Evaluating the Benefits and Costs of Net Energy Metering in California

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Abstract

This paper explores recent claims by California's investor-owned utilities (IOUs) that the state's net energy metering (NEM) policy causes substantial cost shifts between energy customers with solar photovoltaic (PV) systems and other non-solar customers, particularly in the residential market. We conclude that the utilities' concerns with the impacts of NEM on non-participating ratepayers are unfounded. Recent changes in residential rate design and updated models of the costs which the utilities avoid when they accept NEM power exported to their grids show that NEM does not produce a cost shift to non-participating ratepayers; instead it creates a small net benefit on average across the IOUs' residential markets. NEM is even more cost-effective for non-participants in the commercial, industrial and institutional (C&I) market. Moreover, the costs of NEM can be further reduced through residential rate design changes which more closely align California's retail electric rates with the utilities' cost of service for residential customers; such changes will ensure that net metering remains cost-effective for residential ratepayers even as the penetration of PV systems continues to grow.

Executive Summary

California is the nation's leading market for the installation of solar PV generation to serve the on-site electric demands of homes, businesses, schools, and institutions. 1,400 megawatts (MW) of PV installations are now operating on the homes or businesses of 134,000 Californians. Net energy metering (NEM) is a core public policy that has enabled this success. NEM is a simple billing arrangement that allows customers who install PV to "run the meter backward" when their production of solar power exceeds their immediate needs. The simplicity and understandability of NEM has reduced the barriers to consumer acceptance of PV, and has been a key contributor to the success to date of the California Solar Initiative (CSI), the state's 10-year, $3.3 billion rebate program designed to transform the once-fledgling solar market into a self-sustaining industry. NEM has been instrumental in extending the benefits of clean, renewable PV generation to a broad range of California energy consumers.

Against this backdrop of success, the California Public Utilities Commission (CPUC) recently interpreted the state's statutory 5% cap on NEM systems to allow more than 5,000 MW of NEM systems in the state, thus allowing substantial growth in NEM systems in coming years. However, at the same time the CPUC also announced that it would suspend NEM as of the end of 2014 unless it has developed new rules for NEM prior to that date.

The recent debate before the CPUC over the interpretation of the statutory 5% NEM cap focused on perceptions of the added costs that net metering may impose on non-NEM customers. California's investor-owned utilities – Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE) – have asserted to policymakers that the new interpretation of the 5% NEM cap will impose billions of dollars of additional costs on ratepayers who do not participate in the NEM program. This report answers the question of whether such a "cost shift" exists by examining and evaluating, using the best available current data and models, the balance of benefits and costs associated with NEM in both the residential and C&I markets in California.

The debate over the economic impacts of NEM has focused largely on the residential market, because there is general agreement that existing commercial and industrial rate structures better reflect the utilities' cost of service than existing residential rates. Our analysis leads us to the following key conclusions concerning the impacts of residential NEM on non-participating ratepayers:

- **On average over the residential markets of the state's three big IOUs, NEM does <u>not</u> impose costs on non-participating ratepayers, and instead creates a small net benefit.** As shown in **Figure ES-1** and **Table ES-1** below, residential NEM customers in PG&E's territory under today's mix of increasing block (IB) and time-of-use (TOU) residential rates impose a small cost on other ratepayers ($0.013 per kWh exported), as a result of PG&E's higher upper tier IB rates and lower avoided costs. However, this small cost is offset by the net benefits of NEM in the SCE and SDG&E residential markets (benefits of $0.007 and $0.028 per kWh exported, respectively), where upper tier IB rates are lower and the costs avoided by NEM generation are higher. In the PG&E residential market, where NEM still represents a small net cost, these net costs have been reduced to one-tenth the level calculated in the NEM cost/benefit study that the CPUC commissioned in 2009. Overall, assuming no changes in rate design and using recent information on the percentage of residential NEM customers that are on TOU rates, the net annual benefits of NEM for the non-participating residential customers of the IOUs will be $2.1 million per year when the 5% NEM cap is reached, as shown in the top section of Table ES-1.

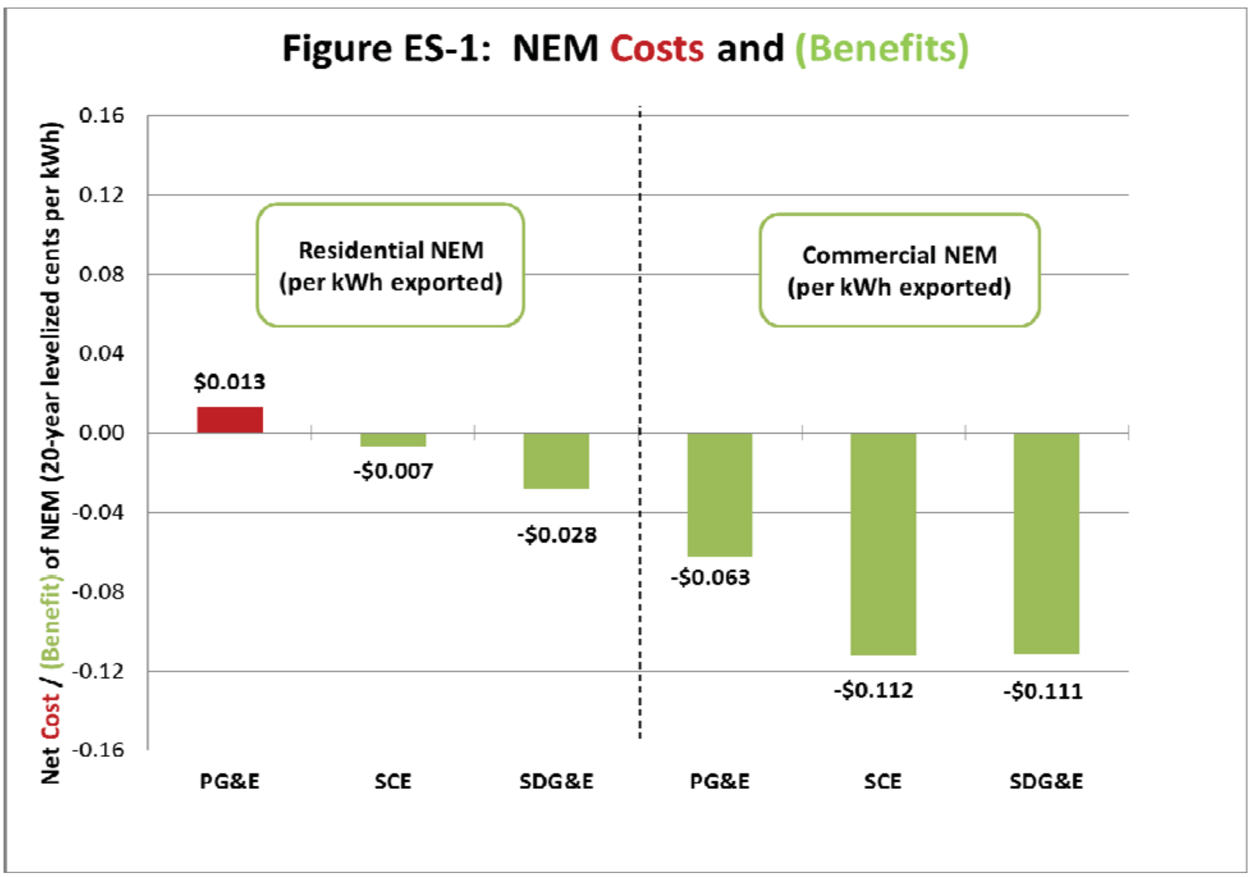

Table ES-1: *NEM Impacts in the Residential Market*

	PG&E	SCE	SDG&E	IOU Total
	Current Mix of Increasing Block and Time-of-Use Rates			
NEM Costs or (Benefits) *($/kWh exported)*	$0.013	**($0.007)**	**($0.028)**	
Annual Net Costs or (Benefits) at 5% NEM Cap *(millions $/year)*	6.4	**(4.2)**	**(4.3)**	**(2.1)**
Monthly Net Costs or (Benefits) for the Average Residential Customer at 5% NEM Cap *($ per month)*	$0.11	**($0.08)**	**($0.30)**	**($0.04)**
	100% TOU Rates			
NEM Cost or (Benefit) *($ per kWh exported)*	$0.007	**($0.024)**	**($0.035)**	
Annual Net Costs or (Benefits) at 5% NEM Cap *(millions $/year)*	3.5	**(13.6)**	**(5.4)**	**(15.5)**
Monthly Net Costs or (Benefits) for the Average Residential Customer at 5% NEM Cap *($ per month)*	$0.06	**($0.26)**	**($0.38)**	**($0.13)**

- **These numbers are extremely small in comparison to the IOUs' annual electric revenues of about $25 billion in 2011.** Table ES-1 shows that the net costs or benefits of NEM for non-participating residential ratepayers will amount to just a few cents on the average residential customer's monthly bill even when the use of NEM has expanded to the present 5% cap on NEM systems, or about four times the current number and capacity of NEM systems.

- **The economic impacts of NEM on non-participating ratepayers are highly dependent on the underlying electric rate design.** We show that modifications to existing residential rates – including (1) the gradual narrowing of the rate differences between the tiers of today's increasing block rate structure under which most of the residential customers of the IOUs take service, (2) a move to greater adoption of current time-of-use (TOU) rates among NEM customers, and (3) increased use of the simpler non-tiered TOU rate structures available today – will result in an increase in the net benefits to non-participating ratepayers from residential NEM. For example, SCE and SDG&E have lower upper tier IB rates than PG&E, and this fact results in

NEM providing small net benefits in the residential markets of the southern California utilities, compared to small net costs for PG&E. As another example, if all residential NEM customers were to take service under the IOUs' current residential TOU rates, the net benefits of NEM when the 5% NEM cap is reached would increase to $15.5 million per year, as shown in the lower section of Table ES-1. Finally, the TOU rate structures that appear to provide the most NEM benefits for non-participating customers are the simpler TOU rates that reduce or eliminate usage-based tiers (such as SCE's TOU-D-T rate and SDG&E's DR-SES rate).

These results are informational, are based on current rate design, and are not intended to advocate for any particular change to NEM customers' rate structures. The CPUC recently began a comprehensive rulemaking proceeding on electric rate design for residential customers. The impact of residential rate design on the economics of NEM is only one of many issues that the Commission will be reviewing in this rulemaking. Rate design changes that more closely align rates with costs and that signal to customers when increases or reductions in consumption are most valuable are likely to make sense for many reasons, including increasing the economic benefits of NEM for non-participating ratepayers. The modeling presented in this report is intended to inform future discussions of possible changes to electric rate design, so that policymakers have an analytic foundation for assessing the impacts of proposed rate design changes on the economics of net metering in California's distributed generation market.

In the commercial, industrial, and institutional (C&I) market, NEM results in significantly greater benefits than costs for non-participating ratepayers. C&I rates typically feature TOU rates, fixed customer charges, and significant demand charges. C&I customers who install solar cannot avoid fixed customer charges and have difficulty avoiding most demand charges. This limits the utility's lost revenues in the C&I market. In addition, PV systems installed in the C&I market tend to be smaller relative to the customer's demand. There are a significant number of C&I systems that do not export power at all, and thus have no impact on other ratepayers. **Figure ES-2** below shows the net costs or benefits of NEM for the major C&I rate schedules of the three IOUs, in terms of $ per kWh exported.

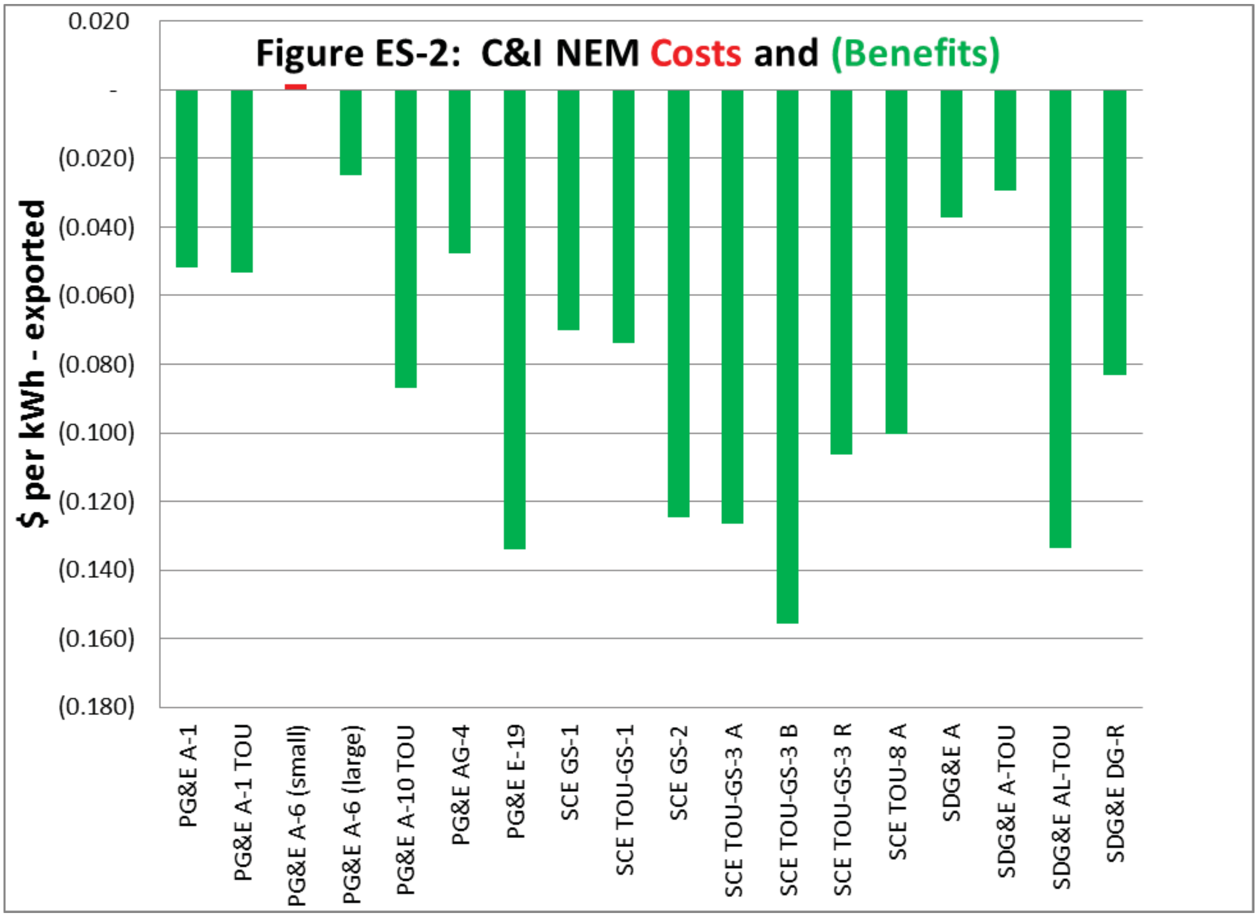

Table ES-2 summarizes the net benefits of NEM in the C&I market for the three IOUs, assuming the amount of C&I solar installations expected at the 5% NEM cap.

Table ES-2: *Annual C&I NEM Costs or (Benefits) (millions per year, 2012$)*

Program	PG&E	SCE	SDG&E	IOU Total
Annual Net Costs or (Benefits) at 5% NEM Cap *(millions $/year)*	**(24.7)**	**(49.2)**	**(16.3)**	**(90.1)**

Our results show that the challenge in the C&I market is to adopt rate designs that do not result in solar customers subsidizing other ratepayers. Such cross-subsidies will slow progress toward reaching solar program goals or will require incentives such as tax credits or CSI direct incentives to remain in effect for longer. Policymakers should continue to support rate designs for solar customers that reduce demand charges, such as PG&E's A-6 rate with zero demand charges or the SCE Option R rates and SDG&E's DG-R tariff that feature reduced demand charges. Such innovations are important means to ensure that such cross-subsidies do not occur, and that non-participating ratepayers are indifferent to NEM in the C&I market.

Combining the results from the residential and C&I markets, this analysis demonstrates that, under current rate structures, net metering provides overall net benefits in the markets served by the three IOUs, and that these overall net benefits will increase as the penetration of PV systems grows.. **Table ES-3** shows that the total economic benefits of NEM for non-participating ratepayers will amount to almost $100 million per year once the 5% NEM cap is reached.

Table ES-3: *Overall Annual NEM Costs or (Benefits) for Non-Participating Ratepayers (millions per year, 2012$)*

Program	PG&E	SCE	SDG&E	IOU Total
Annual Net Costs or (Benefits) at 5% NEM Cap *(millions $/year)*	**(18.2)**	**(53.4)**	**(20.6)**	**(92.2)**

I. Introduction

Net energy metering is a billing arrangement for customers who install clean, on-site distributed generation (DG) that is interconnected to the electric grid, typically solar PV systems. At certain times, such as in the middle of the day, a PV system will produce more energy than the customer uses on its premises, and the excess generation is exported to the grid. NEM provides a way to calculate a bill for the customer which considers that the customer at times imports electricity from the grid and at other times exports power to the grid.

With NEM, the customer's meter runs both forward and backward, and at the end of the billing period the customer simply pays for the net energy used, or receives a credit at the retail rate if more energy is produced than consumed.[1] Consumers understand the idea of running the meter backward, and the simplicity and understandability of NEM are essential elements in marketing DG systems to potential customers. NEM's simplicity ensures that consumers who are considering whether to buy DG systems understand how those systems will impact their energy bills. In contrast, it would be much more confusing if consumers with DG systems received different prices for their energy imports versus exports. The fact that 43 states and the District of Columbia have adopted the use of NEM for DG systems attests to the attractiveness of NEM as a key component in encouraging the use of DG.[2]

Consumers also understand that NEM provides a natural and certain hedge against future increases in their utility rates. A net-metered system will supply some or all of the customer's on-site energy requirements for a known price, either the upfront cost of the system or the known monthly lease payments to the solar installer. The result is that the NEM customer significantly reduces his exposure to utility rate increases. Alternative billing arrangements, such as the feed-in tariff arrangements common in Europe and often known in the U.S. as the "buy-all / sell-all" model, pay the customer a separate wholesale price for the entire output of the PV system, while the customer continues to pay for all of his power use at the utility's regular retail rate. Consumers have far less experience with wholesale power prices than with retail rates, and understandably are less certain that the relationship between wholesale prices and retail rates will be stable over time or that the utilities and their regulators will maintain promised feed-in tariff prices over time.

For the solar customer, the simplicity and certainty of NEM are its chief virtues. In contrast, the economics of NEM for the utility and its other ratepayers are a more complicated question. The economics of NEM are under increasing scrutiny, as California recently passed the milestone of 1,000 MW of grid-interconnected DG systems. The California IOUs and others contend that NEM causes a significant cost shift from customers who install solar to other, non-participating ratepayers, and have suggested that NEM should be replaced with a buy-all / sell-all model or, at a minimum, that additional charges should be assessed on NEM customers. The CPUC also recently interpreted California's statutory cap on NEM systems to allow more than 5,000 MW of net metered systems, allowing significant growth in the solar market beyond the

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[1] Section 2827 of the California Public Utilities Code provides the statutory basis for net metering in California.
[2] *See* http://www.dsireusa.org/summarymaps/index.cfm?ee=1&RE=1 . Three other states allow utilities to offer net metering on a voluntary basis.

2,300 MW of PV systems that will be installed in the IOU service territories under the CSI.[3] However, at the same time the CPUC also announced that it would temporarily suspend NEM at the end of 2014 for new customers, pending the issuance of new rules for NEM which the CPUC intends to develop after reviewing a new cost-effectiveness study of NEM which the CPUC will complete in 2013.[4]

Past studies of the economics of NEM have shown clearly that the impacts of NEM on non-participating ratepayers depend on the utility's retail rate design. Severin Borenstein, the E.T. Grether Professor of Business and Public Policy at the Haas School of Business, U.C. Berkeley, and the Director of the U.C. Energy Institute, stated at a recent California Energy Commission hearing that the "fundamental problem isn't net metering, but rather marginal prices that greatly exceed marginal cost."[5] As a result, the cost-effectiveness of NEM could be addressed, if necessary, through changes to retail rate design, particularly for residential customers. Modifications to rate design may be desirable for a host of other reasons. The CPUC recently initiated a major rulemaking proceeding to investigate possible policy changes in how it designs residential electric rates, citing NEM as one reason, among many, for starting the rulemaking.[6] Addressing the cost-effectiveness of NEM through rate design would preserve NEM's virtues of simplicity and certainty for the solar customer. This would avoid the disruption of a change to a completely new billing paradigm for the solar industry.

This study presents a new analysis of the economics of net metering in the residential and C&I markets of the California IOUs. The study focuses on the benefits and costs of NEM looking forward, based on the mix of customers that NEM systems are serving today. The study also examines how the cost-effectiveness of NEM changes under several different residential rate designs, in order to inform the upcoming debate over possible changes to residential rate design in California.

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3 *See* CPUC Decision No. 12-05-036, issued May 24, 2012.
4 *Ibid.*, at 13-16.
5 Severin Borenstein, "Rate Design and Renewables," presentation to the May 22, 2012 Lead Commissioner Workshop on Renewable Energy Costs for the 2012 Integrated Energy Policy Report Update (CEC Docket # 12-IEP-01), at Slide 8. Available at http://www.energy.ca.gov/2012_energypolicy/documents/2012-05-22_workshop/presentations/05_Borenstein_UC_Berkeley_2012-05-22.pdf .
6 *See* CPUC Rulemaking No. 12-06-013, issued June 28, 2012, at 14-15.

II. The "Three States" of Customer-Owned Solar Generation

To understand the economics of net metering, it is important to appreciate exactly how a DG system located on a customer's premises works. Through the course of the day, a net metered PV system will operate in one of three different "states":

- **The "Retail Customer State."** The sun is down and there is no PV production. All electricity consumed flows into the house from the grid. The customer is a regular utility customer.

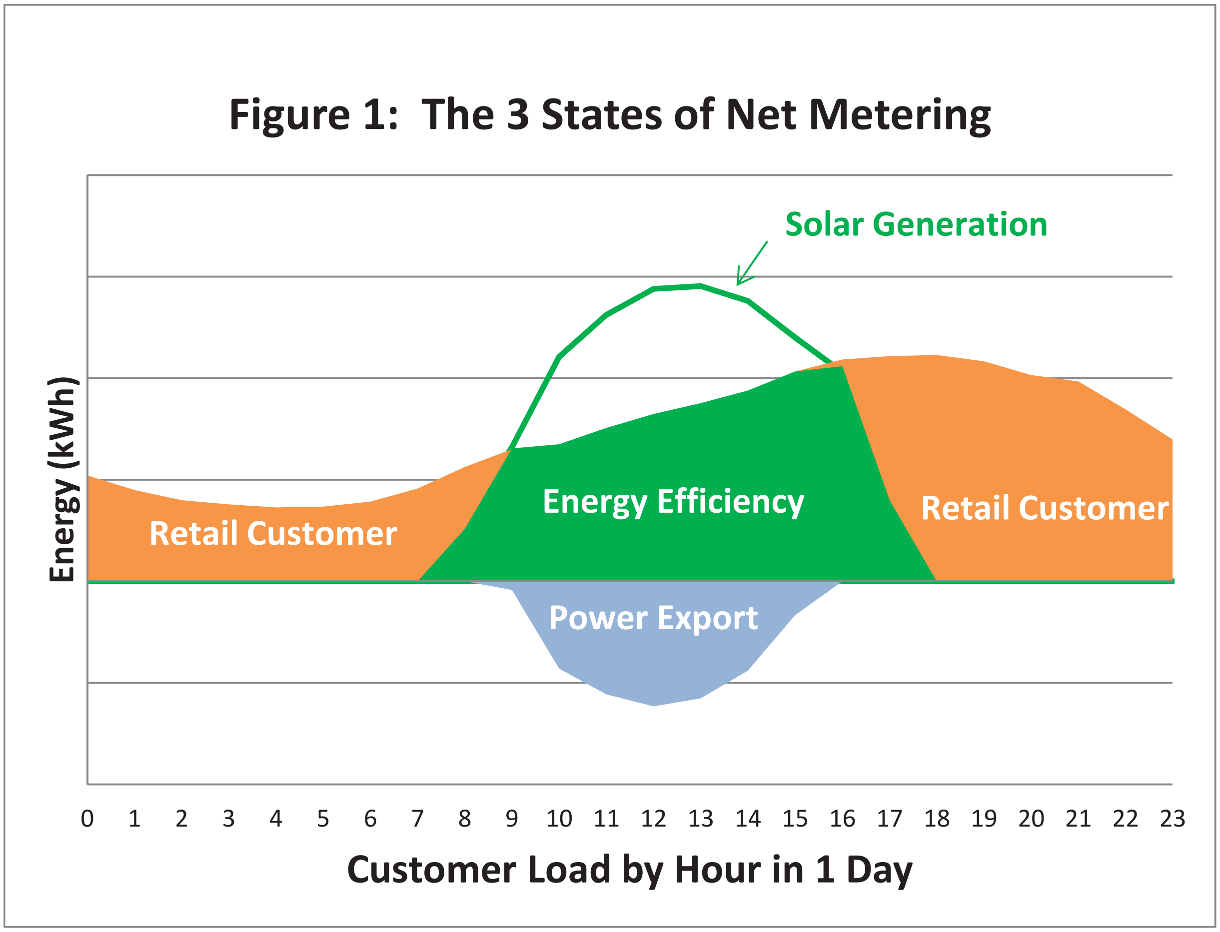
- **The "Energy Efficiency State."** The sun is up and there is some PV production, but not enough to serve all of the homeowner's instantaneous load. Here the customer is served both with power from the solar system as well as with power flowing in from the grid. In this state, the solar DG serves as a means to reduce the customer's load on the grid, in the same fashion as a more efficient air conditioner or other energy efficiency measure. None of the solar customer's output flows out to the utility grid. Typically, 50% to 80% of the output of a solar PV system will be used on-site, without touching the utility's grid.

- **The "Power Export State."** The sun is high overhead and PV production exceeds the customer's instantaneous use. In this state, the solar power flows into the house to serve the entire load, with the excess power flowing back out to the neighborhood grid. As a matter of physics, this power will serve neighboring loads with 100% renewable energy, displacing power that the utility would otherwise generate at a more distant power plant and deliver to that local area over its transmission and distribution (T&D) system. It is critical to recognize that the customer's generation only touches the grid in this third, "power export" state. Typically, just 20% to 50% of the output of a residential PV system will be exported to the grid in this third state.

  These exports, in effect, "run the meter backward," and the essence of net metering is the means by which the utility compensates the solar customer for these power exports. Under net metering, when the meter runs backward and power is exported to the grid, the utility provides the solar customer with bill credits that can be netted against the customer's imports. Thus, the solar customer is compensated for his power exports in the form of credits at the full retail rate.

  Finally, the utility sells the exported power to neighboring loads, thus avoiding the costs of the power that it would have generated and delivered from another source.

Figure 1 shows typical daily profiles of a residential load and of the output of a PV system on the roof of that house, and illustrates when each of these three states occurs.



III. Scoping the Benefits and Costs of Net Metering

A. Focus on Exports to the Grid

The first step in evaluating the benefits and costs of net metering is to delineate the proper scope for this inquiry. As described above, NEM is the billing arrangement under which the utility compensates a customer for the power which the customer's solar or other DG system exports to the grid in the "power export" state.

In fact, if the customer did not export power to the grid and 100% of PV generation was consumed on-site, there would be no need for NEM. In that case, the customer simply would use his on-site generation to reduce his load, and to the utility the installation of such a DG system would appear no different than if the customer had installed a more efficient air conditioner or focused on reducing power usage in the middle of the day. The customer's regular utility bill would be lower, and the savings presumably would pay for the DG system over time. In addition, it is only when the solar customer exports power to the grid that there are possible safety or operational impacts on the grid. For these reasons, the operation of DG in the "energy efficiency" state does not require NEM.

Furthermore, even without NEM, a federal law – the Public Utilities Regulatory Policies Act of 1978 (PURPA) – and longstanding state policies implementing that law require California utilities to do the following:

- to interconnect with renewable DG systems, including solar PV,
- to allow a customer to use the output of such a system to offset his on-site load, and
- to purchase excess power exported from such systems at a state-regulated avoided cost price.[7]

The tariffs of the California IOUs have longstanding provisions which allow customer-owned generation to offset a portion of the customer's load provided the customer pays a standby rate for power that the utility must supply when the on-site generation is not operating. For SCE, there are also existing tariff provisions for compensating the customer for net power exports if a customer installs DG but for some reason does not want to use NEM.[8] Both PURPA and these tariff provisions predate the adoption of NEM in California in the 1990s and would continue to allow customers to install PV systems, offset their on-site usage, and export excess power to the utility even if NEM did not exist. In other words, NEM is not related directly to using solar to serve on-site load in the energy efficiency state, because that is already permitted in California without NEM. The only change that results from NEM is how the customer-generator is compensated when power is exported to the grid – with NEM, exports are credited at the full retail rate; without NEM, the customer-generator would receive a wholesale avoided cost rate instead of the full retail rate. Thus, net metering only impacts the compensation which the customer-generator receives for power exports to the grid, and any analysis of the economics of NEM should focus only on those exports.

More broadly, it is important to understand that an evaluation of the cost-effectiveness of NEM is a different inquiry than the cost-effectiveness tests used for broad evaluations of the state's demand-side programs and DG resources. The NEM analyses discussed in this study are, in the lexicon of the cost-effectiveness tests used in California, ratepayer impact measure (RIM) tests.[9] RIM tests use a different set of costs and benefits than broader, societal cost-benefit tests such as the total resource cost (TRC) test. The CPUC does not rely on RIM tests in assessing energy efficiency programs, and routinely adopts energy efficiency and demand response programs that do not pass the RIM test, if those programs score well on broader, societal cost-benefit tests such as the TRC test. In other words, these programs result in higher rates for non-participants, but save money overall. For example, the 2010 CSI cost-effectiveness study, conducted by the consulting firm Energy and Environmental Economics (E3), used such broader tests to confirm that the CSI is on course to achieve its goal of a cost-effective solar industry by

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7 The PURPA requirements can be found in 18 CFR §292.303.

