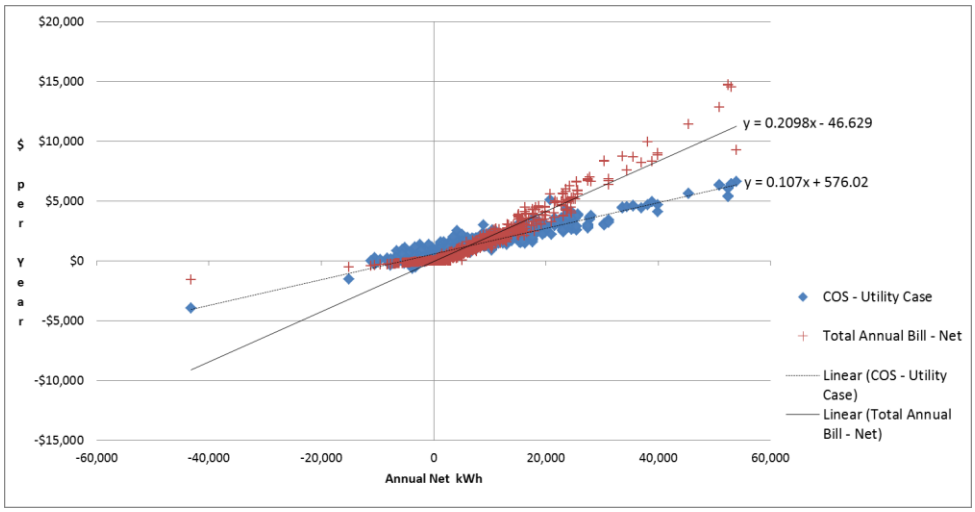


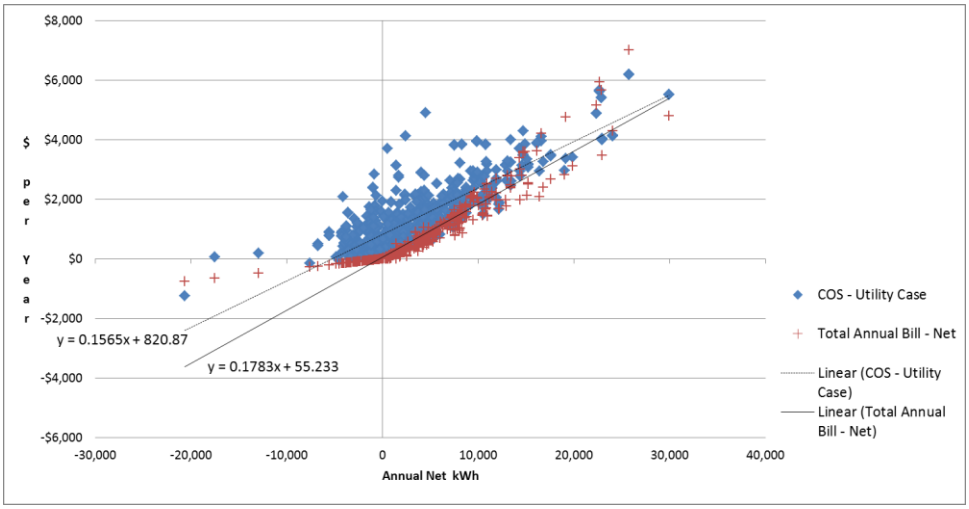
Figure 4 shows the same relationship for SCE residential NEM accounts, albeit with less of a tiered rate effect.

Figure 4: SCE DOMESTIC and TOU-D NEM Accounts – Bill Comparison with Utility Case Full Cost of Service



For SDG&E, the preliminary results suggest that the full cost of service for residential NEM accounts exceeds the bills of even relatively large residential customers, but the correlation between cost of service and net use is relatively less pronounced for SDG&E customers than for those of the other IOUs. This result is driven by the fact the SDG&E recommended that their entire distribution capacity cost be assigned to accounts based on the maximum demand of the account. Because the maximum demand for NEM residential accounts is only negligibly reduced by DG output, if at all, NEM accounts see almost no reduction in their distribution full cost of service. This result is driven by the use of maximum demand for determining all distribution capacity costs for the SDG&E NEM accounts.

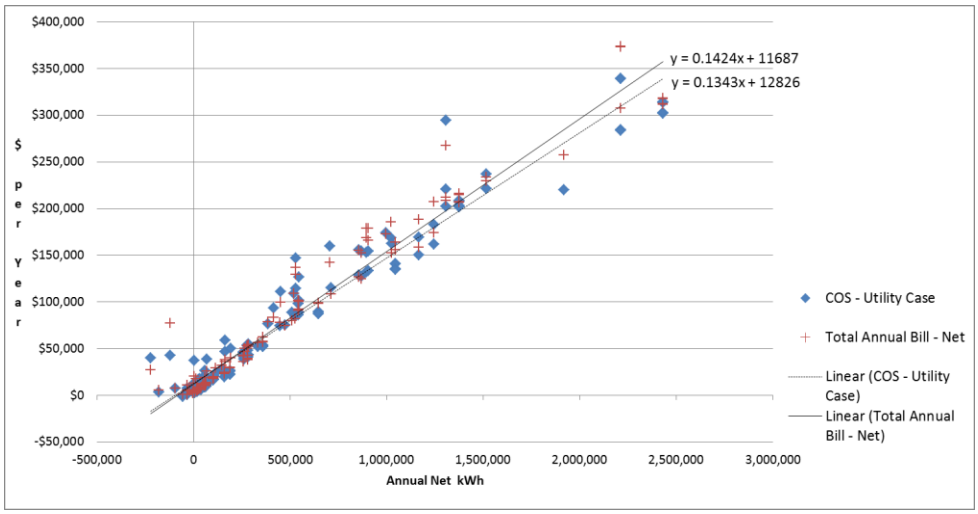
Figure 5: SDG&E Residential Schedule Accounts – Bill Comparison with Utility Case Full Cost of Service



For non-residential accounts, the bills and full cost of service for PG&E accounts are comparable overall, with bills slightly in excess of the full cost of service. The lack of a strong systematic difference between bills and full cost of service is illustrated by Figure 6, which depicts annual bills and cost of service for A-10

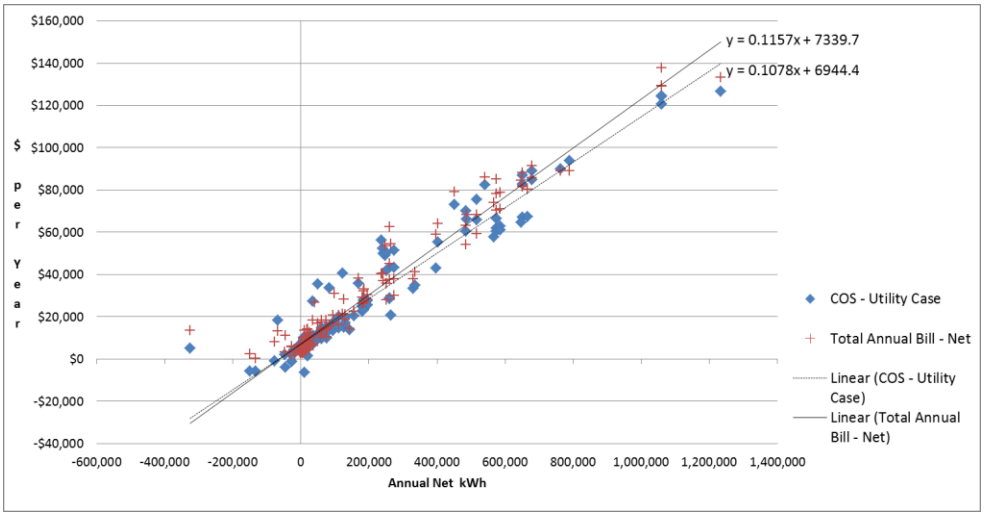
and E-19 accounts. A-10 and E-19 accounts comprise the bulk of the PG&E NEM non-residential accounts.

Figure 6: PG&E A-10 and E-19 NEM Accounts – Bill Comparison with Utility Case Full Cost of Service



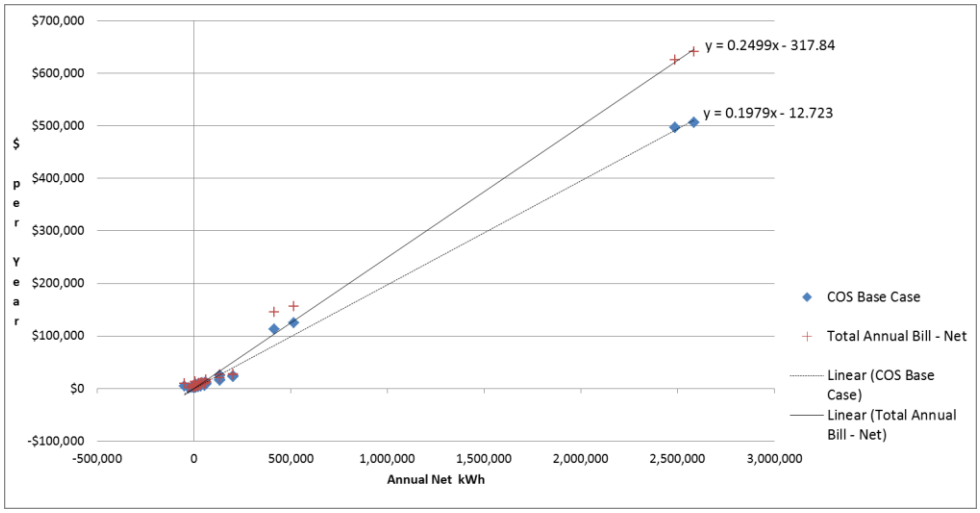
For SCE, the bills and full cost of service of non-residential accounts are also comparable. Figure 7 compares SCE non-residential accounts and their full cost of service.

Figure 7: SCE GS-2 and GS-3 NEM Accounts – Bill Comparison with Utility Case Full Cost of Service



For SDG&E non-residential accounts, we find that a few very large accounts account for the majority of the difference between their bills and cost of service. Figure 8 shows the AL-TOU accounts. The four large outlier bins account for over 96% of the total difference between bills and full cost of service.

Figure 8: SDG&E AL-TOU NEM Accounts – Bill Comparison with Utility Case Full Cost of Service



Removing those large bins from the figure shows that the difference between the bills and full cost of service for the small and medium-sized customers substantially smaller (see Figure 9).

Figure 9: SDG&E AL-TOU NEM Accounts – Bill Comparison with Utility Case Full Cost of Service, Excluding Four Largest Customer Bins

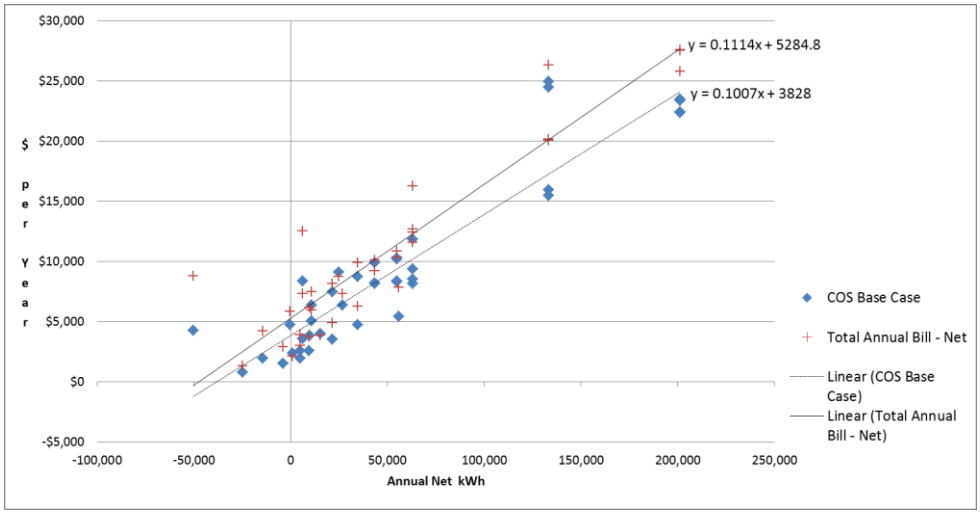


Figure 9 shows that the cost of service result for this bin is being driven by a few very large, outlier customers who pay substantially more than their cost of service.

