Decision 14-12-080 December 18, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for 2013 Rate Design Window Proceeding (U39E).	Application 12-12-002 (Filed December 3, 2012)

DECISION ON A RATE DESIGN PROPOSAL TO ADOPT AN OPTION R TARIFF FOR PACIFIC GAS AND ELECTRIC COMPANY

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DECISION ON A RATE DESIGN PROPOSAL TO ADOPT AN OPTION R TARIFF FOR PACIFIC GAS AND ELECTRIC COMPANY

Summary

Pacific Gas and Electric Company (PG&E) filed a demand charge cost study and an evaluation of "Option R" for customers on PG&E's rate Schedule E–19 and E-20. PG&E is not the primary sponsor of the proposal; it was filed in compliance with Decision 11-12-053. PG&E met its compliance obligation with this application.

The Option R proposal would reduce the peak and part-peak maximum demand charges to certain customers with installed solar systems and move the collection of capacity costs for infrastructure driven by coincident demand to higher peak and part-peak energy charges. This change will lower the total bills paid by many solar customer-generators because demand charges designed to recover coincident capacity costs would no longer be based on a customer's single highest 15-minute peak and part-peak demand that occurred during the billing cycle. The proposed Option R would also lower the transmission portion of the non-coincident demand charge and recover those costs by increasing the energy rate by an equal amount in all time of use periods. Customer-generators choosing Option R may also receive lower bills because these customers would be paid a higher energy price whenever their production exceeded consumption and exported energy to PG&E's grid. We find the Solar Energy Industries Association's proposed Option R rate more appropriately charges customers for their average expected contributions to coincident peak demands and we adopt it, in part. While we approve the proposed reductions in peak and part-peak demand charges, we decline to adopt the proposed reduction in the non-coincident demand charge.

As a result of this decision, some revenues will likely be shifted among customers on the E-19 and E-20 tariffs. There are no safety related questions with this application because it does not affect electric operations.

This proceeding is closed.

1. Background

Pacific Gas and Electric Company (PG&E) filed this application in compliance with Decision (D.) 11-12-053 to conduct a demand charge cost study and an evaluation of "Option R" for customers on PG&E's rate Schedule E-19 and E-20, for customers with solar photovoltaic systems that produce at least 15% of the customers' annual usage. If adopted, Option R would modify these customers' rates to collect a smaller portion of generation and distribution capacity costs through the demand charge and more from the energy charge. This issue was deferred from Application 10-03-014 when the Commission adopted the settlement of all other issues in D.11-12-053.

The primary issue in this proceeding is to determine whether or not some form of Option R should be adopted. The secondary issue, which is only relevant if an Option R is reasonable, is establishing the specific rate design elements and eligibility criteria for Option R. The proposed Option R affects two tariffs, E-19 and E-20, which are tariffs for medium and large commercial and industrial customers. The following descriptions are abstracted from PG&E's Tariff Book:[1]

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[1] http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-19.pdf.

1.1. Electric Schedule E-19

MEDIUM GENERAL DEMAND-METERED TIME OF USE (TOU) SERVICE[2]

1. **APPLICABILITY**: Initial Assignment: A customer must take service under Schedule E-19 if: (1) the customer's load does not meet the Schedule E-20 requirements, but, (2) the customer's maximum billing demand (as defined below) has exceeded 499 kilowatts for at least three consecutive months during the most recent 12-month period (referred to as Schedule E-19). If 70% or more of the customer's energy use is for agricultural end-uses, the customer will be served under an agricultural schedule. Schedule E-19 is not applicable to customers for whom residential service would apply, except for single-phase and polyphase service in common areas in a multifamily complex (*see* Common-Area Accounts section).

Customer accounts which fail to qualify under these requirements will be evaluated for transfer to service under a different applicable rate schedule.

1.2. Electric Schedule E-20

SERVICE TO CUSTOMERS WITH MAXIMUM DEMANDS of 1000 KILOWATTS or MORE

Initial Assignment: A customer is eligible for service under Schedule E-20 if the customer's maximum demand (as defined below) has exceeded 999 kilowatts for at least three consecutive months during the most recent 12-month period.

