Decision 15-08-005 August 13, 2015

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U39M).	Application 13-04-012 (Filed April 18, 2013)

DECISION ADOPTING EIGHT SETTLEMENTS AND RESOLVING CONTESTED ISSUES RELATED TO PACIFIC GAS AND ELECTRIC COMPANY'S ELECTRIC MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN

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DECISION ADOPTING EIGHT SETTLEMENTS AND RESOLVING CONTESTED ISSUES RELATED TO PACIFIC GAS AND ELECTRIC COMPANY'S ELECTRIC MARGINAL COSTS, REVENUE ALLOCATION, AND RATE DESIGN

Summary

This decision adopts eight separate settlements as proposed by the settling parties and resolves the remaining outstanding issues based on the merits of the litigated positions. This completes the current review of Pacific Gas and Electric Company's (PG&E) electric marginal costs, revenue allocation, and rate design. Adoption of these new rates will reallocate the existing authorized revenue requirement amongst the various customer classes and within those customer classes. One settlement was partially contested and this decision resolves those contested issues primarily in accordance with the proposed settlements.

Because this proceeding deals with only rate design related questions and not operating or capital costs, or how PG&E operates its electric system, there are no changes to PG&E's overall authorized revenue requirement, although individual customer's bills may change as a result of changes in rate design. Also, there is no impact on employee, customer, or public safety, again because this decision does not change PG&E's revenue requirement or have any direct impact on electric operations.

This proceeding is closed.

1. Procedural History

The proceeding has a complex history, as parties sought and were granted numerous extensions of time to complete settlement negotiations with various sub-groups of interested parties which resulted in eight separate settlements covering all but a few issues that were litigated. All settlement rules were followed and all parties had notice and opportunity to participate. The proceeding was initially submitted on January 8, 2015 (pursuant to Rule 13.4(a)), 30 days after the last settlement was filed (in order to allow time for comments pursuant to Rule 12.2).

1.1. Submission

There were separate motions to adopt each settlement as it was filed. After allowing an opportunity for anyone to protest, each settlement was accepted into the record. The outstanding unsettled issues were fully litigated and briefed and the proceeding was submitted on January 8, 2015, 30 days after the last date for anyone to oppose the eighth and final settlement, the Agricultural Rate Design Settlement Agreement, filed December 2, 2014. However, on March 30, 2015 Pacific Gas and Electric Company (PG&E) filed an Amended E-Credit Rate Design Supplemental Settlement Agreement (Amendment) and submission was set aside to allow for comment by a ruling dated April 1, 2015. The proceeding was submitted again on April 29, 2015.

2. The Record

The record in this proceeding consists of all filed documents and all exhibits received into evidence, as well as the transcripts of all hearings. We rule here that all motions for the receipt of various exhibits served outside the evidentiary hearings are granted. All other non-evidentiary motions not otherwise granted by ruling are deemed denied.

3. Standard of Review

PG&E bears the burden of proof to show that the rates it requests are just and reasonable and the related ratemaking mechanisms are fair.

In order for the Commission to consider whether any proposed settlement in this proceeding is in the public interest, the Commission must be convinced that the parties had a sound and thorough understanding of the applications, and all of the underlying assumptions and data included in the record. This level of understanding of the application and development of an adequate record is necessary to meet our requirements for considering any settlement.

4. Adopting a Proposed Settlement

As the United States Court of Appeals for the Ninth Circuit has observed, in evaluating a settlement the agreement must stand or fall on its own terms, not compared to some hypothetical result that the negotiators might have achieved, or that some believe should have been achieved:

> Settlement is the offspring of compromise; the question we address is not whether the final product could be prettier, smarter or snazzier, but whether it is fair, adequate and free from collusion. (*Hanlon v. Chrysler Corp., 150 F.3d 1011, 1027 (9th Cir. 1998)*).

Based upon our review of the extensive prepared testimony, evidentiary hearings and comprehensive briefing of the litigated applications, we find that the parties to all of the settlements herein had a sound and thorough understanding of the application, and all of the underlying assumptions and data included in the record and, thus, we can consider the various individual settlements as offered by competent and well-prepared parties able to make informed choices in the settlement process.