APPENDIX E:

INCOME ANALYSIS

October 28, 2013

The analysis in this section was performed by Advent Consulting Associates with direction from Energy and Environmental Economics, Inc.

Advent Consulting Associates

Income Analysis

E-1. Overview

In this analysis we assess the household incomes of NEM participants and compare them to non-NEM customers of each Investor Owned Utility (IOU) and Californians overall. Income analysis of California Solar Initiative (CSI) participants, which are the vast majority of NEM customers, is currently reported on the Go Solar Website as well as the California Solar Initiative Annual Report.[1] In this study, we make a significant update to the prior methodology by performing the analysis based on census tracts from the 2010 US Census, rather than zip codes used in the current public reporting. The census tracts are much smaller geographic areas, and are selected to have more homogenous demographics. Therefore, a census tract approach provides a more accurate estimate of NEM customer household income and has significantly different results.

E-2. Data

The majority of the data used in the analysis is the median household income in the census tract of a NEM customer. This data was obtained for 115,340 NEM customers from the three investor-owned utilities (IOUs),[2] including 73,043 (63%) from PG&E, 21,955 (19%) from SCE, and 20,342 (18%) from SDG&E. Each utility provided this data through data request to the CPUC.

The information was developed using NEM customer service addresses to identify the corresponding 2010 Federal Information Processing Standards (FIPS) Census Tract and the associated median household income and other fields. The data sources for household income in 2010 by Census Tract varied by IOU:

- PG&E and SDG&E income data came from 2010 American Communities Survey 5 Year Estimates from the U.S. Census Bureau.

[1] See http://www.cpuc.ca.gov/NR/rdonlyres/0C43123F-5924-4DBE-9AD2-8F07710E3850/0/CASolarInitiativeCSIAnnualProgAssessmtJune2012FINAL.pdf

[2] The three IOUs are Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)

- SCE income data came from estimates provided by Experian Marketing Services.

Table 1, below, provides the data fields provided by each utility for the purposes of the analysis.

Table 1: Examples of Data Fields by Utility

Utility	Description
All	Account identifier
All	Host customer address (street, city, and ZIP)
All	Host customer rate code
All	DG technology
All	Installed system size (DC)
PG&E, SDG&E	Incentive program of installation
All	System interconnection date
All	FIPS county code
All	FIPS tract code
All	Estimate of median household income, for 2010
SCE only	Estimate of mean household income for 2010
SCE only	Proportion of households estimated below 200% poverty, based on CPUC ESA and similar guidelines [a]
SCE only	Proportion of households estimated 200 to 400% poverty
SCE only	Proportion of households estimated 400% poverty plus

[a] California Energy Savings Assistance (ESA) Program and HHS guidelines

The datasets of each NEM customer were relatively complete. Table 2 shows the percentages of missing data for selected data fields across the IOUs. For the purposes of this analysis, the most important data fields were for FIPS County Code and household income, which had less than 2% of data missing.

Table 2: Percentages of Missing Data

Utility	Rate	Tech	Incentive	Year	FIPS	kW	Income	Mean
PG&E	0.12	15.85	16.61	15.72	1.16	15.91	1.16	9.50
SCE	0.05	-	N/A	6.14	1.63	-	1.91	1.62
SDG&E	19.11	28.71	28.8	28.71	-	28.36	-	19.10

In addition, each utility provided a distribution of the 2010 Median Household Income of their customers overall to compare to those of the NEM customers. Each of the utilities provided data on NEM participants' median household income in slightly different ways.

- PG&E provided data on the ranges (minimums and maximums) of deciles in the income distribution.
- SDG&E provided census tract household income data that also was expressed in percentiles, but *medians* of the percentile ranges were reported instead of the minimum and maximum of the ranges.
- SCE used pre-designated income-level classifications for median household income. The spans of income across the SCE classifications ranged from $10,000 to $25,000, and their percentile anchors differed from the levels used by both PG&E and SDG&E.

Due to the reporting style of median household income, arithmetic means of deciles above and below the median (e.g. average of 40% to 50% and 50% to 60% deciles) were used to estimate the overall median household income for PG&E and SCE. SDG&E reported this number directly and was only adjusted for inflation to be comparable $2010. Due to the averaging, utility-specific medians reported in this study are only approximate.

E-2.1 CHARACTERISTICS OF HOUSEHOLD INCOME DATA

All measures of the household income of NEM participants were based on the census tracts established by the US Census Bureau.

Since the analysis reflects a significant update from zip code to a smaller geographic area, the definition of the census tract is important for the quality of the analysis. The US Census Bureau defines[3] census tract as:

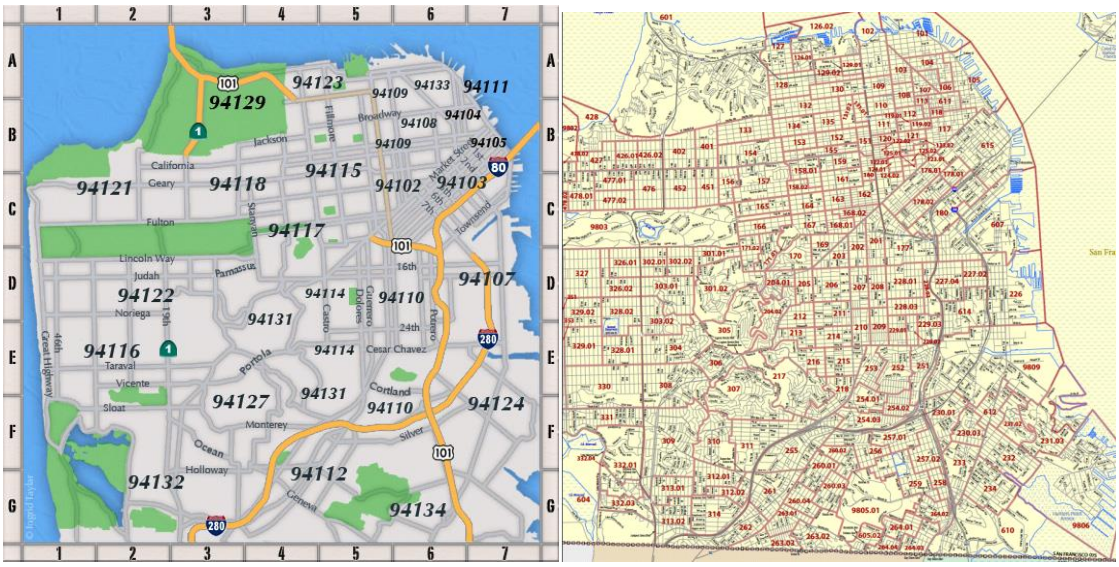
> **Census Tracts** are small, relatively permanent statistical subdivisions of a county or equivalent entity that are updated by local participants prior to each decennial census as part of the Census Bureau's Participant Statistical Areas Program. The Census Bureau delineates census tracts in situations where no local participant existed or where state, local, or tribal governments declined to participate. The primary purpose of census tracts is to provide a stable set of geographic units for the presentation of statistical data.
>
> Census tracts generally have a population size between 1,200 and 8,000 people, with an optimum size of 4,000 people. A census tract usually covers a contiguous area; however, the

[3] See http://www.census.gov/geo/reference/gtc/gtc_ct.html

spatial size of census tracts varies widely depending on the density of settlement. Census tract boundaries are delineated with the intention of being maintained over a long time so that statistical comparisons can be made from census to census. Census tracts occasionally are split due to population growth or merged as a result of substantial population decline.

A graphical illustration of the improvement in granularity is highlighted by Figure 1. While census tract provides a better estimate of NEM household income, it is important to note that we still are not using specific customer data, but the median household income of the approximate 4,000 households in each census tract as the basis of the analysis.

Figure 1: A Map of San Francisco Labeled at the Zip Code Level (left) and Census Tract Level (right)



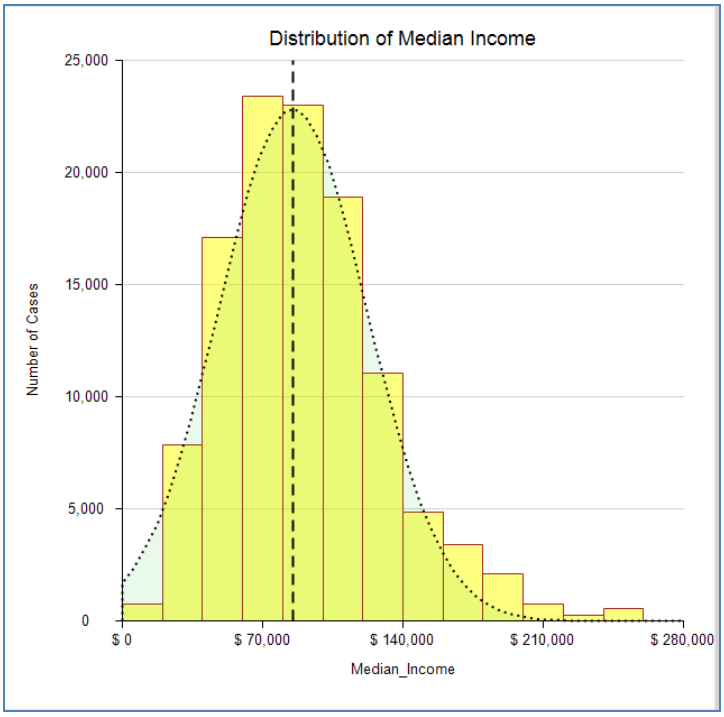
E-3. Results

E-3.1 DISTRIBUTION OF MEDIAN HOUSEHOLD INCOME OF NEM CUSTOMERS

Median household income data were available for the census tracts of 114,076 NEM participants across all three utilities, and the overall average of median household income was $91,210. The distribution of median household income across the NEM population is shown in Figure 2, below.

The distribution of household income (yellow) is superimposed on the normal curve (shaded). The tail of the distribution is slightly higher than normal (in particular, the tail higher than the median).[4]

Figure 2: Distribution of Household Median Income

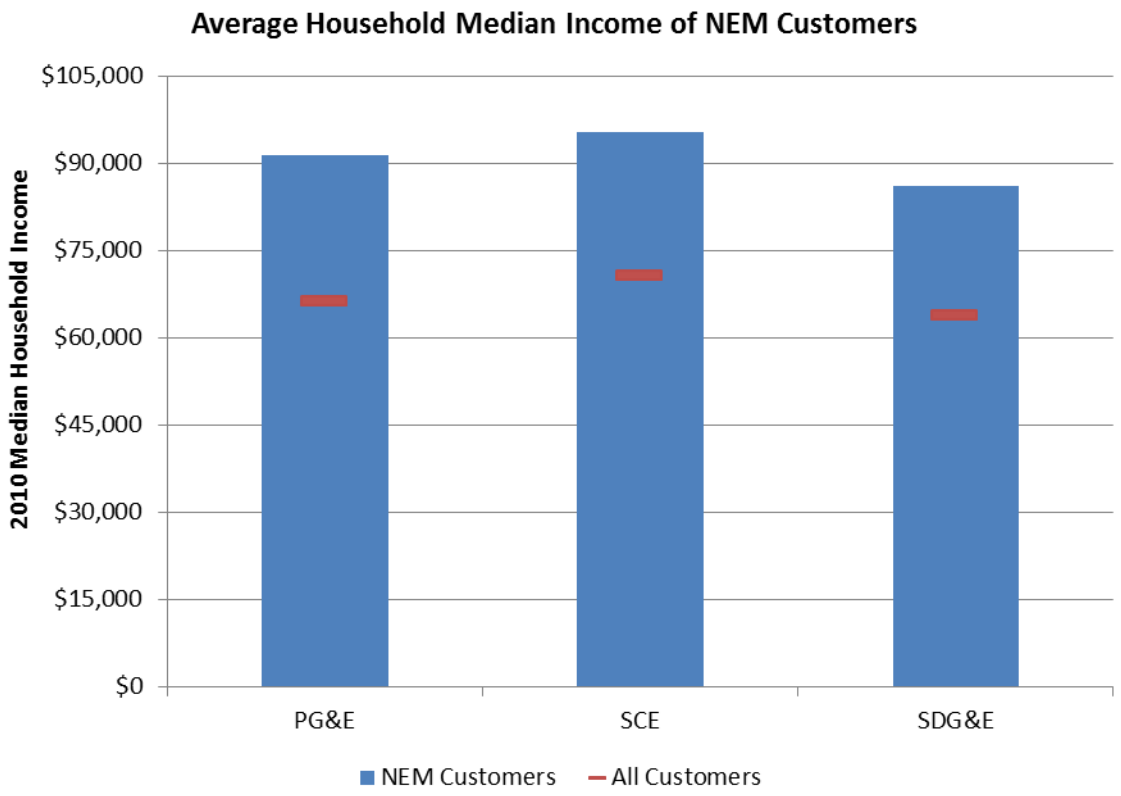


E-3.2 AVERAGES OF MEDIAN HOUSEHOLD INCOME OF NEM CUSTOMERS

The average 2010 median household income of NEM customers for each utility is shown in Figure 3. For comparison, median income of all residential customers for each utility is indicated. Overall, NEM customers are in census tracts with median household incomes approximately $24,000 per year higher than the median income for each utility.