2. Description of Option R

The Option R rate is an optional tariff, proposed by the Solar Energy Industries Association (SEIA), that would be available to customers on PG&E's E-19 and E-20 tariffs for medium and large commercial and industrial customers. PG&E's E-19 and E-20 tariffs consist of four different types of charges: 1) a fixed

[2] Implemented by Advice Letter No: 3631-E, filed March 11, 2010.

monthly customer charge; 2) time-varying peak and part-peak maximum demand charges (to recover marginal generation and distribution coincident capacity costs); 3) non-coincident demand charges (to recover the costs of distribution infrastructure needed to serve each customer's maximum demand, such as final line transformers), and 4) peak, part-peak and off peak energy charges. The Option R rate would lower the various demand charges in exchange for higher energy rates, particular during the peak and part-peak hours. Reductions would be concentrated in the peak and part-peak demand charges, although SEIA also proposes reducing the non-coincident demand charge (using the E-19S tariff as an example) by approximately 23%. (SEIA Ex. 1 at 25.) SEIA proposes that the rate would only be available to customers with solar photovoltaic (PV) systems that provide at least 15% of the host's annual energy consumption. The proposed Option R is modeled on comparable rates adopted in settlements by Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E).

As SEIA explains in its testimony, the rationale for shifting revenue collection for coincident capacity costs from demand charges to energy charges is that charging solar customers for their contributions to coincident system peaks on the basis of their single highest 15-minute interval of demand during a billing cycle's peak hours fails to appropriately compensate solar customers for their solar PV systems' effective capacity. Solar customers are often only able to offset a relatively small portion of their capacity costs, which will be less than the amount that would be avoided if their bills reflected the effective capacity provided to the system. (SEIA Opening Brief at 8.)

As an illustrative example of why this discrepancy between the demand charges avoided and capacity costs avoided occurs, SEIA posits that solar customers' coincident demands on the system are "likely to be the highest on cool, overcast days, when their solar production is much lower." On hot, sunny days when system peaks are most likely to occur, solar customers' PV systems will generally provide higher capacity. Thus, the peak demand charge for solar customers will often be set on the days that system peaks do not occur. (SEIA, Opening Brief at 11.) Spreading these charges across all peak hours via volumetric time of use (TOU) peak energy charges mitigates the bill impact of spikes in energy demand that may or may not occur on the days of actual system peak loads.

3. Positions of the Parties

PG&E did not support the adoption of Option R. In Opening Briefs, PG&E, Wal-Mart Stores, and the Energy Producers and Users Coalition all opposed adoption of the specific Option R proposed in this proceeding. PG&E and SEIA were the most active parties in the proceeding, and we rely primarily on their testimony. The Commission's Office of Ratepayer Advocates did not participate.

3.1. PG&E

3.1.1. Overview

PG&E argues that the Commission previously rejected an Option R proposal in D.11-12-053 but left open the opportunity for parties to raise the issue here. Based on the record in this proceeding, PG&E argues we should again reject the Option R rate because it violates our longstanding policy in support of demand charges for large customers; is not cost-justified; and would create unneeded new cost shifts among customers at a time when solar customers are already being subsidized by other customers. PG&E further argues Option R is not needed to continue the success of the solar program in PG&E's service area, because solar system costs are rapidly falling and customers on existing rate schedules continue to adopt solar. PG&E asserts that SEIA has not justified the need to "reverse course" on the rates adopted just two years ago in D.11-12-053. (PG&E Opening Brief at 1.)

PG&E points out that in D.11-12-053 the Commission approved a settlement between PG&E and numerous other parties[3] which explicitly rejected the Solar Alliance[4] Option R proposal.

In D.11-12-053, at 12-28, the Commission rejected arguments made by the Solar Alliance (which are similar to the arguments made here by SEIA), stating:

- "We are not persuaded by Solar Alliance claims that the Commission's longstanding policy regarding the use of demand charges has become outdated, given advances in metering technology, and solar and other Distributed Generation (DG)." (D.11-12-053 at 20.)
- "We are not persuaded that expanding A-6 eligibility and introducing an Option R rate would be cost-justified. We conclude that Solar Alliance's proposals may result in cost shifting to subsidize the solar facilities." (D.11-12-053 at 20.)
- "Solar Alliance is seeking to increase peak rates provided to solar customers for exports from the 13 cents per kilowatt hour (kWh) rate in E-19 to a price of 23 cents per kWh under Option R, or over 40 cents per kWh under A-6. We conclude that solar customers on net-metering are currently receiving enough compensation for the costs they allow the utility to avoid." (D.11-12-053 at 22.)

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[3] California Large Energy Consumers Association, the California Manufacturers & Technology Association, the Office of Ratepayer Advocates, the Energy Producers and Users Coalition, the Energy Users Forum, and the Federal Executive Agencies.

[4] The Solar Alliance merged with SEIA in January 2012.