5. Pertinent Commission Rules

The Commission's Rules of Practice and Procedure (Rules) specifically address the requirements for adoption of proposed settlements in Rule 12.1 Proposal of Settlements, and subject to certain limitations in Rule 12.5 Adoption Binding, Not Precedential. Specifically, Rule 12.1(a) states:

> Parties may, by written motion any time after the first prehearing conference and within 30 days after the last day of hearing, propose settlements on the resolution of any material issue of law or fact or on a mutually agreeable outcome to the

> proceeding. Settlements need not be joined by all parties; however, settlements in applications must be signed by the applicant and, in complaints, by the complainant and defendant.
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> The motion shall contain a statement of the factual and legal considerations adequate to advise the Commission of the scope of the settlement and of the grounds on which adoption is urged. Resolution shall be limited to the issues in that proceeding and shall not extend to substantive issues which may come before the Commission in other or future proceedings.
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> When a settlement pertains to a proceeding under a Rate Case Plan or other proceeding in which a comparison exhibit would ordinarily be filed, the motion must be supported by a comparison exhibit indicating the impact of the settlement in relation to the utility's application and, if the participating staff supports the settlement, in relation to the issues staff contested, or would have contested, in a hearing.

Rule 12.1(d) provides that:

> The Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

Rule 12.5 limits the future applicability of a settlement:

> Commission adoption of a settlement is binding on all parties to the proceeding in which the settlement is proposed. Unless the Commission expressly provides otherwise, such adoption does not constitute approval of, or precedent regarding, any principle or issue in the proceeding or in any future proceeding.

6. Required Findings – Rules 12.1(d) and Rule 12.5

Based upon the record of this proceeding we find the parties complied with Rule 12.1(a) by making the appropriate filings and noticing of settlement conferences. Based upon our review of the individual settlement documents we find that they contain a statement of the factual and legal considerations adequate to advise the Commission of the scope of the settlement and of the grounds for its adoption; that the settlement was limited to the issues in this proceeding; and that the settlement included a comparison indicating the impact of the settlement in relation to the utility's application and contested issues raised by the interested parties in prepared testimony, or that would have been contested in a hearing. These two findings that the settlement complies with Rule 12.1(a), allow us to conclude, pursuant to Rule 12.1(d), that the settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

Based upon our review of the settlement documents we find, pursuant to Rule 12.5, that the proposed settlements would not bind or otherwise impose a precedent in this or any future proceeding. We specifically note, therefore, that neither PG&E nor any party to any of the settlements may presume in any subsequent applications that the Commission would deem the outcome adopted herein to be presumed reasonable and it must, therefore, fully justify every request and ratemaking proposal without reference to, or reliance on, the adoption of these settlements.

7. Summary of Settlements

A copy of all eight of the Settlement Agreements, fully executed by all interested parties, are available at the links below following each settlement. The final language of the settlement controls the terms and conditions of the adopted rates except as specifically modified herein. The proposed settlements are as follows:

1. Settlement Agreement on Marginal Cost and Revenue Allocation Issues, filed July 16, 2014;

http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=99753189;

2. Residential Rate Design Supplemental Settlement Agreement, filed July 24, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=101125976;

3. Large Light and Power Rate Design Settlement Agreement, filed July 25, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=102226995;

4. Streetlight Rate Design Supplemental Settlement Agreement, filed August 29, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=103390568

5. Amended E-Credit Rate Design Supplemental Agreement, filed March 30, 2015;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=151726093;

6. Medium Commercial Rate Design Settlement Agreement, filed September 5, 2014;

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=105647677;

7. Small Commercial Rate Design Settlement Agreement, filed September, 5, 2014; and

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=107147806

8. Agricultural Rate Design Settlement Agreement, filed December 2, 2014.

   http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=143515264.