[4] The entire sample had virtually no skewness (g_1 = 1.002) and was slightly leptokurtic (g_2 = 5.607) which means it is slightly peakier than a normal distribution.

Figure 3: Means of Median Household Income of NEM Customers for Each Utility



The means, standard deviations, and sample sizes for each utility are presented in Table 3. For each utility company, the sample sizes upon which calculations were based for averages of the median household income were substantial. Thus, the averages in Table 3 are likely to be fairly stable.

Table 3: Means of Median Household Income per Utility Company

Statistics	PG&E	SCE	SDG&E	Total
M	91,390	95,472	86,058	91,210
S	42,576	39,435	32,232	40,426
N	72,197	21,537	20,342	114,076

E-3.3 TREND OF MEDIAN HOUSEHOLD INCOME OF NEM CUSTOMERS

A similar analysis was completed by NEM system installation year to evaluate the trend in median household income of NEM customers over time. The years 1999 through 2011 were selected for

this analysis since only a small number of cases (23) contained the median household income for the census tracts of installations prior to 1999. In addition, much of the census tract median income data were missing for the year 2012. The resulting reduction in years reduced the effective sample to 114, 076 by eliminating a total of 6,399 cases (including 6,376 from the year 2012).

The means (*M*), standard deviations (*S*), the number of cases in each of the annual samples (*N*) were calculated across the utilities, and are summarized in Table 4. The figures reported are based on only the new installations of NEM generators each year. Household income data were not collected on the census tracts of customers whose installations occurred in previous years unless the customer had a second installation of an NEM generator.

Table 4: NEM Means of Median Household Income (in $) 1999-2011

Year	M	S	N
1999	84,776	42,314	76
2000	93,065	42,388	73
2001	87,100	37,960	785
2002	91,995	38,414	1,425
2003	89,259	38,186	2,143
2004	87,371	37,403	3,526
2005	88,560	39,267	3,300
2006	91,245	40,579	4,826
2007	97,319	43,924	8,341
2008	96,210	44,103	8,420
2009	94,290	41,541	14,399
2010	94,760	39,686	17,558
2011	90,686	38,936	24,678
Total	**91,210**	**40,426**	**114,076**

Means of the annual medians of household income for new installations were plotted since 1999 to analyze patterns over the course of time. Figure 4 and is superimposed over a graph of the number of new NEM installations during the same time period. Table 4 served as the source of the charted data in Figure 4, such that:

- The census tract median of household income for new NEM installations is indicated by the marker-line in dark red.
- The mean of income for the 13-year period is indicated by the horizontal gray line (the symbol $\overline{X}$ is used to indicate the mean, X-Bar).

- Three thin horizontal lines on either side of the mean indicate each of the standard deviations (±*s*) for six-sigma analysis.
- Vertical bars indicate the number of new NEM installations each year for all three utilities combined.

The averages of census tract median household income for new installations rose fairly consistently beginning in 2004, peaked in the year 2007, and then declined slightly but fairly steadily through the end of 2011.

Figure 4: Run Chart of the Means of Median Household Income for the Census Tracts of New NEM Installations, 1999-2011

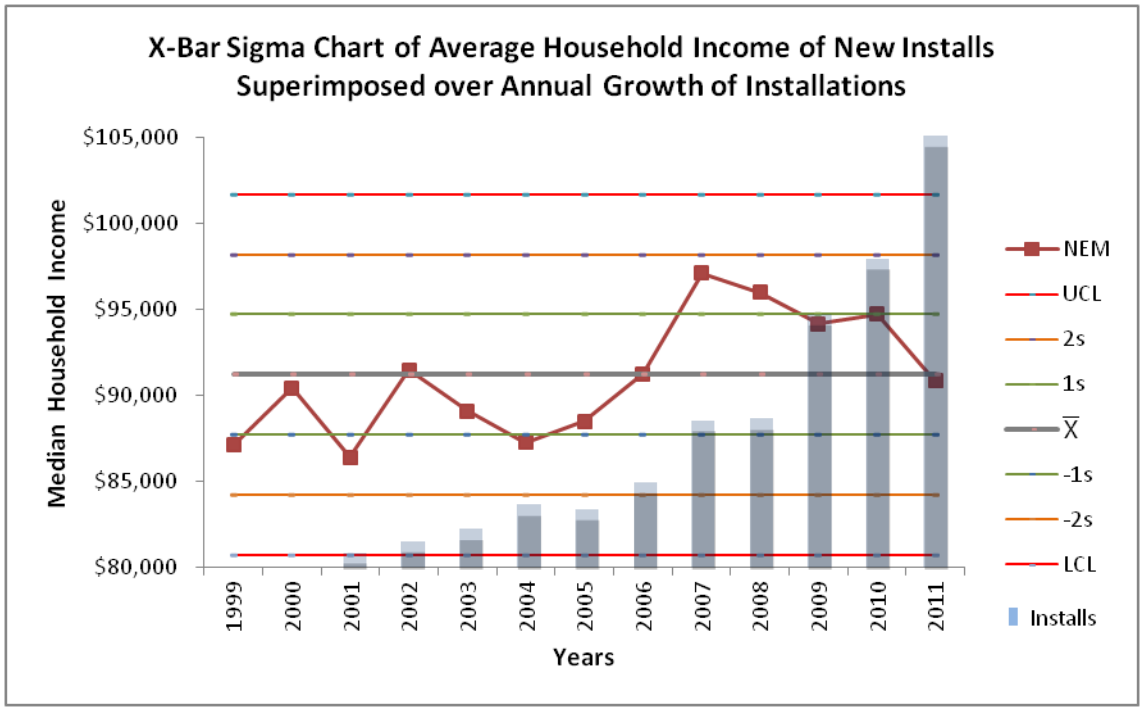


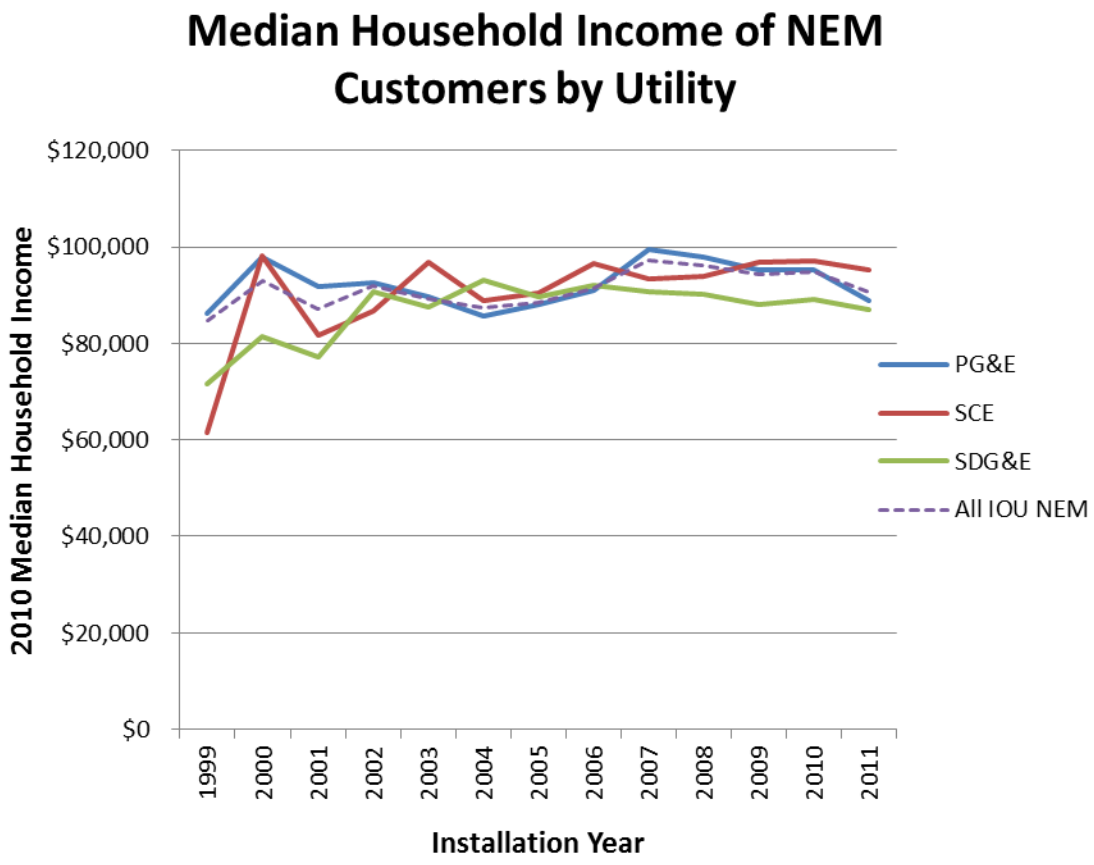
Table 5 disaggregates the averages of census tract median household income by each IOU.