- "E-19 and E-20 customers are continuing to install solar systems without an A-6 rate or an Option R rate available to them. The business of selling and installing solar panels in PG&E's service territory can and will continue unaffected by approval of the MLLP Settlement." (D.11-12-053 at 26-27.)

PG&E argues that the Commission's willingness to reexamine the issue was limited:

- "While we do not adopt the Solar Alliance proposals based on the record in this proceeding, we believe that additional study is warranted in a subsequent proceeding examining the demand charges in the E-19 and E-20 tariffs, and the extent to which those demand charges may penalize customers with erratic loads by overcharging them for their contributions to systems peaks…. [PG&E shall present a study]. Solar Alliance and/or other interested parties may introduce a proposal for consideration of an Option R rate in PG&E's Rate Design Window filing." (D.11-12-053 at 28.)

PG&E argues the Commission adheres to the ratemaking philosophy that demand-related costs should be recovered in demand-related charges, including rates applied to a utility's very largest electric customers. Therefore, some share of generation, transmission and distribution capacity costs are properly collected in demand charges for larger commercial and industrial customers, and the rate design objective for fully cost-based rates is full collection of these costs in demand charges, i.e., non-energy costs are best recovered through demand charges. (PG&E Opening Brief at 4.)

PG&E asserts that these customers do not reduce their use of the grid because PG&E still has to provide the same grid capacity to support these customers in case they use the grid during periods of peak demand.

PG&E's witness testified that capacity-related costs are the result of the infrastructure that must be put in place so that electricity can be generated and distributed to customers. This includes, but is not limited to, generators, transmission lines, substations, circuits and final line transformers. If customers are to be served at all times, the utility's facilities must be sufficient to meet each customer's demands during all hours. Additionally, on-peak demand charges are intended to reduce peak demand by providing an incentive for customers to limit their demands during system peaks when generation costs are the highest.

3.1.2. PG&E Study

In support of its position, and in compliance with D.11-12-053, PG&E submitted a study exploring the correlation between E-19 and E-20 customers' solar PV system generation, as well as their net loads[5], and peak demands at four levels of PG&E's electric grid: feeder, substation, distribution planning area, and total system. For this study, PG&E selected five customers (three E-19 and two E-20) served by four different feeders and two substations in two distribution planning areas (Hayward and Livermore). PG&E gathered and cleaned the 15-minute interval load data from 2011 for each customer, feeder, substation and distribution planning area. For the total system demand, only hourly data were available. In addition, PG&E collected the 15-minute interval output data for the five customers' solar PV systems.

PG&E examined two metrics in the study: the capacity factor of the solar PV systems in each interval and the customer's load as a percentage of the

[5] The net load is simply the gross load of the facility minus the output of its on-site solar (or other generation technology) equipment. Unless otherwise stated, "demand" or "load" as used in this decision refers to customers' net loads.

customer's maximum load in the year. For each level of the grid studied (feeder, substation, distribution planning area, and total system), PG&E examined the customers' capacity factor and percent of maximum load data for the top 40 intervals of demand at that level. PG&E's data generally show relatively high capacity factors (and conversely, low percent load factors) during the system and distribution planning area peaks with greater variability at the substation and feeder levels.[6]

3.2. SEIA

3.2.1. Overview

SEIA supports the availability of an Option R tariff for PG&E's E-19 and E-20 customers. SEIA notes that an Option R rate (DG-R) was first adopted by SDG&E as part of a settlement of its 2007 General Rate Case (GRC) Phase 2 application (Application (A.) 07-01-047). SDG&E's DG-R tariff has no limit on participation. (SEIA Opening Brief at 4.) SEIA notes that the Commission approved Option R rates for SCE the following year in its 2008 GRC Phase 2 (A.08-03-002). SCE's settlement included a cap on participation of 150 MW. For its next general rate case, SCE completed a cost analysis of Option R and concluded that with modest changes, the Option R tariff does appropriately charge solar customers for the demands they place on SCE's generation, transmission and distribution systems. (SEIA Opening Brief at 5; SEIA Exh. 1, Attachment RTB-3.)

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[6] For example, on Feeder A1-1105 35 of the top 40 intervals occur on or after 6 p.m. whereas all of the peak intervals on Feeder A1-1106 occur between 12:30 p.m. and 4:15 p.m. Consequently, the capacity factors during the respective feeder peaks are much higher for the customer on Feeder A1-1106. (PG&E Exh. 1, Appendix B at 1-2.)