7.1. Discussion

As can be seen by the detailed and complex nature of each settlement's summary, PG&E and the relevant interested parties have addressed a series of issues to their mutual satisfaction. All parties were required to affirm or assert their specific level of participation and their position on each settlement. They either: agreed to, opposed, did not participate in, or withdrew from the discussions, on every settlement (*See* Attachment 1[1]). Only the solar manufacturing participants opposed certain rate design issues otherwise settled in the Settlements; these issues were therefore litigated. These contested issues are discussed and resolved herein.

7.1.1. Settlement Agreement on Marginal Cost and Revenue Allocation

This Settlement resolved the issues raised by marginal costs and revenue allocation. There are three major components to this Settlement. First, it resolves all marginal cost issues. The Settlement adopts the specific marginal costs to be used solely for the purpose of evaluating customer-specific contracts including as required for Schedule E-31 (Distribution Bypass Deferral Rate) and Schedule

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[1] The following are the parties that actively participated at some stage in the settlement discussions: Agricultural Energy Consumers' Association (AECA); Bodean Company (Bodean); City and County of San Francisco (CCSF); California City-County Street Light Association (CAL-SLA); California Farm Bureau (CFBF); California Large Energy Consumers Association (CLECA); California League of Food Processors (CLFP); California Manufacturers & Technology Association (CMTA); California Solar Energy Industries Association (CALSEIA); Direct Access Customer Coalition (DACC); Energy Producers and Users Coalition (EPUC); Energy Users Forum (EUF); Federal Executive Agencies (FEA); Marin Clean Energy (MCE); Modesto and Merced Irrigation Districts (MMID); Office of Ratepayer Advocates (ORA); PG&E; Small Business Utility Advocates (SBUA); Solar Energy Industries Association (SEIA); The Utility Reform Network (TURN); and Western Manufactured Housing Communities Association (WMA).

EDR (Economic Development Rate). Second, for Revenue Allocation, the Settling Parties[2] agree that electric revenue should be allocated as a result of A.13-04-012 on an overall revenue-neutral basis to preserve then-required total revenue. Third, for rate changes to implement revenue requirement changes between proceedings, the Settling Parties agree that revenue requirement changes will be identified by function (e.g., nuclear decommissioning, generation, etc.). Each customer class and schedule will be allocated the average percentage change in functional revenue necessary to collect the functional revenue requirement.

In addition, the Settlement Agreement provides that PG&E will conduct certain studies and workshops to be completed prior to filing its next rate design application. All parties to the 2014 rate design proceeding will be invited to participate in all such workshops. First, the Settling Parties agreed to pursue additional analyses to examine the desirability of an Agricultural Class Balancing Account, by reviewing year-to-year variations of agricultural class revenues and sales versus those of other customer classes, and assessing possible over-collections of agricultural class revenue that accounts for variation in both PG&E's cost of service and revenues. The Settling Parties agreed to a detailed process for workshops to discuss such data and analysis, resulting in a workshop report to be finalized by December 30, 2015.

Second, the Settling Parties agreed to a detailed process by which PG&E will hold up to three workshops to discuss methodological issues pertaining to

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[2] "Settling Parties" is used to generically identify the changing collective groups of parties that joined each settlement. The groups for each settlement vary according to whether an individual party participated. It would be too cumbersome to separately identify each group for all eight settlements. *See* Attachment 2 for the status of every party for each settlement.

the development of cost of service. Those workshops will be separate from the Agricultural Class Balancing Account Workshops and timed to avoid scheduling conflicts as much as possible. A workshop report will be prepared and included as a compliance item attached to PG&E's next rate design application. The Settling Parties agreed that, to the extent possible, the workshop report will identify potential changes to PG&E's prior marginal cost methodologies that it may consider proposing in its next rate design proceeding. (July 16, 2014 Motion at 2-4.)

7.1.2. Residential Rate Design Supplemental Settlement Agreement

The settled residential rate design issues are: Schedule ET and ES electric master-meter discounts; natural gas baseline quantities; Electric Vehicle rate review in compliance with Decision (D.) 11-07-029; and rate design to adjust generation rates such that they do not exceed the total rate for Schedules E-7, EL-7, E-8 and EL-8. (July 24, 2014 Motion at 1.)

7.1.3. Large Light and Power Rate Design Settlement Agreement

One issue is excluded from this settlement but otherwise the parties agreed to the following.