Table 5: Means of Median Household Income by Utility from 1999-2011

Year	Statistics	Utility			
		PG&E	SCE	SDG&E	Total
1999	M	$ 86,251	$ 61,618	$ 71,666	$ 84,776
	S	$ 43,464	N/A	$ 28,662	$ 42,314
	N	69	1	6	76
2000	M	$ 97,787	$ 98,083	$ 81,304	$ 93,065
	S	$ 46,409	$ 40,412	$ 31,369	$ 42,388
	N	47	5	21	73
2001	M	$ 91,869	$ 81,674	$ 77,182	$ 87,100
	S	$ 42,043	$ 35,473	$ 24,588	$ 37,960
	N	524	20	241	785
2002	M	$ 92,446	$ 86,741	$ 90,776	$ 91,995
	S	$ 41,365	$ 31,794	$ 25,868	$ 38,414
	N	1,096	23	306	1,425
2003	M	$ 89,582	$ 96,749	$ 87,483	$ 89,259
	S	$ 39,660	$ 42,174	$ 32,131	$ 38,186
	N	1,628	42	473	2,143
2004	M	$ 85,763	$ 88,921	$ 92,976	$ 87,371
	S	$ 38,318	$ 37,129	$ 33,422	$ 37,403
	N	2,713	48	765	3,526
2005	M	$ 88,143	$ 90,457	$ 89,717	$ 88,560
	S	$ 41,174	$ 31,403	$ 33,331	$ 39,267
	N	2,443	39	818	3,300
2006	M	$ 90,904	$ 96,589	$ 92,046	$ 91,245
	S	$ 41,569	$ 40,326	$ 35,819	$ 40,579
	N	3,851	117	858	4,826
2007	M	$ 99,430	$ 93,434	$ 90,640	$ 97,319
	S	$ 46,288	$ 40,739	$ 30,762	$ 43,924
	N	5,832	1,591	918	8,341
2008	M	$ 97,832	$ 93,862	$ 90,257	$ 96,210
	S	$ 46,303	$ 41,284	$ 32,264	$ 44,103
	N	5,716	1,894	810	8,420
2009	M	$ 95,151	$ 96,758	$ 88,079	$ 94,290
	S	$ 43,782	$ 41,767	$ 31,627	$ 41,541
	N	8,563	3,327	2,509	14,399
2010	M	$ 95,155	$ 97,189	$ 89,192	$ 94,760
	S	$ 41,283	$ 40,529	$ 31,558	$ 39,686
	N	9,468	5,166	2,924	17,558
2011	M	$ 88,943	$ 95,252	$ 86,940	$ 90,686
	S	$ 41,677	$ 37,607	$ 29,231	$ 38,936
	N	13,172	7,946	3,560	24,678
Total	M	$ 91,390	$ 95,473	$ 86,058	$ 91,210
	S	$ 42,577	$ 39,435	$ 32,232	$ 40,426
	N	72,197	21,537	20,342	114,076

The averages of 2010 median household income for each utility shown in Table 5 are plotted in Figure 5. It can be seen that the decline in the averages of median household income after the year 2007 was less pronounced for SCE (which actually showed a slight *increase* in the averages of median household income) than it was for PG&E and SDG&E. After the first few start-up years, however, the averages of census tract median household income for each utility became fairly stable.

Figure 5: Means of Median Household Income by Utility from 1999-2011

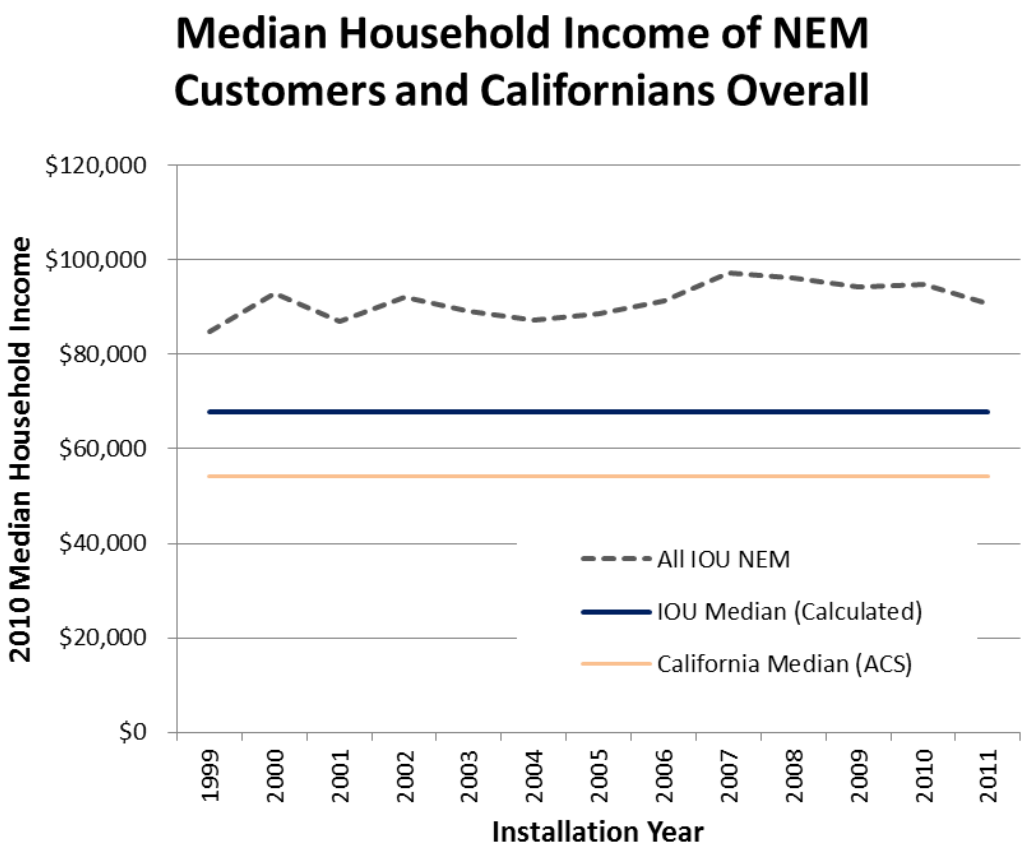


E-3.4 COMPARISONS WITH THE CALIFORNIA POPULATION

Household income data for the State of California were obtained for purposes of comparing differences between NEM customers and the California population. We use the American Community Survey 2010 Median Household Income for California overall which was $54,283 in

$2010.[5] Differences between the averages in median household income of NEM customers, all IOU customers, and the general population of California are shown in Figure 6. Across the thirteen years of available data, the annual census tract median household incomes of NEM customers were consistently higher than both reference household incomes.

Figure 6: NEM 2010 Household Income by Installation Year Compared to California Median Income



A more detailed analysis of the consistent pattern of income differences in Figure 6 can be found in Table 6. Across the 13 years, the census tract median household incomes of new NEM installations averaged 34.3% (or $23,279) higher overall than the median household income of all IOU customers. When the program was first beginning in 1999, the census tract household incomes for NEM were 30% higher than that of the general IOU customer population. As the NEM program developed and the number of new customers rose, the excesses in income peaked at 43% in 2007, but showed a gradual decline to around 34% in 2011.

[5] Available on the Internet at http://www.census.gov/hhes/www/income/data/statemedian/

Table 6: Percentage that NEM Household Income Exceeded the General Population

Year	*N*	Census Tract Medians for New NEM Customers, 2010 Inflation-Adjusted	Percentage Difference, 2010 Inflation-Adjusted Dollars	$ Difference
1999	88	$ 87,100	28.4	$19,279
2000	84	$ 90,429	33.3	$22,608
2001	817	$ 86,399	27.4	$18,578
2002	1,462	$ 91,494	34.9	$23,673
2003	2,173	$ 89,075	31.3	$21,254
2004	3,548	$ 87,241	28.6	$19,420
2005	3,301	$ 88,488	30.5	$20,667
2006	4,830	$ 91,247	34.5	$23,426
2007	8,392	$ 97,119	43.2	$29,298
2008	8,475	$ 95,985	41.5	$28,164
2009	14,461	$ 94,159	38.8	$26,338
2010	17,657	$ 94,736	39.7	$26,915
2011	24,678	$ 90,831	33.9	$23,010
Average	6,920	91,100	34.3	$23,279

* All averages are unweighted for annual sample size.

E-3.5 DISTRIBUTION NEM CUSTOMERS COMPARED TO CUSTOMERS OVERALL

We compared the distribution of median household income of NEM customers to residential customers at each utility based on the data provided by each utility on the percentiles of their overall population. Since each utility provided data on their overall customers in a different format, the percentiles for NEM customers were calculated to match. All results are reported in $2010 to align with 2010 Census Bureau Data. SDG&E provided the distribution in $2012, so an adjustment was made to make the dollars comparable.

For each utility this analysis shows that the household incomes of NEM customers are higher in almost every decile. In Table 7, below, the minimum, maximum, and midrange for each decile of PG&E residential customer median household income is reported along with the computed mean of the NEM customers for each decile. So, for example, mid-range of the 40% to 50% decile of PG&E

customers overall has a median household income of $53,868 while the mean of the NEM customers it the 40% to 50% decile has a median household income of $73,581.

Table 7: Residential Household Income for PG&E, 2010

Decile	Percentile Range	Minimum Median Income	Maximum Median Income	Pop. Midrange	%-tile	Mean of NEM Distribution
Lowest 10%	1 – 10	$2,499	$33,409	$ 17,954	5	$ 39,612
2nd 10%	11 – 20	$33,409	$42,361	$ 37,885	15	$ 54,469
3rd 10%	21 – 30	$42,361	$50,057	$ 46,209	25	$ 65,375
4th 10%	31 – 40	$50,057	$57,679	$ 53,868	35	$ 73,581
5th 10%	41– 50	$57,679	$66,000	$ 61,840	45	$ 83,981
6th 10%	51 – 60	$66,000	$75,268	$ 70,634	55	$ 93,929
7th 10%	60 – 70	$75,268	$85,926	$ 80,597	65	$ 104,514
8th 10%	71 – 80	$85,926	$99,931	$ 92,929	75	$ 118,019
9th 10%	81 – 90	$99,931	$119,792	$ 109,862	85	$ 136,875
Highest 10%	91 - 100	$119,792	$250,001	$ 184,897	95	$ 174,483

Table 9, below, provides similar information comparing household income of SCE to the residential NEM customers in SCE service territory. In this case, SCE provided the percentage of population by income group. For example, 16.28% of NEM customers have income between $75,000 and $99,999 while 15.64% of the population overall have household incomes in this range.

Table 9 Table 8, below, a similar comparison is made between the population overall and NEM customers for SDG&E. The format of this table is different to that of PG&E because the residential population information was provided in a different format. The assessment of NEM customers was made to correspond to the available information on the overall population. For SDG&E, the median SDG&E residential customer household income of $67,034 which can be compared to the median household income of residential NEM customers of $93,953.

Table 8: Average Household Income for SDG&E, 2010

%tile	Population in 2010	NEM 2010	Difference (NEM-Pop.)	% Difference
1	$ 26,049	$ 38,264	$ 12,215	47
5	$ 32,004	$ 50,450	$ 18,446	58
10	$ 38,083	$ 57,657	$ 19,574	51
25	$ 51,214	$ 73,175	$ 21,961	43
50	$ 67,034	$ 93,953	$ 26,919	40
75	$ 86,849	$ 119,590	$ 32,741	38
90	$ 112,126	$ 144,704	$ 32,578	29
95	$ 127,664	$ 163,624	$ 35,961	28
99	$ 155,923	$ 193,466	$ 37,543	24

Table 9, below, provides similar information comparing household income of SCE to the residential NEM customers in SCE service territory. In this case, SCE provided the percentage of population by income group. For example, 16.28% of NEM customers have income between $75,000 and $99,999 while 15.64% of the population overall have household incomes in this range.

Table 9: Household Income for SCE, 2012

Income Class	Percentage of SCE Residential Population	
	NEM	Non-NEM
< $15,000	2.03	6.39
$15,000 - $24,999	2.27	6.54
$25,000 - $34,999	2.87	7.41
$35,000 - $49,999	4.96	12.6
$50,000 - $74,999	13.97	20.77
$75,000 - $99,999	16.28	15.64
$100,000 - $124,999	11.67	10.01
$125,000 - $149,999	9.46	6.16
$150,000 - $174,999	9.68	4.18
$175,000 - $199,999	9.7	3.42
$200,000 - $249,999	5.91	3.13
$250,000+	10.54	3.12
Sum	**100**	**100**

E-3.6 COUNTIES

NEM participation was spread across 54 counties within the state. The means, standard deviation, and sample sizes of median household income for each county are shown in

Table 10. Counties that had the smallest numbers of NEM customers were in rural Northern California: Sierra (3), Trinity (4), and Lassen (6). The two counties with the highest number of NEM customers were both along the Southern California coastline: San Diego (13,030) and Los Angeles (6,077).