SEIA argues that PG&E's E-19 and E-20 customers should have access to Option R rates because the use of demand charges does not accurately charge solar customers for the demands they place on PG&E's system. As SEIA explains, these customers pay generation capacity costs for their highest usage in any 15 minute billing interval in the peak and part-peak TOU periods each month. SEIA reasons that solar customers will often experience their peak loads on overcast days when the output of the solar systems is diminished but total system loads are significantly less than peak loads. Conversely, on the hot, sunny days that typically drive system peaks, solar output will tend to be high, keeping solar customers' net loads low. (SEIA Opening Brief at 9.) True cost-based rates should generally allow solar customers to avoid peak demand charges commensurate with the amount of capacity their solar PV systems provide to the grid. (SEIA Opening Brief at 8.) As an analogy, SEIA notes that utility side of the meter solar is credited with significant capacity value during summer months under the Commission's resource adequacy counting rules. (SEIA Exh-1 at 3.)

In order to revise PG&E's E-19 and E-20 tariffs to more equitably collect coincident capacity-related revenues from solar customers, SEIA recommends that all peak and part park generation demand charges be eliminated and shifted to peak and part-peak energy rates. Similarly, SEIA recommends shifting 75% of the primary distribution peak and part-peak costs from demand charges to peak and part-peak energy rates. SEIA notes that the Federal Energy Regulatory Commission (FERC) regulates transmission rates and that the FERC-approved rates for transmission recover transmission costs via a non-coincident maximum demand charge. However, since PG&E has a summer peaking system, SEIA asserts that recovery of transmission costs via a maximum non-coincident demand charge does not appropriately recover transmission-related costs. In order to mitigate the discrepancy between the recovery of costs from customers and the incurrence of those costs by PG&E, SEIA proposes that the distribution portion of the maximum demand charge, over which the Commission does have jurisdiction, be reduced by an amount equivalent to 50% of the transmission portion of the maximum demand charge. The revenues would be collected by an equal-cents per kWh increase in energy rates spread across all TOU periods.

3.2.2. SEIA Study and Analysis of PG&E Study

In support of its position, SEIA requested load data on the 306 E-19 customers that had installed solar PV systems during 2006 to 2011. SEIA pared the data set down to 71 customers, culling entries for customers with either incomplete data or data producing anomalous results. SEIA compared these customers' loads during the peak hour of the year before they installed solar PV systems to their loads during the peak hour of the year following installation. SEIA asserts that the load reductions observed between pre- and post-installation demonstrate the substantial capacity provided by these customers' solar PV systems.

PG&E criticizes SEIA's study on various grounds. The three principal critiques are: 1) SEIA biased its results by dropping customers from its study with complete data when the results did not support SEIA's desired conclusion (i.e., customers whose loads increased) but including customers whose load reductions were greater than the capacity of the solar PV systems they had installed; 2) loads may have changed for a variety of reasons and SEIA's study does not control for those factors; and 3) examining loads for only the highest peak hour in a year is insufficient for assessing the capacity value of the customers' solar systems.

We acknowledge that while the results of SEIA's study suggest that solar PV systems provide significant peak capacity, its study was severely hampered by lack of access to the actual solar production data. The use of load differences as a proxy undermines the validity of the study, and consequently we do not give it much weight to reach our conclusions.

Of greater value was the additional analysis that SEIA conducted on the five customers in PG&E's study. Although PG&E's study provided some interesting and useful data, it failed to compare the capacity factors and percent load factors during the top 40 intervals of demand to the maximum peak period loads for which the customers were billed. Such a comparison would have allowed us to evaluate SEIA's central claim that customers with solar are systematically overbilled for their contributions to coincident peak loads. Fortunately, SEIA complemented PG&E's analysis by requesting the customers' maximum peak, part-peak, and non-coincident loads for each of summer months in 2011 and did perform such comparisons. We rely largely on this additional SEIA analysis to reach our conclusions, as we discuss in more detail below.

4. Discussion

In rate design the objective is to set retail electric prices so that the utility has a reasonable opportunity to recover its authorized revenue requirements while the customers pay a fair rate that is based on the cost to serve them. The cost of serving a customer of an electric utility consists of fixed costs that are driven primarily by the number and type of customers, energy costs, and various coincident and non-coincident capacity costs. Because the fairness of fixed charges and energy rates of the E-19 and E-20 tariffs are not in dispute, we limit our discussion to the design of the various demand charges in these tariffs.

4.1. Types of Capacity Costs

The crux of SEIA's argument is that the demand charges in PG&E's E-19 and E-20 tariffs do not accurately allocate various capacity costs to customers commensurately with the costs customers impose on PG&E. Capacity costs are generally categorized into four broad groups: Generation, transmission, primary distribution, and secondary distribution. (*See* for example, PG&E Exh-1 at 3–7.)

