**BEFORE THE PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF CALIFORNIA**

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| Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations | Rulemaking 12-06-013<br>(Filed June 21, 2012) |

# PREPARED TESTIMONY OF ADAM GERZA ON BEHALF OF THE CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION (revised November 20, 2014)

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September 15, 2014

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Q **Please state your name, occupation and business address.**

A My name is Adam Gerza. I am the Vice President of Business Development for Energy Toolbase. My business address is 169 11th Street, San Francisco, CA 94103.

Q **Please describe your professional background.**

A Prior to joining Energy Toolbase in October 2014, I worked for Sullivan Solar Power for the last six years in various leadership roles for the company, including project development, finance, and policy. Sullivan Solar Power, headquartered in San Diego, is one of California's leading solar installation companies. Over the last ten years the company has installed more than 3,000 residential, commercial and municipal solar projects, totaling over 20 megawatts of capacity. I have worked extensively with utility rate tariffs, having designed and built models for objectively calculating the project economics of various types of solar projects. I have worked on previous CPUC proceedings on behalf of different parties, including Sullivan Solar Power, CALSEIA, and the San Diego Solar Coalition. In 2012 I performed the analysis used by the San Diego Solar Coalition in A.11-10-002, SDG&E's GRC phase 2 proceeding. I was elected to CALSEIA's Board of Directors last year, then resigned my board seat when I changed

jobs.

Q **On whose behalf are you testifying in this proceeding?**

A This testimony is presented on behalf of the California Solar Energy Industries Association (CALSEIA). CALSEIA is a 501(C)(6) not-for-profit solar industry trade association with 200 company members involved in the solar energy business in California. CALSEIA is an active participant in a number of Commission proceedings addressing state policy and electric utility rates. Changes to electricity rates have direct economic impacts on the current and prospective customers of CALSEIA's member companies and may help or hinder the companies' ability to market solar energy products. Sullivan Solar Power is a member of this industry trade association.

Q **What is CALSEIA's interest in this proceeding?**

A CALSEIA member companies are the leading providers of residential solar systems in California, having installed the vast majority of the existing residential solar systems in California. CALSEIA member companies include the largest national installers as well as local and regional players.

Rate design is one of the single most important factors in determining the economic viability of a solar project. Changing the underlying rate design directly affects both existing homeowners who have already gone solar and potential solar customers considering going solar in the future. CALSEIA member companies would be directly affected if the California Public Utilities Commission (Commission) adopts a residential rate structure that deteriorates the economic value proposition of going solar. Furthermore, we believe the state would not be able to achieve its clean energy goals if the Commission does not maintain a regulatory environment that enables customer investment in rooftop solar.

Q **What is the purpose of your testimony?**

A In this testimony, I present analysis of the extent to which the residential rate changes proposed by the investor-owned utilities (IOUs) would deteriorate solar project economics. The state has invested billions of dollars of ratepayer money in developing the solar market, and I presume the Commission does not want the successes of that market development to be fleeting. The Commission must ensure that its decision in this proceeding does not have too severe a negative impact on solar project economics. I present this analysis to help inform that criterion of the decision.

I also present CALSEIA's alternative proposal for residential rate change in this testimony. Since passage of AB 327 in 2013, CALSEIA has recognized that the Commission wishes to reduce the differential between the top and bottom rates in California's tiered residential rates. The IOU proposals for "flattening" rate tiers goes too far too fast, but the Commission can approve a more limited and gradual reduction in tier differential without destroying the value proposition of solar for residential customers.

Q **What are the history and benefits of a tiered rate structure?**

A Steeply tiered rates were established in 2001 in response to the California energy crisis. "The more you use, the higher your rate" is both simple and well understood. It has incentivized customers to use less electricity from the grid, through conservation, energy efficiency retrofits, and on-site generation. There is indisputable evidence that homeowners have responded to this pricing signal, as California is a national leader in energy efficiency and distributed generation. Tiered rates have been a cornerstone of the decision making process for customers to make their homes and businesses more energy efficient and to invest in distributed generation.

When the Commission established the 5-tiered rate structure in D.01-05-064, they set a 2:1 differential between the top tier and the bottom tier.[1] Rather than maintaining that differential as utility costs grew and rates increased, the Commission established caps on the first two tiers. This caused utilities to recover increased costs almost entirely in the upper tiers. In 2009, Senate Bill (SB) 695 eased this cap, but not enough for rates to return to a 2:1 differential. In 2013, the differential between the top and bottom tiers was 2.6:1 for Pacific Gas and Electric (PG&E), 2.8:1 for Southern California Edison (SCE), and 1.9:1 for San Diego Gas & Electric (SDG&E). Assembly Bill (AB) 327 of 2013 removed the caps on the lower tiers, so the IOUs are now able to return to a differential of 2:1 or less.

Relative to the last decade of tier differentials, the "end-state" rate structure that the IOUs have proposed is effectively flat. Having a differential of 20% only creates a token tier. In our experience it will not motivate sufficient energy reduction, via conservation, energy efficiency or self-generation.

[1] The 2:1 differential was reflected right away in the rates for PG&E and SCE. SDG&E rates did not reach a 2:1 differential until 2007.

Regarding solar specifically, ratepayers have a vested interest in maintaining momentum in the solar market. Through the California Solar Initiative, ratepayers have invested $3 billion in recent years in developing the solar market. This has helped the industry reach a level of maturity and achieve economies of scale that have made solar more affordable for more people. If the market slips backward, those gains will be compromised and the value of the ratepayer investment will be reduced. The Commission must adopt a long-term residential rate structure that builds on the successes of the past by continuing to move the solar market in a positive direction.

AB 327 directs the Commission to adopt a policy framework that "ensures that customer-sited renewable distributed generation continues to grow sustainably."[2] Although that provision is a condition of the net energy metering (NEM) successor tariff and does not directly constrain residential rate design, as a policy matter the decisions made in residential rate design will have direct impacts on the effects of the NEM successor tariff. Decisions in this proceeding must take into account their implications in R.14-07-002, the proceeding to develop the NEM successor tariff. Changes to rate design that will not ensure sustainable growth in renewable distributed generation even under a continuation of net metering with full retail credit would make it practically impossible for the Commission to establish a NEM successor tariff that ensures sustainable growth in renewable distributed generation.