8 Appendix A to this report are the Special Condition 5 provisions of SCE's residential Schedule D tariff which provide for the purchase of excess customer-owned generation at avoided cost prices. Although PG&E and SDG&E do not have explicit provisions for such purchases in their residential tariffs, we believe that their customers would have the same rights under PURPA to make such sales as do SCE's customers.

9 See the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (October 2001), available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF .

2017.[10] The CPUC's 2009 decision on the cost-effectiveness evaluation of DG programs rejected the use of RIM tests except for very limited purposes.[11] Thus, the results of a study such as this one should not be interpreted as providing any perspective on the broader societal costs and benefits of renewable DG.

B. The Benefits and Costs of NEM

In the "power export" state, NEM presents both costs and benefits for the utility's other ratepayers who do not install solar.

The costs for non-participating ratepayers are the bill credits that the utility provides to solar customers as compensation for NEM exports, plus any incremental utility costs to meter and bill NEM customers.

The benefits are the costs that the utility avoids by using the NEM exports to serve nearby loads, instead of generating or purchasing a like amount of power and moving that power down to the distribution system. These avoided costs are a benefit for non-participating ratepayers. The CPUC has approved avoided cost models with the following benefits:[12]

- Avoided energy costs
- Avoided capacity costs for generation
- Reduced costs for ancillary services
- Lower line losses on the transmission and distribution system (T&D)
- Reduced investments in T&D facilities
- Lower costs for the utility's purchase of other renewable generation

We next review the existing cost-effectiveness studies of these costs and benefits of NEM in California.

C. Existing Cost-effectiveness Studies of NEM in California

There have been two significant studies of the cost-effectiveness of NEM in California. The first is the 2009 study conducted by E3 for the CPUC, with the final version published in March 2010.[13] The Legislature mandated this study in P.U. Code Section 2827[c][5]. The second is a study that the Lawrence Berkeley National Lab (LBNL) completed in April 2010 on the economics of solar for residential customers in California, including the economics of net metering.[14]

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[10] *CSI Cost-Effectiveness Evaluation* (E3, April 2011), available at ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/csi/CSI%20Report_Complete_E3_Final.pdf .

[11] D. 09-08-026, at 24-26.

[12] *See*, generally, D. 05-04-024, D. 06-06-063, and D. 09-08-026.

[13] *Net Energy Metering Cost Effectiveness Evaluation*, (E3, March 2010), the "E3 NEM Study," as well as the CPUC Energy Division's introduction to this study, available at http://www.cpuc.ca.gov/NR/rdonlyres/0F42385A-FDBE-4B76-9AB3-E6AD522DB862/0/nem_combined.pdf

[14] Dargouth, N; Barbose, G; and Wiser, R., "The Impact of Rate Design and Net Metering on the Bill Savings from Distributed PV for Residential Customers in California" (April 2010, LBNL), the "LBNL NEM Study," available at http://eetd.lbl.gov/ea/emp/reports/lbnl-3276e.pdf .

The 2009 CPUC NEM Cost-effectiveness Study. The 2009 E3 study focused on the ratepayer impacts of NEM in its third state, when power is exported to the grid. The study acknowledges that a solar customer also benefits from being able to serve his own load when his system is not exporting (i.e. in the energy efficiency state), but observes that "the customer would receive these benefits even in the absence of NEM."[15] Accordingly, the E3 analysis computed the costs of NEM as the bill credits provided for the customer's hourly NEM exports, plus the utilities' incremental billing costs, and compared these to the benefits which non-participating customers receive from the costs which the utility avoids as a result of NEM exports. To calculate these avoided cost benefits, E3 used the avoided cost model which it developed under contract to the CPUC for use in evaluating the benefits of energy efficiency programs, and which the Commission has reviewed and approved for that purpose beginning in 2004. E3 determined the net costs or benefits of NEM as the costs (bill credits plus billing costs) less the benefits (utility avoided costs).

The key findings of the 2009 E3 NEM Study included:

- **The net rate impacts of NEM were small.** Once the CSI is fully built out, the net cost of NEM for IOU ratepayers would be approximately $137 million per year (in 2008 dollars). This net cost would be about four-tenths of one percent of projected IOU revenues in 2020 and would result in an average rate impact of $0.00064 per kWh of end-use load in 2020.[16]

- **The large majority of NEM impacts (87%) were in the residential market.** The study calculated that the net costs of NEM are much higher for the residential market ($0.19 per kWh exported) than for the non-residential market ($0.03 per kWh exported).[17] 87% of the cost shifts resulting from NEM were in the residential market.[18]

- **72% of the residential impacts from NEM were in PG&E's territory.** The study found that 72% of the calculated residential NEM cost shift was tied to PG&E's residential customers.[19] Based on the E3 results, this cost shift would be $86 million per year in 2008 dollars once the full capacity of the CSI was built out.[20] This would produce a monthly cost of about $1.53 for an average PG&E residential customer who consumes 550 kWh per month.[21]

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[15] E3 NEM Study, at 5.
[16] *Ibid.*, at 8, and Table 5.
[17] *Ibid.*, at Table 3, pages 6-7. The study noted that the volume of (NEM) energy exported to the utilities is just a fraction of the total power produced by on-site DG and in 2008 was *de minimus* (sic) compared to the total energy procured by utilities. *Ibid.*, at 7. As a result, to express the study's results for the net costs of NEM in terms of dollars per kWh of power produced by solar DG, the above numbers for NEM costs per kWh exported should be divided roughly by a factor of 2 to 5, because only 20% to 50% of the generation is exported.
[18] *Ibid.*, at 7, Table 3.
[19] *Ibid.*
[20] *Ibid.*, at Table 5. The figures in Table 5 are allocated to the residential market using the relative 20-year NPVs of NEM in the residential and non-residential markets for each IOU, as shown in Table 3.
[21] Assuming annual residential sales of 30,872 GWh per year (PG&E's 2011 forecast from A. 10-03-014).

- **The impacts of NEM in the C&I market were small.** Just 13% of the net costs of NEM were in the non-residential C&I market, with the net costs of NEM in the C&I market averaging just $0.03 per kWh exported.[22] Among C&I customers, the net costs of NEM decreased as the size of the C&I customer increased, with very low net costs among the largest C&I customers for PG&E and SDG&E. NEM provided small net benefits for SCE's largest C&I customers.[23]

- **14% of the NEM cost shift was due to incremental billing costs**, with most of this impact from PG&E's stated billing costs. PG&E's costs included substantial manual billing costs. Even PG&E's "automatic" billing costs were five times higher than SCE's comparable costs. Almost one-third (32%) of the costs of NEM for PG&E were incremental billing costs.[24]

- "**NEM . . . provides a small fraction of the total costs of the demand side programs**. Overall, the demand side programs provide a net benefit to ratepayers."[25]

The LBNL Study on Residential NEM. In April 2010, the Lawrence Berkeley National Lab (LBNL) completed a study on the economics of net metering in California for residential solar customers. The LBNL NEM Study investigated the economic value that NEM provided to residential customers with PV in California, using hourly usage data for 215 residential customers of PG&E and SCE for whom LBNL simulated the addition of a solar PV system. The LBNL work found that the value of NEM to the solar customer depended heavily on the design of the solar customer's retail rate and on the characteristics of the customer and the PV system. Importantly, the LBNL study compared the value of the bill savings under NEM to three potential alternative compensation mechanisms, each of which provides bill credits for some or all PV production at prices based on the state's Market Price Referent (MPR).[26] These three alternatives were:

(1) ***A Full MPR-based feed-in tariff,*** with all of the customer's PV generation credited at the time-of-use-adjusted MPR rate, with the customer paying the standard rate for all of its usage;

(2) ***Hourly netting,*** in which PV production first offsets up to 100% of customer usage within each hour, with any excess <u>hourly</u> production credited to the customer at the TOU MPR rate for that hour; and

(3) ***Monthly netting,*** whereby PV production can offset up to 100% of customer usage within each TOU period of each month, but any excess <u>monthly</u> production is credited at an MPR-based rate.

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[22] E3 NEM Study, at 6-7 and Table 3.
[23] *Ibid.*, at 53, Table 34.
[24] *Ibid.*, at 8, Table 6; also, at 39-40, Tables 23-24 and Table 44.
[25] *Ibid.*, at 5.
[26] The MPR is the price used to evaluate wholesale contracts with renewable generators and is intended to represent long-run avoided generation supply costs, based on the cost of a combined-cycle natural gas-fired generator.

The LBNL study concluded that NEM provides substantial value to solar customers relative to the first option of a full MPR-based feed-in tariff, and that the third option – monthly netting of PV imports and exports – is almost the same as the current NEM program where netting occurs annually instead of monthly.

The LBNL study's most significant analysis was the second option, where LBNL netted imports and exports on an hourly basis. This was the same approach taken in the E3 NEM cost-effectiveness study, although E3 used its own avoided cost model, instead of the MPR, to value NEM exports. The LBNL researchers determined the difference between the value of its hourly netting option and the value of full net metering; this difference is essentially the same metric as the net cost of NEM that E3 calculated. Significantly, LBNL's analysis found that standard net metering was only slightly more beneficial for solar customers (and thus only slightly more costly for other ratepayers), compared to the hourly netting option. LBNL estimated that, if one added avoided T&D costs of $0.01 per kWh and avoided line losses of 10% to the MPR, the net cost of residential NEM was under $0.01 per kWh of solar production, or less than $0.02 to $0.05 per kWh of power exported.[27] Using the same assumptions for the size of the CSI program that E3 used, these impacts are about one-quarter the size of those calculated by E3, and equate to an average impact on non-participating customers of 38 cents per month for the average residential customer.

A Tale of Two Studies. The E3 and LBNL studies seem to reach different conclusions on the economics of NEM for residential customers. E3 calculated that residential NEM customers impose a net cost of $0.19 per kWh of power exported to the grid. In contrast, the LBNL study suggests that the net cost of NEM is less than $0.02 to $0.05 per kWh of power exported. The LBNL work thus can be read as suggesting that there is not a significant problem with NEM for residential customers. Why the LBNL study shows a smaller net impact from NEM is not entirely clear – it could be because the residential customers in the LBNL sample were smaller in size than the overall NEM population that E3 used, or because LBNL's use of the MPR resulted in higher avoided costs than E3 used.

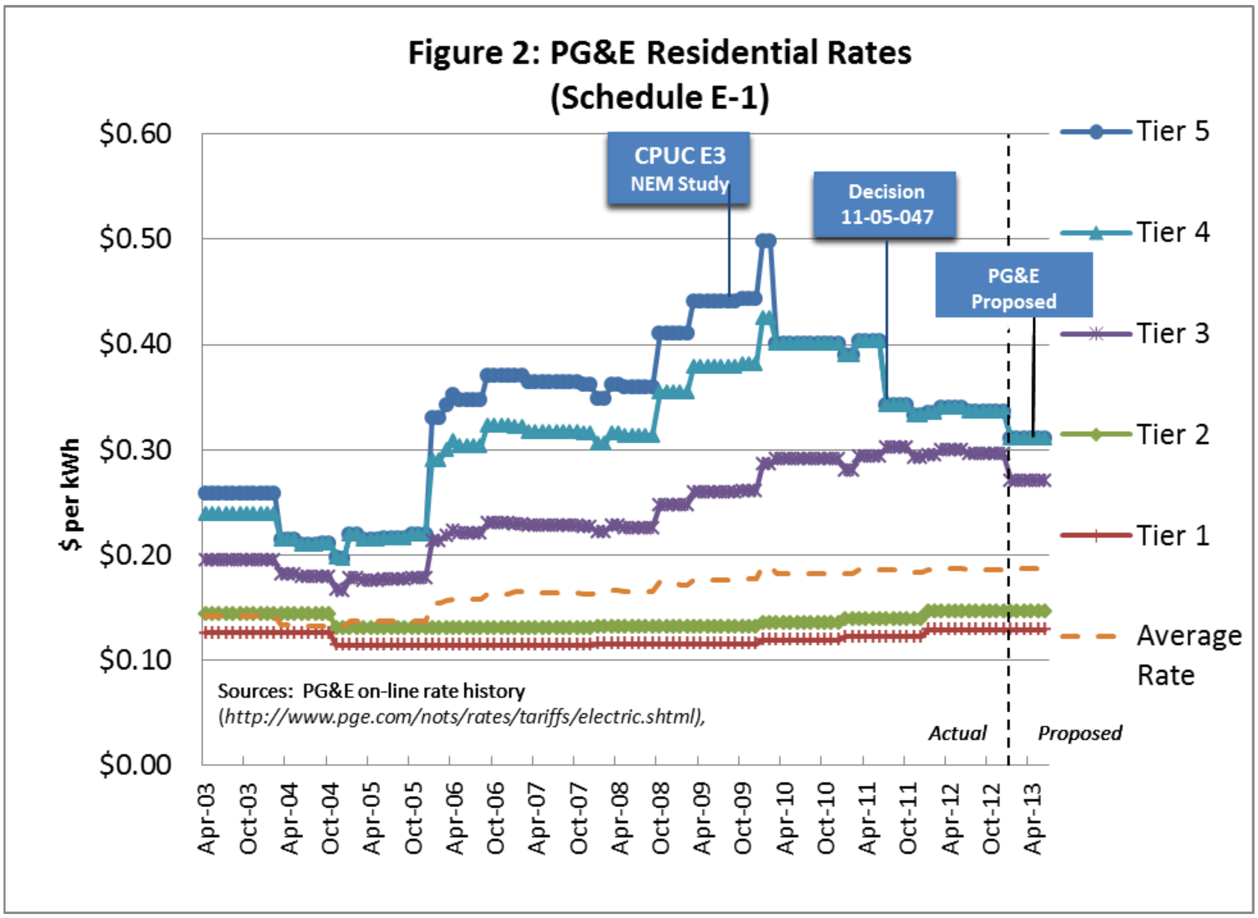
Both studies show that retail rate design has a significant impact on the economics of NEM. The E3 study shows that the largest contributors to any NEM "cost shift" are large residential customers who install PV systems that move them out of the expensive upper Tiers 3 - 5 of the state's residential rate structure, but which preserve their benefits from the low Tier 1 and 2 rates for their remaining usage. This is an artifact of the design of California's residential rates, not of NEM. Clearly, the economics of NEM will change as California's rate structure evolves over time.

[27] LBNL NEM Study, at Table 5. The avoided T&D costs that the CPUC has adopted in the E3 avoided cost model are higher than $0.01 per kWh, and tend to average between $0.01 and $0.02 per kWh for a typical solar PV output profile. E3 NEM Study, at Appendix A, page 7. The updated avoided cost model used in this report, with the most recent marginal T&D costs, produces avoided T&D costs of $0.02 to $0.03 per kWh for a PV profile.

IV. The Need for a New Evaluation of the Benefits and Costs of NEM

There is a clear and present need for a new evaluation of the economics of net metering in California. The E3 and LBNL NEM studies used rates from 2009 or early 2010 and were conducted in 2009 and early 2010. Since then, several of the critical drivers of these results have changed significantly, as follows:

- **Upper tier residential rates are much lower, and lower tier rates are higher.** In the E3 NEM Study, over 70% of the NEM cost shift calculated for the residential market was tied to PG&E residential customers, who paid very steeply tiered rates in 2009. **Figure 2** below shows the history of the increasing block rate tiers in PG&E's standard E-1 residential rate over the last decade. The figure shows clearly how PG&E's upper tier rates for Tiers 4 and 5 peaked in 2009 and early 2010, when the E3 and LBNL studies were performed.



Since these analyses were performed, the CPUC has ordered PG&E to eliminate its highest rate tier (Tier 5) and has lowered PG&E's Tier 4 rate substantially (e.g., the top tier has been lowered from $0.50 per kWh to $0.33 per kWh). This year, PG&E has proposed further reductions to its upper tier rates, by reducing the Tier 1 baseline quantities.[28] As shown in Figure 2, the result has been a significant reduction of PG&E's upper tier E-1 rates, compared to the rates in effect when the E3 and LBNL NEM studies were performed.

Significant reductions in upper tier rates also have occurred for SCE and SDG&E. The residential rate changes from 2009 to 2012 for the increasing block rates for all three of the IOUs are summarized in **Table 1**. Not only have upper tier rates declined significantly, but Tier 1 and 2 rates have also increased, based on the annual rate escalation allowed under SB 695.

Table 1: *Residential Increasing Block Rates – 2009 versus 2012 (cents per kWh)*

Date	Utility and Rate Schedule	Tier 1 (Baseline)	Tier 2 (101-130%)	Tier 3 (131-200%)	Tier 4 (201-300%)	Tier 5 (Over 300%)
July 2012	PG&E (E-1)	12.845	14.602	29.561	33.561	33.561
	SCE (D)	12.597	15.511	24.217	27.717	31.217
	SDG&E (DR)	14.334	16.580	24.493	26.493	26.493
October 2009[29]	PG&E (E-1)	11.531	13.109	26.078	38.066	44.348
	SCE (D)	10.933	13.635	27.040	31.931	36.823
	SDG&E (DR)	11.682	13.699	29.058	31.058	31.058
Change	PG&E (E-1)	**+11%**	**+11%**	**+14%**	**-12%**	**-24%**
	SCE (D)	**+15%**	**+14%**	**-10%**	**-13%**	**-15%**
	SDG&E (DR)	**+23%**	**+21%**	**-16%**	**-15%**	**-15%**

** Note: SDG&E rates are an annual average of summer / winter seasonal rates.*

- **Expected future rate escalation is lower.** E3 calculated the 20-year levelized cost shift from NEM assuming that retail rates would escalate at 4.5% per year.[30] This sharp escalation is well above the historical trends in IOU rates (which have increased by 1.4% to 1.8% over last decade and by 2% over the last two decades).[31] Moreover, in the most recent LTPP case (R. 10-05-006), the IOUs projected rate increases of about 2.7% per year (nominal) over the 2011-2030 period.[32]

- **New legislation and new perspectives on avoided renewables costs.** The E3 NEM Study used an avoided cost model based on short-term market prices until 2015, and new fossil resources thereafter. The E3 avoided costs included a small adder for avoided Renewable Portfolio Standard (RPS) resources only in years after 2020, even though the IOUs have RPS obligations today.[33] This appears to have understated avoided RPS costs.

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[28] *See* PG&E's 2012 Rate Design Window Application, A. 12-02-020.
[29] 2009 rates are from the E3 NEM Study, at 39, Table 22.
[30] E3 NEM Study, at 37, Table 20.
[31] Based on statewide EIA data and CEC IOU-specific data from 1990 – 2010. See http://www.eia.gov/electricity/data.cfm#sales or http://energyalmanac.ca.gov/electricity/Utility-Wide_Average.xls .
[32] "Joint IOU Supporting Testimony at Appendix A: Performance Evaluation Metrics – Testimony of E3, Inc.," (IOU LTPP Testimony) served July 1, 2011 in R. 10-05-006, at page A-72, Figure 4 and associated workpapers (*LTPP_EMC_07-01-2011.xlsm*) for the CPUC Trajectory case.
[33] E3 NEM Study, at Appendix A, Figure 9, p. 13.

LBNL's study used the MPR, which has been a benchmark for RPS costs but which is based on fossil resources. SB 2, California's 33% RPS legislation enacted in 2010, directed the CPUC to replace the MPR with a benchmark for the RPS program based on the costs of renewables.[34] Projections of the costs of RPS power are generally above the MPR.[35] As a result, the LBNL work may have understated avoided renewables costs. Further, NEM power exported to the grid serves IOU loads, is 100% renewable, and displaces power which is 33% renewable. In the light of SB 2 and the limitations of the avoided renewables costs used in the prior studies, there is a need to re-examine the renewables costs which NEM exports allow the utilities to avoid.

To understand the renewables costs which NEM exports avoid, one must focus on the impact of NEM generation on the utility's costs, not on the solar customer's costs. NEM exports impact the utilities' renewables costs in two ways. First, the customer's NEM exports reduce the IOU's retail sales, because the solar customer runs the meter backward when exporting power. This drop in the IOU's retail sales reduces the utility's own RPS obligations and the amount of renewable power that the IOU must buy to meet that obligation. Second, the NEM exports which serve nearby utility loads are 100% renewable power, and displace utility-procured power which is 33% renewable, and thus increase the market share of renewables on the utility system. Both of these factors must be included in determining the utility's avoided renewables costs resulting from NEM exports, because both are benefits for the utility's other ratepayers.

A simple example can help to illuminate this issue. Assume the utility serves three retail customers – A, B, and C – each of whom consumes 8 units of electricity, for a total power demand of 24 units. The utility has a 33% RPS obligation; in other words, it must procure 8 units of renewable energy to serve these customers. This is shown in **Table 2**. Each customer receives 33% renewable generation, and the overall market share of renewables on the utility grid is also 33%.

Table 2

Pre-Solar: Utility Serves All Loads With a 33% RPS Obligation								
	Load	Power to Load		Utility Renewables		Renewables Market Share		
Customer	Electric Use	Utility Grid Power	DG Output	DG Exports to Grid	Utility 33% RPS Purchase	Customer	Utility	Total
A	8	8				33%		
B	8	8				33%		
C	8	8				33%		
Total	24	24	0	0	8		33%	33%

Now assume that Customer A installs an on-site renewable DG system whose output is 6 units, of which 4 units serve A's on-site loads in the energy efficiency state

[34] *See* P.U. Code Section 399.15[c][2].

[35] *See* workpapers for the IOU LTPP Testimony (*LTPP_EMC_07-01-2011.xlsm*), comparing system average electric rates for 2011-2030 between the CPUC Trajectory and All-Gas cases.

and 2 units are exported to the grid where they help to serve B's and C's loads. **Table 3** shows the resulting power flows and renewables market shares. There are two ways in which the 2 units of NEM exports benefit the utility and Customers B and C.

First, the demand on the grid that the utility must serve drops from 24 units to 18 units, and thus the utility's 33% RPS obligation is now reduced by 2 units, from 8 to 6 units. This is the first benefit – the installation of Customer A's DG system allows the utility to avoid the costs of procuring 2 units of RPS generation. The NEM exports account for one-third of this benefit, that is, they avoid the cost premium for 2/3 unit of renewables.

The second benefit is that the NEM exports actually result in an <u>increase</u> in the market share of renewables on the grid, from 33% to 44%, even though the utility has reduced its RPS purchases and Customers B and C have done nothing. In our example, this increase is 2 units – in Table 3 there are 8 units of renewables on the utility grid, an increase of 2 units over the 6 units required by the 33% RPS obligation. This increase is the direct result of the 2 units of 100% renewable NEM exports that serve non-participating Customers B and C and displace utility power which would be just 33% renewable. This benefit is the 2 units of NEM exports times their incremental renewable content compared to grid power (100% - 33% = 67%), or 4/3 unit of renewables.

Adding these two benefits together, the value to Customers B and C from the NEM exports is 2/3 + 4/3 = 2, in other words, the full renewable premium associated with the 2 units of renewable generation exported to the grid by Customer A.

Table 3

Post-Solar: Customer A Produces 6 Units from On-site DG, and Exports 2 Units to Grid								
	Load	Power to Load		Utility Renewables		Renewables Market Share		
Customer	Electric Use	Utility Grid Power	DG Output	DG Exports to Grid	Utility 33% RPS Purchase	Customer	Utility	Total
A	8	4	4	2		72%		
B	8	7	1			44%		
C	8	7	1			44%		
Total	24	18	6	2	6		44%	50%

Another way to think about this issue is to recognize that the CSI and net metering have statutory goals which are independent of the RPS program, and are likely to result in a market penetration of renewable generation on the California grid which exceeds the 33% goal of the RPS program alone. These additional renewables will be supplied to the grid through NEM exports, and thus these exports avoid 100% of the cost premium for renewable generation, not just 33% of this premium.

An obvious question is whether the above example remains valid given that CPUC policy allows the solar customer to retain ownership of the renewable energy credits (RECs) associated with his or her output. The answer is that the example is valid assuming that Customer A does not sell the RECs associated with his DG system. If a viable market for unbundled RECs from small DG systems is established in California (which has not happened to date), the utility could purchase up to 15% (2014-2016) or 10% (2017 and thereafter) of its RPS requirements in the form of unbundled RECs.[36] Utility purchases of RECs from small DG systems will only happen if the following all occur:

- there is a viable market for such RECs,
- issues with tracking and accounting for these RECs are resolved,
- the utilities have significant remaining need for RPS purchases to reach their 33% RPS obligations that could be satisfied with unbundled RECs, and
- the unbundled RECs associated with NEM exports are more economic than other unbundled RECs.

It remains to be seen if these conditions all will be met. In the example in Table 3, the result of the utility purchasing RECs from Customer A to cover its RPS need would be a reduction in the renewables market shares shown in Table 3. Even in this case, however, the utility and non-participating Customers B and C would continue to receive the benefit of at least 2 units of avoided RPS purchases compared to Table 2, as a result of Customer A's DG installation and the resulting reduction in the utility's sales.

Finally, the renewable premium in the E3 avoided cost model is based on the difference between the costs of renewable and fossil resources. This cost difference may not account fully for the different value of these resources to utility customers. For example, this cost difference may not capture the following benefits that renewables provide in comparison to fossil resources:

- Health benefits
- Elimination of the use of scarce water resources
- Increased local employment
- Reductions in gas and electric market prices due to reduced demand for these commodities
- Energy security and reliability benefits from the use of local resources

Studies that have sought to quantify these benefits have demonstrated that they are significant.[37] Obviously, many of these broader, societal benefits will not directly reduce a customer's utility bill. Nonetheless, they underscore the limited, conservative nature of the avoided renewables costs used in NEM analyses, and that it is reasonable to assume that the full renewables premium in the E3 model is a conservative estimate of the value of NEM exports, including these societal benefits. For example, one could consider that 33% of the renewables premium is associated with avoided RPS purchases and the other

[36] *See* P.U. Code Section 399.16(c).

[37] Lori Schell, Empowered Energy "Small-Scale Solar Photovoltaics in California: Incremental Value Not Captured in the 2009 Market Price Referent – Description of Methodology" (April 23, 2010), filed by CalSEIA in CPUC Docket No. R. 11-05-005 on July 21, 2011.

67% with a conservative estimate of the value of the societal benefits of the increased penetration of renewable generation on the California grid.

In sum, the E3 and LBNL NEM studies provided some value for the avoided RPS costs associated with NEM export volumes, but these studies either used an out-of-date metric for RPS value (the MPR used by LBNL) or did not value fully the avoided renewables costs associated with the export of 100% renewable generation to the grid from DG facilities (E3's partial RPS adder applicable only in 2020 and later years). Thus, these studies did not fully value the avoided renewables costs from NEM exports, even if one assumes that the only renewables costs avoided by NEM exports are the direct reduction in the IOU's RPS obligations that result from lower IOU sales. The discussion above demonstrates that, in today's circumstances in which residential solar customers are not realizing a market value for their RECs, NEM exports increase the penetration of renewable power on the utility system to above 33%. In addition, the societal value of NEM exports is likely to equal or to exceed the other two-thirds of the renewable premium. Thus, it is reasonable to value the avoided renewables costs associated with NEM exports at 100% of the cost premium for renewables.

- **Questions on NEM incremental billing costs.** As noted above, the E3 NEM Study reported that in 2009 almost one-third of the costs of NEM for PG&E were NEM billing costs that were incremental to the costs of billing non-solar customers. PG&E's reported manual billing costs per NEM customer ($29.34 per month) were about ten times larger than SCE's reported billing costs ($2.34 to $3.03 per month); even PG&E's "automatic" billing costs ($15.55 per month) were five times higher than SCE's costs.[38] PG&E's stated incremental billing costs were extremely high – its manual billing costs of $29.34 per month are almost one-third of the average PG&E residential electric bill – for all services, electricity included – of $90 per month. To our knowledge, in 2009 E3 simply used the billing costs reported by each IOU, without an independent review for consistency or reasonableness. The E3 NEM study provides few details on how the IOUs determined these costs, or why they differ so markedly between the IOUs. Given that all of the California IOUs are nearing the completion of installing smart meters for virtually all of their residential customers, it is questionable whether these self-reported billing costs from the early stages of the CSI are accurate, particularly once smart meter installation is completed and NEM billing is fully automated.

In sum, the changed circumstances and new perspectives described above are strong reasons why there is a need today to re-evaluate the cost-effectiveness of net energy metering in California. Further, given the CPUC's desire to examine its residential rate design policies, it is also important to understand how various residential rate designs impact the economics of NEM.

[38] E3 NEM Study, at 39-40 and Tables 23-24.

V. A New Analysis of the Economics of NEM in California

We have undertaken a new analysis of the economics of NEM for all three of the California IOUs.[39] This analysis uses current (2012) rates and updated avoided costs. This work builds upon the initial analysis that we released in January 2012 concerning the economics of NEM in the PG&E residential market.[40]

A. Method

We employ the same hourly analysis used in the E3 and LBNL studies.[41] We have modeled the economics of net metering on an hourly basis for a wide range of customer and PV system sizes in the major rate classes listed in **Table 4**. Residential bills depend on the climate zone in which the residential customer lives, so we have modeled the major climate zones for each IOU, also shown in Table 4. We have aggregated climate zones that have similar baseline quantities. The rates used in our analysis are the IOUs' tariffed rates for July 2012, with the increasing block rates shown in Table 1.