7.1.3.1. Rate Design for Schedules E-19 and E-20

The Settlement Agreement describes how rates for Schedules E-19 and E-20 will be designed, and includes the following fundamental components: Illustrative Settlement Rates; Basic Rate Design; Demand Charges; Customer Charges; Energy Charges; Peak Day Pricing Updates; Transmission Rates; and an agreement to litigate a proposal to allow Net Energy Metering customers that are on Schedules E-19 and E-20 to take service on Peak Day Pricing rates.

7.1.3.2. Rate Design for Standby

The Settlement Agreement describes how rates for Standby Schedule S will be designed, and includes the following fundamental components: Illustrative Settlement Rates; Basic Rate Design; Reservation Charge; Customer Charges; Energy Charges; and Standby Distribution Diversity Study (PG&E will conduct a study of the diversity of standby load on the distribution system similar to that conducted by Southern California Edison Company). (July 25, 2014 Motion at 4-7.)

7.1.4. Streetlight Rate Design Supplemental Settlement Agreement

The Streetlight Settlement Agreement is supplemental to the Marginal Cost/Rate Design Settlement Agreement. The Streetlight Settlement Agreement uses the agreed revenue allocation and addresses rate design issues that were not resolved in that initial settlement.

7.1.4.1. Improved Network Controlled Dimmable Streetlight Rate 2014 Pilot Program

The Streetlight Settling Parties agreed that it is reasonable for the Commission to adopt a Network Controlled Dimmable Streetlight Rate 2014 Pilot Program (2014 Dimmable Pilot Program), which is set forth in detail in Appendix 1 to the Streetlight Settlement Agreement. The proposed 2014 Dimmable Pilot Program is a revision of the 2011 Dimmable Pilot Program the Commission adopted in PG&E's 2011 Phase 2 General Rate Case (D.11-12-053). The 2014 Dimmable Pilot Program will provide dimmable streetlight service as an option to Schedule LS-2 that is expected to be simpler and provide participants with some certainty that they will benefit from related energy savings in a timely and mutually workable way.

7.1.4.2. Streetlight Settlement Rates

The Streetlight Settling Parties agree that it is reasonable for the Commission to adopt rates Schedules LS-1, LS-2, LS-3, OL-1, and CCSF, set forth in Appendix 2 and Appendix 3 of the Streetlight Settlement Agreement. Appendix 2 of the Streetlight Settlement Agreement provides the non-energy facility charge rates for Schedules LS-1, LS-2, OL-1 and CCSF to be implemented over a three year period.

7.1.4.3. Schedule LS-1 LED Streetlight Conversion Program

In Phase I of PG&E's 2014 General Rate Case, PG&E proposed, and the Commission approved, an LED[3] Conversion Program to allow customers to elect to have PG&E replace existing PG&E-owned non- decorative High Pressure Sodium Vapor streetlights under Schedule LS-1 with more energy efficient LED technology. Under the program, eligible customers would pay a new, monthly incremental facility charge and the facility charge for Schedule LS-1 through the current rate case cycle, and would receive the benefit of lower total energy charges resulting from lower usage associated with LED technology. A determination of the need to continue the incremental facility charge would be made in PG&E's 2017 General Rate Case.

7.1.4.4. Schedule OL-1 Tariff Revisions

Currently, the non-energy and energy portions of the total lamp rate are presented separately for each lamp type in tariffs for Schedules LS-1 and LS-2. However, only the total lamp rate for each lamp type is presented in

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[3] Light-emitting Diode technology is commonly called LED.

Schedule OL-1 (i.e., energy and non-energy lamp rates are not separately listed). The Streetlight Settling Parties agree to align the presentation of rates in Schedules LS-1, LS-2 and OL-1 by modifying Schedule OL-1 to separately display the non-energy and energy portions of the total lamp rate. This change will allow PG&E the flexibility to introduce LED lamp types without overly complicating the lamp rate presentation format.