Q **What is CALSEIA's proposal for residential rate changes pursuant to AB 327?**

A CALSEIA recognizes that there is a strong preference by the Commission and many parties to reduce the differential between rate tiers, but cautions that a genuinely tiered rate structure is necessary to maintain sufficient price signals to achieve California's clean energy goals. The Commission must strike the appropriate balance of continuing to encourage conservation, energy efficiency and self-generation while easing rates for high-usage customers. We believe the following simple objectives form a reasonable middle ground between the current structure and the extreme proposals submitted by the IOUs:

[2] Public Utilities Code section 2827.1 (b)(1).

- Create a three-tiered structure by collapsing the current Tiers 3 & 4. This will help maintain affordability for low-usage customers by giving Tier 2 a lower rate than it would have if Tiers 2 & 3 were collapsed.
- Reduce the differential between the top and bottom tiers by 3% per year, from 90% in 2015 to 75% in 2020.
- Maintain the same minimum bill currently in place for each IOU and do not add a fixed charge. See the further discussion on fixed charges below.

Table 1 shows illustrative rates that would result from these objectives. All of these rates are revenue neutral assuming a 2.1% annual increase in revenue requirement. PG&E rates were derived from PG&E's Electric Bill Calculation Tool. SCE rates were derived from SCE's Tiered Rate Generator Model. Because SDG&E does not make a similar model available for parties to use, we were unable to produce comparable numbers for SDG&E.

**Table 1. CALSEIA Compromise Rate Proposal** (cents/kWh)
*Illustrative Rates Based on Escalation of February 2014 Revenue Requirement at 2.1% Per Year*

| | | Feb 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| PG&E | Tier 1 | 14.7 | 14.9 | 15.3 | 15.6 | 16.1 | 16.5 | 16.9 |
| | Tier 2 | 17.0 | 19.6 | 19.9 | 21.3 | 21.6 | 22.2 | 23.0 |
| | Tier 3 | 25.9 | 28.3 | 28.6 | 28.7 | 29.1 | 29.4 | 29.6 |
| | Tier 4 | 31.9 | 28.3 | 28.6 | 28.7 | 29.1 | 29.4 | 29.6 |
| SCE | Tier 1 | 13.3 | 14.6 | 15.0 | 15.4 | 15.9 | 16.2 | 16.7 |
| | Tier 2 | 16.5 | 17.5 | 18.0 | 18.5 | 19.1 | 21.1 | 21.7 |
| | Tier 3 | 27.4 | 27.7 | 28.1 | 28.4 | 28.8 | 28.9 | 29.3 |
| | Tier 4 | 30.4 | 27.7 | 28.1 | 28.4 | 28.8 | 28.9 | 29.3 |
| Tier Differential | | 117%/ 129% | 90% | 87% | 84% | 81% | 78% | 75% |

Q **What evidence do you have that the IOU rate change proposals would harm the solar market?**

A For this testimony, we measured the capital recovery period for solar customers in 2018 for each of the IOUs according to their rate change proposals and CALSEIA's alternative rate change proposal for PG&E and SCE. We also compared these results to a forward projection of current rate structure. We found that the IOU proposals would make it much harder for customers to go solar in the future. The

CALSEIA proposal would also result in a negative impact on solar economics compared to the current rate structure, but would maintain enough value for solar customers that it would not devastate the market.

To study the impact for different types of customers, we measured the impacts for customers of six different electricity consumption levels ranging from 250 kWh per month in gross usage to 1500 kWh per month. We measured three sizes of solar systems, offsetting 100%, 75% and 50% of load for each customer usage size. We assumed total installed costs of solar systems will decline 5% per year. We also assumed no federal tax credit.[3] For all scenarios we assumed net metering at full retail rates.[4]

The full results of this analysis are in Appendix A. Highlights of the results include the following:

1. Capital recovery periods for customers who use 750 kWh per month and invest in a 75% offset solar system would be 11 years for PG&E, 10.4 years for SCE, and 10 years for SDG&E. Experience demonstrates that capital recovery periods this long will not motivate customers to make investments in solar. Generally speaking, only the most environmentally-motivated or independence-minded customers are willing to wait 10 years to recover upfront cost and another 10 years to accumulate a reasonable return, and many of those types of customers have already invested in solar.
2. The 20-year internal rate of return (IRR) for customers who use 750 kWh per month and invest in a 75% offset solar system would be 8.2%-9.9% under the IOU proposals. Again, this is not a level that will motivate most customers. It is important to note that until the capital recovery period is reached, the rate of return is negative. The investment then has a positive return, but doesn't reach the 20-year rate of return until the end of the 20$^{th}$ year.
3. All potential customers in each of the IOU territories who use 750 kWh or more per month would experience a reduction in financial value from a solar investment under the IOU proposals, compared with a forward projection of

[3] The federal Investment Tax Credit will expire in December 2016 according to current policy. After that, commercial customers will be able to use a 10% production tax credit, but residential customers will not have any tax credit from solar installation.
[4] Further assumptions are detailed in Appendix C.

current rate structure.[5] I expected this result but was surprised at the extent of the reduction in value. As a typical example, a PG&E customer with gross usage of 1000 kWh per month would see a 47% extension in the capital recovery period from an investment in a 75% offset system, as shown in Table A-1 in Appendix A.

4. PG&E and SCE customers with gross usage of 750 kWh or more per month would also be negatively impacted by the CALSEIA rate proposal, but to a lesser degree than the IOU proposals. To use the same example, a PG&E customer who uses 1000 kWh per month and invests in a 75% offset system would see an 18% increase in the capital recovery period.

5. All customers who use 250 kWh per month and some who use 500 kWh per month would have shorter capital recovery periods than they do currently, but the capital recovery periods are still too long to motivate customers. For example, the capital recovery period for a PG&E customer using 250 kWh per month investing in a 75% offset system would be reduced by 14.6% to 12.9 years under the PG&E proposal. Under the CALSEIA proposal, it would be reduced by 7% to 14 years. Additionally, as detailed in a separate section below, a majority of low-usage customers live in apartments or are on CARE rates and are therefore not viable solar customers.

Based on this analysis, it is clear that the IOU proposals would result in a large reduction in the solar market. Increasing the capital recovery period on the order of 47% would vastly reduce the pool of customers who are willing to make investments in on-site generation. Additionally, extending capital recovery periods for current solar customers would likely lead to a vocal backlash that would put a chill on the market. Although rates are never guaranteed, the existence of a tiered rate structure has been a conscious price signal that the state has given to customers. For customers who have responded to policies that encouraged them to make investments, the state has an obligation not to make changes abruptly.