Table 4: *Market, Rate Classes, and Climate Zones Modeled*

Utility	Market	Rate Class	Climate Zones / PV Locations
PG&E	Residential	E-1 E-6 (TOU)	T, Q – San Francisco X, Y – San Jose S, R, P – Sacramento W – Bakersfield
PG&E	C&I	A-1 A-6 A-10 AG-4 E-19	San Jose
SCE	Residential	D TOU-D-T	Coast/Mountains (5, 6, 8, 9, 16) - Long Beach Inland (10, 13, 14, 15) – Corona
SCE	C&I	GS-1 GS-2 TOU-GS-3 TOU-8S Option R	Long Beach
SDG&E	Residential	DR DR-TOU	Coast (7) – San Diego Inland (10, 14, 16) – Escondido
SDG&E	C&I	A AL-TOU DG-R	San Diego

39 Our analysis considers only net-metered PV systems, which comprise the great majority of net-metered renewable DG systems in California.
40 R. Thomas Beach and Patrick G. McGuire, "Re-evaluating the Cost-Effectiveness of Net Energy Metering in California" (January 17, 2012).
41 The E3 approach to the analysis is described on pages 4-5, 18-21, and 36-43 of the E3 NEM Study.

The customers' hourly load profiles are simulated using each IOU's published dynamic load profiles for each customer class.[42] Although it is possible that the typical residential hourly usage profile differs between climate zones, the available studies do not show major differences across climate zones in the profile of PV exports to the grid.[43] We use the National Renewable Energy Laboratory's (NREL) PVWATTS calculator to produce representative hourly PV outputs at the locations listed in the final column of Table 4.[44] We assume a long-term degradation of 0.75% per year in PV output.[45]

We first compute the solar customer's bill under standard NEM, with all exports credited to the customer at the retail rate. Then we re-compute the bill assuming that, in any hour in which the customer's generation exceeds its load, the exported power is credited at the hourly avoided costs instead of at the retail rate. The pricing of exported power at avoided costs assures that other ratepayers are indifferent to the export. This second, "indifference" case is the reference scenario under which other ratepayers are not impacted by the solar customer's exports to the grid. If the solar customer's bill in the second case is less than or equal to his bill under standard NEM, then NEM will benefit non-participating ratepayers and is cost-effective. Conversely, if the solar customer's bill is lower under standard NEM than in the indifference case, there is a cost to NEM for non-participating ratepayers. We calculate these benefits or costs as 20-year levelized values, assuming rate increases of 2.7% per year with a discount rate of 7.57%.[46]

For the avoided costs in the "indifference" case, we have used E3's latest avoided cost model for DG resources, dated September 20, 2011. We have updated this model to use the input assumptions adopted by the CPUC in Resolution E-4442 on December 1, 2011 for use with the 2011 MPR. Our avoided costs also include updates to the avoided T&D costs for SCE and SDG&E based on the marginal T&D costs contained in those utilities' most recent general rate case (GRC) electric rate design filings with the CPUC. **Appendix B.1** discusses in more detail the updates and modifications that we have made to E3's avoided cost model; **Appendix B.2** is E3's own documentation of the version of the E3 model we have used. We have applied 100% of E3's renewables premium to all NEM exports, in recognition that NEM exports both reduce the utility's RPS obligation (by lowering its sales) and increase the market share of renewable power on the California grid (assuming no sale of RECs).

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[42] These profiles are available on the IOUs' websites, as follows:
PG&E: http://www.pge.com/nots/rates/tariffs/energy_use_prices.shtml
SCE: http://www.sce.com/AboutSCE/Regulatory/loadprofiles/default.htm
SDG&E: http://www.sdge.com/customer-choice/customer-choice/dynamic-load-profiles

[43] *CPUC CSI 2009 Impact Evaluation Final Report* (Itron, June 2010), at 8-23 to 8-26. This report is available at http://www.cpuc.ca.gov/PUC/energy/Solar/impactevaluation2009.htm .

[44] Where hourly PVWATTS output data was not available, we used Clean Power Research's historical Solar Anywhere data set for 2006-2009, converted to PV output using the NREL SAM model.

[45] The *CPUC CSI 2010 Impact Evaluation: Addendum to Final Report* (Itron, April 2012). evaluates the limited available data on PV equipment degradation and concludes at page 5-24 that degradation rates for crystalline silicon and thin film PV panels "did fall close to the commonly accepted 0.5% to 1.0% annual degradation rates." This study is available at http://www.cpuc.ca.gov/PUC/energy/Solar/impactevaluation2010.htm .

[46] The rate escalation is based on modeling for 2011-2030 from the 2010 LTPP case, as referenced in Footnote 20 above. The discount rate is the adopted weighted average cost of capital (WACC) from the 2011 MPR Resolution E-4442, Appendix G.

In the residential market, we determine the net benefits or costs of NEM for the full array of possible sizes for both the customer's annual usage (from 50% to 500% of the baseline quantity) and for the size of the PV system (PV output covering from 10% to 110% of the customer's annual usage).[47] For example, **Table 5** shows our model's output of NEM benefits and costs for PG&E's standard E-1 residential rate in Climate Zone S. Our model also determines the annual NEM exports (in kWh) and the NEM system size (in kW) for each element in the array shown in Table 5. To be consistent with the E3 NEM Study, the costs and benefits are expressed as 20-year levelized $ per kWh (2012 $) of exported power, with net costs as positive (red) values and net benefits as negative (green). The table shows that NEM has net benefits for non-participating ratepayers in the case of PG&E residential solar systems with lower customer usage and larger PV capacities, while NEM has net costs for non-participants for small PV systems installed by large customers with significant usage in Tier 4 (over 300% of baseline), such that the PV system principally offsets more expensive, higher-tier usage. These results are driven not by NEM itself, but by the existing residential rate design with its increasing block structure and statutory limits under AB 1x on the rates in Tiers 1 and 2.

The next step is to determine the distribution of NEM systems for the array of possible customer usages and PV system sizes shown in Table 5. To do this, a major California solar installer has provided us with access to a database of more than 10,000 NEM customers of all three California IOUs, mostly residential customers. This database includes information on each customer's pre-solar annual usage, PV system size, and climate zone. As an example, **Table 6** shows the distribution of residential systems in this database for PG&E's Central Valley Climate Zones S, R, and P. By combining the data in Tables 5 and 6, we can calculate the expected net benefits or costs of NEM for the solar customers in each group of similar climate zones.

Characterizing C&I NEM customers is complicated by the fact that the IOUs can have multiple C&I tariffs that apply to C&I customers of a certain size. For example, a PG&E small commercial customer with a peak demand of 250 kW could qualify for the A-6, A-10, or E-19 rate schedules. In addition, the public database of CSI systems does not specify the rate class of each CSI participant. We have used data obtained from a solar installer with 61 MW of C&I systems installed in California (including the PV system size, annual usage, serving utility, and rate schedule) to characterize C&I NEM customers in each of the C&I rate classes listed in Table 4. Detailed data also is available to us on 236 of PG&E's E-19 NEM customers with 76 MW of solar capacity, through discovery in a recent PG&E rate case. Finally, information on the distribution of the number and installed PV capacity of NEM C&I customers by rate schedule is available from discovery in recent rate cases as well as from an E3 presentation on its upcoming NEM cost-effectiveness study.[48] In performing bill calculations for C&I customers, we have used the publicly-available load profiles to model the customer's demand (in kW) and energy usage (in kWh) in each hour, in order to apply accurately the more complex demand and energy components of most C&I rates.

[47] Our PV system sizes include systems that produce more than 100% of a customer's usage. In such cases, the customer does not receive a full retail rate credit for production above 100% of his annual usage. Instead, the customer receives a net surplus compensation rate that is much lower than the retail rate. Our NEM model does not include the impacts of the lower net surplus compensation rate. Thus, our results over-estimate the costs of NEM for PV system sizes at 110% of annual usage. However, only a small percentage of residential systems produce more than the customer uses on an annual basis, as shown in Table 6.

[48] E3 presentation, "NEM Cost-Effectiveness Evaluation Workshop" (October 22, 2012), at Slide 16.

Table 5: *PG&E Residential (E-1) NEM Costs / (Benefits) in 20-year levelized $ per kWh Exported, PG&E Baseline Area S*

Annual Customer Usage As a Percent of Baseline	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	110%
500%	$ -	$ 0.250	$ 0.181	$ 0.150	$ 0.137	$ 0.116	$ 0.088	$ 0.057	$ 0.035	$ 0.023	$ 0.017
450%	$ -	$ 0.250	$ 0.181	$ 0.148	$ 0.128	$ 0.104	$ 0.072	$ 0.043	$ 0.024	$ 0.011	$ 0.006
400%	$ -	$ 0.250	$ 0.172	$ 0.141	$ 0.115	$ 0.087	$ 0.053	$ 0.027	$ 0.010	$ (0.002)	$ (0.006)
350%	$ -	$ 0.237	$ 0.166	$ 0.126	$ 0.097	$ 0.062	$ 0.028	$ 0.007	$ (0.007)	$ (0.016)	$ (0.021)
300%	$ -	$ 0.237	$ 0.150	$ 0.098	$ 0.064	$ 0.025	$ (0.002)	$ (0.017)	$ (0.027)	$ (0.034)	$ (0.039)
250%	$ -	$ 0.214	$ 0.101	$ 0.052	$ 0.008	$ (0.021)	$ (0.036)	$ (0.044)	$ (0.050)	$ (0.055)	$ (0.058)
200%	$ -	$ 0.157	$ 0.032	$ (0.028)	$ (0.046)	$ (0.057)	$ (0.063)	$ (0.067)	$ (0.068)	$ (0.069)	$ (0.071)
150%	$ -	$ 0.033	$ (0.040)	$ (0.068)	$ (0.074)	$ (0.076)	$ (0.078)	$ (0.080)	$ (0.081)	$ (0.082)	$ (0.082)
100%	$ -	$ 0.020	$ (0.049)	$ (0.077)	$ (0.084)	$ (0.086)	$ (0.087)	$ (0.087)	$ (0.087)	$ (0.086)	$ (0.086)
50%	$ -	$ 0.020	$ (0.049)	$ (0.077)	$ (0.084)	$ (0.087)	$ (0.087)	$ (0.087)	$ (0.087)	$ (0.086)	$ (0.086)
	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	110%

PV System Size as a Percent of Customer Usage

Table 6: *Allocation of PV Systems in PG&E Baseline Areas S, R, and P*

Annual Customer Usage As a Percent of Baseline	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	110%
500%	0.0%	0.2%	0.6%	1.0%	0.9%	1.1%	1.0%	0.5%	0.5%	0.2%	0.0%
450%	0.0%	0.0%	0.3%	0.6%	0.6%	0.6%	0.5%	0.3%	0.2%	0.0%	0.0%
400%	0.0%	0.1%	0.4%	1.0%	1.0%	1.3%	1.0%	0.3%	0.1%	0.1%	0.0%
350%	0.0%	0.1%	0.5%	1.8%	2.5%	2.3%	2.1%	1.1%	0.4%	0.2%	0.0%
300%	0.0%	0.3%	1.3%	2.3%	2.8%	3.7%	3.9%	1.5%	0.5%	0.1%	0.0%
250%	0.0%	1.4%	5.2%	5.1%	5.1%	6.3%	4.4%	1.8%	0.6%	0.3%	0.2%
200%	0.0%	0.2%	1.2%	3.6%	4.2%	3.7%	2.9%	1.5%	0.5%	0.4%	0.2%
150%	0.0%	0.0%	0.2%	1.3%	1.4%	1.6%	1.1%	0.6%	0.5%	0.6%	0.5%
100%	0.0%	0.0%	0.0%	0.0%	0.1%	0.3%	0.2%	0.1%	0.1%	0.2%	0.1%
50%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%	110%

PV System Size (as a percent of usage)

The following **Table 7** shows the key metrics for the typical C&I customer in each of the major IOU C&I rate classes, as well as the portion of the C&I market which that rate class represents.[49]

Table 7: *Characteristics of Typical C&I NEM Customers*

Utility	Rate Schedule	Market Share	Average PV System (kW)	Annual Usage (kWh)	PV Output as % of Usage
PG&E	A-1	5%	26	56,738	65%
	A-6 Small	7%	63	133,000	68%
	A-6 Large	29%	392	1,366,000	41%
	A-10	14%	425	1,262,000	48%
	AG-4	22%	130	206,000	90%
	E-19	23%	333	2,652,000	18%
	Total	100%			
SCE	GS-1	7%	30	52,200	86%
	GS-2	32%	105	210,000	75%
	TOU-GS-3B	24%	535	1,729,000	47%
	TOU-8	38%	445	4,934,000	14%
	Total	100%			
SDG&E	A	8%	14	24,500	81%
	AL-TOU	63%	104	250,000	61%
	DG-R	29%	141	308,000	67%
	Total	100%			

Table 7 characterizes representative NEM customers. Our model uses more detailed distributions of C&I customers by usage, PV system size, and rate class to analyze the costs and benefits of NEM in the C&I market. As in the residential market, we determine the costs and benefits as 20-year levelized $ per kWh of exported power.

B. Results for the Net Costs or Benefits of Residential NEM

The results of our analysis for each IOU's existing residential rates – both increasing block and TOU rates – are shown in **Table 8.** The overall results for each utility, averaged across all climate zones, are also shown in **Figure 3.** Most NEM customers take service under the standard increasing block rates, although the penetration of TOU rates among PG&E's residential NEM customers is high (49%). The results for current rates are based on the present mix of IB and TOU rates for the residential NEM customers of each utility.[50] The results for TOU rates assume that all NEM customers use current TOU rates.

[49] Our analysis includes the major C&I rate schedules that serve well over 90% of C&I customers. We have grouped the customers served from other C&I rate schedules with the major rate schedule that is most similar. For example, PG&E E-20 customers have been grouped with E-19 customers.

[50] For PG&E and SCE data on this mix of IB and TOU rates, see Slide 16 from the E3 presentation dated October 22, 2012, referenced in footnote 48. SDG&E reported in a data response in its current GRC (A. 11-10-002) that 3.6% of its residential NEM customers by number, and 4.1% by PV system capacity, are on one of SDG&E's three TOU rates available to solar customers – DR-TOU, DR-SES, or EV-TOU-2.

Table 8: *Costs or (Benefits) of Residential NEM (20-year levelized $ per kWh exported)*

Utility	Climate Zone	Market Share	Residential Rate Schedule	
			Current Mix of IB and TOU Rates	100% TOU
PG&E			E-1 / E-6	100% E-6 (TOU)
	S, R, P	40%	$0.006	$0.002
	X, Y	34%	$0.022	$0.012
	T, Q	15%	$0.015	$0.008
	W	11%	$0.010	$0.011
	Average	100%	$0.013	$0.007
SCE			D	TOU-D-T
	Coastal	38%	$0.008	**($0.002)**
	Inland	62%	**($0.017)**	**($0.038)**
	Average	100%	**($0.007)**	**($0.024)**
SDG&E			DR	DR-TOU
	Coastal	38%	**($0.004)**	**($0.012)**
	Inland	62%	**($0.043)**	**($0.049)**
	Average	100%	**($0.028)**	**($0.035)**
				DR-SES
	Coastal	38%		**($0.023)**
	Inland	62%		**($0.057)**
	Average	100%		**($0.044)**

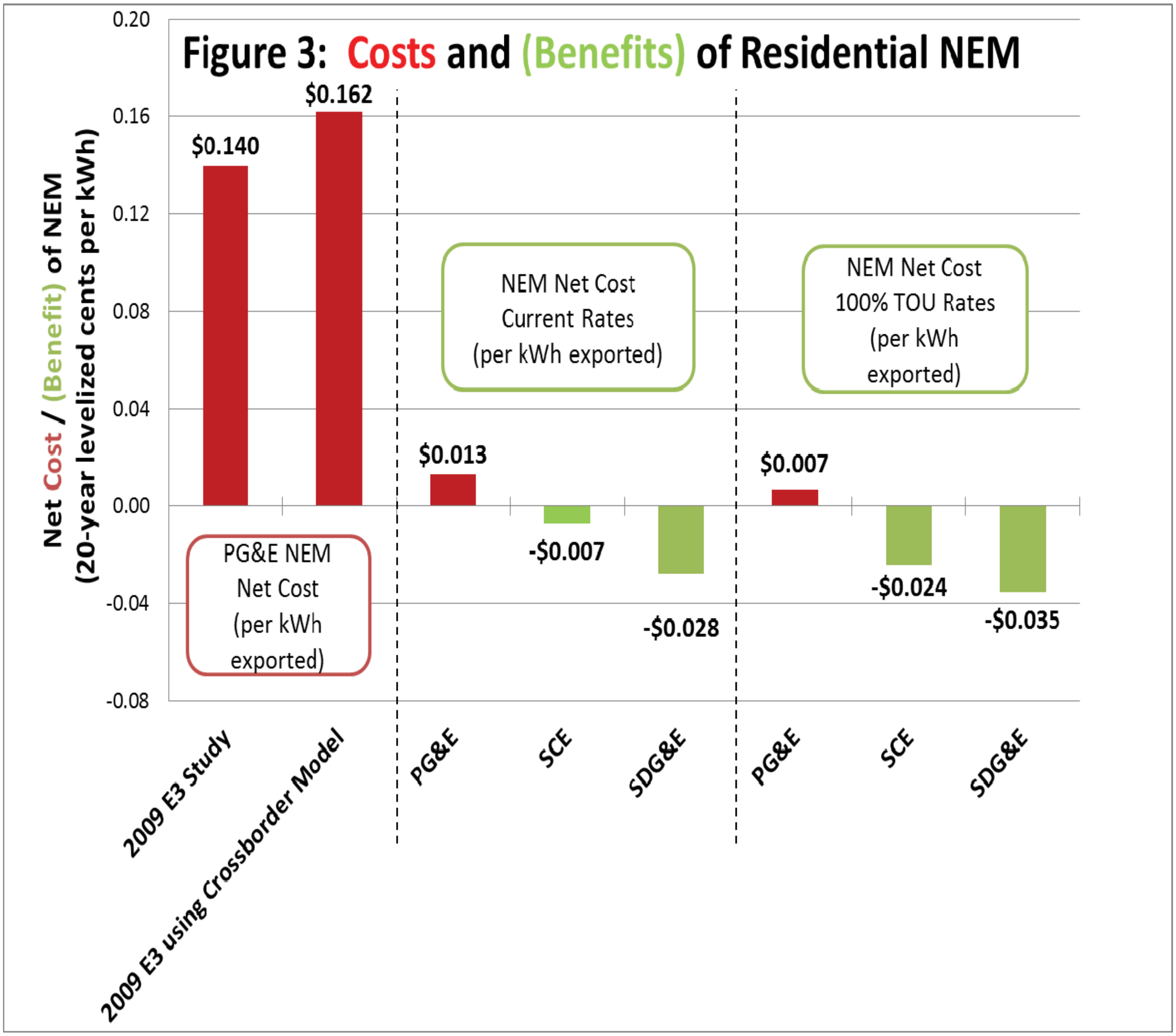
The following key conclusions emerge from these results:

- **Today, in aggregate for all three IOUs, the net cost of residential net metering is essentially zero.** NEM has a small net cost – just $0.013 per kWh exported – in PG&E's residential market, but NEM has net benefits of ($0.007) and ($0.028) per kWh exported for residential customers in southern California, in SCE's and SDG&E's service territories respectively. The modest difference in these results between PG&E and SCE / SDG&E is due, first, to PG&E's higher upper tier rates and, second, to higher avoided costs in the southern California utilities' service territories.

- **Expanded use of current residential TOU rates by NEM customers would increase NEM benefits to non-participating ratepayers.** Use of the utilities' current TOU rates would increase the net benefits of NEM for non-solar ratepayers in all three IOU service territories, by $0.01 to $0.02 per kWh exported.[51] This result reflects the fact that existing TOU rates are more closely aligned with the utilities' marginal and avoided costs than the existing tiered IB rates. The NEM rate credits for exports under increasing block rates can be high in all hours if upper-tier rates are being offset – for example, if a relatively large customer installs a smaller PV system. In contrast, under TOU rates, NEM

[51] This result assumes the continued use of current TOU periods.

credits in off-peak periods will be lower than in on-peak periods regardless of the relative size of the customer and his PV system. The largest improvements are for the residential TOU rates of SCE (D-TOU-T) and SDG&E (DR-SES). These are also the simplest residential TOU rates. The SCE D-TOU-T rate has just on- and off-peak rates and two usage tiers; SDG&E's DR-SES rate does not have usage tiers. The implications of these results for future TOU rate design are discussed in more detail below.



- **NEM economics in the residential market have improved substantially since 2009.** The results shown in Table 8 are substantially different than those that E3 obtained in 2009. E3's 2009 study showed net costs from NEM for all IOU residential customers regardless of customer size.[52] Table 8 and Figure 3 show clearly that circumstances have changed substantially since the 2009 E3 NEM study. Using 2012 rates and the E3 avoided cost model updated to 2012, the net cost of NEM for PG&E residential customers – just $0.013 per kWh exported – is less than one-tenth as large as reported by E3 in its NEM Study ($0.14 per kWh) using 2009 rates and avoided costs.[53] Particularly important to these results are the major reforms in PG&E's residential rates that the CPUC has adopted since 2009, as well as our use of an updated 2012 avoided cost model that more fully values the renewables costs that DG power avoids.

- **Our residential NEM model reproduces the results of the 2009 E3 study when 2009 assumptions are used.** We have used E3's avoided cost model from 2009, plus the PG&E E-1 rates in effect in 2009, to run our model for PG&E's residential market under the same assumptions used in the E3 NEM Study. These assumptions also include the 4.5% annual growth in rates that E3 used in 2009. These results are shown in the second column of Figure 3. The average cost of NEM for PG&E's residential customers from our model using 2009 rates and avoided costs is $0.16 per kWh exported, close to $0.14 per kWh exported reported in the E3 NEM Study. This comparison indicates that our model of the costs and benefits of NEM produces similar results to E3's 2009 work when rates and avoided costs from 2009 are used, even though our dataset of customer usage and system sizes is different than the 2008 NEM billing data that E3 used.

We have used the 2012 results shown in Table 8 and Figure 3 to calculate the total impact of NEM in the residential market assuming both (1) full development of the CSI (including pre-CSI capacity developed before 2007) and (2) expanded residential PV deployment up to the expanded NEM cap approved by the CPUC in D. 12-05-036. **Table 9** shows the megawatts (MW) of residential PV that we assume to be deployed in each of these cases, for each IOU. The Post-CSI residential PV capacity assumes the same allocation among the IOUs and among the residential and non-residential markets as CSI capacity, with the total NEM capacity for each IOU expanded to 5% of the IOU's non-coincident peak demand. The 2,141 MW of total residential PV capacity at the 5% NEM cap, shown in the bottom line of Table 9, is the residential market's share of the 5,262 MW of statewide PV capacity that would be allowed under the NEM cap set at 5% of the IOUs' non-coincident peak demands.

[52] E3 NEM Study, Tables 33 and 34.
[53] E3 NEM Study, Table 6, Bill Impacts less Avoided Costs, omitting the impacts of Incremental Billing Costs.

Table 9: *Residential PV Capacity (MW)*

Program	PG&E	SCE	SDG&E
Pre-CSI[54]	77	28	14
CSI Completion[55]	493	519	116
Post-CSI to 5% NEM Cap[56]	413	367	114
Total at 5% NEM Cap	983	914	244

Table 10 combines the NEM impact data from Table 8 with the residential PV capacity shown in Table 9 to calculate the overall annual impacts of net metering, in millions of dollars per year, both through the end of the CSI program and for the additional PV capacity that could be added after the CSI until the 5% NEM cap is reached for each IOU. The table shows that the annual net impacts of net metering on non-participating ratepayers are small under current rates, ranging from a small cost for PG&E to small net benefits for SCE and SDG&E ratepayers, with overall net benefits of $1.1 million upon completion of the CSI and $2.1 million when the 5% NEM cap is reached. With the use of existing TOU rates by all NEM customers, NEM provides benefits to non-participants of $9.0 million per year at CSI completion and $15.5 million per year at the 5% NEM cap. Finally, for comparison, the last section of Table 10 shows the corresponding annual net impacts of NEM for full build-out of the CSI residential market, as calculated in the E3 NEM Study using 2009 rates and avoided costs.

Table 10: *Annual NEM Costs or (Benefits) in the Residential Market (millions per year, 2012$)*

Program	PG&E	SCE	SDG&E	IOU Total
	Current Mix of Increasing Block / TOU Rates			
Pre-CSI & CSI	3.7	**(2.5)**	**(2.3)**	**(1.1)**
Post-CSI to 5% NEM Cap	2.7	**(1.7)**	**(2.0)**	**(1.0)**
Total at 5% NEM Cap	6.4	**(4.2)**	**(4.3)**	**(2.1)**
	TOU Rates			
Pre-CSI & CSI	2.0	**(8.1)**	**(2.9)**	**(9.0)**
Post-CSI to 5% NEM Cap	1.5	**(5.4)**	**(2.5)**	**(6.5)**
Total at 5% NEM Cap	3.5	**(13.6)**	**(5.4)**	**(15.5)**
	2009 E3 NEM Study (2008 $)[57]			
Pre-CSI & CSI	86.1	25.0	9.1	120.2

54 Pre-CSI data is based on 120 MW of pre-CSI residential installations through the CEC Emerging Renewables Program, as shown in the *January 2009 CPUC Staff Progress Report for the CSI*, at Table 1.

55 Includes the CSI General Market, CEC New Solar Homes Partnership, and CSI SASH/MASH programs. For CSI program goals, see D. 06-12-033, Appendix B, Table 11.

56 Assumes NEM cap is set at 5% of each IOU's non-coincident peak demand, per D. 12-05-036. Non-coincident peak demands are 48,229 MW for PG&E, 44,775MW for SCE, and 12,237 MW for SDG&E, from the June 25, 2012 workshop on methods for calculating non-coincident aggregate customer peak demand. 5% of these non-coincident peak demands are 5,262 MW; the residential market's share of this total is 2,141 MW as shown in the bottom line of Table 9.

57 E3 NEM Study, at Table 5. The figures in Table 5 of the E3 NEM Study are allocated to the residential market using the relative 20-year NPVs of NEM in the residential and non-residential markets for each IOU, as shown in Table 3 of that study.

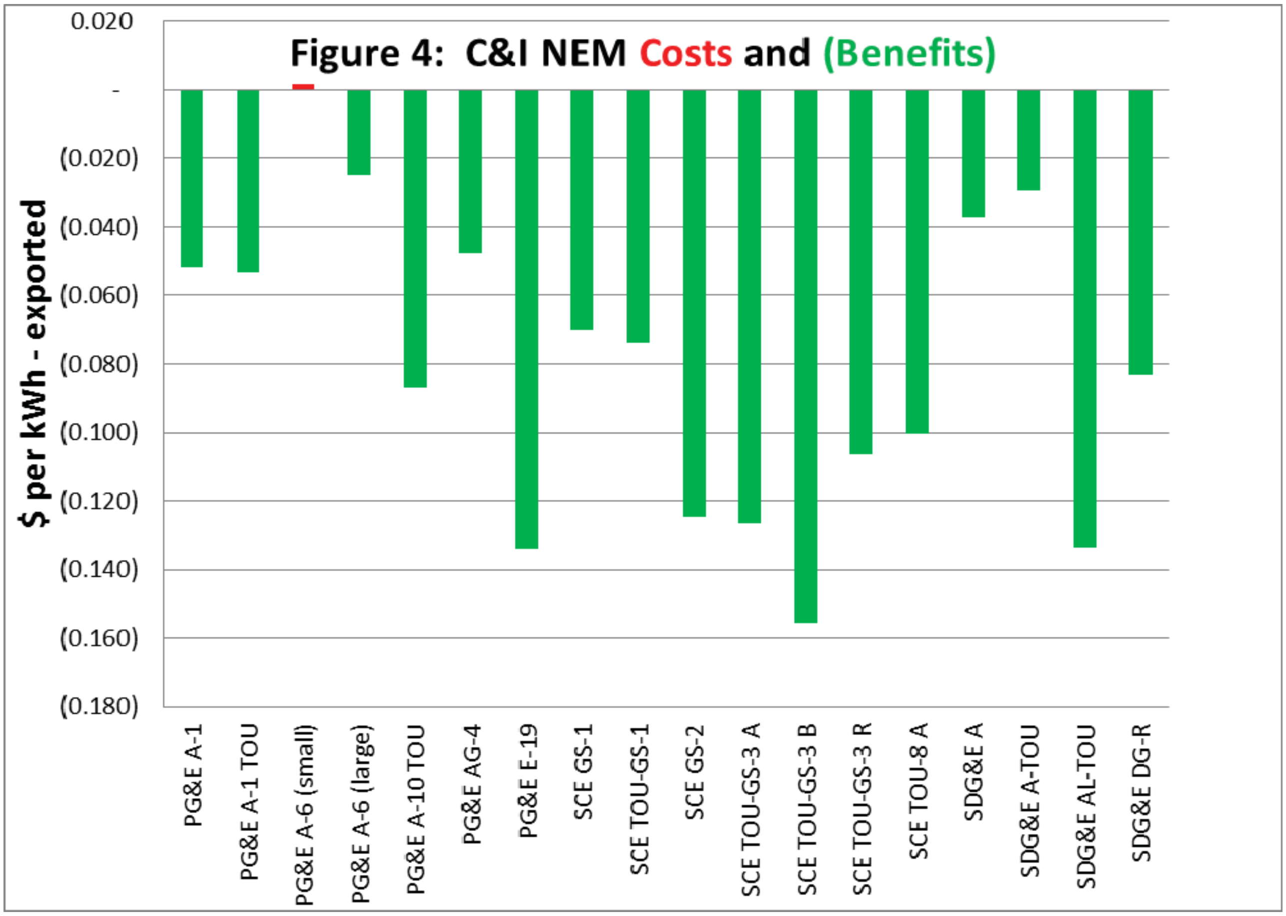
To provide context for these results, we note that the 2011 revenue requirements for the three IOUs total about $25 billion; thus, the impacts shown in Table 10 are very small in comparison. We have calculated the results in Table 10 in terms of impacts on the average residential customer's monthly bill, assuming average residential consumption of 550 kWh per month and that the cost impacts are kept entirely within the residential class. The results for PG&E under current rates amount to a bill increase of 11 cents per month for the average PG&E residential customer once NEM systems reach the 5% cap. SCE and SDG&E residential customers would see their average monthly bills decrease by 8 cents per month for SCE and 30 cents per month for SDG&E when the 5% NEM cap is reached.