7.1.5. Amended E-Credit Rate Design Supplemental Agreement

Schedule E-CREDIT is a tariff that identifies what billing credit a Direct Access customer will receive if certain services (e.g., metering, billing, and/or customer inquiry services) are not provided by PG&E. The values are provided in Appendix A to the Amended E-CREDIT Rate Design Settlement.

7.1.6. Medium Commercial Rate Design Settlement Agreement

All relevant interested settling parties in this and the other settlement agreements addressed in this decision agreed that The Solar Energy Industries Association's proposal to allow Net Energy Metering customers that are on Schedule A-10-TOU to take service on Peak Day Pricing Rates should be litigated. Consequently, that issue is resolved separately elsewhere in this decision.

Within this settlement, the Settling Parties agreed to the following.

7.1.6.1. Illustrative Settlement Rates

Rates to collect the revenue allocated to the Medium Light and Power customer class under the Marginal Cost/Revenue Allocation Settlement Agreement shall be designed consistent with the illustrative settlement rates set forth in Appendix A to this Settlement Agreement.

7.1.6.2. Basic Rate Design

The basic rate design for each of the applicable medium commercial rate schedules will be updated upon implementation of this Medium Commercial Settlement Agreement, using the methods underlying development of the illustrative settlement rates for Schedules A-10 and A-10-TOU, as presented in Appendix A to the Settlement Agreement.

7.1.6.3. Medium Commercial Customer Charge

Retain the current customer charge for Schedules A-10 and A-10-TOU of $140 per month.

7.1.6.4. Medium Commercial Revenue Neutrality

Design Schedules A-10 and A-10-TOU on a revenue neutral basis.

Continue the current annual updates to revise the Peak Day Pricing rate credits for Schedule A-10-TOU to be revenue neutral, based on updated customer and sales forecasts and billing determinants.

7.1.6.5. Medium/Demand Charges

Schedule A-10 demand charges will be set based on the methods described in Exhibit PG&E-4, Chapter 5 at 5-7 to 5-8. Illustrative demand charges are based on the Marginal Cost/Revenue Allocation (MC/RA) Settlement Agreement.

7.1.6.6. Medium Commercial Energy Charges

Increase the Time of Use differentiation for Schedule A-10-TOU from approximately 3 cents per kWh (differential from summer on peak to off peak) to approximately 8 cents per kWh (differential from summer on peak to off peak) in the generation rate component.

Distribution and generation energy charge principles and seasonal relationships for Schedule A-10 are based upon PG&E's August 16, 2013 filed proposals and methods (*see* Exhibit PG&E-4 at 5-8, 5-9), as updated to reflect the MC/RA Settlement Agreement.

With rate changes for revenue requirement changes between General Rate Case Phase 2 proceedings, set the Time of Use pricing differentials for Schedule A-10-TOU to be equal (on a cents per kWh basis) to the differentials established in this Phase 2 decision.

7.1.6.6.1. Rate Programs

Continue the Schedule A-6 Net Energy Metering solar pilot for current load. New customers or additional load from existing customers may not be added to the pilot. After the Commission's decision on the Option R proposal in A.12-12-002, PG&E will address the status of this pilot and present its proposals for the future of this pilot in a subsequent Rate Design Window proceeding.[4] This A-6 Net Energy Metering solar pilot is for customers over 500 kW in size and is limited to 20 MW of solar capacity in total. It is completely subscribed.

A new rate, Schedule A-8, that is structured like Schedule A-6 (i.e., without demand charges) should not be made available to customers between 75 kW and 500 kW. This proposal was offered by Solar Energy Industries Association in conjunction with grandfathering certain customers that take Net Energy Metering service under Schedule A-6, if the Commission adopts a new eligibility threshold for Schedule A-6. The Solar Energy Industries Association's proposed Schedule A-8 would be a rate that is revenue neutral to Schedule A-10, but

[4] A final decision on Option-R was adopted in D.14-12-008.

structured as a Time of Use rate with no demand charge, similar to Schedule A-6. While the Medium Commercial Rate Design Settling Parties have agreed a new rate schedule as proposed by Solar Energy Industries Association should not be established, the question of allowing grandfathering of certain Net Energy Metering customers onto Schedule A-6 should be litigated.