[5] There is no way to project current rate structure forward as an accurate prediction of 2018 rate structure since rates are normally set by settlements that do not follow transposable rules. To create a basis for comparison for purposes of this analysis, we projected current rate structure forward by applying the revenue requirement increase equally to all tiers.

Q **Can you present the impacts of the IOU proposals on capital recovery periods for solar investments for the full range of customer sizes and system sizes you analyzed?**

A Figures 1-3 show the results of our analysis in terms of capital recovery periods under the IOU rate change proposals. Figures 1 and 2 also show the impacts under CALSEIA's compromise rates for PG&E and SCE. These graphs all measure the impacts on systems sized to 75% of customer demand. As shown in the tables in Appendix A, the impacts on systems sized to 100% of customer demand and 50% of customer demand are very similar to those sized to 75% of customer demand.

Under the IOU proposals, capital recovery periods for customers who use 750-1500 kWh per month would be 10.1-11 years for PG&E, 9.6-10.4 years for SCE, and 9-10 years for SDG&E. Under CALSEIA compromise rates, capital recovery periods would be 7.8-9.3 years for PG&E and 7.5-9.1 years for SCE. This is 13%-23% shorter than under the IOU proposals.

Compared with forward projections of current rate structure, capital recovery periods under the IOU proposals for customers who use 750-1500 kWh per month are 29%-60% longer for PG&E, 16%-39% longer for SCE, and 32%-55% longer for SDG&E. For the CALSEIA compromise rates, capital recovery periods increase by 9%-24% for PG&E customers and 1%-9% for SCE customers.