Table 10: Means of Median Household Income by County

County (A – P)	M	S	N	County (P – Y)	M	S	N
Alameda	$ 112,955	$ 45,834	4,616	Plumas	$ 43,572	$ 15,467	50
Amador	$ 54,255	$ 12,835	191	Riverside	$ 81,557	$ 27,399	4,014
Butte	$ 60,390	$ 18,818	950	Sacramento	$ 52,610	$ 29,531	15
Calaveras	$ 59,560	$ 14,056	357	San Benito	$ 62,720	$ 30,812	222
Colusa	$ 58,304	$ 12,947	62	San Bernardino	$ 85,856	$ 30,718	2,524
Contra Costa	$ 119,086	$ 47,060	4,638	San Diego	$ 86,364	$ 30,396	13,030
El Dorado	$ 90,657	$ 28,054	1,482	San Francisco	$ 91,403	$ 34,687	2,598
Fresno	$ 75,345	$ 27,273	4,100	San Joaquin	$ 73,557	$ 23,611	1,267
Glenn	$ 48,258	$ 13,869	133	San Luis Obispo	$ 74,218	$ 23,071	1,683
Humboldt	$ 44,820	$ 14,866	429	San Mateo	$ 135,728	$ 53,512	2,509
Inyo	$ 68,047	$ 8,998	47	Santa Barbara	$ 89,938	$ 32,369	1,047
Kern	$ 83,311	$ 30,639	2,263	Santa Clara	$ 125,645	$ 43,300	7,038
Kings	$ 63,306	$ 19,969	375	Santa Cruz	$ 77,820	$ 29,479	2,070
Lake	$ 46,326	$ 12,234	380	Shasta	$ 56,445	$ 18,946	415
Lassen	$ 60,469	$ 995	6	Sierra	$ 59,981	$ 30,819	3
Los Angeles	$ 102,985	$ 46,194	6,077	Solano	$ 90,219	$ 29,746	1,021
Madera	$ 60,009	$ 17,046	619	Sonoma	$ 79,631	$ 26,621	4,157
Marin	$ 108,558	$ 40,295	2,151	Stanislaus	$ 75,424	$ 24,906	227
Mariposa	$ 53,210	$ 14,931	85	Sutter	$ 61,051	$ 20,607	364
Mendocino	$ 47,959	$ 17,299	507	Tehama	$ 48,959	$ 11,209	202
Merced	$ 62,389	$ 20,219	328	Trinity	$ 37,007	$ 4,748	4
Mono	$ 70,981	$ 13,602	36	Tulare	$ 56,900	$ 21,381	987
Monterey	$ 73,210	$ 30,538	1,181	Tuolumne	$ 52,405	$ 14,667	235
Napa	$ 88,169	$ 30,262	780	Ventura	$ 107,647	$ 32,380	1,705
Nevada	$ 60,754	$ 13,196	896	Yolo	$ 70,413	$ 34,440	1,518
Orange	$ 111,636	$ 38,425	5,054	Yuba	$ 70,363	$ 19,689	307
Placer	$ 93,280	$ 30,070	2,454	**Total**	**$ 93,037**	**$ 40,601**	**89,409**

APPENDIX F:

PUBLIC MODEL USER GUIDE

October 28, 2013

Public Model User Guide

F-1 Model Overview

Built for the purposes of evaluating the costs and benefits of the net energy metering (NEM) program, the *E3 NEM Summary* model was constructed by Energy and Environmental Economics (E3) to inform the analysis used throughout this report. Though the model is designed for public use, the complexity of the question the model seeks to answer necessitates a certain amount of complexity in the model. As such, the purpose of this user guide is to help orient model users to be able to use the high level functionality of the tool, and to be able to interpret the resulting outputs.

F-1.1 MODEL STRUCTURE

The model consists of 14 tabs, each of which serves a unique purpose. This section outlines the contents of each tab.

Cover: This tab gives a model overview, briefly describes each tab, and provides a key to the color coding of cells used throughout the rest of the model.

Inputs: This tab contains the inputs used to define a run of the model. There are both general inputs, and those used to setup each scenario. Additionally, the buttons to call the macros that run the model are housed on this tab. Further detail on the use of this tab is provided in Section 0.

Lifetime Summary: This tab summarizes the results of the lifetime analysis performed on the Lifetime Calcs tab. Results are presented on a levelized $/kWh or a lifetime $/W basis for systems installed in a given year. All results tables and charts associated with the lifetime analysis reside on this tab.

Snapshot Summary: This tab summarizes the results of the snapshot analysis performed on the Snapshot Calcs tab. Results are presented on an absolute $/year basis for all systems installed prior to a single given snapshot year. All results tables and charts associated with the snapshot analysis reside on this tab.

NEMFC Summary: This tab summarizes the results of the lifetime fuel cell analysis performed on the NEMFC Calcs tab. Results are presented on a levelized $/kWh or a lifetime $/W basis for systems installed in 2012. All results tables and charts associated with the fuel cell analysis reside on this tab.

Lifetime Calcs: This tab combines the cost and benefit data contained within the Avoided Cost, Bills, and Program Costs tabs to calculate the costs and benefits of each customer bin contained in the model over the lifetime of a system installed in a given year (as identified by the Install year for Lifetime Analysis input on the Inputs tab). This tab also stores the customer bin characteristics used to identify each unique customer bin. This includes characteristics such as utility service area, rate, baseline territory, customer size, customer DG size, customer DG technology, and number of customers represented by each customer bin.

Snapshot Calcs: This tab combines the cost and benefit data contained within the Avoided Cost, Bills, and Program Costs tabs to calculate the costs and benefits of each customer bin contained in the model during a single year for all NEM installations installed prior to that given year (as identified by the Snapshot year for Snapshot Analysis input on the Inputs tab). Hardcoded customer characteristics are not stored on this tab, but rather on the Lifetime Calcs tab.

NEMFC Calcs: This tab combines the cost and benefit data of all NEMFC customer bins to calculate the costs and benefits over the lifetime of a system installed in 2012. Unlike the Lifetime Calcs and Snapshot Calcs tabs, this tab does not reference the Avoided Cost and Bills tabs, but rather contains the avoided cost and bill data for NEMFC customers in itself. Also, due to the small number of customer bins, it is not necessary to deactivate several rows of calculations as it is in the other calculation tabs.

Forecasts: This tab contains several forecasts that are crucial to model calculations. These forecasts include NEM and CSI enrollment, IOU revenue requirement, IOU load growth for tracking the NEM cap, retail rate escalation, gas price, carbon cost, and inflation. It should be noted that the forecasts of gas price, carbon cost, and inflation are not actively linked into the mode, but are used in external models that provide input to this model.

Avoided Cost: This tab contains the hardcoded lifetime NPV avoided costs that are calculated based on avoided cost streams calculated in the E3 avoided cost model and applied to each customer bin

in an external SAS model. These factors are differentiated by avoided cost scenario, the All Generation or Export Only case, avoided cost component, and vintage of DG system for each customer bin.

AC Annualization: This tab holds a series of factors used to convert the NPV avoided cost values stored in the Avoided Cost tab to single year values to be used in the Snapshot Calcs tab. These factors are differentiated by avoided cost scenario, the All Generation or Export Only case, avoided cost component, vintage of DG system, and year of snapshot.

Bills: This tab contains two of the bills calculated externally in the E3 Utility Bill Calculator. Bills are input for each customer and disaggregated by bill component. The components listed are Transmission (Trans), Distribution (Dist), Public Purpose Charges (PPC), Nuclear Decommissioning Fund (NDC), Competitive Transition Charges (CTC), Energy Cost Recovery (ECR), Department of Water Resources Bond Charge (DWR BC), Public Utilities Commission Reimbursement Fee (PUC RF), California Energy Commission Surcharge (CEC Surcharge), California Alternate Rates for Energy Surcharge (CARE Surcharge), and Net Surplus Compensation (NSC).

Program Costs: This tab contains utility program costs associated with interconnection, NEM billing, initial setup, and standby charges. The standby charges have been gleaned from IOU tariff sheets, while the other costs are an amalgamation of data obtained from the IOUs in a series of data requests by the CPUC. Some simplifying assumptions about how these charges are applied and allocated to various customers have been made in order to generalize these calculations across the IOUs in the model. Also, as SDG&E was unable to provide any program cost data, we assume their costs to be an average of PG&E and SCE costs.

Lists: This tab contains the lists used in the dropdown menus of the Inputs tab. Also, the named cells AC_Offset and Install_Year_Offset are stored on this tab.

F-1.2 KEY ASSUMPTIONS AND SIMPLIFICATIONS

Due to limitations of data and what can be reasonably built into an Excel model, several simplifications are made in the model. These simplifications aim to reduce model size and runtime and increase transparency to the user, all while not materially affecting the results. This section outlines the most noteworthy of these simplifications.

Avoided cost annualization factors: To carry in the model the full set of annual avoided costs for each of the 8,043 customer bins, 20 years of system lifetime, 14 vintages, 7 avoided cost components, 3 avoided cost scenarios, and 2 export/all-generation cases would require 95 million cells in Excel (for reference the Avoided Cost tab, which is the most data-heavy tab of the model, has less than 5 million cells). In order to keep model size and calculation time to a reasonable minimum, we create a set of annualization factors that are disaggregated by all of the above elements aside from customer bins. Because the relationship between an NPV value and a single year value is primarily a function of the discount rate and not a customer's unique hourly profile, using an average annualization factor across all customer bins is reasonable.

NEM forecast: In order to provide results for the year 2020 that involve full subscription of NEM, the forecast of NEM installations has been slightly accelerated. Trends of current installation levels would have the NEM cap reached somewhere between 2020 and 2025, but displaying values in 2020 gives the user a better context for understanding the results. Given the decreasing solar PV cost trends, this accelerated adoption may be realistic. Also, the calculation of the 5% cap is based on the CEC demand forecast of peak load by IOU, which is grossed up to non-coincident peak based on the IOUs presentation to the CPUC at the non-coincident peak workshop. The links to these data sources can be found in the model.

Load feedback: The demand forecast in this model is static – changing the NEM penetration level does not feed back into the demand forecast in any way. Similarly, the revenue requirement forecast does react to the selected gas price forecast, but does not react to the NEM penetration level.

Also, it is worth noting that, because a large number of complex active formulas quickly make a model extremely cumbersome, several rows of calculations are kept in a deactivated state. Where this is the case, the first row of the section is highlighted in dark blue and contains the active formulas for the entire section. When the model runs, the deactivated cells are temporarily reactivated to calculate.

F-1.3 EXTERNAL INPUTS TO THE MODEL

Due to the large amount of data required to calculate the costs and benefits of NEM, a large amount of preprocessing must be done outside of this public mode. This processing is done in a series of independent SAS and Excel modules, the results of which are fed into the public model. This section outlines the inputs to the model that are produced externally.

F-1.1.1 Customer Bins Characteristics

The most fundamental of all externally developed inputs to the model is the definition of the customer bins used to represent the entire population of NEM customers. This process is described in detail in Appendix A. The final products of this are a list of customer bin characteristics and a half-hourly load and generation profile for each customer bin over a typical meteorological year. The former of these products is stored in columns A through U of the Lifetime Calcs tab, while the latter is too large a dataset to be stored anywhere in the public model. However, the annual generated and exported kWh for each DG system, based on system age, is stored in columns CU through EI of the Lifetime Calcs tab.

F-1.1.2 Avoided Costs

Located on the Avoided Cost tab, the avoided costs values represent the 20-year NPV avoided cost in nominal dollars attributed to a DG system installed in a given year for each customer bin. These values are calculated in an external SAS module, which combines the hourly avoided costs for each climate zone developed by the E3 Avoided Cost model with the hourly generation profiles of each customer bin developed by the SAS load research module.

Also calculated externally are the factors contained on the AC Annualization tab. These factors are used by the Snapshot calculations to convert NPV avoided costs into single-year avoided costs. These factors are developed empirically in an external SAS model as the NPV avoided cost values are calculated. Because this conversion of an NPV value to a single-year value is primarily a function of the discount rate and the escalation of avoided costs, using an average value across all customer bins is a reasonable simplification.