C. Results for the Net Costs or Benefits of C&I NEM

Our results for the cost-effectiveness of NEM in the C&I market are summarized in **Table 11** and **Figure 4** for each of the IOUs' major C&I rate schedules.

Table 11: *Costs or (Benefits) of C&I NEM (20-year levelized $ per kWh exported)*

Utility	Rate Schedule	Market Share	NEM Cost or (Benefit)
PG&E	A-1	8%	**($0.052)**
	A-1 (TOU)		**($0.053)**
	A-6 (small)	6%	$0.002
	A-6 (large)	24%	**($0.025)**
	A-10	11%	**($0.087)**
	AG-4	25%	**($0.048)**
	E-19	26%	**($0.134)**
SCE	GS-1	7%	**($0.070)**
	GS-1 (TOU)		**($0.074)**
	GS-2A	32%	**($0.125)**
	TOU-GS-3A	24%	**($0.127)**
	TOU-GS-3B		**($0.156)**
	TOU-GS-3R		**($0.106)**
	TOU-8A	38%	**($0.100)**
SDG&E	A	8%	**($0.037)**
	A-TOU		**($0.030)**
	AL-TOU	63%	**($0.134)**
	DG-R	29%	**($0.083)**



These results show that NEM in the C&I market is generally cost-effective for non-participating ratepayers, across a wide range of customer sizes and rate schedules with different rate designs. There are significant variations in the size of the net benefits (or costs, in one case), in other words, in how closely different C&I rate designs approach the point of ratepayer indifference, i.e. zero net benefits or costs. Generally, the closer to zero the net benefits or costs of NEM are, the more accurate NEM credits are as a proxy for the value of NEM exports. At zero net benefits or costs, non-participating ratepayers are perfectly indifferent to NEM exports.

The net benefits are smaller and closer to zero for the small commercial schedules (A-1 for PG&E, GS-1 for SCE, and A for SDG&E), because those schedules are flat, seasonal rates with higher summer rates and without demand charges that are difficult for NEM customers to avoid. The rate schedules with the largest net benefits are those with substantial demand charges and lower volumetric rates, such as the medium C&I rates (A-10 for PG&E, GS-2 for SCE, and AL-TOU for SDG&E). Such large net benefits indicate that NEM under these rates results in a cost shift from non-participating ratepayers to solar customers. Compared to NEM customers under the medium C&I rates, NEM systems installed by the largest C&I customers show smaller net benefits, even though the large C&I rates also include significant demand charges. This result occurs because large C&I customers typically install PV systems that serve a smaller percentage of their demand than medium C&I customers. As shown in Table 7, the PV systems of large C&I customers serve an average of 21% of the customer's loads, while the PV systems of small and medium C&I customers typically serve 60% to 80% of their usage. The smaller PV systems relative to load of large C&I customers export less power, but do so in more valuable mid-afternoon hours than do medium C&I systems, thus increasing the avoided cost value of these exports. In addition, a significant fraction of PV systems installed on large C&I customers do not export any power at all; for example, of 236 PG&E E-19 solar customers, 52% do not export according to our model. Given that NEM is a billing arrangement for exported power, when exports are zero, the impact of NEM on other customers also is zero.

The C&I rate whose net cost or benefit is closest to zero is PG&E's A-6 rate (a small net cost of 0.2 cents per kWh exported for smaller A-6 customers). The A-6 rate is a time-of-use rate with high on- and mid-peak rates that includes the allocation of significant generation and distribution capacity costs to these peak periods, comparable to the manner in which E3's avoided cost model allocates similar costs to peak demand hours. As a result, it is not surprising that net metering under the A-6 rate most accurately captures the benefits of NEM exports to the grid.

Table 11 also shows the results for SCE's Option R rates and for SDG&E's DG-R tariff. These rates are designed specifically for solar customers, and feature reduced demand charges and higher TOU volumetric rates. SCE presented a study of its Option R rates in its last GRC which showed that these rates are cost-justified, with minor adjustments to the reductions in demand charges.[58] Generally, our analysis shows that these "solar-friendly" rates bring net metering closer to the indifference point of zero net costs or benefits. Thus, we conclude that rate design innovations such as Option R rates which reduce demand charges for solar customers are cost-justified and reduce any cost shift from solar customers to non-participating rate payers that rates with large demand charges may impose.

As we did for the residential market, we have used the 2012 results shown in Table 11 to calculate the total impact of NEM in C&I market at both (1) full development of the CSI and (2) the expanded 5% NEM cap. **Table 12** shows the megawatts (MW) of C&I PV that we assume to be deployed in each of these cases, for each IOU.

Table 12: *C&I Non-Residential PV Capacity (MW)*

Program	PG&E	SCE	SDG&E
Pre-CSI	72	39	22
CSI Completion	512	540	121
Post-CSI to 5% NEM Cap	842	746	227
Total at 5% NEM Cap	1,427	1,325	370

Table 13 combines the NEM net costs or benefits from Table 11 with the PV capacity in the C&I market shown in Table 12 to calculate the overall annual dollar impacts of net metering in the C&I market. We perform this calculation both through the end of the CSI program and at the 5% NEM cap, for each IOU. NEM in the C&I market has overall net benefits of $34 million per year upon completion of the CSI and $90 million per year when the 5% NEM cap is reached.

58 *See* A. 11-06-007, at Exh. SCE-04, at 68-71.

Table 13: *Annual NEM Costs or (Benefits) in the C&I Market (millions per year, 2012$)*

Program	PG&E	SCE	SDG&E	IOU Total
Pre-CSI & CSI	**(8.8)**	**(20.0)**	**(5.3)**	**(34.1)**
Post-CSI to 5% NEM Cap	**(15.8)**	**(29.1)**	**(11.0)**	**(55.9)**
Total at 5% NEM Cap	**(24.7)**	**(49.2)**	**(16.3)**	**(90.1)**

D. Overall Results for the Net Costs or Benefits of NEM

Combining Tables 10 and 13 yields results for the overall cost-effectiveness of NEM for the three IOUs, across both their residential and C&I markets. **Table 14** presents these summary results at the 5% NEM cap, assuming the current mix of increasing block and. TOU rate schedules among NEM customers.. Almost one-half of PG&E's NEM customers have already elected TOU rates.

Table 14: *Overall Annual NEM Costs or (Benefits) at the 5% NEM Cap (millions per year, 2012$)*

Market	PG&E	SCE	SDG&E	IOU Total
Residential	6.4	**(4.2)**	**(4.3)**	**(2.1)**
C&I	**(24.7)**	**(49.2)**	**(16.3)**	**(90.1)**
Total	**(18.2)**	**(53.4)**	**(20.6)**	**(92.2)**

E. Sensitivities

We have completed a number of sensitivity analyses for the above results. These sensitivities are intended to show how our results change when important assumptions are modified. We have focused our sensitivity analyses on the residential market, as this is the market in which the net costs or benefits of NEM are closest to beak-even. The important sensitivities we have tested in the residential market include:

1. **Reduced Renewable Premium.** We have run a sensitivity that applies the E3 renewable premium only to the reduction in the utility's RPS obligation that results from the reduced sales due to NEM exports. Thus, in this sensitivity, the RPS benefits of NEM generation are the RPS premium times the current RPS obligation percentage (20% to 2015, 25% from 2016-2019, and 33% from 2020 on). This sensitivity fails to value the facts that NEM exports are 100% renewable and that they increase the market share of renewables on the grid to above the RPS obligation, as shown in Table 3 above, by displacing utility-procured power that is only 33% renewable. Nonetheless, it also can be argued that the RPS percentages are the legal limit on the utilities' obligation to "green" the grid. This sensitivity also represents the case in which residential solar customers become willing and able to sell their RECs to the utility for use in RPS compliance.

2. **Residential PV Systems Sized at 90% of Usage.** The advent of solar leasing and power purchase agreement programs has allowed customers to purchase PV systems for no money down. An increasing share of residential systems uses such arrangements. These

financing innovations, combined with declining PV costs, should allow for the installation of larger residential systems covering a higher percentage of the customer's usage. Larger PV systems relative to the customer's usage improves the economics of residential NEM, as the PV output does not just offset consumption in the higher-priced usage tiers. We have modeled this by calculating the costs and benefits of NEM for residential systems that produce 90% of the customer's usage.

3. **1.8% and 4.0% Retail Rate Escalation.** The results are sensitive to the assumed growth in retail rates, which is 2.7% per year in our base case, from the 2010 LTPP modeling. We have run our model for retail rate escalations of 1.8%, as a low scenario that is approximately the historical average growth in the California IOUs' rates over the last ten years, and 4.0%, as a high case that significantly exceeds the expected 20-year growth in rates of 2.7% per year which was modeled in the 2010 LTPP case.

4. **NEM Billing Costs.** The E3 NEM Study reported very high incremental billing costs for NEM, particularly for PG&E. This issue deserves much closer scrutiny in the future. Obviously, this will need to include the public release by the utilities of substantial additional detail on how these costs are determined. For this study, we assume zero incremental billing costs, but include as a sensitivity the addition of incremental billing costs for residential customers at the level reported by SCE in 2009 -- $0.01 per kWh of power exported.[59]

5. **West-facing PV Systems.** Our analysis assumes south-facing PV systems. We have taken an initial look at how these results might change for west-facing systems. Although the annual output of a west-facing system is lower, the change in orientation shifts the peak in PV output to the mid-afternoon (about 3 p.m.), when the power is more valuable. We found that, for coastal systems in PG&E's territory (Climate Zone T) under PG&E's E-1 rate, south-facing systems showed a net NEM **cost** of $0.022 per kWh exported, while west-facing systems produced net NEM **benefits** of ($0.008) per kWh exported.[60]

The sensitivity results in the residential market are summarized in **Table 14** and **Table 15**. Table 14 reports the results in terms of levelized $ per kWh exported (similar to Table 8), while Table 15 shows the annual total costs or (benefits) of NEM for NEM capacity equal to the present 5% NEM cap (similar to the results shown at the 5% NEM cap in Table 10).

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[59] E3 NEM Study, at Table 6.

[60] We have not developed a full set of results for west-facing systems for all three IOUs and their associated climate zones.

Table 14: *Residential Sensitivities - NEM Costs or (Benefits)*
(20-year levelized $ per kWh exported)

Case	Utility	Residential Rate Schedule	
		Current Rates	100% Time-of-use
Base from Table 8	PG&E	$0.013	$0.007
	SCE	**($0.007)**	**($0.024)**
	SDG&E	**($0.028)**	**($0.035)**
Reduced Renewables Premium	PG&E	$0.045	$0.039
	SCE	$0.025	$0.008
	SDG&E	$0.004	**($0.003)**
PV Systems Sized at 90% of Usage	PG&E	**($0.007)**	$0.002
	SCE	**($0.042)**	**($0.043)**
	SDG&E	**($0.047)**	**($0.047)**
1.8% Retail Rate Escalation	PG&E	**($0.003)**	**($0.009)**
	SCE	**($0.021)**	**($0.037)**
	SDG&E	**($0.043)**	**($0.050)**
4.0% Retail Rate Escalation	PG&E	$0.039	$0.032
	SCE	$0.016	**($0.003)**
	SDG&E	**($0.004)**	**($0.012)**
Incremental Billing Costs of $0.01 per kWh	PG&E	$0.023	$0.017
	SCE	$0.003	**($0.014)**
	SDG&E	**($0.018)**	**($0.025)**

Table 15: *Residential Sensitivities - NEM Costs or (Benefits) at the 5% NEM Cap (millions per year, 2012$)*

Case	Utility	Residential Rate Schedule	
		Current Rates	100% Time-of-use
Base from Table 10	PG&E	$6.4	$3.5
	SCE	**($4.2)**	**($13.6)**
	SDG&E	**($4.3)**	**($5.4)**
	Total	**($2.1)**	**($15.5)**
Reduced Renewables Premium	PG&E	$22.4	$19.4
	SCE	$13.6	4.2
	SDG&E	$0.5	**($0.5)**
	Total	$36.5	$23.1
PV Systems Sized at 90% of Usage	PG&E	**($3.9)**	$0.9
	SCE	**($30.8)**	**($31.3)**
	SDG&E	**($9.9)**	**($9.9)**
	Total	**($44.5)**	**($40.2)**
1.8% Retail Rate Escalation	PG&E	**($1.5)**	**($4.3)**
	SCE	**($11.9)**	**($20.7)**
	SDG&E	**($6.6)**	**($7.7)**
	Total	**($20.1)**	**($32.7)**
4.0% Retail Rate Escalation	PG&E	$19.3	$16.0
	SCE	$8.4	**($2.0)**
	SDG&E	**($0.6)**	**($1.8)**
	Total	$27.0	**($12.2)**
Incremental Billing Costs of $0.01 per kWh	PG&E	$11.4	$8.4
	SCE	$1.3	**($7.9)**
	SDG&E	**($2.8)**	**($3.9)**
	Total	$9.9	**($3.4)**

To provide some context for these results, we have calculated the impact on the average residential customer's monthly bill from the sensitivity that results in the largest increase in NEM net costs – the reduced renewables premium. In this sensitivity case, assuming the current mix of increasing block and TOU rates, the net cost of NEM for the average non-participating residential customer is $0.40 per month for PG&E, $0.26 per month for SCE, and $0.04 per month for SDG&E when the 5% NEM cap is reached. The net costs in this sensitivity would decrease by approximately one-third if all residential NEM customers were on TOU rates.

For the C&I market, the principal sensitivity that we ran is the reduction in the renewables premium. Net metering remains cost-effective in the C&I market even using this reduced renewables premium, with net benefits of $53.0 million per year at the 5% NEM cap, as shown in the following **Table 16**, which should be compared to the base case results in Table 13 above.

Importantly, in this sensitivity case the benefits from NEM in the C&I market (-$53.0 million per year in Table 16) more than offset the costs of NEM in the residential market (a maximum of +$36.5 million per year from Table 15). This shows that net metering as a whole is cost effective across both the residential and C&I markets, even assuming a lower renewables premium. As noted earlier, if more residential NEM customers were on existing TOU rates, benefits to non-solar customers would increase.

Table 16: *Annual NEM Costs or (Benefits) in the C&I Market—Reduced Renewables Premium Sensitivity (millions per year, 2012$)*

Program	PG&E	SCE	SDG&E	IOU Total
Pre-CSI & CSI	**(2.1)**	**(14.5)**	**(3.8)**	**(20.4)**
Post-CSI to 5% NEM Cap	**(3.8)**	**(21.1)**	**(7.8)**	**(32.6)**
Total at 5% NEM Cap	**(5.9)**	**(35.6)**	**(11.6)**	**(53.0)**

F. Rate Design Implications of the Results

Our analysis has examined a variety of different residential rate designs, in an effort to provide quantitative analysis supporting potential rate design changes that will more closely align rates with costs and thus ensure that NEM reduces costs and provides benefits for non-participating ratepayers. We draw the following significant conclusions from our analysis:

1. **Residential Tier 3-5 rates that average below 30 cents per kWh do not appear to result in NEM costs for non-participating ratepayers.** As shown in Table 1, today SCE's and SDG&E's Tier 3-5 rates average less than 30 cents per kWh, whereas PG&E's Tier 3-4 rates are slightly higher than this level. Our analysis shows that only PG&E's increasing block rates impose a small net cost on other ratepayers; SCE's and SDG&E's current rates provide a small net benefit. Although upper tier rate levels are not the only driver of NEM costs and benefits, they are an important influence, and our work suggests that maintaining upper tier rates near the 30 cents per kWh level will minimize any rate impacts from NEM. This may be a challenge given the constraints of AB 1x and SB 695 on the design of residential electric rates. SB 695 limits the allowed annual increases in Tier 1 and 2 rates to no more than 3% to 5% per year, and thus if overall rates increase more quickly than this, the upper tier rates (Tiers 3 - 5) can grow more quickly than the lower tiers, as happened from 2001 through 2009. Another option would be to implement or increase monthly fixed charges for residential customers. However, AB 1x and SB 695, as interpreted by the CPUC, have limited the ability of the IOUs to use monthly fixed charges to reduce upper tier rates.

2. **Encouraging more residential NEM customers to adopt TOU rates would increase NEM benefits to non-participating ratepayers.** This result can be seen clearly by comparing the results for the current mix of IB and TOU rates to the results for 100% TOU rates in Tables 8, 10, 14 and 15. TOU rates reduce the costs of NEM for non-participating ratepayers by more closely aligning the utility's marginal rates with its marginal costs to serve residential customers. In contrast, with increasing block rates a PV customer's NEM credits depend only on the amount of the customer's usage that the

PV exports offset, and not on when those exports occur or on the utility's marginal costs in those hours.

Appendix C shows the structure and design of the IOU's residential TOU rates. The IOUs typically set TOU rates for the lowest usage tiers based on marginal costs. If one carefully compares the results shown in Table 8, it appears that the largest improvements in moving from an increasing block to a TOU rate are (1) changing from SCE's standard D rate to its residential TOU rate (D-TOU-T) and (2) moving from SDG&E's DR rate to its DR-SES TOU rate. As shown in Appendix C, SCE's TOU-D-T rate and SDG&E's DR-SES rate also happen to be the simplest of the IOUs' residential TOU rates: DR-SES does not have usage tiers, and D-TOU-T has just on- and off-peak rates and two usage tiers. Simplifying residential TOU rates may be critical to gaining customer understanding and acceptance of these time-sensitive rates. In addition, such simplification – in particular, reducing the impact of usage-based tiered rate structures – also appears to increase NEM benefits to non-participating ratepayers, because these simpler tariffs align revenue recovery more closely with costs.

3. **Commercial and industrial rates that reduce demand charges for solar customers continue to be important to prevent cross-subsidies in that market.** In the C&I market, NEM results in significantly greater benefits than costs for non-participating ratepayers; in fact, the challenge in that market is to adopt rate designs that do not result in solar customers subsidizing other ratepayers. Such cost shifts to solar customers are counter-productive because they either slow progress toward solar program goals or require larger incentives through tax credits or direct incentives such as provided through the CSI. Rate design innovations for solar customers – such as PG&E's A-6 rate with no demand charges, or the SCE Option R rates and SDG&E's DG-R tariff which feature reduced demand charges for solar customers – are important means to ensure that such cross-subsidies do not occur, and to bring non-participating ratepayers closer to indifference to NEM.

VI. Conclusion

NEM is an important component of California's efforts to encourage electric ratepayers to install clean, renewable DG. NEM is a simple and understandable way to bill customers who install DG, and removes what might otherwise be a substantial barrier to customer acceptance of DG systems as integral features of their homes and businesses. NEM does impact other, non-participating utility ratepayers, because a minority of the power produced is exported to the grid and is credited to the customer-generator at the full retail rate. Whether the impact of these exports is a net cost or benefit for other ratepayers depends on the design of the NEM customer's rate and on the avoided cost benefits to the utility of this source of renewable generation located on the distribution grid.

This study shows that the recent significant changes that the CPUC has adopted in the IOUs' residential rate designs – principally increases in lower tier rates and reductions in the upper tier rates – plus the recognition that exports of solar DG are 100% renewable and avoid other purchases of renewable power (and not fossil resources), result in a significant improvement in the economics of NEM compared to the CPUC's 2009 E3 NEM Study. The 2009 E3 NEM Study found that 87% of the net costs of NEM were in the residential market, with 72% of the calculated residential NEM cost shift tied to PG&E's residential customers alone. Our new analysis of PG&E's residential market shows that the net costs of NEM in the PG&E residential market have been reduced to less than one-tenth of the level calculated in the 2009 E3 NEM Study. In southern California, where SCE's and SDG&E's current upper tier residential rates are lower than PG&E's, and also have declined since 2009, residential net metering now provides small benefits for non-participating ratepayers. These results show that the cost-effectiveness of NEM in the IOUs' residential markets has improved significantly since the prior E3 and LBNL NEM studies, to the point that residential NEM now provides a small net benefit to non-solar customers on average across the California IOUs' service territories.

In the commercial and industrial market, NEM is clearly cost-effective today. The challenge in the C&I market is to reduce the use of rate design elements such as demand charges which solar customers cannot easily avoid and thus which undervalue the avoided cost benefits of NEM exports to the grid. Removal of these rate design barriers in the C&I market would hasten the day when solar is cost-effective for participants in the C&I market without significant tax credits or direct state incentives.

We conclude that the utilities' concerns with the impacts of NEM on non-participating ratepayers are unfounded. Recent changes in rate design and updated models of the costs which the utilities avoid when they accept NEM power exported to their grids show that residential NEM does not produce a cost shift to non-participating residential ratepayers on average across the IOUs and that NEM is cost-effective for commercial and industrial customers. Moreover, the benefits of NEM can be further increased through rate design changes which more closely align California's retail electric rates with the utilities' cost of service. Such rate design changes can ensure that net metering will remain cost-effective for ratepayers as the penetration of PV systems continues to grow.

Appendix A

Provisions for Non-NEM Customer Generation In SCE's Residential Tariff Schedule D

Schedule D
DOMESTIC SERVICE
Sheet 5 (T)

(Continued)

SPECIAL CONDITIONS (Continued)

5. Customer-Owned Electrical Generating Facilities:

a. For customers not eligible for service under Schedule NEM, Net Energy Metering, and where customer-owned electrical generating facilities are used to meet a part or all of the customer's electrical requirements, service shall be provided concurrently under the terms and conditions of Schedule S and this Schedule. Parallel operation of such generating facilities with SCE's electrical system is permitted. A generation interconnection agreement is required for such operation.

b. For customers with a generation interconnection agreement that provides for the netting of generation and load, the charges for all retail rate components for such parallel generation customers shall be based only on the customer's net kWh consumption, without regard to the customer's choice of electricity provider, and shall be determined using kWh of Net Energy as defined and set forth below:

(1) Net Energy: Net Energy is E_S minus E_F where E_S is energy supplied by SCE and E_F is energy generated by the customer and fed back into SCE's system at such times as customer generation exceeds customer requirements. Only if Net Energy is positive shall Net Energy charges be applied at the rates specified above except that the Minimum Charge will be applied in any case. If the calculation of Net Energy yields a negative result, all such negative Net Energy shall be considered Net Energy transmitted and shall be treated as stated in Section (2), below. The components of Net Energy, E_S and E_F shall be separately recorded unless SCE and customer agree that energy fed back, E_F, is negligible or zero, and so specify by waiver in the generation interconnection agreement.

(2) Net Energy Transmitted: Net Energy transmitted occurs when the cumulative value of E_F exceeds the cumulative value of E_S during an entire billing period and is the amount by which the energy generated by the customer and fed back into SCE's system exceeds the energy supplied by SCE over an entire billing period. Such Net Energy transmitted will be purchased by SCE at a rate for payment equal to SCE's applicable standard offer energy payment rate filed with the Commission. A new rate for payment shall be effective for Net Energy transmitted on and after the effective date of each such filing.

(3) Billing: Payment by SCE to the customer for Net Energy transmitted shall be included as a component of the customer's bill for service rendered under this tariff.

c. Customer-owned electrical generating facilities used solely for auxiliary, emergency, or standby purposes (auxiliary/emergency generating facilities) to serve the customer's load during a period when SCE's service is unavailable and when such load is isolated from the service of SCE are not subject to Schedule S. However, upon approval by SCE, momentary parallel operation may be permitted to allow the customer to test the auxiliary/emergency generating facilities. A Momentary Parallel Generation Contract is required for this type of service.

(Continued)

Appendix B.1

Avoided Costs

This appendix reviews the avoided cost model which we used to calculate the benefits to ratepayers from NEM exports. We used the most recent avoided cost model developed by the consulting firm Energy and Environmental Economics (E3). This is most recent version of the avoided cost model which the CPUC first adopted in 2004 and has used since then to evaluate the avoided costs associated with energy efficiency (EE) and demand response (DR) programs. E3 also has used this model to evaluate the benefits and costs of distributed generation resources in California, most prominently in its 2010 cost-effectiveness evaluation of the CSI. Finally, E3 used this avoided cost model in its 2009 NEM Study.

The most recent version of the E3 avoided cost model is dated September 20, 2011, and is available publicly on the E3 website.[61] **Appendix B.2** is E3's documentation for this version of its model. We have updated the input assumptions used in the model, and have made certain choices in how the model calculates hourly avoided costs for each IOU. These updates and choices are discussed in more detail below.

2011 MPR Updates. E3's model of long-term avoided energy and capacity costs relies on the costs and operating parameters for combined-cycle (CCGT) and combustion turbine (CT) power plants, plus a long-term natural gas price forecast. We have updated the long-term natural gas price forecast, the forecast of greenhouse gas allowance prices beginning in 2013, and the CCGT assumptions; these updates use the values most recently approved by the CPUC, in Resolution E-4442 (dated December 1, 2011) adopting the 2011 MPR. The updated CCGT assumptions include:

- Capital costs
- Property taxes and insurance
- Fixed O&M costs (and escalation)
- Heat rate
- Financing parameters, including the weighted average cost of capital (WACC)

Ancillary Services Costs. The E3 model includes an assumption for the revenues earned by a CT in the California Independent System Operator's (CAISO) ancillary services (A/S) markets. We have updated this assumption to use the assumption for CT A/S revenues (8.2%) reported in the CAISO's *2011 Annual Report on Market Issues and Performance*.[62]

Avoided Renewables Costs. E3's latest avoided cost model, unlike its 2009 model, recognizes that behind-the-meter DG reduces the IOUs' sales, and thus allows DG to avoid the above-market costs of RPS central-station generation in years before 2020. The latest E3 model

[61] We use the "Distributed Resource Avoided Cost Calculator" version of the E3 model titled "DERAvoidedCostModel_v3.9_2011 v4b CA Avg," which is available at http://www.ethree.com/public_projects/cpuc4.php .

[62] CAISO, *2011 Annual Report on Market Issues and Performance*, at 48 and Table 1.10, using 2007-2011 data.

does not, however, recognize the further benefit that NEM exports provide of increasing the market share of renewables on the California grid to above the 33% RPS requirement.

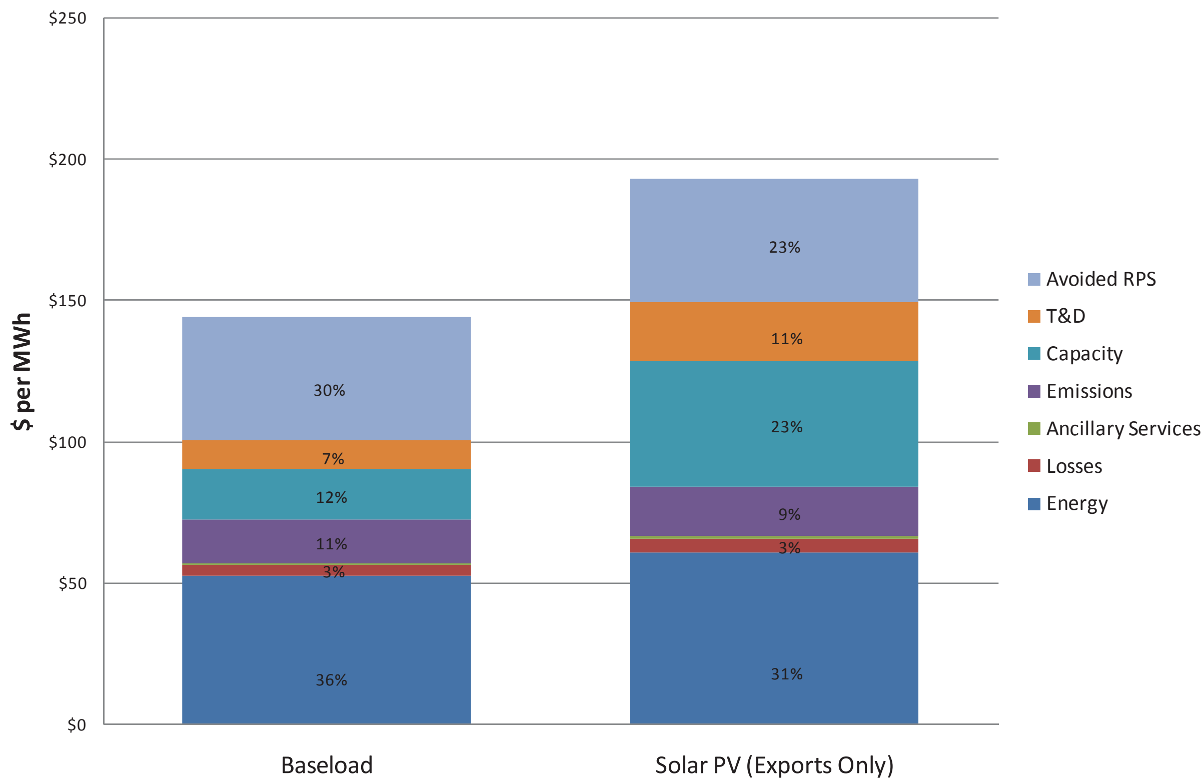
Resource Balance Year. In our version of the E3 model, we do not use the "resource balance year" concept in which short-run avoided costs are used until some chosen "resource balance year" after which long-term resources are assumed to be avoided. E3's determination of a resource balance year that is 5-7 years in the future assumes the addition of large amounts of preferred renewable resources (from both the RPS and the CSI) between today and 2015-2017. However, these include the resources we are trying to value. When these resources are removed from the resource plan, the resource balance year is much closer to the present. In addition, the use of lower short-run marginal costs in the years leading to the resource balance year results in a cost-effectiveness benchmark for the generation costs of renewable DG that is always below the full costs of a long-term resource, such as the combined-cycle gas turbine (CCGT) that is the basis for the MPR. This treats renewable DG in a manner that is inconsistent with, and much more conservative than, the treatment of large-scale RPS resources which the IOUs have had to purchase if their costs were less than the MPR. In short, the resource balance year concept ignores the facts that there is an ongoing need for RPS resources, that RPS resources are being added today, and that renewable DG avoids RPS costs.