SEIA acknowledges maximum non-coincident demand charges may be appropriate to recover secondary distribution costs because system components that serve only one or relatively few customers often have peak demands that do not coincide with system peak demands. (SEIA Opening Brief at 17; SEIA Exh-1 at 19.) SEIA and PG&E agree that generation, transmission, and primary distribution costs are driven by the need to meet coincident peak demands.

Unlike SCE and SDG&E, PG&E's medium and large commercial and industrial tariffs include peak and part-peak demand charges in addition to a more common non-coincident maximum demand charge. These TOU demand charges are designed to more accurately allocate coincident demand-related costs than non-coincident demand charges. The E-19 and E-20 TOU demand charges include generation and primary distribution capacity costs, but despite PG&E's characterization of transmission capacity as being driven by the need to meet peak loads on the transmission system (PG&E Exh-1 at 3), the E-19 and E-20 tariffs recover transmission costs through a non-coincident demand charge that does not vary by time of day or season. The transmission portion of PG&E's tariffs is subject to the jurisdiction of the FERC. Consequently, shifting transmission cost recovery from non-coincident demand charges to TOU demand charges would require FERC approval.

4.2. Accuracy of Peak and Part-Peak Demand Charges as a Proxy for Contributions to Coincident Peak Demands

Although PG&E's E-19 and E-20 tariffs more appropriately allocate generation and primary distribution costs to TOU demand charges rather than non-coincident demand charges, SEIA argues that an Option R rate is needed nonetheless because the use of TOU maximum demand charges unfairly overcharges solar customers for their contributions to system peaks. SEIA makes a two-pronged argument in support of this proposition. The first line of argument is that the collection of coincident peak related capacity costs on the basis of customers' highest single intervals of demand does not reflect the diversity benefit of multiple customers' solar output, and net loads on PG&E's system, changing by different amounts at different times. (SEIA Exh-1 at 19 and Attachment RTB-3.) Stated differently, total coincident demand will never equal the sum of each customer's highest recorded demand during a given time period because of the variability of millions of customers' demands.[7] Due to the smoothing effect of load diversity, coincident loads in any interval will more closely resemble the sum of customers' average loads during and near that

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[7] The following example illustrates this phenomenon. Customer A's peak period load alternates between 800 kilowatt (kW) and 400 kW every 15 minutes. Customer B's peak period load also alternates between 800 kW and 400 kW every 15 minutes but is off by exactly one phase relative to Customer A. Customer C's load is always 600 kW. PG&E's system experiences a steady load from these three customers of 1800 kW. Customer C is billed for 600 kW of demand. However, Customer A and Customer B are both billed for 800 kW, for a total of 1600 kW of demand, even though their combined demand never exceeds 1200 kW.

interval than the sum of each customer's maximum load. Thus, customers with erratic loads are overcharged compared to customers with steady loads.

SEIA devotes much more attention to the second line of argument, namely that the use of maximum TOU demand charges will often result in a mismatch between the days that individual customers experience their individual peak period maximum demands and the days that system peak demands actually occur. SEIA suggests that this is particularly true for solar customers because the maximum peak demands of solar customers will often occur on overcast days when solar PV output is low. Because overcast days are generally cooler, they will seldom be among the highest peak demand days that drive capacity costs. (SEIA Opening Brief at 9.) SEIA requested interval load and solar output data for the five solar customers PG&E analyzed in the study included with PG&E's application. For the summer months of 2011 (May through October), SEIA compared these customers' peak period net loads on the peak day of the month to the customers' individual maximum peak period net loads during those months. (SEIA Exh-1 at 11 – 15 and Attachment RTB-4.) Individual customer results are presented for the months of June and July with summary results shown for the group as a whole for all months. (SEIA Exh-1 at 15.)