F-1.1.3 Utility Bills

Located on the Bills tab, the bill values represent the single year bill for each customer bin using 2011 rates. These values are calculated in the *E3 Utility Bill Calculator* model, which is described in detail in Appendix B. In the *E3 NEM Summary* model, these values are escalated to the proper calculation year by the cumulative retail rate escalation found in the Forecasts tab. Additionally, because an older more degraded DG system will have less output, and therefore do less to offset a customer's bill, we run a second set of bills using load profiles that include 20 years of system degradation. Depending on the age of a system, a linear interpolation between the new-system bill and the degraded-system bill is used.

Another consideration in the calculation of bill savings is that a customer may switch from one rate to another upon installation of DG in order to take advantage of a TOU pricing structure, or a rate with lower fixed components and a higher energy component. For these customers, an accurate calculation of bill savings compares a bill that uses net load and the customers' new rate to a bill that uses gross load and the customers' old rate. To account for this, we also run a set of bills that uses gross load and each customer's old rate code; these are found beginning in row 24,144 of the Bills tab. Where we do not assume any different former rate, the bill value is set to zero. Furthermore, because each customer bin represents many customers, we only apply the bill using the former rate code to a certain percentage of each bin, specified in column G of the Lifetime Calcs tab.

F-2 Using the Model

The typical model user should be able to run any cases he or she wishes to see by only modifying the Inputs tab of the model, and should find all the desired outputs on the set of three Summary tabs. This section explains each of the inputs located on the Inputs tab and goes on to give a set of sample results to help the reader understand how to interpret results.

F-1.4 INPUTS AND RUNNING THE MODEL

The tables in this section provide a list of all of the inputs to the model and the buttons used to call the macros that run the model.

The inputs of Table 1 are those used to create a single scenario to be run. These inputs allow the user to select the avoided cost scenario, the weights given to each avoided cost component, any scaling done to program costs, and whether or not standby charges are included in the bill savings calculation. The inputs of this section listed under the Active Case are the inputs that will actually be used in the calculation of the model when the Run Model button is pressed. The inputs listed under the headings of Base Case, Low Case, and High Case are used when the Run All Sensitivities button is pressed.

Table 1: Scenario Inputs

Input	Effect	Default value
Avoided Costs		
Avoided Cost Scenario	Selects among the Base Case, High Case, or Low Case for avoided costs. The differences between these cases lie in the resource balance year, CO2 price, and gas price forecasts.	Base Case
Component Adjustment Multipliers	Allows the user to increase or attenuate the extent to which each avoided cost component is included in the aggregate avoided cost calculation. The components that can be adjusted are energy, losses, capacity, ancillary services, transmission and distribution, CO2 price, and RPS adder.	100% (for each component)
Program Costs		
Metering and Set-up Cost Multiplier	Allows the user to increase or reduce the cost of metering and set-up to the utilities.	100%
Interconnection Cost Multiplier	Allows the user to increase or reduce the cost of interconnection to the utilities. Since little data is currently available on interconnection cost, this input does not necessarily have a ceiling at 100%.	100%
Integration Cost ($/MWh)	Introduces a $/MWh cost to the system associated with balancing the energy produced by each DG system.	0 $/MWh
Bill Savings		
Include Standby Charges in Bill Savings	A true/false toggle to determine whether a customer's bill savings includes the added benefit of not paying standby charges.	FALSE

The inputs of Table 2 are more general than those in Table 1. Most notably, these inputs allow the user to select the years used for the Snapshot Analysis and the Lifetime Analysis, and the penetration level. This section also contains inputs that are referred to as being "partially active,"

which affect only some components of the model. As a result, these inputs exist largely to make the user aware of the values and should not be changed unless the external inputs to the model are also being reloaded. For example, changing the year of retail rates would necessitate that the retail rates be re-run and new bill values be loaded into the Bills tab. Similarly, the discount rate and DG degradation factor are used in the external avoided cost code, so changing these inputs would require the user to rerun the avoided costs and place these updated values in the Avoided Cost and AC Annualization tabs.

Table 2: General Inputs

Input	Effect	Default value
Fully Active Inputs		
Snapshot year for Snapshot Analysis	Selects the year of the snapshot analysis. This selection is the single year we look at for the dollar-per-year cost-benefit analysis, and all systems installed in this year or before are considered.	2020
Install year for Lifetime Analysis	Selects the install year for the lifetime analysis. This selection is the starting year of the 20-year life assumed for each system, and only systems installed in this year are considered.	2012
Penetration Level	Allows the user to choose between three different DG penetration levels; installations through 2012, full CSI subscription, or full NEM subscription. Once the selected level is attained, no further installations are assumed.	NEM 5% Cap
Dollar Year for Reporting Snapshot Results	Selects the currency vintage (in US $) of the snapshot analysis results. Allows the user to adjust the results for price level.	2012
Partially Active Inputs		
Year of retail rates used in bills tab	Indicates the vintage year of the rates being used by the bill calculator to develop the bills in the Bills tab. This input should only be changed if a new set of bills is loaded into the model that uses rates based on a different year than 2011.	2011
Discount Rate	The discount rate used to calculate NPV values throughout the model. The default assumption is a state-wide after-tax Weighted Average Cost of Capital (WACC) to the IOUs.	6.96%
20-year Real Annualization Factor	A factor used to convert total NPV results to annualized results.	8.80%
DG Degradation Factor	The annual degradation assumed to occur in each DG system.	1.00%

Table 3 gives the buttons used to run the model. “Run model” updates the active case results in the Snapshot Summary tab and all of the non-sensitivity related results in the Lifetime Summary tab. “Run for all penetration levels” updates the hardcoded penetration level results in columns F-H and M-O of the Snapshot Summary tab; this button does not update the Lifetime Summary results. “Run all sensitivities” updates every value on both the Snapshot Summary and Lifetime Summary tabs; this takes close to 15 minutes to run. Because the fuel cell analysis contains very few customer bins, those formulas are left active, and so the results update any time F9 is hit to calculate the workbook.

Table 3: Buttons Used to Run the Model

Button	Approx. Runtime	Action
Run model	2 minutes	Updates all values on Lifetime Calcs and Snapshot Calcs tabs for Active Case specified in the scenario inputs section and Penetration Level specified in the general inputs section.
Run for all penetration levels	5 minutes	Updates all values only on Snapshot Calcs tab for Active Case specified in scenario inputs section at all possible Penetration Levels.
Run all sensitivities	15 minutes	Updates all values on Lifetime Calcs and Snapshot Calcs for all scenarios specified in scenario inputs section at all possible Penetration Levels.

APPENDIX G:

Assembly Bill 2514 and

Public Utilities Code

October 28, 2013

Assembly Bill 2514 (Bradford, 2012)

An act to amend Section 2827.8 of, and to add and repeal Section 2827.1 of, the Public Utilities Code, relating to electricity.

[Approved by Governor September 27, 2012. Filed Secretary of State September 27, 2012.]

LEGISLATIVE COUNSEL'S DIGEST

AB 2514, Bradford. Net energy metering.

Under existing law, the Public Utilities Commission has regulatory authority over public utilities, including electrical corporations. Existing law, relative to private energy producers, requires every electric utility, as defined, to make available to an eligible customer-generator, as defined, a standard contract or tariff for net energy metering on a first-come-first-served basis until the time that the total rated generating capacity of renewable electrical generation facilities, as defined, used by eligible customer-generators exceeds 5% of the electric utility's aggregate customer peak demand. The existing definition of an eligible customer-generator requires that the generating facility use a solar or wind turbine, or a hybrid system of both, and have a generating capacity of not more than one megawatt. Electrical corporations are an electric utility for these purposes.

This bill would require the commission to complete a study by October 1, 2013, to determine who benefits from, and who bears the economic burden, if any, of, the net energy metering program, and to determine the extent to which each class of ratepayers and each region of the state receiving service under the net energy metering program is paying the full cost of the services provided to them by electrical corporations, and the extent to which those

customers pay their share of the costs of public purpose programs. The bill would require the commission to report the results of the study to the Legislature within 30 days of its completion.

Existing law establishes separate requirements for wind energy co-metering that provides a credit against the generation component of an electricity bill of an electric utility for those customer-generators utilizing a wind energy project greater than 50 kilowatts, but not exceeding one megawatt. The wind energy co-metering provisions include a requirement that the eligible customer-generator utilize a meter, or multiple meters, capable of separately measuring electricity flow in both directions.

This bill would state that nothing in the wind energy co-metering provisions precludes the use of advanced metering infrastructure devices.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1.

Section 2827.1 is added to the Public Utilities Code, to read:

2827.1.

(a) By October 1, 2013, the commission shall complete a study to determine who benefits from, and who bears the economic burden, if any, of, the net energy metering program authorized pursuant to Section 2827, and to determine the extent to which each class of ratepayers and each region of the state receiving service under the net energy metering program is paying the full cost of the services provided to them by electrical corporations, and the extent to which those customers pay their share of the costs of public purpose programs. In evaluating program costs and benefits for purposes of the study, the commission shall consider all electricity generated by renewable electric generating systems, including the electricity used onsite to reduce a customer's consumption of electricity that otherwise would be supplied through the electrical grid, as well as the electrical output that is being fed back to the electrical grid for which the customer receives credit or net surplus electricity compensation under net energy metering. The study shall quantify the costs and benefits of net energy metering to

participants and nonparticipants and shall further disaggregate the results by utility, customer class, and household income groups within the residential class. The study shall further gather and present data on the income distribution of residential net energy metering participants. In order to assess the costs and benefits at various levels of net energy metering implementation, the study shall be conducted using multiple net energy metering penetration scenarios, including, at a minimum, the capacity needed to reach the solar photovoltaic goals of the California Solar Initiative pursuant to Section 25780 of the Public Resources Code, and the estimated net energy metering capacity under the 5-percent minimum requirement of paragraphs (1) and (4) of subdivision (c) of Section 2827.

(b) (1) The commission shall report the results of the study to the Legislature within 30 days of its completion.

(2) The report shall be submitted in compliance with Section 9795 of the Government Code.

(3) Pursuant to Section 10231.5 of the Government Code, this section is repealed on July 1, 2017.

SEC. 2.

Section 2827.8 of the Public Utilities Code is amended to read:

2827.8.

Notwithstanding any other provisions of this article, the following provisions apply to an eligible customer-generator utilizing wind energy co-metering with a capacity of more than 50 kilowatts, but not exceeding one megawatt, unless approved by the electric service provider.

(a) The eligible customer-generator shall be required to utilize a meter, or multiple meters, capable of separately measuring electricity flow in both directions. Nothing in this section precludes the use of advanced metering infrastructure devices. All meters shall provide “time-of-use” measurements of electricity flow, and the customer shall take service on a time-of-use rate schedule. If the existing meter of the eligible customer-generator is not a time-of-use meter or is not capable of measuring total flow of energy in

both directions, the eligible customer-generator is responsible for all expenses involved in purchasing and installing a meter that is both time-of-use and able to measure total electricity flow in both directions. This subdivision shall not restrict the ability of an eligible customer-generator to utilize any economic incentives provided by a government agency or the electric service provider to reduce its costs for purchasing and installing a time-of-use meter.

(b) The consumption of electricity from the electric service provider for wind energy co-metering by an eligible customer-generator shall be priced in accordance with the standard rate charged to the eligible customer-generator in accordance with the rate structure to which the customer would be assigned if the customer did not use an eligible wind electrical generating facility. The generation of electricity provided to the electric service provider shall result in a credit to the eligible customer-generator and shall be priced in accordance with the generation component, excluding surcharges to cover the purchase of power by the Department of Water Resources, established under the applicable structure to which the customer would be assigned if the customer did not use an eligible wind electrical generating facility.

Public Utilities Code 2827 on Net Energy Metering

2827. (a) The Legislature finds and declares that a program to provide net energy metering combined with net surplus compensation, co-energy metering, and wind energy co-metering for eligible customer-generators is one way to encourage substantial private investment in renewable energy resources, stimulate in-state economic growth, reduce demand for electricity during peak consumption periods, help stabilize California's energy supply infrastructure, enhance the continued diversification of California's energy resource mix, reduce interconnection and administrative costs for electricity suppliers, and encourage conservation and efficiency.