Fundamentally, the fact that resources are not in balance with demand until some year in the future results from the "lumpy" nature of large electric resource additions and the long lead times needed to develop, permit, and build major new power plants. New resource additions "overshoot" the amount of needed capacity, pushing out the resource balance year until demand growth catches up. In contrast, DG resources typically have much shorter lead times and can be installed in a less lumpy, more continuous fashion than large plants. As a result, a resource balance year that is far in the future will value DG resources in part using lower, short-run avoided costs in the early years, and thus impose on them an avoided cost "penalty" compared to large-scale RPS resources that are fully valued in all years with long-run avoided costs (i.e. at the MPR or, under SB 2, at the expected costs of renewables). It is fundamentally inconsistent to calculate the avoided costs for "unlumpy," short-lead-time DG resources using a resource balance year approach, whereas the cost-effectiveness of large-scale renewables has been evaluated against a measure (such as the MPR) that does not consider the lumpiness of those large additions.

Avoided T&D Costs. The E3 model states that it uses avoided T&D costs taken from the marginal T&D costs contained in each utility's electric rate design filing in its most recent general rate case (GRC). We have verified that E3 uses PG&E's most recent marginal T&D costs filed in its 2010 GRC (A. 10-03-014). However, we have not been able to verify that E3's September 2011 model is using the most recent marginal T&D costs for SCE and SDG&E. Indeed, both of these utilities filed new electric GRC cases in 2011 – A. 11-06-007 for SCE and A. 11-10-002 for SDG&E. We have therefore updated the E3 model to use the marginal T&D costs which SCE and SDG&E filed in these cases.

Summary of Avoided Cost Components. Figure B-1, shown below, illustrates the components and overall level of the annual average avoided cost prices in our updated version of the E3 avoided cost model, for PG&E's Climate Zone S. We show the avoided cost components weighted using two different profiles: (1) a baseload profile that is a simple annual average of the 8,760 hourly avoided cost prices in a year, and (2) a solar production profile for a PV resource in PG&E Climate Zone S, in which the hourly avoided cost prices are weighted by the quantity of PV output in each hour. Please note that the PV-weighted avoided cost prices use the profile of exports to the grid from a solar PV resource to weight the hourly prices. This figure is similar to Figure 9 of E3's 2009 NEM Study, and shows that the weighted average avoided costs are higher for a peaking resource, such as solar PV, that tends to produce during daytime on-peak hours, than it is for a baseload resource that produces equally in all hours.

Figure B-1
Avoided Cost of Solar PV and a Baseload Resource



The energy price component is about 16% higher for the PV resource than for the baseload resource. In contrast, the capacity and T&D components are several times higher for the PV resource than for the baseload profile, due to the fact that capacity and T&D avoided costs are focused on system peak hours. The avoided renewables cost adder does not vary by hour, and therefore is the same for each type of resource. The total level of avoided costs indicated in the chart is $144 per MWh for the baseload resource and $193 per MWh for the solar PV resource.

Appendix B.2

E3 Avoided Cost Model
2011 Update

Energy and Environmental Economics, Inc

Energy Efficiency Avoided Costs 2011 Update

Brian Horii, Eric Cutter
December 19, 2011

Table of Contents

Overview

This technical memo describes the inputs and methods used to update the avoided costs for energy efficiency cost-effectiveness valuation for the 2014 through 2016 program cycle. In the past, such updates have been performed quickly by changing a minimal set of input values and leaving the extant (circa 2004) avoided cost methodology unchanged. In the years since the EE avoided cost methodology was adopted, however, numerous methodology changes and enhancements have occurred in other CPUC proceedings. Specifically, Energy and Environmental Economics Inc's (E3) work on the California Solar Initiative (CSI) and Demand Response (DR) proceedings have produced numerous methodology enhancements that have been incorporated into this EE avoided cost update.

The major methodology changes affect the forecast of electricity generation energy and capacity, and are listed below.

Updates consistent with the SGIP and CSI Cost-effectiveness Evaluation[1]

1. Explicitly calculate capacity value based on CT net capacity cost
2. Set energy price at the "make whole" level for a CCGT unit
3. Replace the use of PX market hourly shapes with 2010 MRTU hourly shapes
4. 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

[1] See D. 09-08-026, CSI Cost-effectiveness Report (http://www.cpuc.ca.gov/PUC/energy/Solar/evaluation.htm) and CPUC SGIP Cost-effectiveness of Distributed Generation Technologies (http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/)

5. Update the ancillary service value to reflect 2010 markets

6. Remove the energy market multiplier

7. Update CO2 values to Synapse Consulting mid-case forecast

Updates based on the DR Cost-effectiveness Protocols[2]

1. Model generator performance with monthly performance adjustment factors based on historical weather

2. Adjust avoided capacity value to reflect the $/kW-yr value of produced capacity, rather than nameplate capacity, under hot ambient temperature conditions.

3. Update allocation of capacity value to be based on 4 years of historical load and temperature data

Other major updates to the 2011 avoided costs are:

1. T&D method left unchanged, but T&D avoided cost levels updated to reflect more recent utility filings

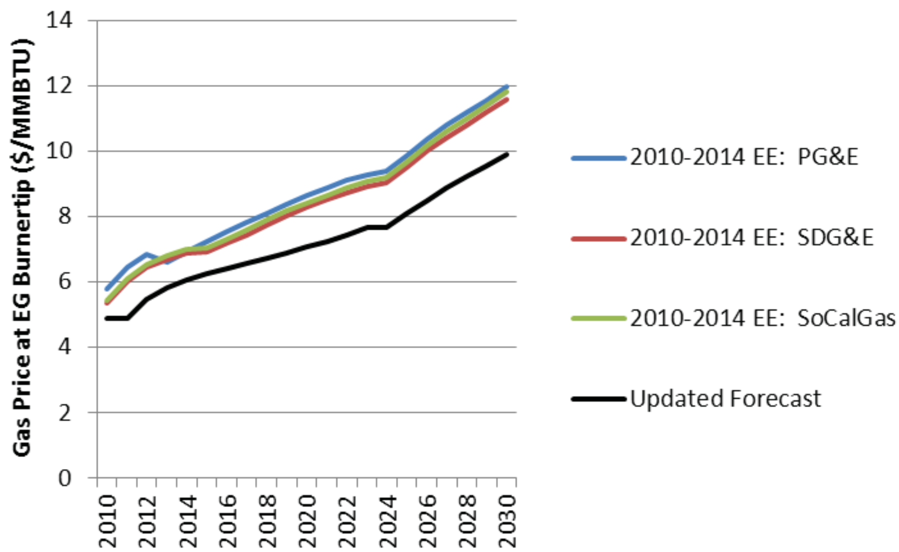
2. Gas forecast lowered to reflect market conditions at the time of the DR proceeding (December 2010.) The gas forecast affects both electricity cost determination and gas avoided procurement costs.

[2] See D. 10-12-024

Natural Gas Avoided Cost Updates

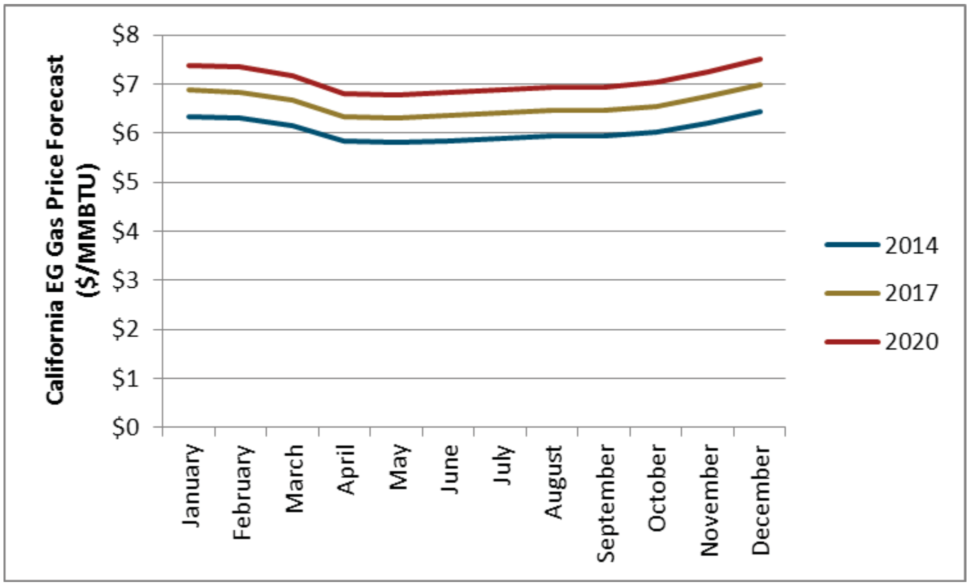
E3 has constructed the natural gas commodity price forecast using NYMEX Henry Hub futures through 2022 updated in December 2010, plus average basis differentials for delivery from Henry Hub to the utility local transmission system (trading through 2015).. After 2022, an average of three fundament price forecasts is used. The forecast methodology for annual natural gas prices is the same as that was used in the CPUC 2009 Market Price Referent (MPR) Update proceeding (the most recent MPR update available at the time). The annual commodity price forecast for each utility service territory is shown in Figure 1.

Figure 1. Natural gas price forecast



This 2011 update augments the MPR's forecast methodology to incorporate expected monthly trends in gas prices—commodity prices tend to rise in the winter when demand for gas as a heating fuel increases. The monthly price profiles are based on the monthly natural gas futures prices used to develop the price forecast. Figure 2 shows three snapshots of the monthly shape of the natural gas price forecast.

Figure 2. Snapshot of monthly gas price forecast shapes for 2014, 2017, and 2020.



For the avoided costs used to evaluate natural gas EE reductions, the following costs are added to the commodity cost.

- compression (0.39%),
- losses and unaccounted for (1.37%),
- marginal transmission and delivery costs (varies by utility),
- NOX and CO2 ($5.82/lb and $15.37/short ton in 2012. Both escalate annually)

Of these additional cost items, only the CO2 $/short ton value has been updated. The cost of CO2 is discussed in more detail in the electricity avoided cost section of this memo.

For the natural gas price for electricity generators, which is an input into the estimation of electricity avoided costs, tariff charges for delivery to the generators (Utility Electric Generation or UEG) are added to the commodity price. The tariffs and calculations used are also from the 2009 MPR update, updated with the tariffs applicable in 2010.

Overview of Electricity Avoided Cost Components

This 2011 avoided cost update incorporates significant methodology changes relative to the avoided cost methodology used for EE since 2006. The most significant change is that rather than use one, all-in avoided cost of electricity and the PX market price shape, energy and capacity prices are calculated and allocated separately. Also, two additional avoided costs are added for a total of six avoided cost components. This section provides a brief overview of the electricity avoided cost components and their contribution to the total electricity avoided costs. This is followed by detailed discussions of the updates for each component in the subsequent sections.

The avoided cost used for electricity energy efficiency evaluation is calculated as the sum of six components shown in Table 1.

Table 1. Components of electricity avoided cost

Component	Description
Generation Energy	Estimate of hourly wholesale value of energy
Generation Capacity	The costs of building new generation capacity to meet system peak loads
Ancillary Services	The marginal costs of providing system operations and reserves for electricity grid reliability
T&D Capacity	The costs of expanding transmission and distribution capacity to meet peak loads
Environment	The cost of carbon dioxide emissions associated with the marginal generating resource
Avoided RPS	The reduced purchases of renewable generation at above-market prices required to meet an RPS standard due to a reduction in retail loads

Each of these avoided costs is must be determined for every hour of the year. The hourly granularity is obtained by shaping forecasts of the average value of each component with historical day-ahead and real-time energy prices and actual system loads reported by CAISO's MRTU system for 2010; Table 2 summarizes the methodology applied to each component to develop this level of granularity.

Table 2. Summary of methodology for electricity avoided cost component forecasts

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	Forward market prices and the $/kWh fixed and variable operating costs of a CCGT.	Historical hourly day-ahead market price shapes from MRTU OASIS
Generation Capacity	Residual capacity value a new simple-cycle combustion turbine	Top 250 CAISO hourly 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 temperature data
Environment	Synapse Mid-Level carbon forecast developed for use in electricity sector IRPs	Directly linked with energy shape with bounds on the maximum and minimum hourly value
Avoided RPS	Cost of a marginal renewable resource less the energy market and capacity value associated with that resource	Flat across all hours

Figure 3, below, shows a three-day snapshot of the avoided costs, broken out by component, in Climate Zone 13. 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 shown in Figure 3 of over $2,500/MWh are driven primarily by the allocation of generation and T&D capacity to the peak hours (because of high demand in those hours), but also by higher energy market prices during the middle of the day.

Figure 3. Three-day snapshot of energy values in CZ13 in 2017

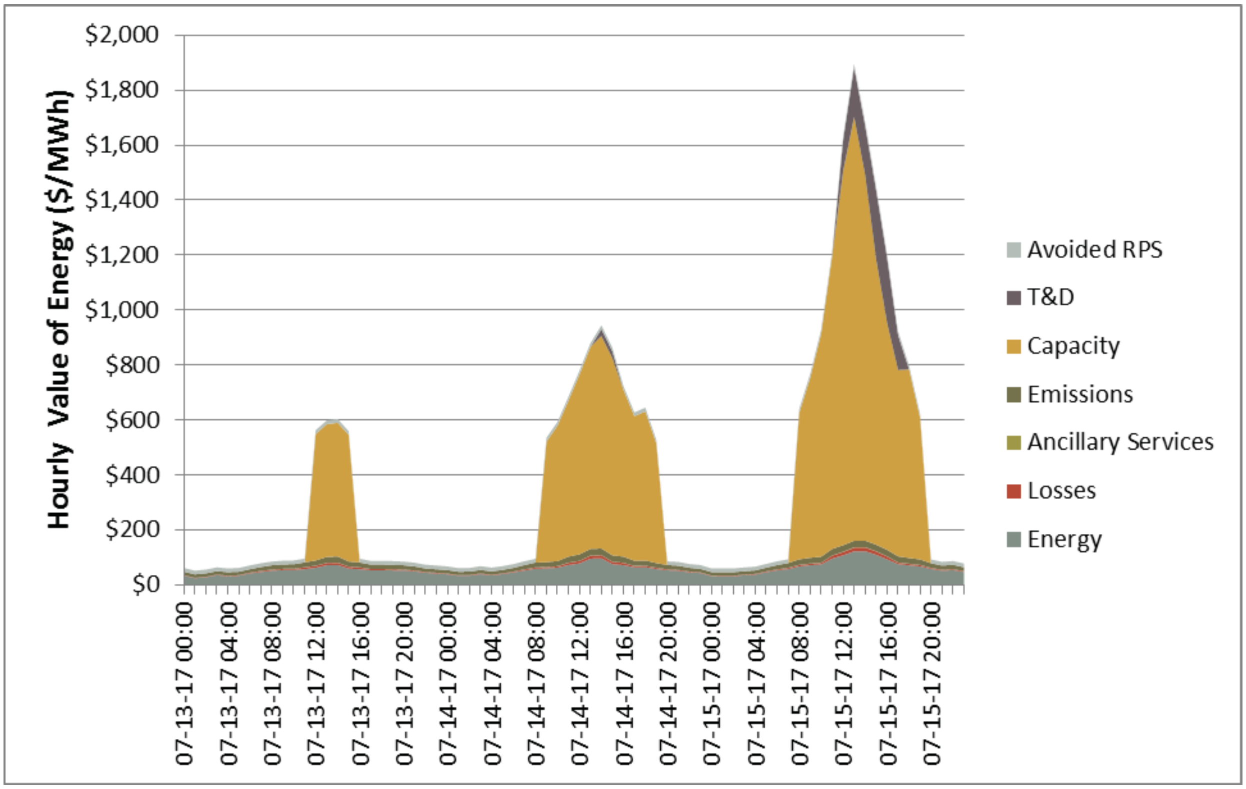


Figure 4 shows average monthly value of electricity reductions, revealing the seasonal characteristics of the avoided costs. The energy component dips in the spring, reflecting low energy prices due to increased hydro supplies and imports from the Northwest; and peaks in the summer months when demand 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 4. Average monthly avoided cost in CZ13 in 2017

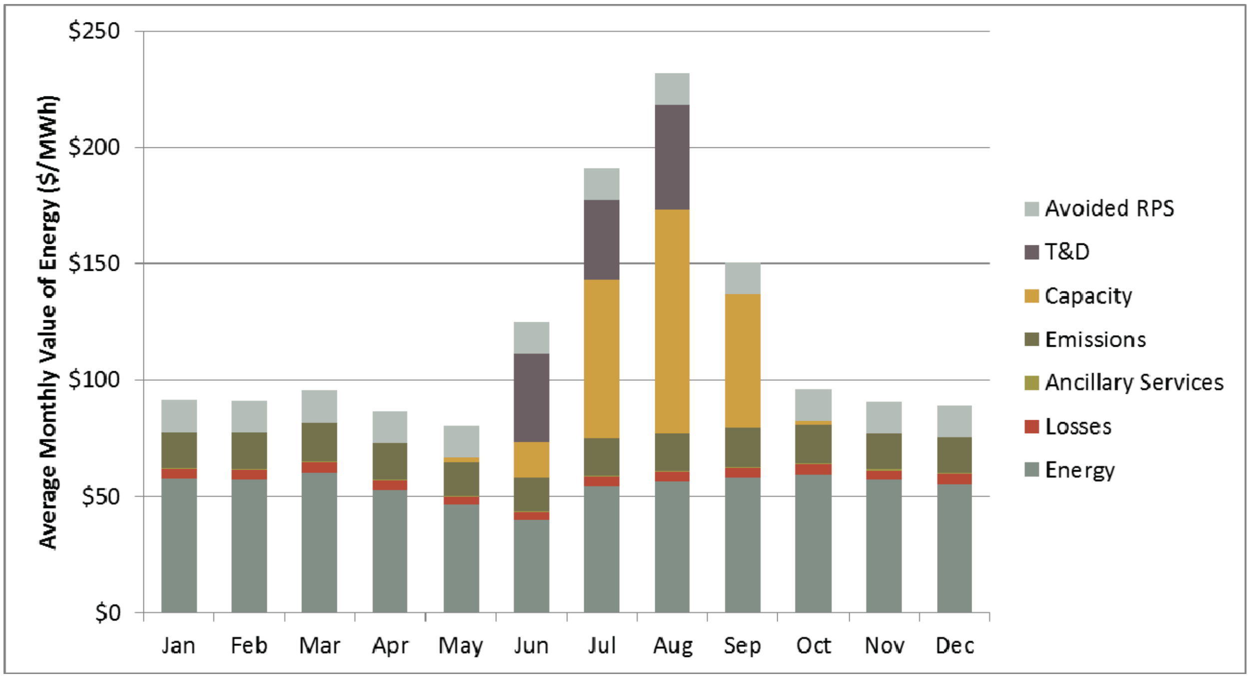
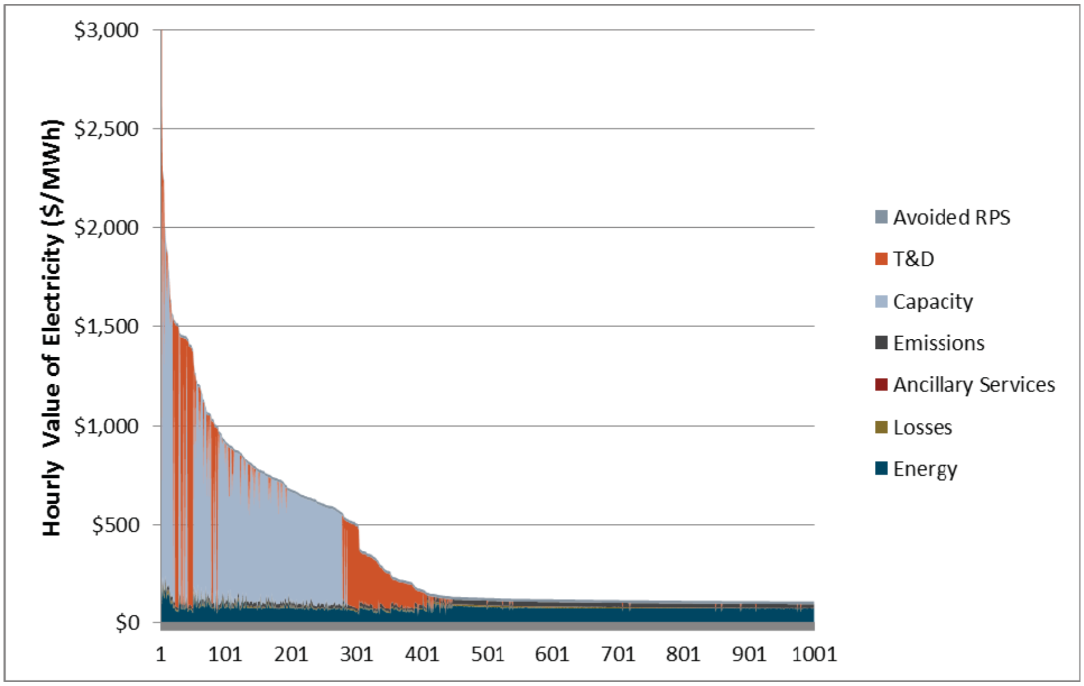


Figure 5 shows the components of value for the highest value hours in sorted order of cost. This chart shows the relative contribution to the highest hours of the year by component. Note that most of the high cost hours occur in approximately the top 200 to 400 hours—this is because most of the value associated with capacity is concentrated in a limited number of hours. While the timing and magnitude of these high costs differ by climate zone, the concentration of value in the high load hours is a characteristic of the avoided costs in all of California.

Figure 5. Price duration curve showing top 1,000 hours for CZ13 in 2017



Avoided Cost Methodology

Generation Energy

The treatment of generation avoided costs received substantial methodology updates in the CSI and DR proceedings. Those methodology updates have been incorporated into this 2011 update. The differences between the extant 2004-2012 energy efficiency approach and the updated generation avoided cost methodology are summarized below.

> **2004-2012 Energy Efficiency Approach:** The extant method uses a long-run cost of generation starting in 2008. Long-run generation cost is the all-in cost of a CCGT running 92% of the year (based on the same assumptions used to calculate the Market Price Referent (MPR)). The all-in cost is the total fuel, O&M, and levelized capital costs of the new generator. This all-in cost is then shaped to an hourly profile based on the California Power Exchange day-ahead market prices from the "functional" periods of that market (1998-1999)[3]. The 2010-2012 avoided costs also include a CO2 emission adder of $30 per short ton.

> **CSI and DR Avoided Cost Update:** The CSI and DR proceedings make a fundamental methodology change by moving away from the prior PX market structure modeled in the EE avoided costs. In the PX market, capacity value was included in the hourly market prices. With the advent of the Resource Adequacy payments and discussions of a capacity market, it became important to explicitly model capacity value separate from energy market value. The CSI and DR avoided cost models calculate explicit capacity

[3] While the extant method uses generator performance and costs and long-run gas forecasts from the MPR, it differs from the MPR in using the Power Exchange hourly energy price profile. The MPR uses hourly shapes based on utility energy market simulations.

and energy values, resulting in total generation avoided costs that are more concentrated in the peak hours of the year. Other substantial updates include the replacement of the PX market shapes with 2010 MRTU market data, the use of the Synapse Consulting mid-case forecast of CO2 costs, and the addition of Renewable Portfolio Standard (RPS) avoided costs. Capital costs for a CT are taken from the most recent CAISO Annual Market Issues and Performance Report (which in turn are based on the CEC Cost of Generation Report). Capital Costs for a CCGT are taken from the most recently adopted MPR update. A book life of 20 years is assumed for both the CT and CCGT. This assumption is consistent with the MPR proceeding, the CEC Cost of Generation Report, the Northwest Electric Power and Conservation Plan, the Lazzard Levelized Cost of Energy Analysis and both the PJM and NYISO Cost of New Entry (CONE) analyses. Independent Power Producer cost of capital and financing assumptions are used. The CPUC has approved the construction or purchase of several natural gas plants by utilities in recent years. However the primary intended mechanism for meeting resource adequacy requirements is bilateral agreements between utilities and independent third-parties. Several modest changes to the calculation of the capital and operating costs were made in the DR Cost-Effectiveness Protocol proceedings in late 2010 and early 2011 in response to party comments. These include making the tax and insurance assumptions consistent with the MPR, including the use of the Domestic Manufacturing Tax Credit.

Determination of energy market values

The updated avoided energy costs are developed using a method similar to what was used for CSI. In years prior to resource balance, the average energy cost is based on the NYMEX market price forecast (available through 2014 for the update in 2010). For the period after the available forward market prices, the method interpolates between the last available NYMEX market price and the long-run energy market price. The long-run energy market price is used for the resource balance and all subsequent years.

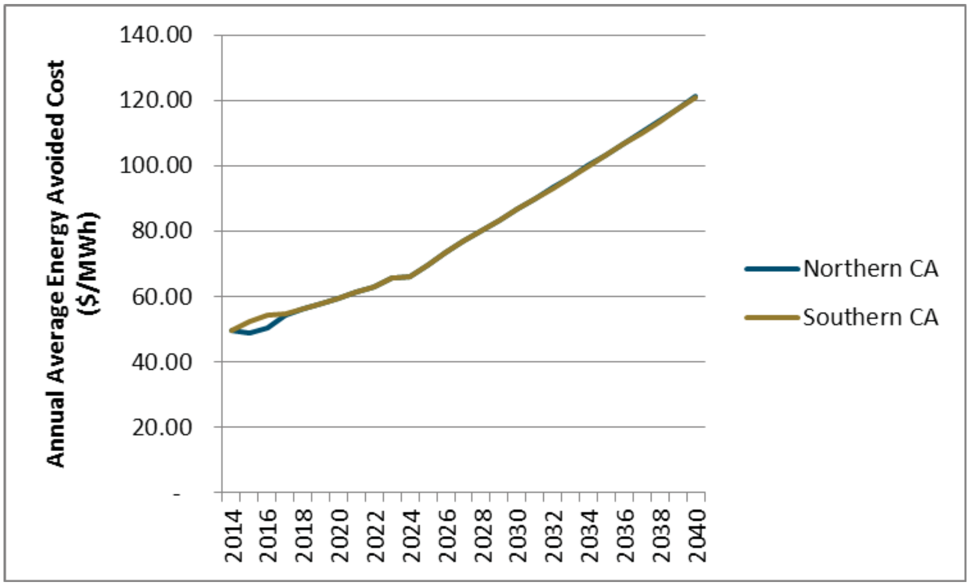
The annual long-run energy market price is set so that the CCGT's energy market revenues plus the capacity market payment equal the fixed and variable costs of the CCGT (i.e.: the CCGT is made whole). The long-run energy market price begins with the 2010 MRTU day-ahead market price escalated by the natural gas burner tip forecast. This reflects the assumption that CAISO Day Ahead energy prices will represent the electricity procurement costs avoided by utilities. The energy market price is then increased or decreased with an energy market calibration factor so that the CCGT is made whole. The energy market calibration factor is applied to both 1) the real-time market prices used to determine CT energy revenues and the value of capacity, and 2) the day-ahead energy market used to determine CCGT energy revenues. This creates a feedback effect between the energy and capacity avoided costs. The feedback effect is illustrated with the following example.

> *Assume that the CCGT would collect more revenue through the capacity and energy markets than is needed to cover its costs. The methodology decreases the calibration factor to decrease the day-ahead energy market prices and market revenues to make the CCGT whole. To keep the real-time and day-ahead markets in sync, the methodology also would decrease the real-time energy market prices by the calibration factor. The decrease in real-time energy market prices would result in lower net revenues for a CT, and therefore raise the value of capacity (as higher capacity payment revenue is needed to incent a new CT to build). When we re-examine the CCGT, the raised value of capacity results in the CCGT collecting excess revenues, so the calibration factor needs to be decreased more, and the process repeats*[4]*.*

[4] The actual process steps for determining the calibration factor for each year (and therefore the real-time and day-ahead market prices) are listed below.

1. Set the annual day-ahead energy price at the 2010 level increased by the percentage change in the forecast annual gas burner tip price.
2. Set the energy market calibration factor to 100%
3. Multiply (1) by (2) to yield the adjusted annual day-ahead price

Figure 6: Annual Average Energy Avoided Costs



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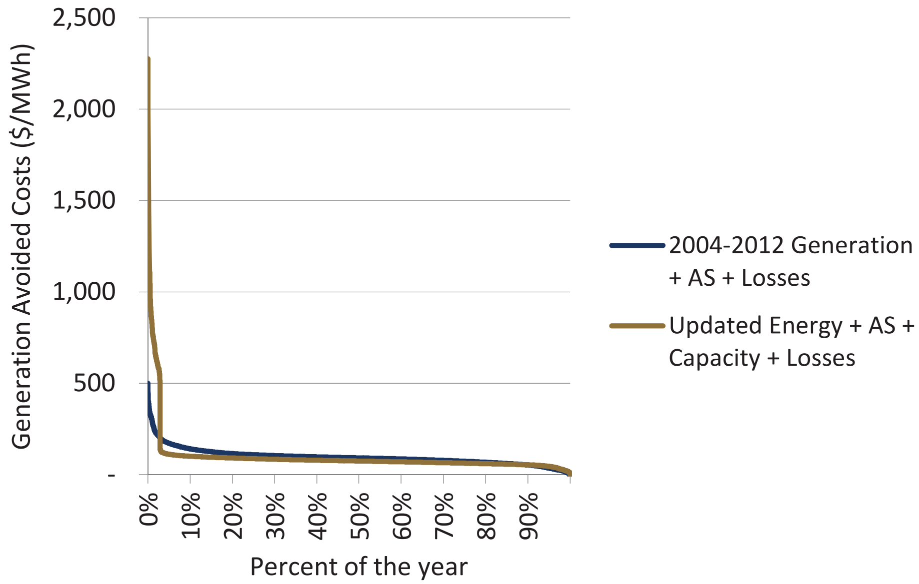
4. Calculate capacity cost
    a. Multiply the real-time 2010 hourly price shape by the adjusted annual day ahead price
    b. Dispatch a new CT against the hourly prices in Northern and Southern CA from 4a to determine real time dispatch revenue in Northern and Southern CA (Figure 6)
    c. Calculate ancillary service revenues as 7.6% of the real-time dispatch revenue
    d. Capacity value is the net capacity cost. Net capacity cost = the levelized cost of the new CT plus fuel and O&M costs less
    e. Adjust capacity value ($/kW-yr) to reflect degraded output at system peak weather conditions (Figure 10)
    f. Set the capacity value at the average of Northern and Southern CA capacity values
5. Calculate energy cost
    a. Multiply the day-ahead 2010 hourly price shape by the adjusted annual day ahead price
    b. Dispatch a new CCGT against the hourly prices from to determine the day-ahead dispatch revenue (
    c. Calculate the excess (deficient) margin of a CCGT unit as the levelized cost of a new CCGT plus fuel and O&M costs less (adjusted for CCGT output degradation)
6. If there is excess or deficient margin for the CCGT unit, decrease or increase the energy market calibration factor, and repeat from step.