**Figure 1. Capital Recovery Periods for PG&E 2018 Solar Customers**

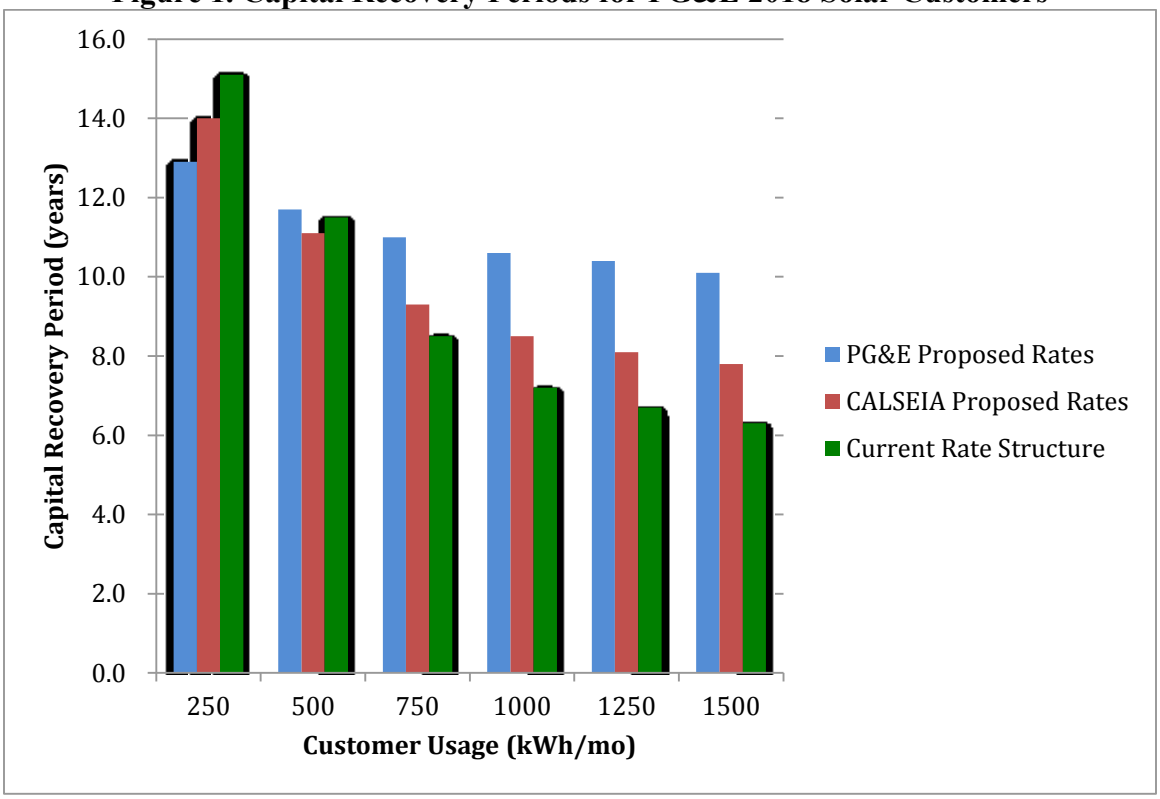



**Figure 2. Capital Recovery Periods for SCE 2018 Solar Customers**

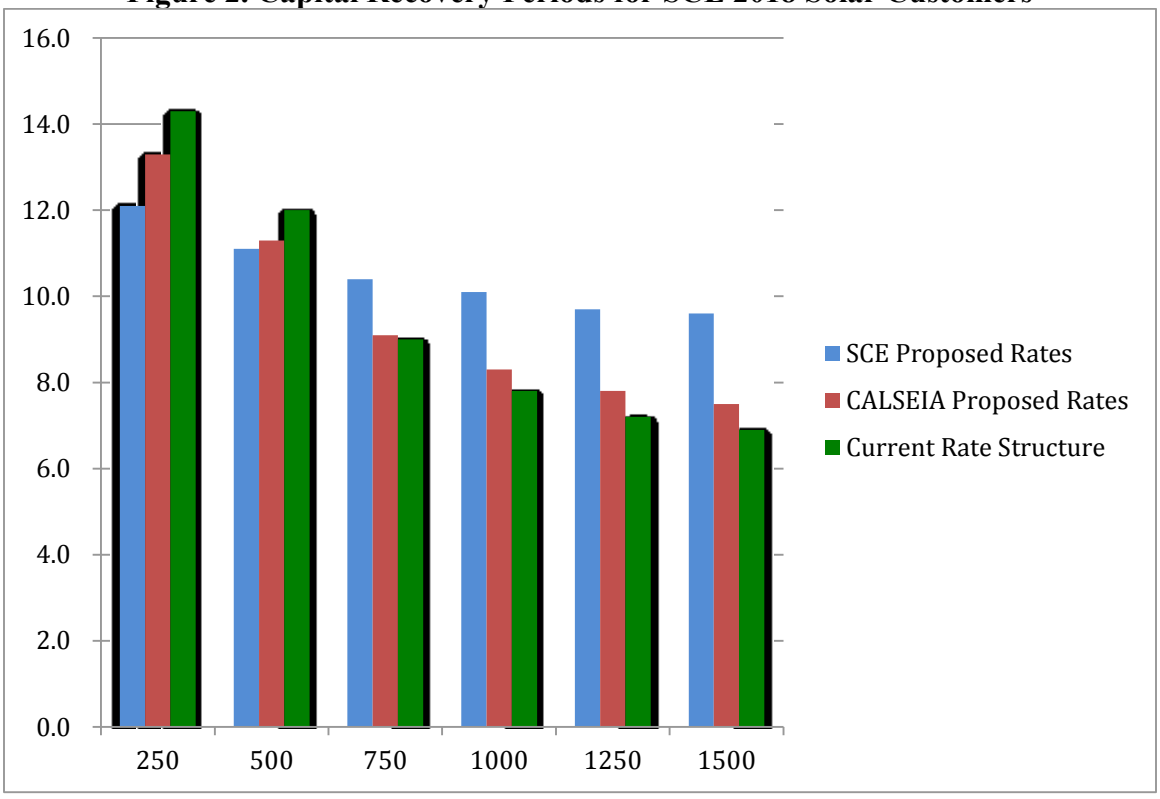
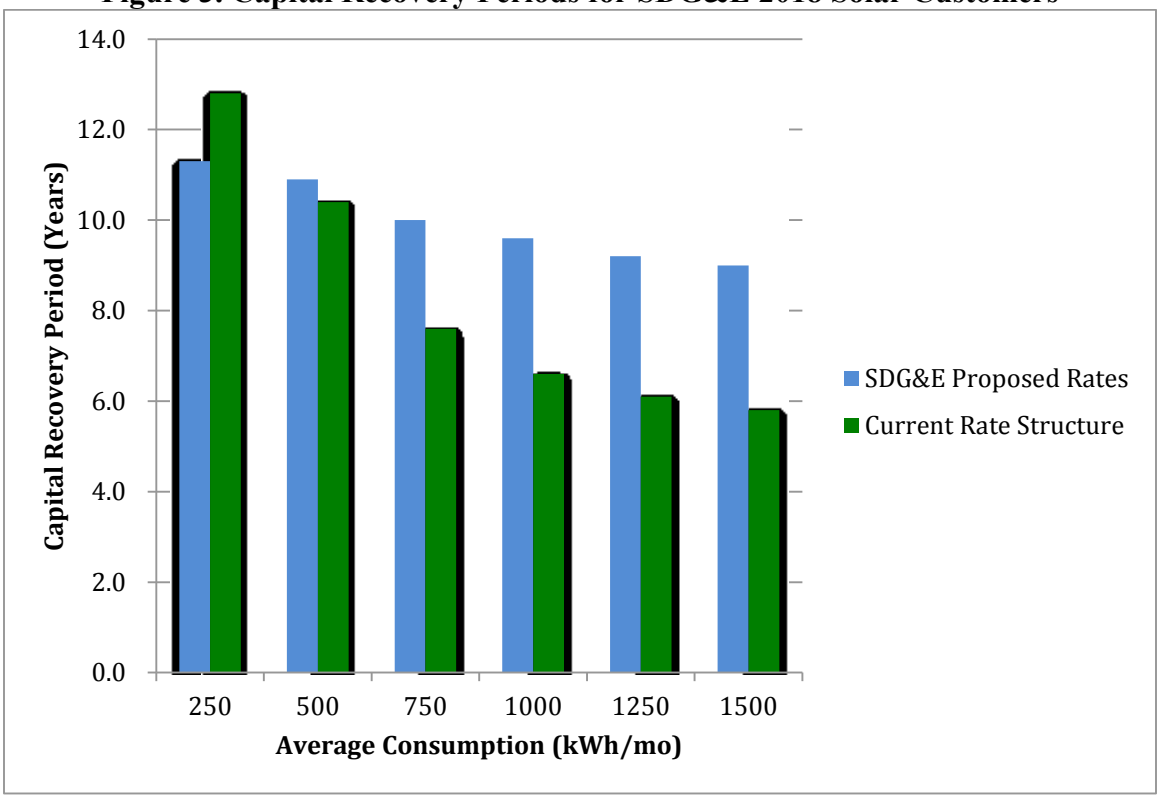


**Figure 3. Capital Recovery Periods for SDG&E 2018 Solar Customers**




Q **What are the implications of changing rates on existing solar customers?**

A The consequences of the IOU rate proposals on the project economics of existing solar homeowners are very significant. The Commission must consider in its decision the reduction in benefit for existing homeowners who have already made solar investments. Table 2 shows the change to monthly bill savings comparing February 2014 rates and the IOU proposed rates for 2018. The IOU rate proposals would reduce bill savings for many types of customers by 20%-35%. This would increase the capital recovery period and reduce the rate of return on investments that have already been made.

**Table 2. Change in Monthly Bill Savings from Existing Solar Investments Under IOU Rate Proposals**

| | Average Monthly Usage (kWh) | Full Offset System | 75% kWh Offset System | 50% kWh Offset System |
|---|---|---|---|---|
| PG&E | 750 | -10% | -19% | -30% |
| | 1000 | -21% | -30% | -38% |
| | 1250 | -26% | -34% | -40% |
| | 1500 | -29% | -36% | -40% |
| SCE | 750 | 1% | -7% | -17% |
| | 1000 | -10% | -18% | -26% |
| | 1250 | -15% | -22% | -29% |
| | 1500 | -18% | -25% | -30% |
| SDG&E | 750 | -12% | -20% | -29% |
| | 1000 | -20% | -28% | -35% |
| | 1250 | -25% | -31% | -36% |
| | 1500 | -27% | -33% | -36% |

Customers know that electricity rates should always be expected to change, but they have an expectation that the basic structure of rates will evolve only slowly. Fundamental changes to underlying rate design must be measured and gradual, with consideration of the impacts on all types of existing customers. Abrupt change would create a massive black eye for the statewide solar industry and for state policy makers. You simply cannot take away 30% of the value of people's investments without expecting a backlash. This would lead prospective solar customers to lose confidence and trust that future changes will be balanced and reasonable. The Commission must consider the potential of this decision to damage the household economies of existing solar customers and the damage to the market that could result.