Since PG&E's 2011 system peak load of 18,024 MW occurred between 4 p.m. and 5 p.m. on June 21 (PG&E Exh-1 at 26) with four of the top ten peak hours of 2011 occurring between 2 p.m. and 6 p.m. that day, we focus our discussion on the June findings. On June 21, all five customers' solar systems generated substantial output, significantly reducing their loads during the peak hours. The average output of all five customers' PV systems between 2 p.m. and 6 p.m. ranged from a minimum of 48% to a maximum of 86%. (PG&E Exh-1, Appendix B at 8 and 16.) All five of these customers experienced their maximum peak period loads on June 28 when their solar output fell drastically due to a marine layer. (SEIA Exh-1, Figure 5-1.)[8] High temperatures across Northern California were much lower than on June 21, and the maximum coincident demand was 27% lower than the peak demand on June 21. (SEIA Exh-1 at 13.) The average of the highest peak period demands of the five customers was 309 kW on June 21 whereas the average of the highest peak period demands on June 28, which determined the coincident capacity charges for these customers that month, was 673 kW. (SEIA Exh-1, Table 5-5 at 15.) Table 5-5 shows that during all of the other summer months of 2011, the average of the highest peak period demands in each month ranged from approximately 90 kW to 290 kW higher than the average of the highest peak period demands that occurred on the peak day of each month.

Following a similar approach, SEIA uses the PG&E data on the five customers' loads during the 40 highest system peak intervals to calculate the average peak demand during those 40 intervals. SEIA finds that the average load during the 40 intervals of highest system peak demand was 203 kW. In contrast, SEIA finds that the average maximum peak period loads billed for these five customers across the six across summer months was 744 kW, resulting in demand charges for generation capacity in excess of the demands these customers imposed on PG&E's grid during the highest coincident peak load hours of the summer. SEIA estimates that these customers were billed for 3.9 times more peak and part-peak period capacity than was required to serve them. (SEIA Exh-1, Tables 5-2 and 5-3 at 10 – 11.)

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[8] Attachment RTB-4 of SEIA Exh-1 depicts the same customer-specific comparisons for the month of July.

SEIA conducted similar analyses for transmission and distribution costs. Regarding transmission capacity, SEIA found that the five PG&E customers were charged for five times more capacity than they required during the 40 highest system peak intervals. For distribution capacity, SEIA compared each of the five customers' loads during the 40 highest intervals of demand at the substation and distribution planning area level. SEIA found that the three customers in the Hayward distribution planning area were overbilled for capacity by a factor of 19.5 and that the two customers in the Livermore distribution planning area were overbilled by a factor of 1.7. Across all five customers, the average factor of overbilling was 2.1. (SEIA Exh-1, Table 5-10 at 22.) Results for generation, transmission and primary distribution are summarized in Table 6-1 of SEIA's testimony. (SEIA Exh-1.)

SEIA's thorough analysis convincingly demonstrates the inaccuracy of maximum TOU demand charges. The inaccuracy is due both to the fact that customers' individual maximum peak period demands may not coincide with system peaks and to the failure of demand charges to appropriately recognize the benefits of load diversity. Shifting the collection of coincident capacity related costs to peak and part-peak TOU energy rates would more accurately reflect the benefits of load diversity and would appropriately mitigate the bill impacts of solar customers' spikes in consumption of grid electricity that occur on overcast days.

4.3. Effect of Increasing Volumetric Rates on Compensation for Exports under Net Energy Metering (NEM)

PG&E also objects to the Option R proposal because it would substantially increase the E-19 and E-20 peak period volumetric rates and therefore the value of electricity exported during this period under NEM. (PG&E Opening Brief at

22 to 26.) PG&E observes that the Option R rate, as proposed by SEIA, would increase the E-19S peak period energy rate then in effect from 13.4 cents per kWh to 28.5 cents per kWh. PG&E claims this increase in the peak rate vastly over-compensates solar customers for their exports during the summer peak period. (PG&E Opening Brief at 23.) PG&E illustrates the consequences of establishing an Option R rate using the example of an E-19 customer with a peak demand of 550 kW that installs a 1,000 kW PV system. Under the existing E-19 tariff this customer would reduce its annual bill by $215,000 (from $350,000 to $135,000). Option R would allow this customer to reduce its bill by another $41,000, of which $15,000 would be attributable to the higher revenues generated by exports during peak period hours. (PG&E Opening Brief at 25–26.) According to PG&E these additional bill savings are problematic because the revenue shortfall must be made up by other E-19 customers, and this cost shift would further exacerbate the cross-subsidy that PG&E claims already flows to solar customers.

We do not necessarily concur with PG&E's characterization that the NEM credits that solar customers would receive under Option R rates are excessive. However, we note that PG&E may seek to remedy this alleged problem through revisions in the structure of the NEM tariff itself in R.14-07-002, the NEM successor tariff rulemaking opened in response to Assembly Bill 327. Alternatively, in a future rate design proceeding, PG&E may propose the use of peak and part-peak average demand charges or daily peak demand charges that better align solar and other erratic load customers' demand charges with their average expected contributions to coincident peak demands. By lessening the bill impact of demand during the single highest interval of each billing cycle, such an approach would provide similar bill "smoothing" benefits as recovering coincident demand related costs in peak period energy rates while maintaining energy rates closer to wholesale marginal costs.