Hourly Shaping of Energy Costs

As with the 2004-2012 energy efficiency avoided cost methodology, the annual energy avoided costs are converted to hourly values by multiplying the annual value by 8760 hourly market shapes. For the 2004-2012 methodology, hourly PX prices were used. For this update, the hourly shape is derived from day-ahead LMPs at load-aggregation points in northern and southern California obtained from the California ISO's MRTU OASIS. 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. The resulting hourly market heat rate curve is integrated into the avoided cost calculator, where, in combination with a monthly natural gas price forecast, it yields an hourly shape for wholesale market energy prices in California.

Total energy and capacity avoided costs are shown in Figure 7. The avoided costs are shown in descending order. Whereas the 2004-2012 EE cost shape is based on the previous PX market hourly prices, the updated cost shape reflects 1) the allocation of capacity costs to the top 250 system load level hours in the year and 2) the shaping of the energy costs based on 2010 MRTU California wholesale market information.

Figure 7: Hourly Generation Avoided Costs for 2017



Note that the 2004-2014 Generation avoided costs reflect the cost assumptions used for the current 2010-2014 E3 Calculators. The Updated avoided costs reflect new input values such as lower natural gas prices. The comparison shows current vs updated avoided costs. If the existing method were updated with the same input values as the updated forecast, the avoided costs would be lower than those shown in the figure.

Generation Capacity

Generation resource balance year

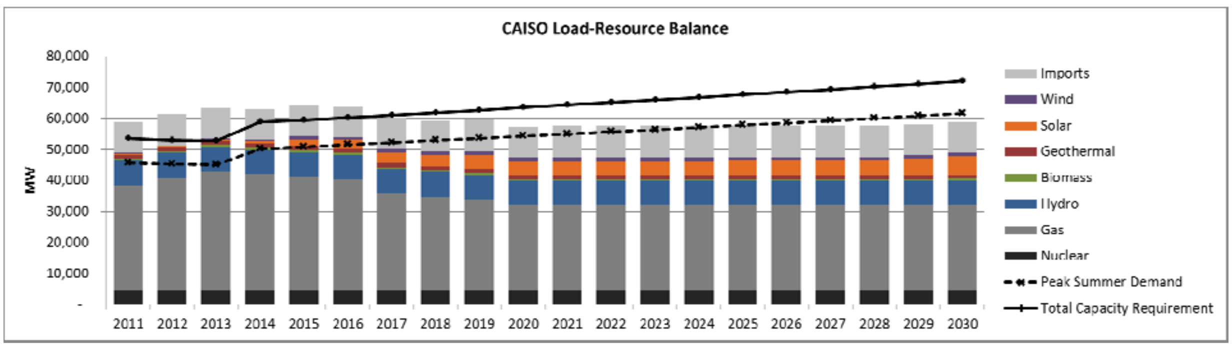
Generation capacity for this update is calculated using the DR method, updated with 2010 input data. The method assumes that in the resource balance year and beyond, the value of capacity will equal the fixed cost of a new CT less the net revenues that the CT would attain from the selling to the real-time energy and ancillary service markets (residual capacity value). In the years prior to resource balance, the capacity value is interpolated from the resource adequacy value of $28.07/kW-yr in 2008 to the residual capacity value in the resource balance year.

The resource balance year determines when the capacity and energy markets will reflect the full cost of new plants. The extant EE calculator uses a resource balance year of 2008 (based on projections performed in 2004), while the CSI proceeding used a resource balance year of 2015.

In the DR proceeding, the CPUC directed that the full residual capacity of a CT be used to quantify the capacity value of DR, so no resource balance year adjustment was made.

E3 has set the resource balance year to reflect the recent Joint IOU July 1, 2011 filing in the LTPP proceeding (R.10-05-006 track 1), E3 uses a resource balance year of 2017 for the updated EE avoided costs. 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 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.

Figure 8. Evaluation of resource balance year



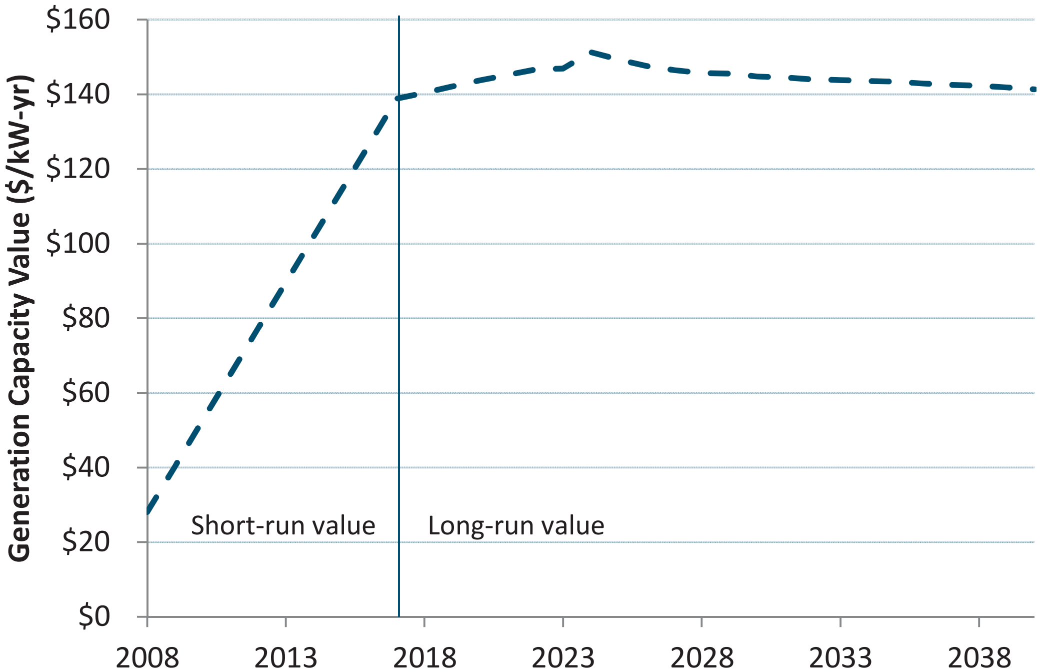
CT dispatch

To determine the long-run value of capacity, the avoided cost model performs an hourly dispatch of a new CT to determine energy market net revenues. 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. The dispatch uses the 2010 MRTU real-time market shape[5] (not the day-ahead market shape), and adjusts for temperature performance degradation using average monthly 9am – 10pm temperatures (see next section).

The market revenues earned in the energy and AS markets are subtracted from the fixed and variable costs of operating a CT to determine the residual capacity value. The capacity value calculations are performed using both Northern California and Southern California market prices and weather information. The cost of a new CT, however, is the same for both Northern and Southern California. Consistent with the DR methodology, the final capacity value for each year is the average of the results for Northern and Southern California (50% Northern and 50% Southern).

[5] The real-time market shape annual level is adjusted annually by 1) the percentage change in natural gas burner tip prices and 2) the energy market calibration factor. The energy market calibration factor is used to adjust the energy market prices to a level such that a new CCGT would not over or under collect in the resource balance and all subsequent years, and is described in more detail in the energy market section.

Figure 9: Statewide Generation Capacity Value before Temperature Adjustments



Hourly allocation of capacity value

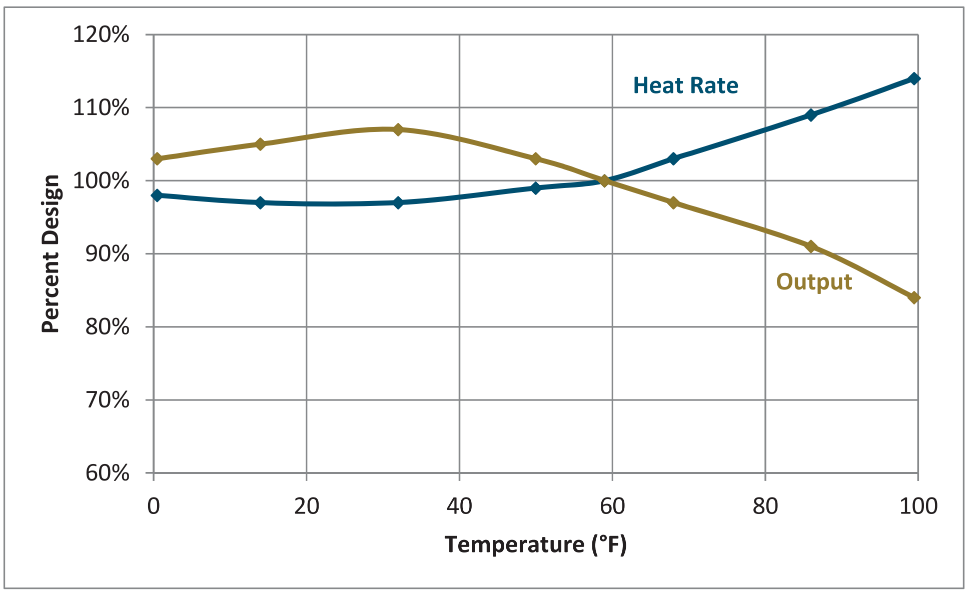
The residual capacity value is allocated over the top 250 hours of CAISO system load, in inverse proportion to the gap between the system peak load plus operating reserves and the system loads for each of the 250 hours. In this manner, the highest load hour will receive the largest allocation of capacity value on a $/kWh basis (~$2,000/MWh). The 250th hour receives an allocation of ~$400/MWh. Most of the capacity value falls in the summer on-peak period, though some falls in the summer and winter partial-peak periods as well.

Temperature effect on unit performance

The capacity value as $ per kW of degraded capacity, rather than $ per kW of nameplate capacity to account for the effects of temperature. This re-expression increases the $/kW capacity value by about 8%. The use of the degraded capacity was introduced in the DR proceeding to more precisely model to operation of a combustion turbine at different ambient temperature conditions throughout the year. Use of degraded, rather than nameplate, capacity value results an increase in the capacity value because combustion turbines perform at lower efficiencies when the ambient temperature is high.

The CT's rated heat rate and nameplate capacity characterize the unit's performance at ISO conditions,[6] 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 10 shows the relationship between temperature and performance for a GE LM6000 SPRINT gas turbine, a reasonable proxy for current CT technology.

Figure 10. Temperature-performance curve for a GE LM6000 SPRINT combustion turbine.



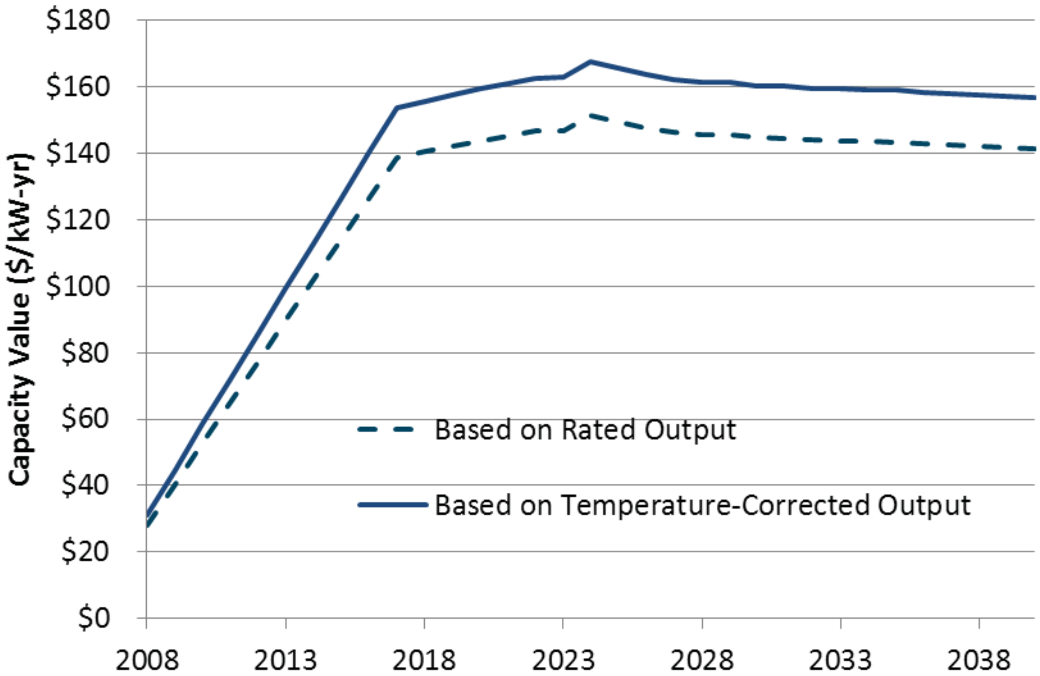
The effect of temperature on performance is incorporated into the calculation of the CT residual; several performance corrections are considered:

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

- 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.
- 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.
- 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 deration. Consequently, the value of capacity is increased by approximately 10% to reflect the plant's reduced output during the top 250 load hours of the year as shown in Figure 11.

The forecast annual generation capacity values are shown below.

Figure 11. Adjustment of capacity value to account for temperature derating during periods of peak load



Planning reserve margin and losses

The capacity value is increased to account for both the Planning Reserve Margin (PRM) and losses. Resource Adequacy rules set capacity procurement targets for Load Serving Entities based on 1.15% of their forecasted load.[7] The must also account for losses in delivering electricity from the generator to the customer, based on peak loss factors for each utility. The capacity value is therefore increased by the PRM and the applicable loss factors for each utility. Note that peak loss factors are used for generation and T&D capacity while TOU loss factors are used for energy.

[7] See D.10-06-036 OP 6b, and the 2012 Final RA Guide at http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm

Ancillary Services (AS)

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. The procurement of regulation services is generally independent of load; consequently, behind-the-meter load reductions and distributed generation exports will not affect their procurement. However, both spinning and non-spinning reserves are directly linked to load—in accordance with 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.

As a result, load reductions do result in a reduction in the procurement of reserves; the value of this reduced procurement is included as a value stream in the Avoided Cost Calculator. It is assumed that the value of avoided reserves procurement scales with the value of energy in each hour throughout the year. According to the CAISO's April 2011 Annual Report on Market Issues and Performance[8], CT A/S revenues from 2008 through 2010 averaged 7.6% of the CT energy market revenue. E3 uses this figure to assess the value of avoided A/S procurement in each hour.

T&D Capacity

The avoided electricity avoided costs include the value of reducing the need for transmission and distribution capacity expansion. Of the six avoided cost components, T&D costs are unique in that both the value and hourly allocation are location specific. Avoided T&D costs are

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[8] Table 2.10 Financial analysis of a new combustion turbine (2006-2010)

determined separately for each utility. The avoided T&D costs have been updated by climate zone for PG&E, and at the system level for SCE and SDG&E territories based on utility ratemaking proceedings.[9] They are the same values used for the 2011 CEC California Building Energy Standards, and the CPUC CSI and DR proceedings. The PG&E values are close to the values used in those proceedings, but reflect a minor update that PG&E filed in its 2011 GRC Phase II proceeding on January 7, 2011. The T&D avoided costs escalate by 2% per year in nominal terms.

Table 3: Updated T&D Capacity Costs in 2011 ($/kW-yr)

	Sub transmission	Distribution	Total T&D, Adjusted For Losses
SCE	$23.39	$30.10	$55.42
SDG&E	$21.08	$52.24	$77.05
PG&E			
1			$83.02
2			$89.19
3A			$62.76
3B			$64.16
4			$74.94
5			$116.75
11			$93.79
12			$85.91
13			$77.51
16			$71.10

The value of deferring distribution investments is highly dependent the type and size of the equipment deferred and the rate of load growth, both of which vary significantly by location. Furthermore, some distribution costs are driven by distance or number of customers rather

[9] SDG&E did not have transmission avoided capacity costs at the time the CEC California Building Standard updates were prepared. The decision was made in consultation with SDG&E staff to use an average of SCE and PG&E transmission avoided costs as a proxy for SDG&E. That proxy value is maintained for the 2011 EE update.

than load and are therefore not avoided with reduced energy consumption. However, expediency and data limitations preclude analysis at a feeder by feeder level for a statewide analysis of avoided costs. The costs taken from utility rate case filings are used as a reasonable proxy for the long-run marginal cost T&D investment that is avoided over time with the addition of distributed energy resources. CPUC Feed-in-Tariff proceedings have considered identifying specific locations or “hotspots” where distributed generation will provide higher avoided T&D cost savings.[10] This approach is not currently incorporated in the avoided cost methodology.

The value of deferring transmission and distribution investments is adjusted for losses during the peak period using the factors shown in Table 4 and Table 5. These factors are lower than the energy and generation capacity loss factors because they represent losses from secondary meter to only the distribution or transmission facilities.

Table 4. Losses factors for SCE and SDG&E transmission and distribution capacity.

	SCE	SDG&E
Distribution	1.022	1.043
Transmission	1.054	1.071

[10] See E3 Avoided Cost Presentation at September 26, 2011 CPUC SB32 Workshop: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/sb2_1x.htm

Table 5: Losses factors for PG&E transmission and distribution capacity.

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

Hourly allocation of T&D capacity cost

The method for allocating T&D capacity costs to hours is unchanged from the extant method[11]. The method allocates the T&D capacity value in each climate zone to the hours of the year during which the system is most likely to be constrained and require upgrades—the hours of highest local load. Because local loads are not readily available for this analysis, hourly temperatures are used as a proxy to develop allocation factors for T&D value. This approach

[11] The DR proceeding changed the allocation of the T&D costs to hours using recent historical weather data. The weather data used for the EE avoided costs, however, must match the weather data used to model impacts in the DEER database. The 2011 update continues to use TMY weather data, as has been the practice since 2006.

results in an allocation of T&D value to several hundred of the hottest (and likely highest local load) hours of the year as presented in Figure 12 shows the total allocation of T&D within each month for each of the climate zones. Different weather patterns throughout the state result in unique allocators for T&D capacity. Generally, in hotter climate zones with loads driven by air conditioning, capacity value will be concentrated in more pronounced peaks than it is for the cooler climate zones.

Figure 12. Development of T&D allocators for CZ13

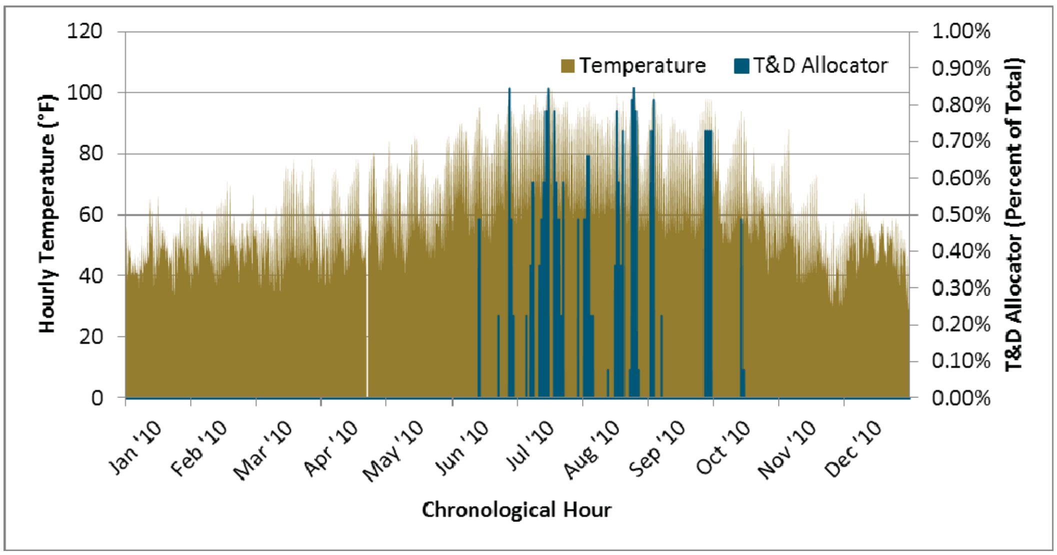
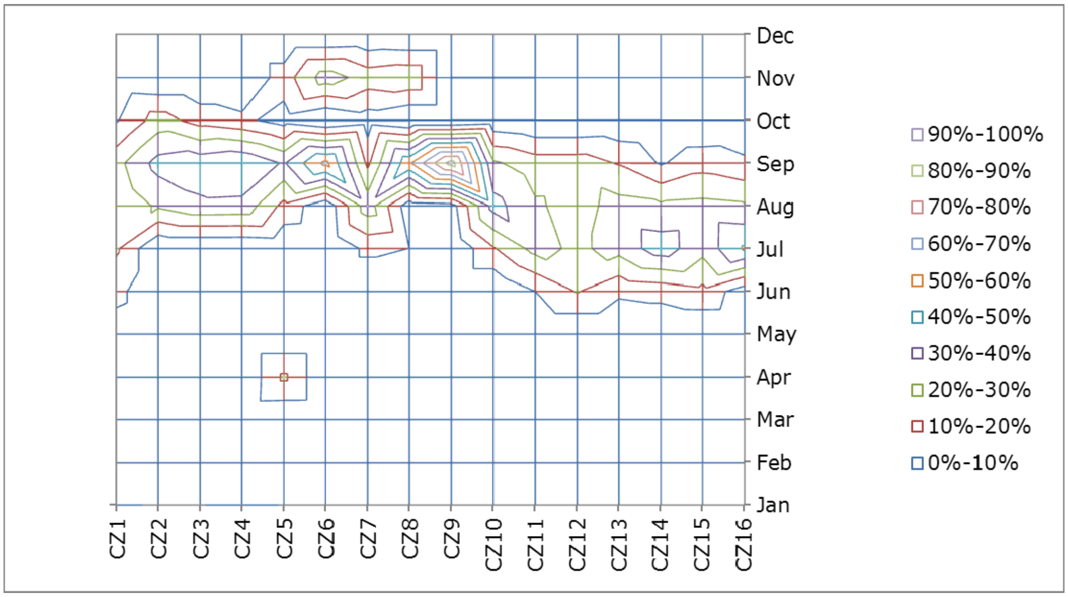


Figure 13. Monthly allocation of T&D capacity value across the sixteen climate zones.



T&D adjustment factors

Currently DR is unique in being considered as a dispatchable resource comparable to a CT. This has led to the use of several adjustment factors to account for the different availability, notification time, triggers and location of DR. A "D" factor for T&D value may be used by utilities to account for the potential for DR to avoid distribution upgrades. This is expected to be more common in the future as communication technology and AMI allow for DR dispatch based on local as well as system conditions. For other programs, which are not dispatchable by the utility, providing efficiency or generation throughout the year and broadly distributed throughout the service territory, utility average T&D avoided costs without adjustment are used.

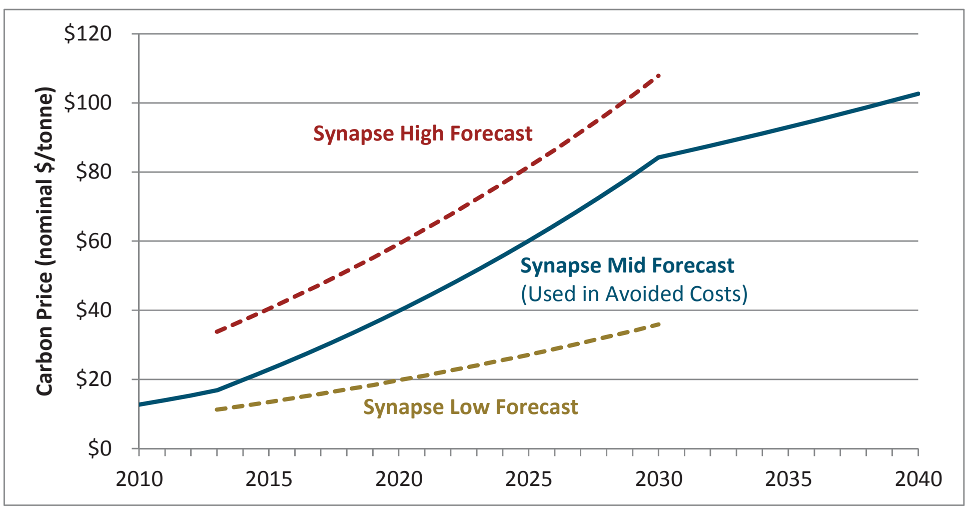
Environment

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

More challenging for CO2 is estimating what the market price is likely to be, given a market for CO2 allowances is established. The price of CO2 will be affected by many factors including market rules, the stringency of the cap set on CO2 allowances, and other elements.

The extant E3 Calculators use $30 per short ton as the value of CO2 reductions from EE. This update uses a forecast developed by Synapse Consulting in 2008 (since updated in 2011) through a meta-analysis of various studies of proposed climate legislation. The Synapse mid-level forecast used for the update was developed explicitly for use in electricity sector integrated resource planning and so serves as an appropriate applied value for the cost of carbon dioxide emissions in the future. This is the same forecast used for CSI and DR. Figure 14 shows the Synapse price forecasts.

Figure 14. The CO2 price series embedded in the avoided cost values



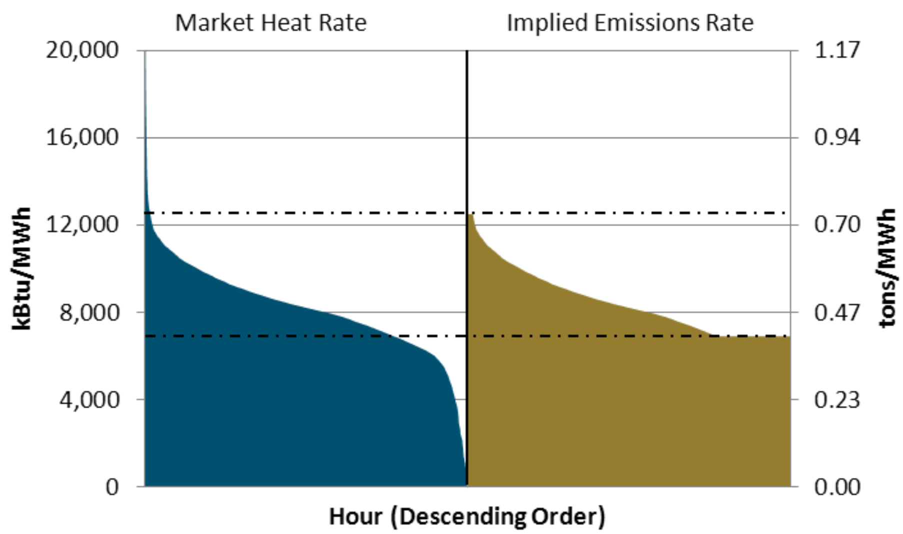
The 2011 MPR adopted a new methodology for calculating assumed prices for California carbon emission allowances based on market price data for electricity and natural gas prices. Increases in the spark spread (the difference between electricity and natural gas prices) before and after major milestones in the development and adoption of CARB regulations are used to impute assumed CO2 prices. This method was developed in October 2011 for the 2011 MPR adopted in December 2011 and is not currently used in the avoided cost methodology. As CARB further defines and implements GHG regulations, it is reasonable to expect that the cost of carbon will be reflected in the forward market prices for electricity used to estimate the avoided generation costs. Future updates will consider how to best account for carbon costs embedded in the market price for electricity and avoid double counting.

The marginal rate of carbon emissions is calculated by the same method used for the extant EE avoided costs. Assuming that natural gas is the marginal fuel in all hours, the hourly emissions rate of the marginal generator is calculated based on the day-ahead market price curve. The link between higher market prices and higher emissions rates is intuitive: higher market prices enable lower-efficiency generators to operate, resulting in increased rates of emissions at the margin. Of course, this relationship holds for a reasonable range of prices but breaks down when prices are extremely high or low. For this reason, the avoided cost methodology bounds the maximum and minimum emissions rates based on the range of heat rates of gas turbine technologies. The maximum and minimum emissions rates are bounded by a range of heat rates for proxy natural gas plants shown in Table 6; the hourly emissions rates derived from this process are shown in Figure 15.

Table 6. 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 15. Hourly emissions rates derived from market prices (hourly values shown in descending order).



The 2004-2012 EE avoided cost methodology included explicit environmental adders for NOX and PM-10. E3 now believes that the costs for control and/or abatement of those emissions are captured in the capital cost of the new plants used to set the long-run cost of energy and capacity. Therefore, these quantities are no longer valued as a separate cost adder. As those costs were small in the 2004-2012 EE avoided cost methodology, their removal as an explicit adder has minimal impact.

Avoided Renewable Purchases Adder

This RPS adder reflects the fact that as energy usage declines, the amount of utility renewable purchases required to meet the RPS goals also declines. Since the cost of renewable energy is higher than the forecasted cost of wholesale energy and capacity market purchases, energy reductions provide some value above the wholesale energy and capacity markets[12]. This adder is not included in the 2004-2012 EE avoided cost methodology.

In the DR methodology this adder is 33% (the RPS goal in 2020) of the cost difference forecast between RPS-eligible resources and the wholesale market price, beginning in 2020. This updated methodology incorporates the new SB2X, and has been updated to reflect the interim goals of 20% in 2013 and 25% in 2016.