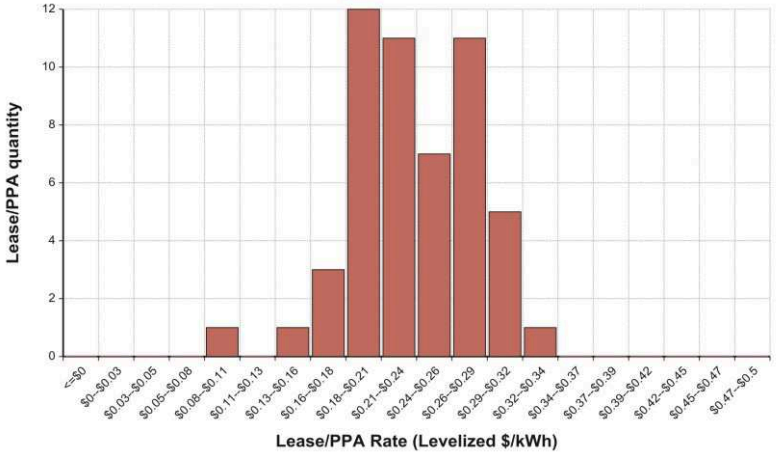
Q **How Would the IOU Proposals Affect PPA or Lease Customers?**

A We did not measure the impacts on customers who have installed solar via power purchase agreements (PPAs) or leases, but the general impact on PPA/lease customers can be inferred. Any time the rate of return is decreased and the capital recovery period is increased for a customer-owned system, some PPA/lease customers with the same usage profile and system size will go "under water," meaning they would be paying more for their solar energy than for utility energy. Depending on a customer's usage profile and the system cost at the time they installed, PPA/lease customers have

varying levels of financial benefits. If the monthly savings is reduced, those customers with smaller original benefits will go under water. My analysis does not quantify this impact, but the trend exists.

PPA/lease rates vary based on the complexity of the solar installation. A December 2013 analysis by Navigant Consulting for PG&E showed significant variation in effective PPA/lease rates for California customers, as shown in Figure 4. Many customers have agreed to more expensive installations because they were still cost-effective given the rate structure in place at the time. Again, rates are never guaranteed but customers have had an expectation that radical changes to the basic structure of rates would not happen abruptly. The Commission should not abandon tiered rates without a very gradual glide path.

**Figure 4. Effective Lease or PPA Rates (Levelized $/kWh) for 52 Residential Third Party Owned Contracts in 2012**[6]




Q **How Will Changes to Net Metering Affect these Results?**

A If the net metering successor tariff being developed in R.14-07-002 reduces the value of net metering credits, capital recovery periods will be longer than those portrayed here and rates of return will be lower.

Q **Should Utilities Establish a Fixed Charge for Residential Customers?**

A No. There may be a time when departing load is such a major factor that utilities are not able to spread out the costs of maintaining the grid across a sufficient base

[6] Navigant Consulting, "Net Metering Grandfathering Analysis for the Residential and Commercial/Industrial Market Sectors," prepared for PG&E reply comments in R.12-11-005, December 23, 2013 at 7.

of customer load, but that time is far in the future. Only 1.9% of IOU customers are currently taking service under NEM tariffs.[7]

Further, a fixed charge would be a new revenue source that would more reasonably be used for new expenses related to grid modernization. A fixed charge should not be adopted for funding existing utility expenses. Thus, it would be more appropriately considered in R.14-08-013.

Q **Would Improved Solar Economics for Low-Usage Customers Offset the Loss of High-Usage Customers from the Market?**

A No. The improved solar economics for low-usage customers that comes from flattening rate tiers does not greatly expand the potential solar market for two reasons: a) the capital recovery period is still too long for the average customer; and b) a minority of low-usage customers live in single-family housing and have non-CARE rates.

Customers with average usage of 250 kWh per month or 500 kWh per month who consider 75% offset solar systems in 2018 will have capital recovery periods of 10.9-12.9 years under the IOU rate proposals. Asking people to wait that long to recoup their upfront costs has never been successful in the marketplace.

Also, a majority of low-usage customers are apartment dwellers and/or CARE customers. In absence of a viable community solar program, most residents of multifamily housing are not able to install rooftop solar to offset their energy use. Customers who receive subsidized rates in the CARE program do not have high enough electricity costs for it to make sense for them to offset those costs with investments in onsite generation. Therefore, the pool of potential solar customers is limited to residents of single-family housing on non-CARE rates.

Customers living in single-family homes on non-CARE rates make up only 46% of low-usage customers for PG&E, 32% for SCE, and 40% for SDG&E. Additionally, a substantial portion of those customers are renters, which also generally removes them from the pool of potential solar customers, so the actual percentage of low-usage customers who are viable candidates for on-site solar is even smaller than these numbers suggest.

[7] Data supplied by IOUs in response to a data request. See Appendix B.

**Table 3. Housing and CARE Distribution of Low-Usage, Non-NEM Customers**

| | | Less than 250 kWh per Month | | 250-499 kWh per Month | | Total | |
|---|---|---|---|---|---|---|---|
| | | Number | Pct | Number | Pct | Number | Pct |
| PG&E | Non-CARE, Single Family | 267,883 | 35% | 703,678 | 52% | 971,561 | 46% |
| | Non-CARE, Multifamily | 313,001 | 41% | 286,911 | 21% | 599,912 | 28% |
| | CARE, Single-Family | 61,936 | 8% | 214,625 | 16% | 276,561 | 13% |
| | CARE, Multifamily | 118,833 | 16% | 152,277 | 11% | 271,110 | 13% |
| | Total | 761,653 | | 1,357,491 | | 2,119,144 | |
| SCE | Non-CARE, Single Family | 200,141 | 24% | 540,992 | 36% | 741,133 | 32% |
| | Non-CARE, Multifamily | 406,275 | 48% | 445,697 | 30% | 851,972 | 36% |
| | CARE, Single-Family | 52,838 | 6% | 232,427 | 16% | 285,265 | 12% |
| | CARE, Multifamily | 185,795 | 22% | 276,329 | 18% | 462,124 | 20% |
| | Total | 845,049 | | 1,495,445 | | 2,340,494 | |
| SDG&E | Non-CARE, Single Family | 85,468 | 28% | 232,734 | 47% | 318,202 | 40% |
| | Non-CARE, Multifamily | 137,430 | 45% | 131,859 | 27% | 269,289 | 34% |
| | CARE, Single-Family | 26,753 | 9% | 62,359 | 13% | 89,112 | 11% |
| | CARE, Multifamily | 52,663 | 17% | 65,171 | 13% | 117,834 | 15% |
| | Total | 302,314 | | 492,123 | | 794,437 | |

**Q Does that conclude your testimony?**

A Yes, it does.