(b) As used in this section, the following terms have the following meanings:

(1) "Co-energy metering" means a program that is the same in all other respects as a net energy metering program, except that the local publicly owned electric utility has elected to apply a generation-to-generation energy and time-of-use credit formula as provided in subdivision (i).

(2) "Electrical cooperative" means an electrical cooperative as defined in Section 2776.

(3) "Electric utility" means an electrical corporation, a local publicly owned electric utility, or an electrical cooperative, or any other entity, except an electric service provider, that offers electrical service. This section shall not apply to a local publicly owned electric utility that serves more than 750,000 customers and that also conveys water to its customers.

(4) "Eligible customer-generator" means a residential customer,

small commercial customer as defined in subdivision (h) of Section 331, or commercial, industrial, or agricultural customer of an electric utility, who uses a renewable electrical generation facility, or a combination of those facilities, with a total capacity of not more than one megawatt, that is located on the customer's owned, leased, or rented premises, and is interconnected and operates in parallel with the electrical grid, and is intended primarily to offset part or all of the customer's own electrical requirements.

(5) "Renewable electrical generation facility" means a facility that generates electricity from a renewable source listed in paragraph (1) of subdivision (a) of Section 25741 of the Public Resources Code. A small hydroelectric generation facility is not an eligible renewable electrical generation facility if it will cause an adverse impact on instream beneficial uses or cause a change in the volume or timing of streamflow.

(6) "Net energy metering" means measuring the difference between the electricity supplied through the electrical grid and the electricity generated by an eligible customer-generator and fed back to the electrical grid over a 12-month period as described in subdivisions (c) and (h).

(7) "Net surplus customer-generator" means an eligible customer-generator that generates more electricity during a 12-month period than is supplied by the electric utility to the eligible customer-generator during the same 12-month period.

(8) "Net surplus electricity" means all electricity generated by an eligible customer-generator measured in kilowatthours over a 12-month period that exceeds the amount of electricity consumed by that eligible customer-generator.

(9) "Net surplus electricity compensation" means a per kilowatthour rate offered by the electric utility to the net surplus customer-generator for net surplus electricity that is set by the ratemaking authority pursuant to subdivision (h).

(10) "Ratemaking authority" means, for an electrical corporation, the commission, for an electrical cooperative, its ratesetting body selected by its shareholders or members, and for a local publicly owned electric utility, the local elected body responsible for setting the rates of the local publicly owned utility.

(11) "Wind energy co-metering" means any wind energy project greater than 50 kilowatts, but not exceeding one megawatt, where the

difference between the electricity supplied through the electrical grid and the electricity generated by an eligible customer-generator and fed back to the electrical grid over a 12-month period is as described in subdivision (h). Wind energy co-metering shall be accomplished pursuant to Section 2827.8.

(c) (1) Every electric utility shall develop a standard contract or tariff providing for net energy metering, and shall make this standard contract or tariff available to eligible customer-generators, upon request, on a first-come-first-served basis until the time that the total rated generating capacity used by eligible customer-generators exceeds 5 percent of the electric utility's aggregate customer peak demand. Net energy metering shall be accomplished using a single meter capable of registering the flow of electricity in two directions. An additional meter or meters to monitor the flow of electricity in each direction may be installed with the consent of the eligible customer-generator, at the expense of the electric utility, and the additional metering shall be used only to provide the information necessary to accurately bill or credit the eligible customer-generator pursuant to subdivision (h), or to collect generating system performance information for research purposes relative to a renewable electrical generation facility. If the existing electrical meter of an eligible customer-generator is not capable of measuring the flow of electricity in two directions, the eligible customer-generator shall be responsible for all expenses involved in purchasing and installing a meter that is able to measure electricity flow in two directions. If an additional meter or meters are installed, the net energy metering calculation shall yield a result identical to that of a single meter. An eligible customer-generator that is receiving service other than through the standard contract or tariff may elect to receive service through the standard contract or tariff until the electric utility reaches the generation limit set forth in this paragraph. Once the generation limit is reached, only eligible customer-generators that had previously elected to receive service pursuant to the standard contract or tariff have a right to continue to receive service pursuant to the standard contract or tariff. Eligibility for net energy metering does not limit an eligible customer-generator's eligibility for any other rebate, incentive, or credit provided by the electric utility, or pursuant to any governmental program,

including rebates and incentives provided pursuant to the California Solar Initiative.

(2) An electrical corporation shall include a provision in the net energy metering contract or tariff requiring that any customer with an existing electrical generating facility and meter who enters into a new net energy metering contract shall provide an inspection report to the electrical corporation, unless the electrical generating facility and meter have been installed or inspected within the previous three years. The inspection report shall be prepared by a California licensed contractor who is not the owner or operator of the facility and meter. A California licensed electrician shall perform the inspection of the electrical portion of the facility and meter.

(3) (A) On an annual basis, every electric utility shall make available to the ratemaking authority information on the total rated generating capacity used by eligible customer-generators that are customers of that provider in the provider's service area and the net surplus electricity purchased by the electric utility pursuant to this section.

(B) An electric service provider operating pursuant to Section 394 shall make available to the ratemaking authority the information required by this paragraph for each eligible customer-generator that is their customer for each service area of an electrical corporation, local publicly owned electrical utility, or electrical cooperative, in which the eligible customer-generator has net energy metering.

(C) The ratemaking authority shall develop a process for making the information required by this paragraph available to electric utilities, and for using that information to determine when, pursuant to paragraphs (1) and (4), an electric utility is not obligated to provide net energy metering to additional eligible customer-generators in its service area.

(4) An electric utility is not obligated to provide net energy metering to additional eligible customer-generators in its service area when the combined total peak demand of all electricity used by eligible customer-generators served by all the electric utilities in that service area furnishing net energy metering to eligible customer-generators exceeds 5 percent of the aggregate customer peak demand of those electric utilities.

(d) Every electric utility shall make all necessary forms and

contracts for net energy metering and net surplus electricity compensation service available for download from the Internet.

(e) (1) Every electric utility shall ensure that requests for establishment of net energy metering and net surplus electricity compensation are processed in a time period not exceeding that for similarly situated customers requesting new electric service, but not to exceed 30 working days from the date it receives a completed application form for net energy metering service or net surplus electricity compensation, including a signed interconnection agreement from an eligible customer-generator and the electric inspection clearance from the governmental authority having jurisdiction.

(2) Every electric utility shall ensure that requests for an interconnection agreement from an eligible customer-generator are processed in a time period not to exceed 30 working days from the date it receives a completed application form from the eligible customer-generator for an interconnection agreement.

(3) If an electric utility is unable to process a request within the allowable timeframe pursuant to paragraph (1) or (2), it shall notify the eligible customer-generator and the ratemaking authority of the reason for its inability to process the request and the expected completion date.

(f) (1) If a customer participates in direct transactions pursuant to paragraph (1) of subdivision (b) of Section 365, or Section 365.1, with an electric service provider that does not provide distribution service for the direct transactions, the electric utility that provides distribution service for the eligible customer-generator is not obligated to provide net energy metering or net surplus electricity compensation to the customer.

(2) If a customer participates in direct transactions pursuant to paragraph (1) of subdivision (b) of Section 365 with an electric service provider, and the customer is an eligible customer-generator, the electric utility that provides distribution service for the direct transactions may recover from the customer's electric service provider the incremental costs of metering and billing service related to net energy metering and net surplus electricity compensation in an amount set by the ratemaking authority.

(g) Except for the time-variant kilowatthour pricing portion of any tariff adopted by the commission pursuant to paragraph (4) of

subdivision (a) of Section 2851, each net energy metering contract or tariff shall be identical, with respect to rate structure, all retail rate components, and any monthly charges, to the contract or tariff to which the same customer would be assigned if the customer did not use a renewable electrical generation facility, except that eligible customer-generators shall not be assessed standby charges on the electrical generating capacity or the kilowatthour production of a renewable electrical generation facility. The charges for all retail rate components for eligible customer-generators shall be based exclusively on the customer-generator's net kilowatthour consumption over a 12-month period, without regard to the eligible customer-generator's choice as to from whom it purchases electricity that is not self-generated. Any new or additional demand charge, standby charge, customer charge, minimum monthly charge, interconnection charge, or any other charge that would increase an eligible customer-generator's costs beyond those of other customers who are not eligible customer-generators in the rate class to which the eligible customer-generator would otherwise be assigned if the customer did not own, lease, rent, or otherwise operate a renewable electrical generation facility is contrary to the intent of this section, and shall not form a part of net energy metering contracts or tariffs.

(h) For eligible customer-generators, the net energy metering calculation shall be made by measuring the difference between the electricity supplied to the eligible customer-generator and the electricity generated by the eligible customer-generator and fed back to the electrical grid over a 12-month period. The following rules shall apply to the annualized net metering calculation:

(1) The eligible residential or small commercial customer-generator, at the end of each 12-month period following the date of final interconnection of the eligible customer-generator's system with an electric utility, and at each anniversary date thereafter, shall be billed for electricity used during that 12-month period. The electric utility shall determine if the eligible residential or small commercial customer-generator was a net consumer or a net surplus customer-generator during that period.

(2) At the end of each 12-month period, where the electricity supplied during the period by the electric utility exceeds the electricity generated by the eligible residential or small commercial

customer-generator during that same period, the eligible residential or small commercial customer-generator is a net electricity consumer and the electric utility shall be owed compensation for the eligible customer-generator's net kilowatthour consumption over that 12-month period. The compensation owed for the eligible residential or small commercial customer-generator's consumption shall be calculated as follows:

(A) For all eligible customer-generators taking service under contracts or tariffs employing "baseline" and "over baseline" rates, any net monthly consumption of electricity shall be calculated according to the terms of the contract or tariff to which the same customer would be assigned to, or be eligible for, if the customer was not an eligible customer-generator. If those same customer-generators are net generators over a billing period, the net kilowatthours generated shall be valued at the same price per kilowatthour as the electric utility would charge for the baseline quantity of electricity during that billing period, and if the number of kilowatthours generated exceeds the baseline quantity, the excess shall be valued at the same price per kilowatthour as the electric utility would charge for electricity over the baseline quantity during that billing period.

(B) For all eligible customer-generators taking service under contracts or tariffs employing time-of-use rates, any net monthly consumption of electricity shall be calculated according to the terms of the contract or tariff to which the same customer would be assigned, or be eligible for, if the customer was not an eligible customer-generator. When those same customer-generators are net generators during any discrete time-of-use period, the net kilowatthours produced shall be valued at the same price per kilowatthour as the electric utility would charge for retail kilowatthour sales during that same time-of-use period. If the eligible customer-generator's time-of-use electrical meter is unable to measure the flow of electricity in two directions, paragraph (1) of subdivision (c) shall apply.

(C) For all eligible residential and small commercial customer-generators and for each billing period, the net balance of moneys owed to the electric utility for net consumption of electricity or credits owed to the eligible customer-generator for net generation of electricity shall be carried forward as a monetary

value until the end of each 12-month period. For all eligible commercial, industrial, and agricultural customer-generators, the net balance of moneys owed shall be paid in accordance with the electric utility's normal billing cycle, except that if the eligible commercial, industrial, or agricultural customer-generator is a net electricity producer over a normal billing cycle, any excess kilowatthours generated during the billing cycle shall be carried over to the following billing period as a monetary value, calculated according to the procedures set forth in this section, and appear as a credit on the eligible commercial, industrial, or agricultural customer-generator's account, until the end of the annual period when paragraph (3) shall apply.