The RPS Adder is a function of the Renewable Premium, the incremental cost of the marginal renewable resource above the cost of conventional generation. The marginal renewable resource is based upon the Fairmont CREZ, the most expensive resource bundle that is included in the renewable portfolio in E3's 33% Model 33% Reference Case. The Renewable Premium is calculated by subtracting the market energy and capacity value associated with this bundle, as well as the average CO2 emissions from a CCGT, from its levelized cost of energy as shown in Figure 16. The RPS Adder is calculated directly from the Renewable Premium by multiplying by the RPS goal for that year. For example, in 2021 the RPS adder is equal to the Renewable premium * 33%, as, for each 1 kWh of avoided retail sales, 0.33 kWh of renewable purchases are avoided. The RPS adder increases in a step-wise manner according to the goals set in 2013, 2016 and 2020. The actual procurement is likely to occur in a more linear fashion, but we expect that the impact of using one method over the other is quite small.

[12] For the CSI analysis, the only RPS goal was 33% in 2020, so the incremental RPS value only accrued in 2020 and beyond. With the passing of SB2X, this should be revised to reflect the 20% and 25% goals.

Figure 16. Evaluation of the Renewable Premium

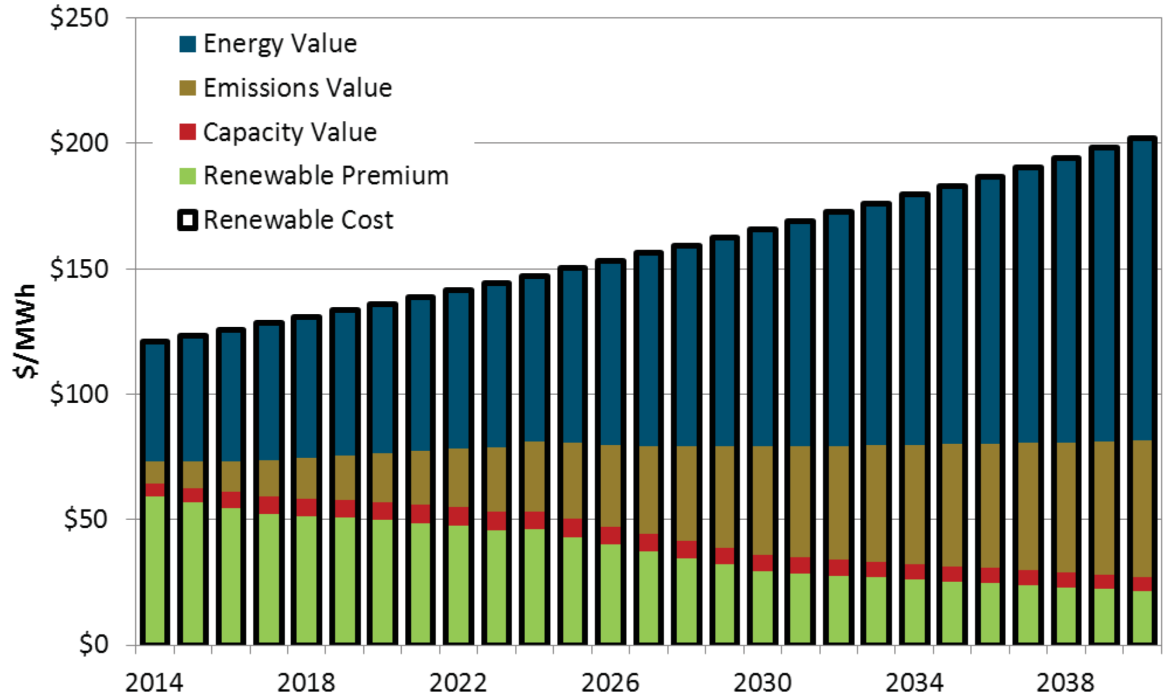
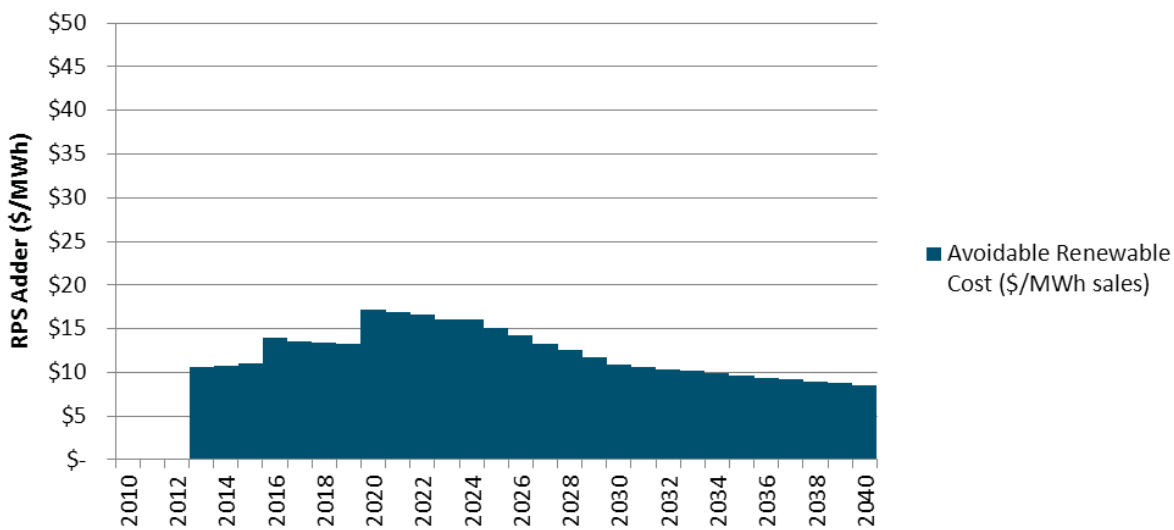


Figure 17: Annual RPS Adder



Components Not Included

Several components suggested by stakeholders in various proceedings are not currently included in the calculation of avoided costs. Non-energy Benefits (NEBs), by their nature, are difficult – if not impossible – to quantify. Work has been done to quantify some of these benefits for low income energy efficiency programs.[13] NEBs are not, however, currently included in the avoided cost methodology. The CPUC has authorized studies and pilot programs regarding embedded energy in water. To date a comprehensive framework for calculating embedded energy in water savings or water avoided costs in energy on a statewide basis has not yet been developed.[14] Avoided costs of current or future Ancillary Services associated with renewable integration or overgeneration are also not included. The need for flexible resources to provide services such as load following or ramping capability are driven primarily by the variation in, rather than the absolute level of, loads and generation. Finally the impacts of power factor and reactive loads are not currently included in the avoided cost methodology. An EM&V study for the CPUC Operational Energy Efficiency Program for water pumping produced by E3 found that the value of reduced reactive loads (kVAR) and associated line loss reductions ranged from 5 to 12 percent of the $/kWh avoided cost savings.[15] However the savings associated with improved power factor and reduced reactive load depend to a large extent on

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[13] More information about the use of non-energy benefits to evaluate Low Income programs can be found in the revised final report " *Non-Energy Benefits: Status, Findings, Next Steps, and Implications for Low Income Program Analyses in California*" issued May 11, 2010. http://www.liob.org/docs/LIEE%20Non-Energy%20Benefits%20Revised%20Report.pdf

[14] http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/EM+and+V/Embedded+Energy+in+Water+Studies1_and_2.htm

[15] http://www.ethree.com/public_projects/cpucOEEP.php

the type and location of loads on the feeder. As with embedded energy in water, a generalized framework for a statewide analysis has not yet been performed.

Comparison of Generation-Related Avoided Cost Values

This section evaluates how the changes to generation-related avoided costs affect the avoided cost savings attributed to EE measures. We limit the comparison to the generation-related avoided costs (T&D excluded), because they comprise the largest changes.

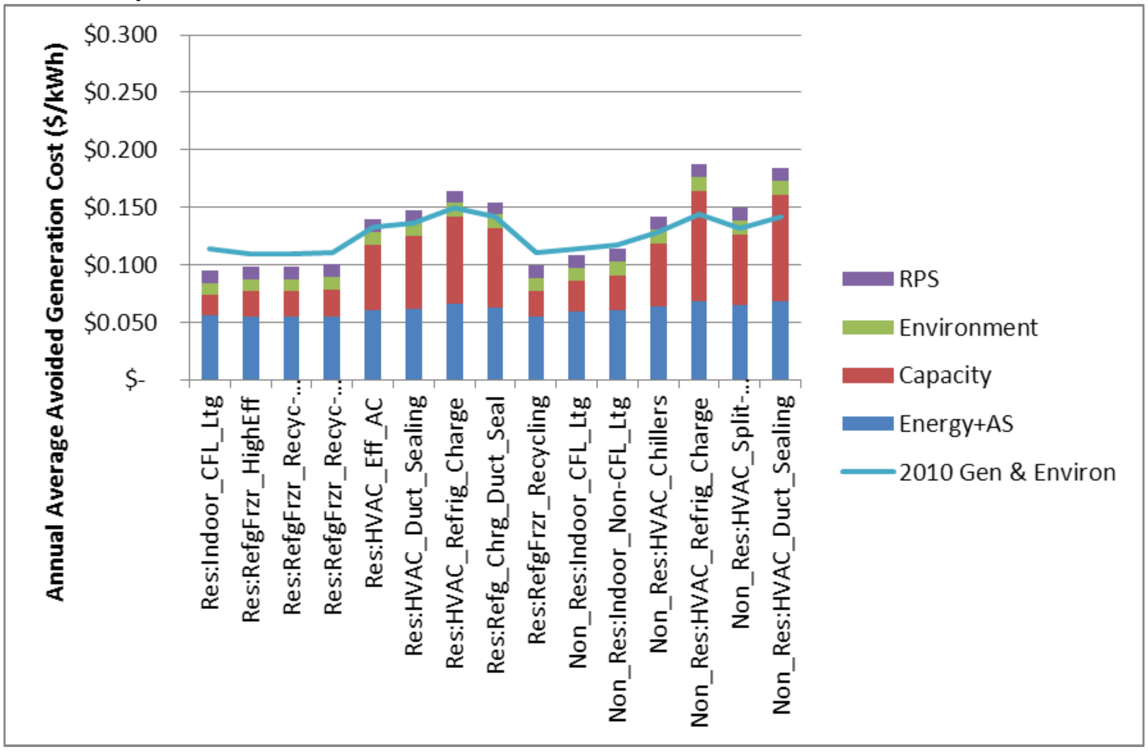
The following charts compare the annual avoided costs for the DEER hourly load shapes used in the E3 Calculators. The stacked columns are the updated avoided costs by component, and the solid blue line is the corresponding value using the extant 2010-2012 EE avoided costs. (the legend “2010 Gen & Environ” indicates that the data is from the 2010-2012 calculators, NOT that it is the 2010 values). Snapshots are presented for 2014, and 2020.

The figures for Northern California show that the updated avoided costs for lighting and refrigeration are lower in 2014, while HVAC is higher. In 2020, the updated avoided costs have lighting at roughly the same level as the 2010-2012 avoided costs, while HVAC is substantially higher.

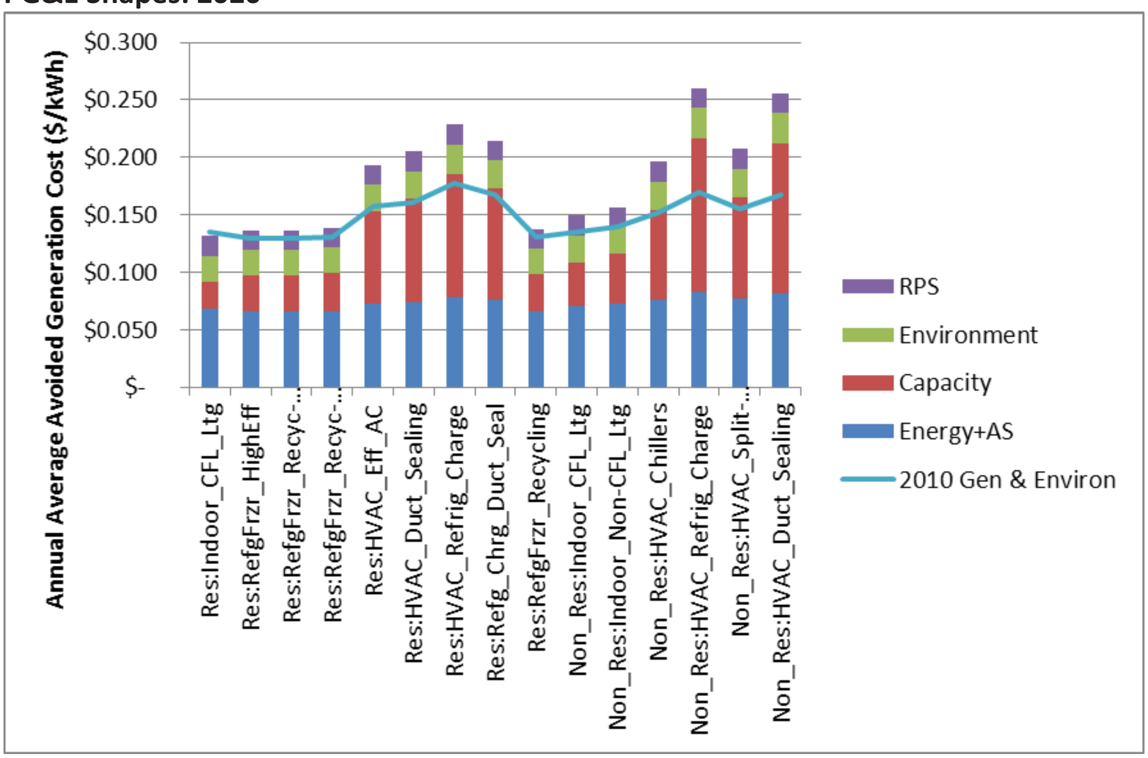
For Southern California, the updated avoided costs lower the results for non-HVAC load shapes in 2014. In 2020, the updated avoided costs have lighting at roughly the 2010-2012 avoided cost level, and HVAC measures are higher.

December 19, 2011

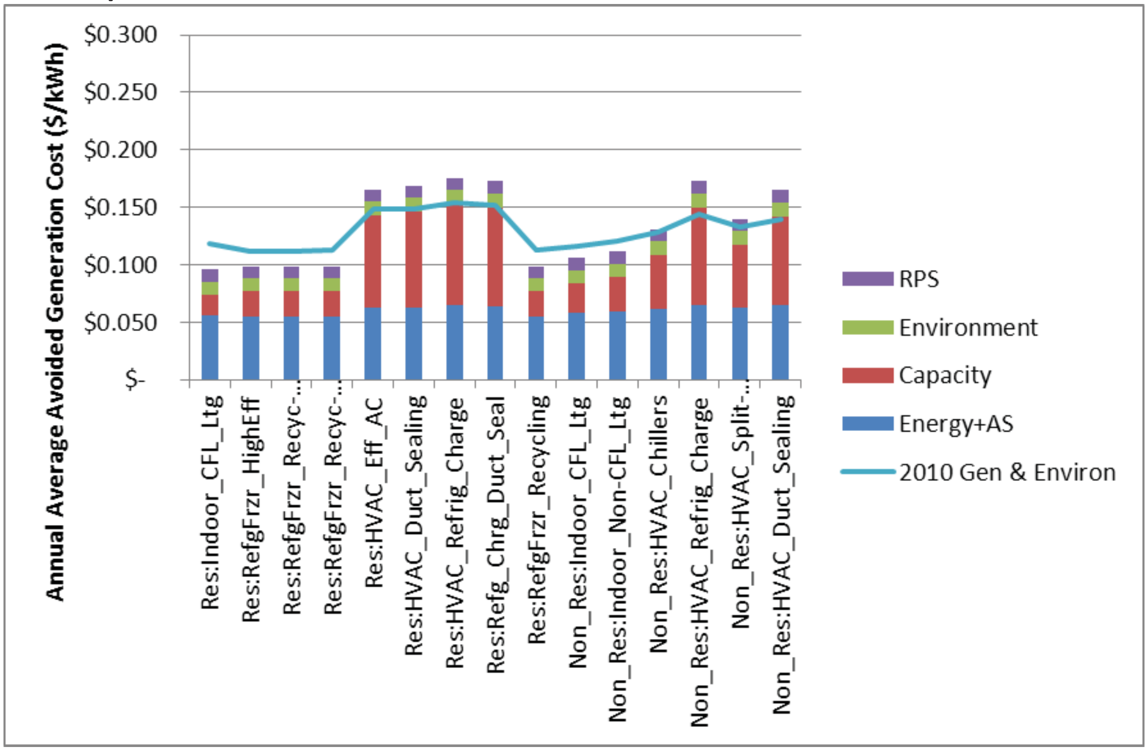
PG&E Shapes: 2014



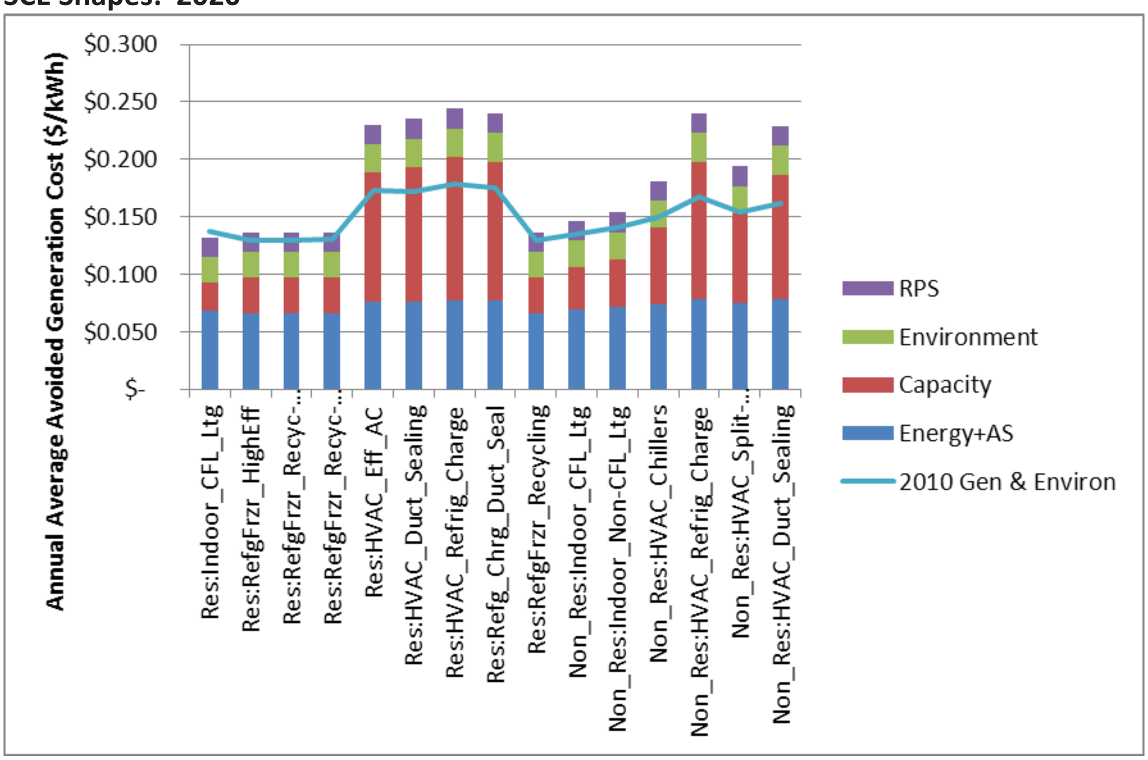
PG&E Shapes: 2020



SCE Shapes: 2014



SCE Shapes: 2020

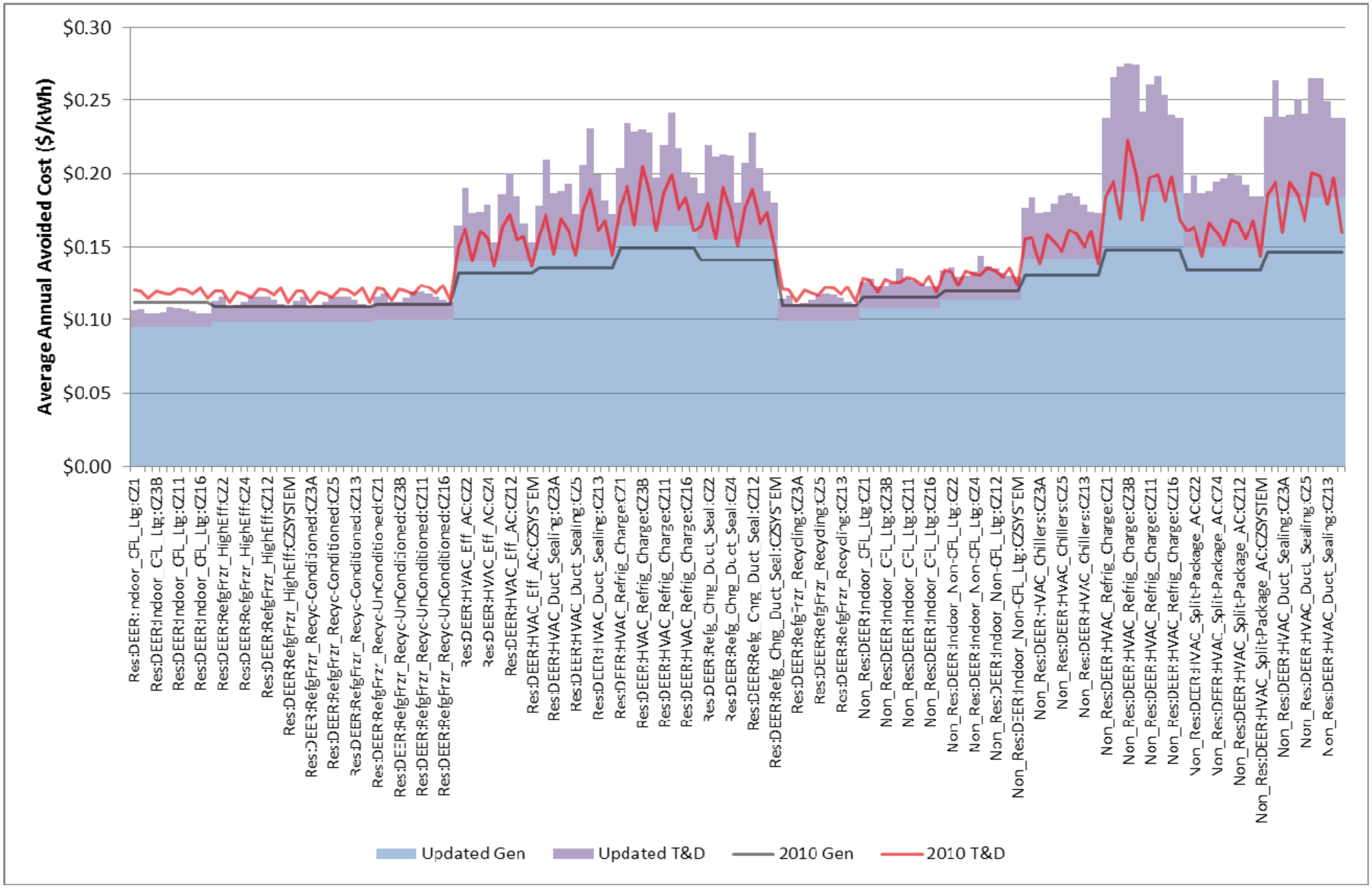


Comparison of the Updated EE Avoided Costs to 2010-2012 EE Avoided Costs

Shown in this section are the total annual average avoided costs for DEER measures by climate zone. The avoided costs for generation (Gen) and transmission and distribution (T&D) are plotted separately. The 2010-2012 EE annual average avoided costs for each DEER measure are shown as stacked lines. 2010 Gen includes energy, emissions, ancillary services, and losses. 2010 T&D is the T&D capacity and losses. The annual average avoided costs using 2014 updated EE are plotted as stacked column charts. 2014 Gen includes energy, capacity, emissions, ancillary services, RPS costs, and losses. 2014 T&D includes T&D capacity and losses.

For each utility a plot of the DEER measure shape avoided costs are shown for 2014, followed by 2020.

PG&E 2014


Average Annual Avoided Cost ($/kWh)
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$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
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Res:DEER:Indoor_CFL_Ltg:CZ3B
Res:DEER:Indoor_CFL_Ltg:CZ11
Res:DEER:Indoor_CFL_Ltg:CZ16
Res:DEER:RefgFrzr_HighEff:CZ2
Res:DEER:RefgFrzr_HighEff:CZ4
Res:DEER:RefgFrzr_HighEff:CZ12
Res:DEER:RefgFrzr_HighEff:CZSYSTEM
Res:DEER:RefgFrzr_Recyc-Conditioned:CZ3A
Res:DEER:RefgFrzr_Recyc-Conditioned:CZ5
Res:DEER:RefgFrzr_Recyc-Conditioned:CZ13
Res:DEER:RefgFrzr_Recyc-UnConditioned:CZ1
Res:DEER:RefgFrzr_Recyc-UnConditioned:CZ3B
Res:DEER:RefgFrzr_Recyc-UnConditioned:CZ11
Res:DEER:RefgFrzr_Recyc-UnConditioned:CZ16
Res:DEER:HVAC_Eff_AC:CZ2
Res:DEER:HVAC_Eff_AC:CZ4
Res:DEER:HVAC_Eff_AC:CZ12
Res:DEER:HVAC_Eff_AC:CZSYSTEM
Res:DEER:HVAC_Duct_Sealing:CZ3A
Res:DEER:HVAC_Duct_Sealing:CZ5
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Res:DEER:HVAC_Refrig_Charge:CZ16
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Res:DEER:Refg_Chrg_Duct_Seal:CZ4
Res:DEER:Refg_Chrg_Duct_Seal:CZ12
Res:DEER:Refg_Chrg_Duct_Seal:CZSYSTEM
Res:DEER:RefgFrzr_Recycling:CZ3A
Res:DEER:RefgFrzr_Recycling:CZ5
Res:DEER:RefgFrzr_Recycling:CZ13
Non_Res:DEER:Indoor_CFL_Ltg:CZ1
Non_Res:DEER:Indoor_CFL_Ltg:CZ3B
Non_Res:DEER:Indoor_CFL_Ltg:CZ11
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Non_Res:DEER:HVAC_Chillers:CZ5
Non_Res:DEER:HVAC_Chillers:CZ13
Non_Res:DEER:HVAC_Refrig_Charge:CZ1
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Non_Res:DEER:HVAC_Refrig_Charge:CZ11
Non_Res:DEER:HVAC_Refrig_Charge:CZ16
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Non_Res:DEER:HVAC_Split-Package_AC:CZ12
Non_Res:DEER:HVAC_Split-Package_AC:CZSYSTEM
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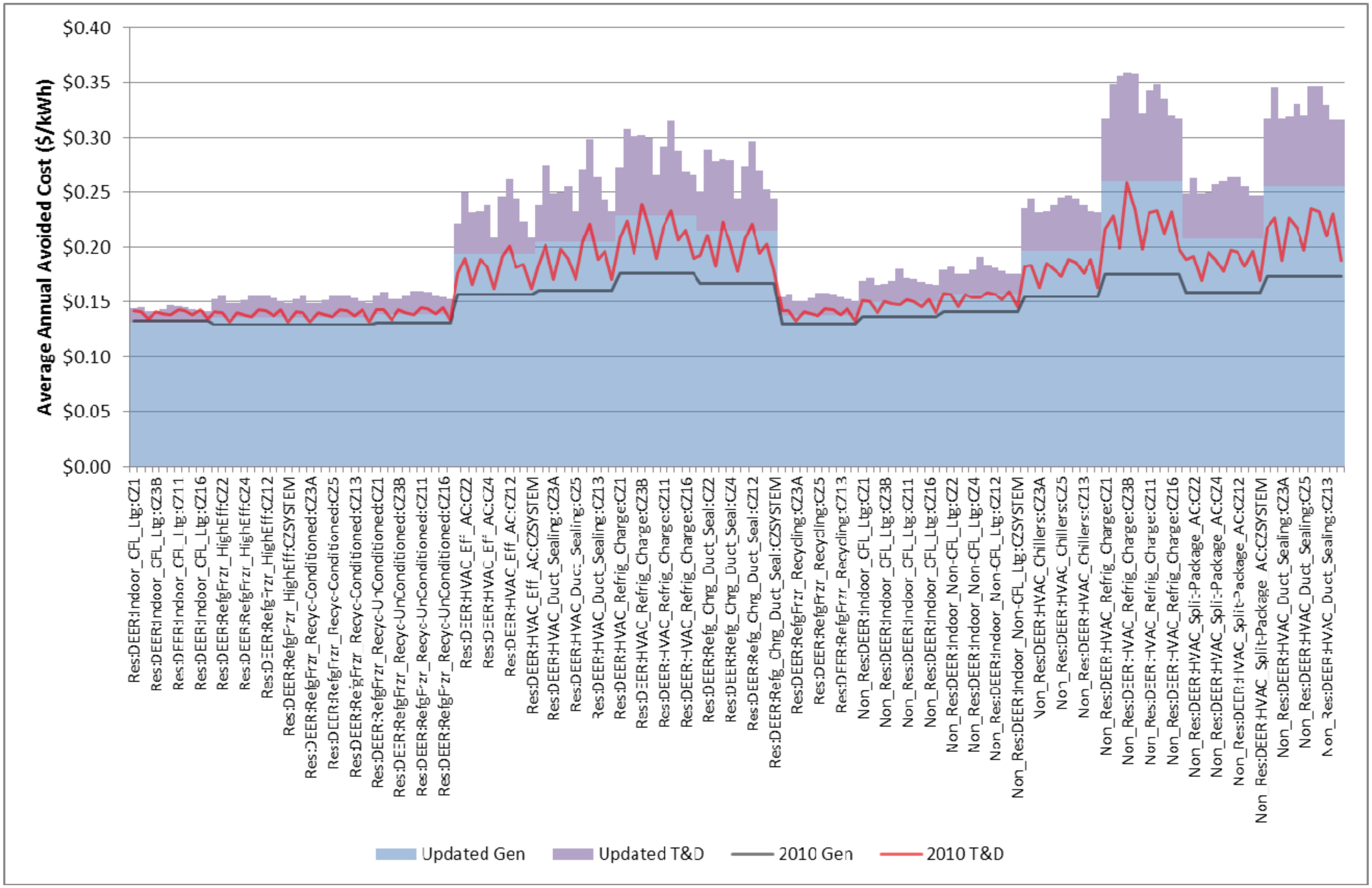
Non_Res:DEER:HVAC_Duct_Sealing:CZ5
Non_Res:DEER:HVAC_Duct_Sealing:CZ13
Updated Gen
Updated T&D
2010 Gen
2010 T&D