5. Adopted Option R Rate for PG&E

We are persuaded by SEIA's arguments that the current demand charge structure unfairly charges solar customers more for coincident demand related capacity costs than they actually cause PG&E to incur. SEIA's analysis clearly demonstrates that for the five customers chosen by PG&E for its analysis, individual customers' maximum peak period demands did not coincide with the monthly summer peak demands on PG&E's system. Moreover, the average peak period loads were significantly lower than the highest loads for which these customers were billed. (SEIA Exh-1, Table 6-1 at 23.) Consequently, these customers were billed for more capacity than was required to serve them.

In order to rectify this misalignment between the demand charges imposed and the costs incurred, we hereby adopt SEIA's proposed Option R rate, which should be available for qualifying E-19 and E-20 customers, including voluntary E-19 customers, who have on-site renewable generation systems that provide at least 15% of the host customer's annual electricity usage. Because we find the Option R rate to be cost-based, there should be no MW limit on participation. We agree with SEIA that all generation capacity costs should be removed from the peak and part-peak demand charges and be recovered instead through the peak and part-peak energy rates. We also agree that 75% of the distribution costs recovered in the peak and part-peak demand charges should be shifted to peak and part-peak energy rates.

We decline to reduce the distribution portion of the non-coincident demand charge in order to compensate for the recovery of transmission costs, over which we lack jurisdiction, via the non-coincident demand charge. While we agree that this method of collecting revenues for transmission-related costs may not optimally align revenue collection with cost causation, we prefer that this misalignment be resolved by revising the transmission rate structure at FERC. SEIA notes that SDG&E committed in the settlement of its 2012 GRC Phase 2 case to asking FERC to move away from the use of maximum non-coincident demand charges to recover transmission costs. We encourage PG&E or another party to file a similar request with FERC.

6. Safety

Rate design issues inherently have no safety implications for utility employees, customers, or the general public.

7. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Douglas M. Long the assigned Administrative Law Judge.

8. Comments on Alternate Proposed Decision

The alternate proposed decision was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on December 8, 2014 by Energy Procedures and Users Coalition, PG&E, and SEIA and reply comments were filed on December 15, 2014 by PG&E and SEIA.

In response to the comments, we have made the following revisions to the alternate proposed decision. Eligibility for Option R shall be restricted to qualifying customers with solar PV systems that provide 15% or more of the customer's annual electricity usage rather than be available to all E-19 and E-20 customers. Although we believe time of use demand charges are likely to unfairly allocate capacity costs to all customers with erratic loads, we have made this revision because the analysis in the record rests mainly on data from solar customers. As requested by PG&E, we have clarified that Option R shall be available to voluntary E-19 customers, and we have revised the effective date of the modified tariffs.

Findings of Fact

1. PG&E complied with D.11-12-053 and filed an Option R rate study.
2. SEIA is the principal sponsor of an Option R rate design for solar customers in PG&E's service territory.
3. The Option R rate proposed by SEIA would differ from PG&E's standard E-19 and E-20 rates in three ways: 1) all generation capacity costs would be removed from the peak and part-peak demand charges and would be recovered instead in peak and part-peak energy charges, 2) 75% of distribution capacity costs would be removed from the peak and part-peak demand charges and would be recovered instead in peak and part-peak energy charges, and 3) non-coincident demand charges would be reduced by an amount equivalent to 50% of the transmission cost component of the demand charge and would be recovered in an equal cents per kWh charge applied equally in all TOU periods.
4. The existing Option R rate designs in effect for SCE and SDG&E customers were adopted as part of comprehensive rate design settlements.
5. The proposed Option R would increase the peak energy price paid for the excess solar generation exported to the grid under net energy metering.
6. PG&E's opposition to adopting an Option R is based on its study of five E-19 and E-20 solar customers.
7. SEIA's support of Option R relies on data for a 71 customer subset of the 306 E-19 customers who installed solar during the 2006–2011 period as well as additional analysis of the five customers selected by PG&E.
8. The need for additional generation, transmission, and primary distribution capacity are driven by customers' coincident peak demands.

9. Due to the benefits of load diversity, the capacity needed to reliably serve customers at the higher levels of the electric grid is determined by the average demands of individual customers during coincident peaks rather than each customer's single highest interval of demand during peak time of use billing hours.