# Appendix A

**Table A-1. Impacts of PG&E Rate Change Proposals on Capital Recovery Periods and Rates of Return for Solar Customers in 2018**

| | Average Monthly Usage (kWh) | Capital Recovery Period | | | 20-Year Internal Rate of Return | | |
|---|---|---|---|---|---|---|---|
| | | Full Offset System | 75% kWh Offset System | 50% kWh Offset System | Full Offset System | 75% kWh Offset System | 50% kWh Offset System |
| PG&E Proposed Rates | 250 | 12.8 | 12.9 | 12.9 | 6.0% | 5.8% | 5.8% |
| | 500 | 11.8 | 11.7 | 11.4 | 7.2% | 7.4% | 7.8% |
| | 750 | 11.1 | 11.0 | 10.8 | 8.1% | 8.2% | 8.6% |
| | 1000 | 10.7 | 10.6 | 10.7 | 8.8% | 8.8% | 8.8% |
| | 1250 | 10.3 | 10.4 | 10.5 | 9.3% | 9.2% | 9.0% |
| | 1500 | 10.0 | 10.1 | 10.4 | 9.9% | 9.7% | 9.2% |
| CALSEIA Proposed Rates | 250 | 14.8 | 14.0 | 14.0 | 3.9% | 4.6% | 4.7% |
| | 500 | 11.9 | 11.1 | 10.3 | 7.1% | 8.1% | 9.3% |
| | 750 | 10.0 | 9.3 | 8.4 | 10.0% | 11.1% | 13.0% |
| | 1000 | 9.1 | 8.5 | 8.0 | 11.5% | 12.8% | 13.9% |
| | 1250 | 8.6 | 8.1 | 7.9 | 12.6% | 13.7% | 14.1% |
| | 1500 | 8.1 | 7.8 | 7.8 | 13.6% | 14.5% | 14.4% |
| Current Rate Structure | 250 | 15.9 | 15.1 | 15.0 | 2.9% | 3.6% | 3.7% |
| | 500 | 12.4 | 11.5 | 10.5 | 6.5% | 7.6% | 9.0% |
| | 750 | 9.3 | 8.5 | 7.2 | 11.0% | 12.9% | 16.1% |
| | 1000 | 8.0 | 7.2 | 6.4 | 13.9% | 16.3% | 18.9% |
| | 1250 | 7.3 | 6.7 | 6.2 | 15.9% | 18.0% | 19.8% |
| | 1500 | 6.8 | 6.3 | 6.1 | 17.5% | 19.6% | 20.4% |

**Table A-2. Impacts of SCE Rate Change Proposals on Capital Recovery Periods and Rates of Return for Solar Customers in 2018**

| | Average Monthly Usage (kWh) | Capital Recovery Period | | | 20-Year Internal Rate of Return | | |
|---|---|---|---|---|---|---|---|
| | | Full Offset System | 75% kWh Offset System | 50% kWh Offset System | Full Offset System | 75% kWh Offset System | 50% kWh Offset System |
| SCE Proposed Rates | 250 | 12.1 | 12.1 | 12.1 | 6.8% | 6.8% | 6.8% |
| | 500 | 11.2 | 11.1 | 10.9 | 8.0% | 8.1% | 8.4% |
| | 750 | 10.5 | 10.4 | 10.2 | 9.0% | 9.2% | 9.5% |
| | 1000 | 10.1 | 10.1 | 10.1 | 9.7% | 9.7% | 9.8% |
| | 1250 | 9.8 | 9.7 | 9.9 | 10.3% | 10.3% | 10.0% |
| | 1500 | 9.5 | 9.6 | 9.8 | 10.8% | 10.6% | 10.2% |
| CALSEIA Proposed Rates | 250 | 13.8 | 13.3 | 13.3 | 4.9% | 5.4% | 5.4% |
| | 500 | 11.9 | 11.5 | 10.9 | 7.0% | 7.6% | 8.4% |
| | 750 | 9.8 | 9.1 | 8.3 | 10.2% | 11.4% | 13.1% |
| | 1000 | 8.9 | 8.3 | 7.7 | 12.0% | 13.3% | 14.6% |
| | 1250 | 8.3 | 7.8 | 7.6 | 13.2% | 14.5% | 15.1% |
| | 1500 | 7.9 | 7.5 | 7.5 | 14.3% | 15.2% | 15.4% |
| Current Rate Structure | 250 | 14.9 | 14.3 | 14.3 | 3.8% | 4.3% | 4.3% |
| | 500 | 12.6 | 12.0 | 11.3 | 6.2% | 6.9% | 7.8% |
| | 750 | 9.9 | 9.0 | 8.1 | 10.1% | 11.6% | 13.8% |
| | 1000 | 8.6 | 7.8 | 7.1 | 12.6% | 14.4% | 16.6% |
| | 1250 | 7.8 | 7.2 | 6.8 | 14.4% | 16.2% | 17.6% |
| | 1500 | 7.3 | 6.9 | 6.6 | 15.8% | 17.3% | 18.1% |

**Table A-3. Impacts of SDG&E Rate Change Proposals on Capital Recovery Periods and Rates of Return for Solar Customers in 2018**

| | Average Monthly Usage (kWh) | Capital Recovery Period | | | 20-Year Internal Rate of Return | | |
|---|---|---|---|---|---|---|---|
| | | Full Offset System | 75% kWh Offset System | 50% kWh Offset System | Full Offset System | 75% kWh Offset System | 50% kWh Offset System |
| SDG&E Proposed Rates | 250 | 11.4 | 11.3 | 11.3 | 7.7% | 7.8% | 7.8% |
| | 500 | 10.9 | 10.9 | 10.8 | 8.4% | 8.5% | 8.5% |
| | 750 | 10.2 | 10.0 | 9.8 | 9.6% | 9.9% | 10.2% |
| | 1000 | 9.7 | 9.6 | 9.4 | 10.4% | 10.6% | 10.8% |
| | 1250 | 9.3 | 9.2 | 9.3 | 11.1% | 11.3% | 11.1% |
| | 1500 | 9.0 | 9.0 | 9.2 | 11.7% | 11.7% | 11.3% |
| Current Rate Structure | 250 | 13.7 | 12.8 | 12.7 | 5.0% | 6.0% | 6.1% |
| | 500 | 11.0 | 10.4 | 9.6 | 8.2% | 9.3% | 10.5% |
| | 750 | 8.4 | 7.6 | 6.7 | 13.0% | 15.1% | 17.9% |
| | 1000 | 7.3 | 6.6 | 5.9 | 15.9% | 18.3% | 20.9% |
| | 1250 | 6.7 | 6.1 | 5.7 | 17.9% | 20.3% | 21.9% |
| | 1500 | 6.3 | 5.8 | 5.6 | 19.6% | 21.5% | 22.4% |