PG&E 2020



Average Annual Avoided Cost ($/kWh)
$0.40
$0.35
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
Res:DEER:Indoor_CFL_Ltg:CZ1
Res:DEER:Indoor_CFL_Ltg:CZ3B
Res:DEER:Indoor_CFL_Ltg:CZ11
Res:DEER:Indoor_CFL_Ltg:CZ16
Res:DEER:RefgFrzr_HighEff:CZ2
Res:DEER:RefgFrzr_HighEff:CZ4
Res:DEER:RefgFrzr_HighEff:CZ12
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Res:DEER:RefgFrzr_Recyc-UnConditioned:CZ3B
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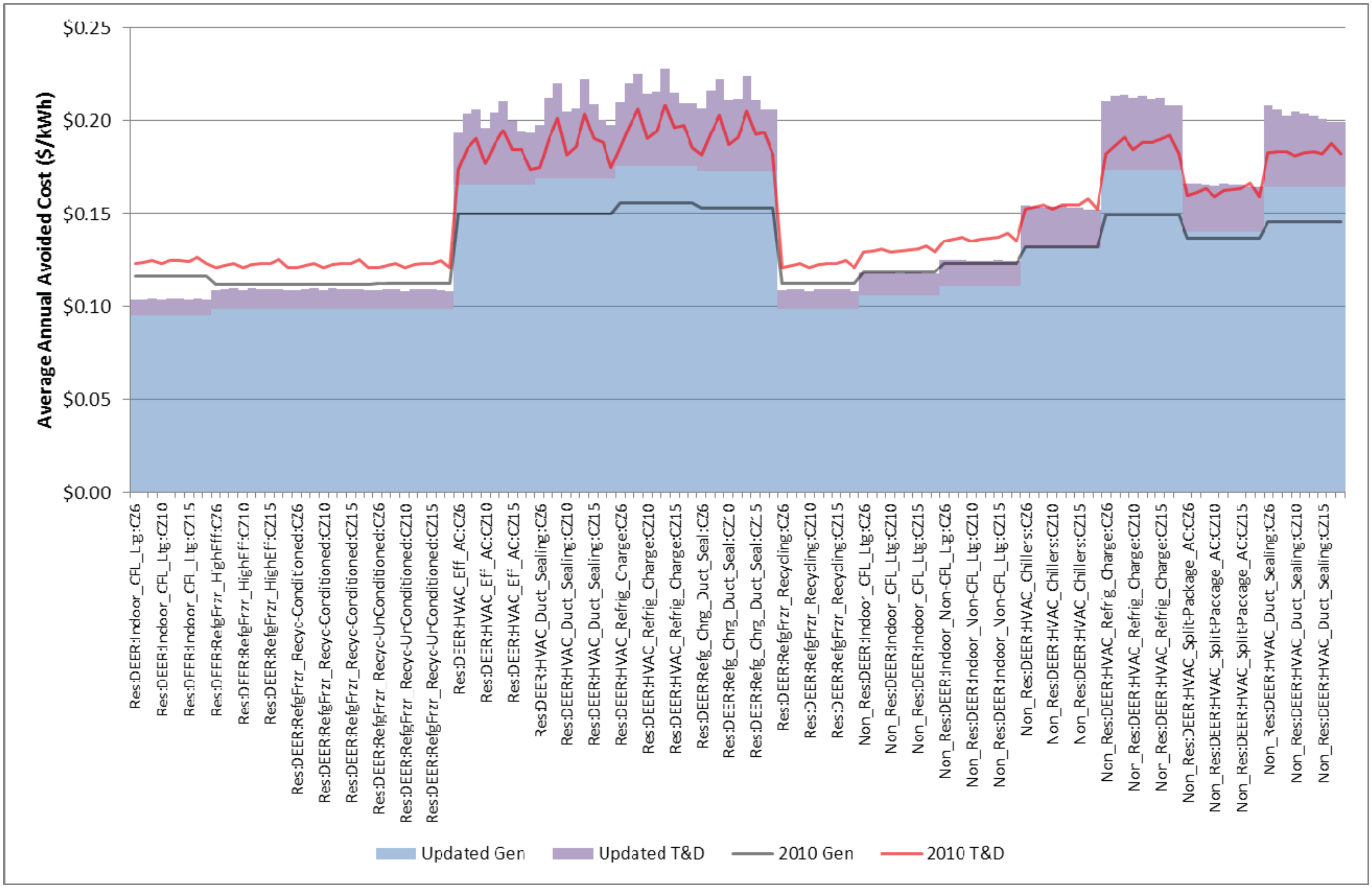
Updated T&D
2010 Gen
2010 T&D

SCE 2014


Average Annual Avoided Cost ($/kWh)
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$0.20
$0.15
$0.10
$0.05
$0.00
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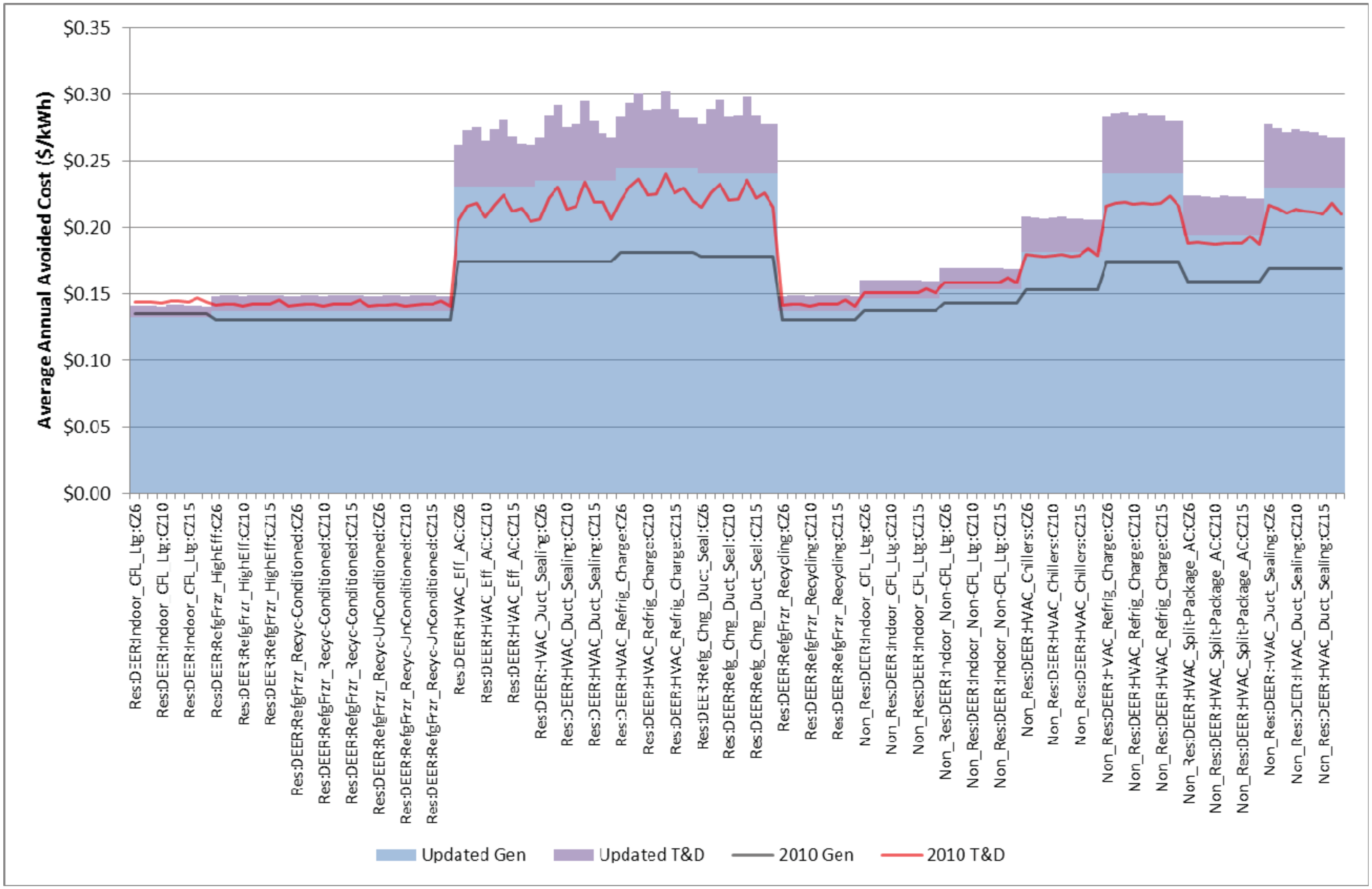
Updated Gen
Updated T&D
2010 Gen
2010 T&D

SCE 2020


Average Annual Avoided Cost ($/kWh)
$0.35
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
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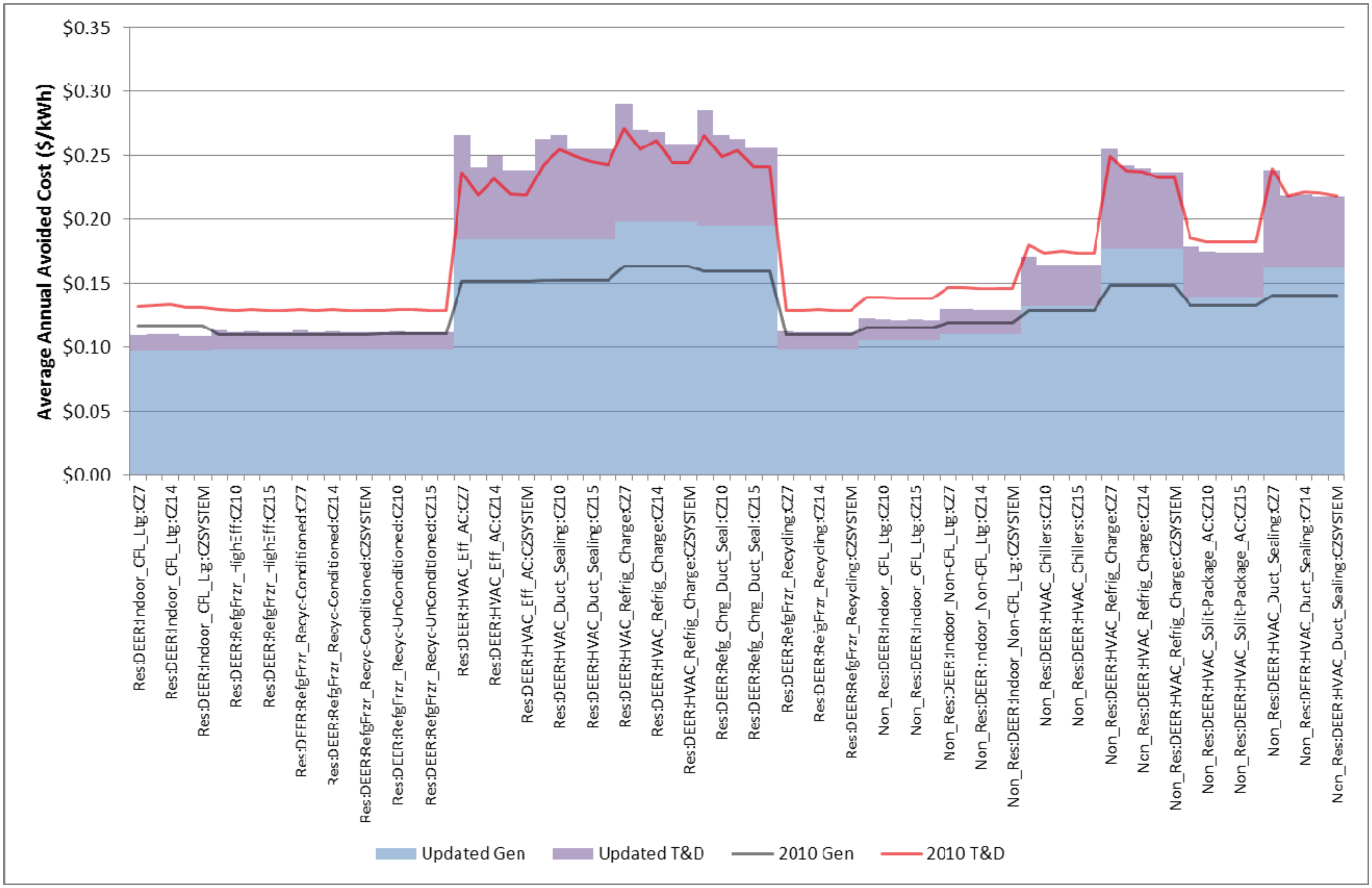
Updated Gen
Updated T&D
2010 Gen
2010 T&D

SDG&E 2014


Average Annual Avoided Cost ($/kWh)
$0.35
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
Res:DEER:Indoor_CFL_Ltg:CZ7
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Res:DEER:Indoor_CFL_Ltg:CZSYSTEM
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Res:DEER:RefgFrzr_HighEff:CZ15
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Res:DEER:RefgFrzr_Recyc-UnConditioned:CZ10
Res:DEER:RefgFrzr_Recyc-UnConditioned:CZ15
Res:DEER:HVAC_Eff_AC:CZ7
Res:DEER:HVAC_Eff_AC:CZ14
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Res:DEER:HVAC_Duct_Sealing:CZ15
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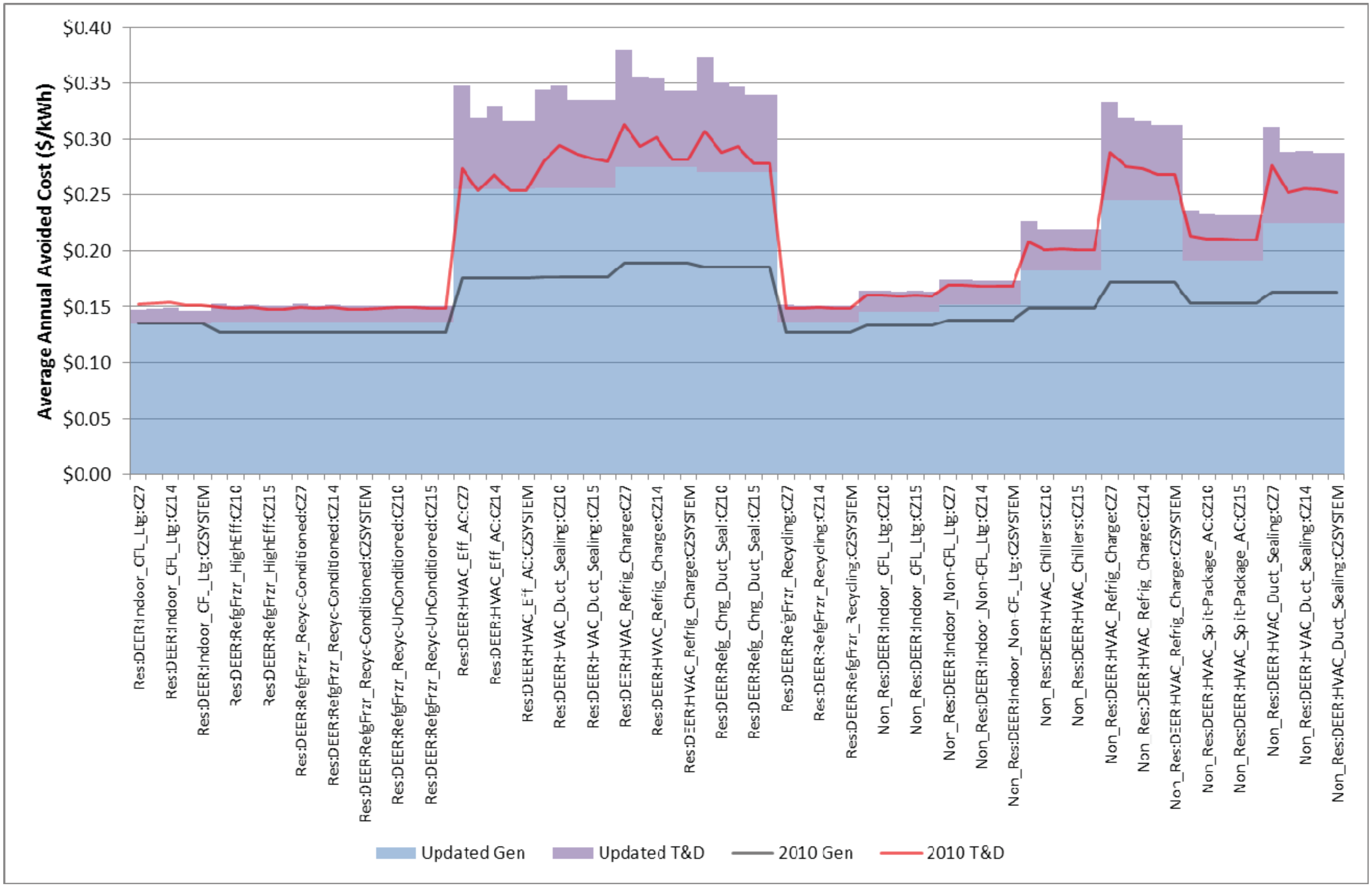
Non_Res:DEER:HVAC_Split-Package_AC:CZ15
Non_Res:DEER:HVAC_Duct_Sealing:CZ7
Non_Res:DEER:HVAC_Duct_Sealing:CZ14
Non_Res:DEER:HVAC_Duct_Sealing:CZSYSTEM
Updated Gen
Updated T&D
2010 Gen
2010 T&D

SDG&E 2020


Average Annual Avoided Cost ($/kWh)
$0.40
$0.35
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
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Res:DEER:RefgFrzr_Recyc-Conditioned:CZ7
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Res:DEER:RefgFrzr_Recyc-Conditioned:CZSYSTEM
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Non_Res:DEER:HVAC_Refrig_Charge:CZ14
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Non_Res:DEER:HVAC_Duct_Sealing:CZ7
Non_Res:DEER:HVAC_Duct_Sealing:CZ14
Non_Res:DEER:HVAC_Duct_Sealing:CZSYSTEM
Updated Gen
Updated T&D
2010 Gen
2010 T&D

Key Data Sources and Specific Methodology

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

Power plant cost 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.

Table 7. Power plant cost and performance assumptions (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%

Hourly Allocation of Generation Capacity Value

The generation capacity value is allocated to hours using the methodology from the DR proceeding. Capacity value is allocated to 250 hours based upon hourly system load data collected from 2007 through 2010. In each full calendar year, hourly allocators are calculated for that year's top 250 load hours; the allocators, which sum to 100% within each year, are inversely proportional to the difference between the annual peak plus operating reserves and the loads in each hour. This allocation methodology, which serves as a simplified and transparent proxy for models of relative loss-of-load probability (rLOLP), results in allocators that increase with the load level.

The annual series of allocators for each of the full calendar years are used to develop reasonable estimates of the relative fraction of capacity value that is captured within each month as shown in Figure 18. By considering loads within the four-year period from 2007-2010, the Avoided Cost Calculator captures the potential diversity of peak loads across different years.

Figure 18. Calculation of monthly capacity allocation based on historical data from 2007-2010.

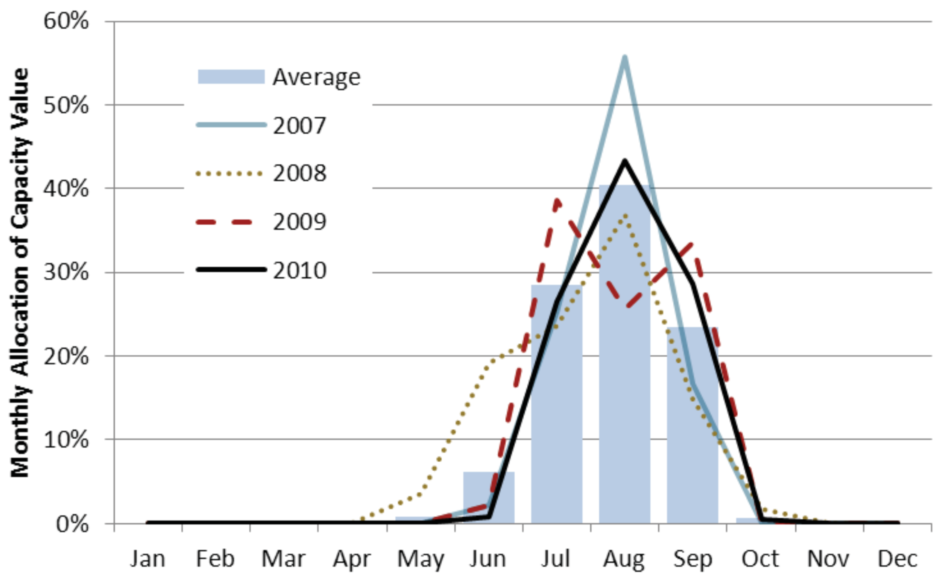


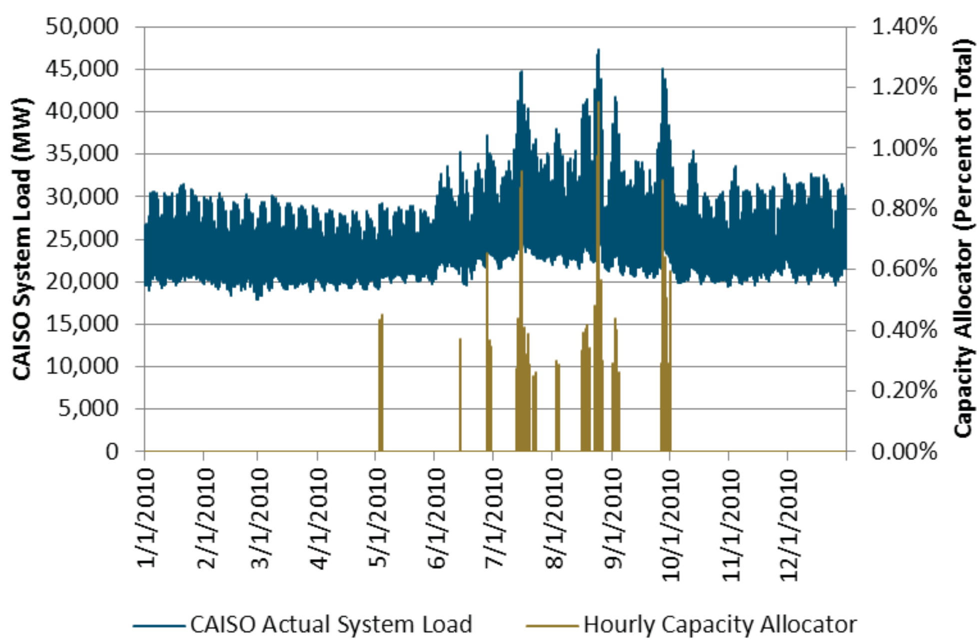
Table 8. Summary of monthly capacity allocation based on historical load data from 2007-2010.

Month	Capacity Allocation (%)	Rounded Number of Peak Hours
January	0.0%	-
February	0.0%	-
March	0.0%	-
April	0.0%	-
May	0.9%	2
June	6.1%	14
July	28.5%	75
August	40.4%	98

September	23.5%	60
October	0.6%	1
November	0.0%	-
December	0.0%	-
Total	100.0%	250

The hourly allocation uses the rounded number of peak hours from above to determine the number of peak hours that are deemed to occur in each month. The algorithm used to allocate the value of capacity to hours parallels the process used for the historical analysis but shifts the time scale from allocation across an entire year to allocation within single months. Thus, for each month in 2010, the value of capacity is allocated to the number of peak hours in that month so that the allocators sum to the total monthly allocation shown in Table 8. As with the historical analysis, the allocators are inversely proportional to the difference between the month's peak load plus operating reserves and the load in the relevant hour.

Figure 19. Hourly allocation of generation capacity based on loads for 2010.



Calculation of the T&D Capacity Allocators

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

1. Select all hours with temperatures within 15ºF of the peak annual temperature (excluding hours on weekends and holidays) and order them in descending order
2. Assign each hour an initial weight using a triangular algorithm, such that the first hour (with the highest temperature) has a weight of 2/(n+1) and the weight assigned to each subsequent hour decreases by 2/[n*(n+1)], where n is the number of hours that have a temperature above the threshold established in the first step
3. Average the initial weights among all hours with identical temperatures so that hours with the same temperature receive the same weight

Generation Loss Factors

The updated avoided costs incorporate loss factors from the DR proceeding. The capacity loss factors are applied to the capacity avoided costs to reflect the fact that dispatched generation capacity is greater than metered loads because of losses. The adjustments assume that the metered load is at the secondary voltage level. The loss factors are representative of average peak losses, not incremental losses.

Table 9: Generation capacity loss factors

	PG&E	SCE	SDG&E
Generation to meter	1.109	1.084	1.081

The energy loss factors are applied to the electricity energy costs to reflect energy losses down to the customer secondary meter. The loss factors vary by utility time of user period, and represent average losses in each time period.

Energy Generated[h] = Metered Load[h] * Energy Loss Factor[TOU]

Cost of Energy Losses = Energy Cost[h] * Metered Load [h] * (Energy Loss Factor[TOU] – 1)

where h = hour, TOU = TOU period corresponding to hour h.

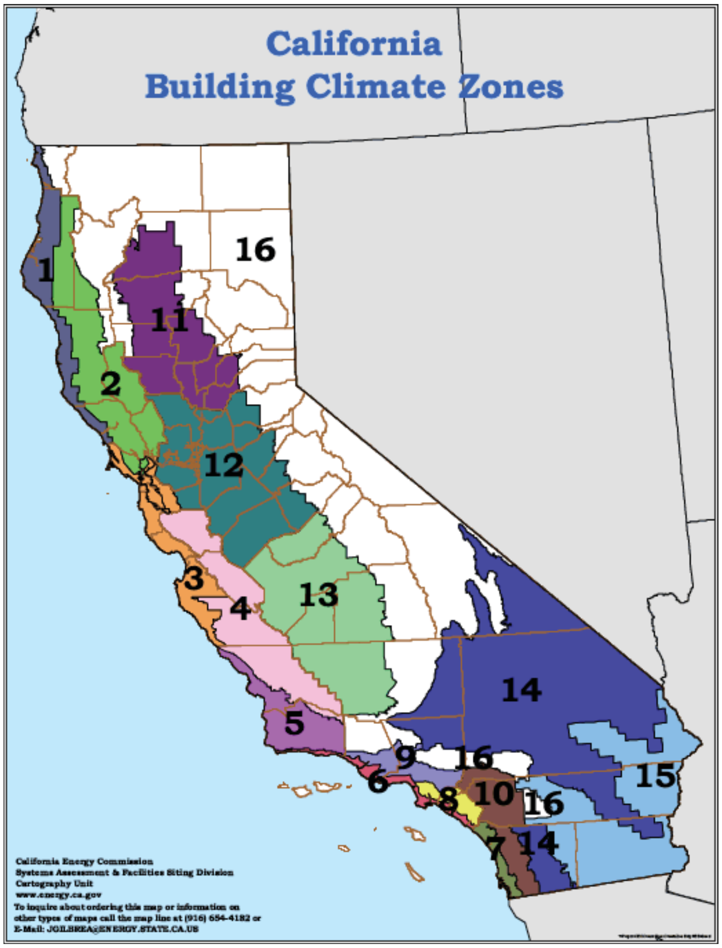
Table 10. Marginal energy loss factors by time-of-use period and utility.

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

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 20 is a map of the climate zones in California.

Figure 20. 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 11. Hourly avoided costs are calculated for each climate zone.

Table 11. 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

Appendix C

Time-of-Use (TOU) Rates

This appendix summarizes the residential TOU rates used in the model. TOU rates include PG&E rate schedule E-6, SCE rate schedule TOU-D-T, and SDG&E rate schedules DR-TOU and DR-SES. The rates shown below are those that were in effect in July 2012.

Table C1: *PG&E E-6 Rates ($ per kWh)*

Period	Usage Tiers	On Peak	Partial Peak	Off Peak
Summer (May-Oct.)	1	0.27883	0.17017	0.09781
	2	0.29640	0.18775	0.11538
	3	0.44653	0.33788	0.26551
	4-5	0.48653	0.37788	0.30551
Winter	1	-	0.11776	0.10189
	2	-	0.13533	0.11947
	3	-	0.28546	0.26959
	4-5	-	0.32546	0.30959

Table C2: *SCE TOU-D-T Rates ($ per kWh)*

Period	Usage Tiers	On Peak	Off Peak
Summer (Jun.-Sep.)	1-2	0.19333	0.12555
	3-5	0.53389	0.24251
Winter	1-2	0.12836	0.12060
	3-5	0.25092	0.22204

Table C3: *SDG&E DR-TOU Rates ($ per kWh)*

Period	Usage Tiers	On Peak	Off Peak
Summer (May-Oct.)	1	0.16885	0.14991
	2	0.17128	0.15234
	3	0.25391	0.22938
	4	0.35518	0.25325
Winter	1	0.15213	0.14991
	2	0.15456	0.15234
	3	0.21592	0.21319
	4	0.26145	0.25259

Note: rates shown include SDG&E's EECC commodity and DWR bond charges.

Table C4: *SDG&E DR-SES Rates ($ per kWh)*

Period	On Peak	Partial Peak	Off Peak
Summer (May-Oct.)	0.25397	0.17900	0.16448
Winter	-	0.17375	0.16604

Note: rates shown include SDG&E's EECC commodity and DWR bond charges.