10. At lower levels of electric distribution infrastructure, the capacity needed to serve customers is driven more by individual customers' non-coincident maximum demands or the coincident demands of a small group of customers that may not coincide with system peak demands.

11. PG&E's use of peak and part-peak demand charges on the E-19 and E-20 tariffs unfairly overcharges solar customers with relatively erratic loads because an individual customer's highest recorded usage during a single 15-minute interval each billing period may not coincide with system-level peak demands.

12. For solar customers, the evidence in the record indicates that the highest net loads (total load minus the load provided by the customer-sited solar PV system) will likely occur on cooler days when cloud cover diminishes the output of PV systems.

13. SEIA's analysis of the five solar customers in PG&E's study demonstrates that individually and collectively, the solar customers' maximum peak period demands did not occur on the same days of the peak demands each month during the summer of 2011.

14. PG&E's maximum system demand in 2011 occurred between 4 p.m. and 5 p.m. on June 21 and four of the top ten peak hours of 2011 were the hours from 2 p.m. and 6 p.m. on June 21.

15. PG&E's data show that the average capacity factors of the five customers' solar PV systems ranged from 48% to 86% during the hours from 2 p.m. to 6 p.m. on June 21, 2011.

16. Each of the five solar customers' June 2011 maximum peak period net loads occurred on June 28, when cloud cover drastically reduced the output of the customers' solar PV systems but also resulted in a PG&E system-wide coincident peak demand that was 27% lower than the coincident peak demand on June 21.

17. In June 2011, the average of the highest recorded loads of the five solar customers during the peak period on the peak day of June 21 was 309 kW. The average of the highest peak period loads recorded in June, which for all five solar customers occurred on June 28, was 673 kW. Similar discrepancies between these customers' average highest peak period loads on the peak days of each month and the customers' average highest peak period loads that occurred on any day of each month were observed for all of the other five summer season months.

18. Recovering coincident peak and part-peak capacity costs via maximum peak and part-peak demand charges does not reflect the diversity benefit of having numerous solar customers, and other erratic load customers, on the system.

19. Recovering coincident peak and part-peak capacity costs via volumetric peak and part-peak energy rates mitigates the bill impacts of any large spikes in usage during a small number of billing intervals and more fairly recovers these costs based on customers' average peak and part-peak demands.

20. A cost study submitted by SCE in Application 11-06-007 (Phase 2 of SCE's 2012 GRC) concluded that SCE's Option R rate was cost justified, and SCE

recommended only minor revisions to the Option R rate in effect at the time in order to better align its rates with the cost of serving solar customers.

21. PG&E recovers transmission capacity costs from E-19 and E-20 customers via a non-coincident demand charge.

22. Transmission-related cost recovery and rate design is the jurisdiction of FERC.

Conclusions of Law

1. The proposed Option R would more equitably allocate costs related to coincident demand to solar customers than the maximum peak and part-peak demand charges currently used on the E-19 and E-20 tariffs.

2. The distribution portion of the non-coincident demand charge in tariffs E-19 and E-20 should not be reduced to compensate for the poor alignment of non-coincident transmission demand charges with transmission cost-causation. It would be preferable for PG&E, SEIA or another party to petition FERC for a modification to PG&E's FERC-approved transmission rate structure.

3. As a cost-based rate, Option R should be available to qualifying customers with solar PV systems that provide 15% or more of their annual electricity usage, with no cap on participation.

4. The Option R proposal filed by SEIA should be approved with the modifications described in Conclusions of Law 2.

5. All motions not previously granted should be denied.

6. This proceeding should be closed.

O R D E R

IT IS ORDERED that:

1. Within 45 days of the issuance of this decision, Pacific Gas and Electric Company shall file a Tier 2 Advice Letter with revised tariff sheets for rate schedules E-19 and E-20 that include an Option R. The Option R rate shall be available to qualifying customers, including voluntary E-19 customers, with solar PV systems that provide 15% or more of their annual electricity usage, with no cap on participation. The Option R rates shall shift all revenues collected for generation capacity costs from peak and part-peak demand charges to peak and part-peak energy charges in a manner that would be revenue neutral within the E-19 and E-20 customer classes. The Option R rates shall shift 75% of the revenues collected for distribution capacity costs from peak and part-peak demand charges to peak and part-peak energy charges. The tariff sheets shall become effective June 1, 2015, subject to Energy Division determining that they are in compliance with this order.
2. All rulings not previously granted are denied.
3. Application 12-12-002 is closed.

This order is effective today.

Dated December 18, 2014, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
MICHAEL PICKER
Commissioners