# Appendix B

## IOU Responses to Data Requests on Distribution of Customers

ResidentialRatesOIR_DR_CalSEIA_004-Q01Atch01

Pacific Gas and Electric response to data request CalSEIA_004-01

**RATE DATA ANALYSIS: DR5365 Avg Monthly kWh Strata for Individual Meter Jul13-Jun14**

| CAREIND | NEM | DWELL | KWHSTRATA | SAMPLE COUNT |
|---|---|---|---|---|
| CARE | NonNEM | Multi | Below 250 kwh | 18,833 |
| CARE | NonNEM | Multi | 250-499 kwh | 52,277 |
| CARE | NonNEM | Multi | 500-749 kwh | 51,512 |
| CARE | NonNEM | Multi | 750-999 kwh | 13,647 |
| CARE | NonNEM | Multi | 1000-1249 kwh | 3,340 |
| CARE | NonNEM | Multi | 1250-1499 kwh | 811 |
| CARE | NonNEM | Multi | 1500+ kwh | 337 |
| CARE | NonNEM | Single | Below 250 kwh | 61,936 |
| CARE | NonNEM | Single | 250-499 kwh | 214,625 |
| CARE | NonNEM | Single | 500-749 kwh | 203,194 |
| CARE | NonNEM | Single | 750-999 kwh | 113,831 |
| CARE | NonNEM | Single | 1000-1249 kwh | 49,388 |
| CARE | NonNEM | Single | 1250-1499 kwh | 18,803 |
| CARE | NonNEM | Single | 1500+ kwh | 13,946 |
| CARE | NEM | Multi | Below 250 kwh | 1,252 |
| CARE | NEM | Multi | 250-499 kwh | 849 |
| CARE | NEM | Multi | 500-749 kwh | 695 |
| CARE | NEM | Multi | 750-999 kwh | 388 |
| CARE | NEM | Multi | 1250-1499 kwh | 141 |
| CARE | NEM | Multi | 1500+ kwh | 141 |
| CARE | NEM | Single | Below 250 kwh | 1,462 |
| CARE | NEM | Single | 250-499 kwh | 824 |
| CARE | NEM | Single | 500-749 kwh | 642 |
| CARE | NEM | Single | 750-999 kwh | 384 |
| CARE | NEM | Single | 1000-1249 kwh | 177 |
| CARE | NEM | Single | 1250-1499 kwh | 140 |
| CARE | NEM | Single | 1500+ kwh | 87 |
| NonCARE | NonNEM | Multi | Below 250 kwh | 13,001 |
| NonCARE | NonNEM | Multi | 250-499 kwh | 86,911 |
| NonCARE | NonNEM | Multi | 500-749 kwh | 71,114 |
| NonCARE | NonNEM | Multi | 750-999 kwh | 15,462 |
| NonCARE | NonNEM | Multi | 1000-1249 kwh | 4,296 |
| NonCARE | NonNEM | Multi | 1250-1499 kwh | 1,542 |
| NonCARE | NonNEM | Multi | 1500+ kwh | 1,812 |
| NonCARE | NonNEM | Single | Below 250 kwh | 67,883 |
| NonCARE | NonNEM | Single | 250-499 kwh | 303,678 |
| NonCARE | NonNEM | Single | 500-749 kwh | 590,602 |
| NonCARE | NonNEM | Single | 750-999 kwh | 311,721 |
| NonCARE | NonNEM | Single | 1000-1249 kwh | 143,620 |
| NonCARE | NonNEM | Single | 1250-1499 kwh | 64,755 |
| NonCARE | NonNEM | Single | 1500+ kwh | 70,840 |
| NonCARE | NEM | Multi | Below 250 kwh | 2,618 |
| NonCARE | NEM | Multi | 250-499 kwh | 690 |
| NonCARE | NEM | Multi | 500-749 kwh | 471 |
| NonCARE | NEM | Multi | 750-999 kwh | 265 |
| NonCARE | NEM | Multi | 1000-1249 kwh | 129 |
| NonCARE | NEM | Multi | 1250-1499 kwh | 110 |
| NonCARE | NEM | Multi | 1500+ kwh | 120 |
| NonCARE | NEM | Single | Below 250 kwh | 25,177 |
| NonCARE | NEM | Single | 250-499 kwh | 16,481 |
| NonCARE | NEM | Single | 500-749 kwh | 8,699 |
| NonCARE | NEM | Single | 750-999 kwh | 4,130 |
| NonCARE | NEM | Single | 1000-1249 kwh | 1,816 |
| NonCARE | NEM | Single | 1250-1499 kwh | 989 |
| NonCARE | NEM | Single | 1500+ kwh | 1,582 |