(3) At the end of each 12-month period, where the electricity generated by the eligible customer-generator during the 12-month period exceeds the electricity supplied by the electric utility during that same period, the eligible customer-generator is a net surplus customer-generator and the electric utility, upon an affirmative election by the net surplus customer-generator, shall either (A) provide net surplus electricity compensation for any net surplus electricity generated during the prior 12-month period, or (B) allow the net surplus customer-generator to apply the net surplus electricity as a credit for kilowatthours subsequently supplied by the electric utility to the net surplus customer-generator. For an eligible customer-generator that does not affirmatively elect to receive service pursuant to net surplus electricity compensation, the electric utility shall retain any excess kilowatthours generated during the prior 12-month period. The eligible customer-generator not affirmatively electing to receive service pursuant to net surplus electricity compensation shall not be owed any compensation for the net surplus electricity unless the electric utility enters into a purchase agreement with the eligible customer-generator for those excess kilowatthours. Every electric utility shall provide notice to eligible customer-generators that they are eligible to receive net surplus electricity compensation for net surplus electricity, that they must elect to receive net surplus electricity compensation, and that the 12-month period commences when the electric utility receives the eligible customer-generator's election. For an electric utility that is an electrical corporation or electrical cooperative, the commission may adopt requirements for providing notice and the manner

by which eligible customer-generators may elect to receive net surplus electricity compensation.

(4) (A) An eligible customer-generator with multiple meters may elect to aggregate the electrical load of the meters located on the property where the renewable electrical generation facility is located and on all property adjacent or contiguous to the property on which the renewable electrical generation facility is located, if those properties are solely owned, leased, or rented by the eligible customer-generator. If the eligible customer-generator elects to aggregate the electric load pursuant to this paragraph, the electric utility shall use the aggregated load for the purpose of determining whether an eligible customer-generator is a net consumer or a net surplus customer-generator during a 12-month period.

(B) If an eligible customer-generator chooses to aggregate pursuant to subparagraph (A), the eligible customer-generator shall be permanently ineligible to receive net surplus electricity compensation, and the electric utility shall retain any kilowatthours in excess of the eligible customer-generator's aggregated electrical load generated during the 12-month period.

(C) If an eligible customer-generator with multiple meters elects to aggregate the electrical load of those meters pursuant to subparagraph (A), and different rate schedules are applicable to service at any of those meters, the electricity generated by the renewable electrical generation facility shall be allocated to each of the meters in proportion to the electrical load served by those meters. For example, if the eligible customer-generator receives electric service through three meters, two meters being at an agricultural rate that each provide service to 25 percent of the customer's total load, and a third meter, at a commercial rate, that provides service to 50 percent of the customer's total load, then 50 percent of the electrical generation of the eligible renewable generation facility shall be allocated to the third meter that provides service at the commercial rate and 25 percent of the generation shall be allocated to each of the two meters providing service at the agricultural rate. This proportionate allocation shall be computed each billing period.

(D) This paragraph shall not become operative for an electrical corporation unless the commission determines that allowing eligible customer-generators to aggregate their load from multiple meters will

not result in an increase in the expected revenue obligations of customers who are not eligible customer-generators. The commission shall make this determination by September 30, 2013. In making this determination, the commission shall determine if there are any public purpose or other noncommodity charges that the eligible customer-generators would pay pursuant to the net energy metering program as it exists prior to aggregation, that the eligible customer-generator would not pay if permitted to aggregate the electrical load of multiple meters pursuant to this paragraph.

(E) A local publicly owned electric utility or electrical cooperative shall only allow eligible customer-generators to aggregate their load if the utility's ratemaking authority determines that allowing eligible customer-generators to aggregate their load from multiple meters will not result in an increase in the expected revenue obligations of customers that are not eligible customer-generators. The ratemaking authority of a local publicly owned electric utility or electrical cooperative shall make this determination within 180 days of the first request made by an eligible customer-generator to aggregate their load. In making the determination, the ratemaking authority shall determine if there are any public purpose or other noncommodity charges that the eligible customer-generator would pay pursuant to the net energy metering or co-energy metering program of the utility as it exists prior to aggregation, that the eligible customer-generator would not pay if permitted to aggregate the electrical load of multiple meters pursuant to this paragraph. If the ratemaking authority determines that load aggregation will not cause an incremental rate impact on the utility's customers that are not eligible customer-generators, the local publicly owned electric utility or electrical cooperative shall permit an eligible customer-generator to elect to aggregate the electrical load of multiple meters pursuant to this paragraph. The ratemaking authority may reconsider any determination made pursuant to this subparagraph in a subsequent public proceeding.

(F) For purposes of this paragraph, parcels that are divided by a street, highway, or public thoroughfare are considered contiguous, provided they are otherwise contiguous and under the same ownership.

(G) An eligible customer-generator may only elect to aggregate the electrical load of multiple meters if the renewable electrical generation facility, or a combination of those facilities, has a

total generating capacity of not more than one megawatt.

(H) Notwithstanding subdivision (g), an eligible customer-generator electing to aggregate the electrical load of multiple meters pursuant to this subdivision shall remit service charges for the cost of providing billing services to the electric utility that provides service to the meters.

(5) (A) The ratemaking authority shall establish a net surplus electricity compensation valuation to compensate the net surplus customer-generator for the value of net surplus electricity generated by the net surplus customer-generator. The commission shall establish the valuation in a ratemaking proceeding. The ratemaking authority for a local publicly owned electric utility shall establish the valuation in a public proceeding. The net surplus electricity compensation valuation shall be established so as to provide the net surplus customer-generator just and reasonable compensation for the value of net surplus electricity, while leaving other ratepayers unaffected. The ratemaking authority shall determine whether the compensation will include, where appropriate justification exists, either or both of the following components:

(i) The value of the electricity itself.

(ii) The value of the renewable attributes of the electricity.

(B) In establishing the rate pursuant to subparagraph (A), the ratemaking authority shall ensure that the rate does not result in a shifting of costs between eligible customer-generators and other bundled service customers.

(6) (A) Upon adoption of the net surplus electricity compensation rate by the ratemaking authority, any renewable energy credit, as defined in Section 399.12, for net surplus electricity purchased by the electric utility shall belong to the electric utility. Any renewable energy credit associated with electricity generated by the eligible customer-generator that is utilized by the eligible customer-generator shall remain the property of the eligible customer-generator.

(B) Upon adoption of the net surplus electricity compensation rate by the ratemaking authority, the net surplus electricity purchased by the electric utility shall count toward the electric utility's renewables portfolio standard annual procurement targets for the purposes of paragraph (1) of subdivision (b) of Section 399.15, or for a local publicly owned electric utility, the renewables portfolio

standard annual procurement targets established pursuant to Section 387.

(7) The electric utility shall provide every eligible residential or small commercial customer-generator with net electricity consumption and net surplus electricity generation information with each regular bill. That information shall include the current monetary balance owed the electric utility for net electricity consumed, or the net surplus electricity generated, since the last 12-month period ended. Notwithstanding this subdivision, an electric utility shall permit that customer to pay monthly for net energy consumed.

(8) If an eligible residential or small commercial customer-generator terminates the customer relationship with the electric utility,

the electric utility shall reconcile the eligible customer-generator's consumption and production of electricity during any part of a 12-month period following the last reconciliation, according to the requirements set forth in this subdivision, except that those requirements shall apply only to the months since the most recent 12-month bill.

(9) If an electric service provider or electric utility providing net energy metering to a residential or small commercial customer-generator ceases providing that electric service to that customer during any 12-month period, and the customer-generator enters into a new net energy metering contract or tariff with a new electric service provider or electric utility, the 12-month period, with respect to that new electric service provider or electric utility, shall commence on the date on which the new electric service provider or electric utility first supplies electric service to the customer-generator.

(i) Notwithstanding any other provisions of this section, paragraphs (1), (2), and (3) shall apply to an eligible customer-generator with a capacity of more than 10 kilowatts, but not exceeding one megawatt, that receives electric service from a local publicly owned electric utility that has elected to utilize a co-energy metering program unless the local publicly owned electric utility chooses to provide service for eligible customer-generators with a capacity of more than 10 kilowatts in accordance with

subdivisions (g) and (h):

(1) The eligible customer-generator shall be required to utilize a meter, or multiple meters, capable of separately measuring electricity flow in both directions. All meters shall provide time-of-use measurements of electricity flow, and the customer shall take service on a time-of-use rate schedule. If the existing meter of the eligible customer-generator is not a time-of-use meter or is not capable of measuring total flow of electricity in both directions, the eligible customer-generator shall be responsible for all expenses involved in purchasing and installing a meter that is both time-of-use and able to measure total electricity flow in both directions. This subdivision shall not restrict the ability of an eligible customer-generator to utilize any economic incentives provided by a governmental agency or an electric utility to reduce its costs for purchasing and installing a time-of-use meter.

(2) The consumption of electricity from the local publicly owned electric utility shall result in a cost to the eligible customer-generator to be priced in accordance with the standard rate charged to the eligible customer-generator in accordance with the rate structure to which the customer would be assigned if the customer did not use a renewable electrical generation facility. The generation of electricity provided to the local publicly owned electric utility shall result in a credit to the eligible customer-generator and shall be priced in accordance with the generation component, established under the applicable structure to which the customer would be assigned if the customer did not use a renewable electrical generation facility.

(3) All costs and credits shall be shown on the eligible customer-generator's bill for each billing period. In any months in which the eligible customer-generator has been a net consumer of electricity calculated on the basis of value determined pursuant to paragraph (2), the customer-generator shall owe to the local publicly owned electric utility the balance of electricity costs and credits during that billing period. In any billing period in which the eligible customer-generator has been a net producer of electricity calculated on the basis of value determined pursuant to paragraph (2), the local publicly owned electric utility shall owe to the eligible customer-generator the balance of electricity costs and credits during that billing period. Any net credit to the eligible

customer-generator of electricity costs may be carried forward to subsequent billing periods, provided that a local publicly owned electric utility may choose to carry the credit over as a kilowatthour credit consistent with the provisions of any applicable contract or tariff, including any differences attributable to the time of generation of the electricity. At the end of each 12-month period, the local publicly owned electric utility may reduce any net credit due to the eligible customer-generator to zero.

(j) A renewable electrical generation facility used by an eligible customer-generator shall meet all applicable safety and performance standards established by the National Electrical Code, the Institute of Electrical and Electronics Engineers, and accredited testing laboratories, including Underwriters Laboratories Incorporated and, where applicable, rules of the commission regarding safety and reliability. A customer-generator whose renewable electrical generation facility meets those standards and rules shall not be required to install additional controls, perform or pay for additional tests, or purchase additional liability insurance.

(k) If the commission determines that there are cost or revenue obligations for an electrical corporation that may not be recovered from customer-generators acting pursuant to this section, those obligations shall remain within the customer class from which any shortfall occurred and shall not be shifted to any other customer class. Net energy metering and co-energy metering customers shall not be exempt from the public goods charges imposed pursuant to Article 7 (commencing with Section 381), Article 8 (commencing with Section 385), or Article 15 (commencing with Section 399) of Chapter 2.3 of Part 1.

(l) A net energy metering, co-energy metering, or wind energy co-metering customer shall reimburse the Department of Water Resources for all charges that would otherwise be imposed on the customer by the commission to recover bond-related costs pursuant to an agreement between the commission and the Department of Water Resources pursuant to Section 80110 of the Water Code, as well as the costs of the department equal to the share of the department's estimated net unavoidable power purchase contract costs attributable to the customer. The commission shall incorporate the determination into an existing proceeding before the commission, and shall ensure that the charges are nonbypassable. Until the commission has made a

determination regarding the nonbypassable charges, net energy metering, co-energy metering, and wind energy co-metering shall continue under the same rules, procedures, terms, and conditions as were applicable on December 31, 2002.

(m) In implementing the requirements of subdivisions (k) and (l), an eligible customer-generator shall not be required to replace its existing meter except as set forth in paragraph (1) of subdivision (c), nor shall the electric utility require additional measurement of usage beyond that which is necessary for customers in the same rate class as the eligible customer-generator.

(n) It is the intent of the Legislature that the Treasurer incorporate net energy metering, including net surplus electricity compensation, co-energy metering, and wind energy co-metering projects undertaken pursuant to this section as sustainable building methods or distributive energy technologies for purposes of evaluating low-income housing projects.