Southern California Edison response to data request R.12-06-013 RRD OIR CALSEIA-SCE-01

| | Category | Number of Residential Customers by Average Monthly Usage (kWh) | | | | | | | Total Number of Customers |
|---|---|---|---|---|---|---|---|---|---|
| | | Less than 250 kWh | 250 kWh - 499 kWh | 500 kWh - 749 kWh | 750 kWh - 999 kWh | 1000 kWh - 1249 kWh | 1250 kWh - 1499 kWh | 1500 kWh or greater | |
| 1 | Non-CARE, net metered customers in single-family housing | 3,266 | 14,145 | 25,008 | 17,974 | 8,328 | 3,676 | 4,040 | 76,437 |
| 2 | CARE, net metered customers in single-family housing | 387 | 1,375 | 1,906 | 1,365 | 608 | 240 | 167 | 6,048 |
| 3 | Non-CARE, non-net metered customers in single-family housing | 200,141 | 540,992 | 526,655 | 294,151 | 133,544 | 59,965 | 67,455 | 1,822,903 |
| 4 | CARE, non-net metered customers in single-family housing | 52,838 | 232,427 | 216,478 | 109,206 | 41,994 | 14,483 | 8,286 | 675,712 |
| 5 | Non-CARE, net metered customers in multifamily housing | 324 | 955 | 1,281 | 895 | 495 | 262 | 330 | 4,542 |
| 6 | CARE, net metered customers in multifamily housing | 87 | 186 | 136 | 89 | 43 | 27 | | 568 |
| 7 | Non-CARE, non-net metered customers in multifamily housing | 406,275 | 445,697 | 166,794 | 52,399 | 17,794 | 7,451 | 8,662 | 1,105,072 |
| 8 | CARE, non-net metered customers in multifamily housing | 185,795 | 276,329 | 100,539 | 28,942 | 7,774 | 2,252 | 1,253 | 602,884 |

| Average Monthly kWh Group | CARE | NEM | MULTI-FAMILY | Number of Customers |
|---|---|---|---|---|
| 1000-1249 kWh | Y | N | Y | 554 |
| 1250-1499 kWh | Y | N | Y | 149 |
| 250-499 kWh | Y | N | Y | 65,171 |
| 270-999 kWh | Y | N | Y | 2,713 |
| 500-749 kWh | Y | N | Y | 14,590 |
| <250 kWh | Y | N | Y | 52,663 |
| >1500 kWh | Y | N | Y | 96 |
| 1000-1249 kWh | | N | Y | 1,696 |
| 1250-1499 kWh | | N | Y | 755 |
| 250-499 kWh | | N | Y | 131,859 |
| 270-999 kWh | | N | Y | 5,734 |
| 500-749 kWh | | N | Y | 29,305 |
| <250 kWh | | N | Y | 137,430 |
| >1500 kWh | | N | Y | 2,048 |
| 1000-1249 kWh | Y | Y | Y | 2 |
| 250-499 kWh | Y | Y | Y | 166 |
| 270-999 kWh | Y | Y | Y | 3 |
| 500-749 kWh | Y | Y | Y | 23 |
| <250 kWh | Y | Y | Y | 987 |
| >1500 kWh | Y | Y | Y | 1 |
| 1000-1249 kWh | | Y | Y | 3 |
| 1250-1499 kWh | | Y | Y | 5 |
| 250-499 kWh | | Y | Y | 203 |
| 270-999 kWh | | Y | Y | 14 |
| 500-749 kWh | | Y | Y | 54 |
| <250 kWh | | Y | Y | 816 |
| >1500 kWh | | Y | Y | 27 |
| 1000-1249 kWh | Y | N | | 5,666 |
| 1250-1499 kWh | Y | N | | 2,446 |
| 250-499 kWh | Y | N | | 62,359 |
| 270-999 kWh | Y | N | | 14,365 |
| 500-749 kWh | Y | N | | 35,960 |
| <250 kWh | Y | N | | 26,753 |
| >1500 kWh | Y | N | | 2,303 |
| 1000-1249 kWh | | N | | 33,254 |
| 1250-1499 kWh | | N | | 15,032 |
| 250-499 kWh | | N | | 232,734 |
| 270-999 kWh | | N | | 76,324 |
| 500-749 kWh | | N | | 168,214 |
| <250 kWh | | N | | 85,468 |
| >1500 kWh | | N | | 18,762 |
| 1000-1249 kWh | Y | Y | | 57 |
| 1250-1499 kWh | Y | Y | | 30 |
| 250-499 kWh | Y | Y | | 426 |
| 270-999 kWh | Y | Y | | 145 |
| 500-749 kWh | Y | Y | | 229 |
| <250 kWh | Y | Y | | 638 |
| >1500 kWh | Y | Y | | 40 |
| 1000-1249 kWh | | Y | | 1,139 |
| 1250-1499 kWh | | Y | | 493 |
| 250-499 kWh | | Y | | 7,162 |
| 270-999 kWh | | Y | | 2,398 |
| 500-749 kWh | | Y | | 4,608 |
| <250 kWh | | Y | | 10,306 |
| >1500 kWh | | Y | | 593 |

# Appendix C

## Assumptions and Data Inputs for Analysis

Utility average rate escalator: 3.0%
Annual panel degradation: 0.5%
DC to AC de-rate factor: 87.0%
Design factor: 90.0%
Rate schedule: All scenarios use the default residential tariff

| | |
|---|---|
| PG&E: | "E-1" |
| SCE: | "D" |
| SDG&E: | "DR" |

Baseline territory and allocations

| | |
|---|---|
| PG&E: | "X", summer: 10.1/kwh/day, winter: 10.9/kwh/day |
| SCE: | "16", summer: 11.8/kwh/day, winter: 11.1/kwh/day |
| SDG&E: | "inland", summer: 11.2/kwh/day, winter: 10.8/kwh/day |

Peak sunlight hours:

| | |
|---|---|
| PG&E: | 5.1 |
| SCE: | 5.5 |
| SDG&E: | 5.5 |

Capacity factor:

| | |
|---|---|
| PG&E: | 16.6% |
| SCE: | 17.9% |
| SDG&E: | 17.9% |

2014 installed costs are based on the average "all-in installed" cost from a recent survey given to CALSEIA member companies. This assumes roof-mounted installations, using standard efficiency panels.

| Watts DC | $/kW DC |
|---|---|
| 1000 to 1999 | $4.75 |
| 2000 to 2999 | $4.69 |
| 3000 to 3999 | $4.63 |
| 4000 to 4999 | $4.57 |
| 5000 to 5999 | $4.51 |
| 6000 to 6999 | $4.45 |
| 7000 to 7999 | $4.39 |
| 8000 to 8999 | $4.33 |
| 9000 to 9999 | $4.27 |
| 10000 to 10999 | $4.21 |
| 11000 to 11999 | $4.15 |
| 12000 to 12999 | $4.09 |
| 13000 to 13999 | $4.03 |
| 14000 to 14999 | $3.97 |
| 15000 to 15999 | $3.91 |
| 16000 to 16999 | $3.85 |
| 17000 to 17999 | $3.79 |

2018 installed costs were generated by reducing the 2014 installed cost estimates by 5% per year, which equates to an 18.5% reduction versus 2014 installed costs.