7.1.6.6.2. Elimination of Flat Rates

Until the next General rate Case Phase 2 proceeding, continue the requirement that current/existing Time of Use customers must have 12 months of interval data before they are transitioned to mandatory Time of Use.

7.1.7. Small Commercial Rate Design Settlement Agreement

7.1.7.1. Overview

This is the settlement where parties focused the litigated dispute. Thus it is a partially contested settlement. The Settling Parties could not agree on whether Net Energy Metering customers currently taking service under Schedule A-6 (or currently planning to take service under Schedule A-6) should be allowed to retain Schedule A-6 even though they would not otherwise qualify for the schedule based on the new 75 kW eligibility threshold (proposed in the settlement); or agree whether Net Energy Metering customers should be allowed to take Peak Day Pricing service. Therefore, the Settling Parties agreed that these issues should proceed to litigation (which they did). SEIA, CALSEIA and BoDean Company chose not to join the Settlement Agreement and reserved the right to oppose the Settlement Agreement - they filed timely comments on the settlement and filed timely briefs on the litigated issues. The balance of this section summarizes the uncontested settled issues.

7.1.7.2. Illustrative Settlement Rates

Rates to collect the revenue allocated to the Small Light and Power customer class under the Settlement Agreement shall be designed consistent with the illustrative settlement rates set forth in Appendix A to this Settlement Agreement.

7.1.7.3. Basic Rate Design

The basic rate design for each of the applicable Small Commercial rate schedules will be updated upon implementation of this Settlement Agreement, using the methods underlying development of the illustrative settlement rates for Schedules A-1, A-1-TOU, A-6, A-15, TC-1, and E-CARE as presented in Appendix A to the Settlement Agreement.

7.1.7.4. Small Commercial Customer Charge

a. Retain the current $10/$20 single/polyphase customer charges for Schedules A-1 and A-6.

b. Continue the practice of using the Schedule A-1 single phase customer charge for Schedule A-15. Retain the current facility charge for Schedule A-15 (A-15 pays the single phase customer charge in addition to the A-15 facility charge).

c. Retain the current customer charge for Schedule TC-1 at $10.

7.1.7.5 Small Commercial Revenue Neutrality

a. Design Schedules A-1, A-1-TOU, A-6, and A-15 on a revenue-neutral basis. Continue the current practice for Schedule A-15 where the allocation for Schedule A-15 includes a revenue neutral allocation plus revenue from the $25 per month special facility charge for direct current service.

b. Design Schedule TC-1 rates based on the revenue allocated to Schedule TC-1 using the assumptions underlying the MC/RA Settlement Agreement. The bundled allocation to Schedule TC-1 is -2.74% based on the assumptions underlying the Marginal Cost/Revenue Allocation Settlement Agreement; however, the actual allocation to Schedule TC-1 may be somewhat different based on the then-required revenue and assumptions in effect at the time of settlement implementation.

c. Continue the current annual updates to revise the Peak Day Pricing rate credits for Schedules A-1-TOU and A-6 to be revenue neutral, based on updated customer and sales forecasts and billing determinants.

7.1.7.6. Small Commercial Energy Charges

a. Increase Time of Use differentials for Schedule A-1-TOU from approximately 3 cents per kWh (differential from summer on peak to off peak) to approximately 5 cents per kWh (differential from summer on peak to off peak) in the generation rate component.

b. Distribution and generation energy charges for Schedule A-6 will be established based on the same methods and rules underlying the illustrative rates provided in the Settlement's Appendix A.

c. With rate changes for revenue requirement changes occurring between General Rate Case Phase 2 proceedings, set the Time of Use pricing differentials for Schedules A-1-TOU, and A-6 to be equal (on a cents-per- kWh basis) to the Time of Use differentials established with implementation of this Phase 2 decision.

7.1.7.7. 75 kW Size Limitation for A-6

a. Revise the size threshold for Schedule A-6 to 75 kW, consistent with Schedule A-1. (This is one of the litigated issues; thus adopting the settlement and rejecting the opposition would result in this outcome.) The transfer of eligible customers on Schedule A-6 to an otherwise applicable schedule will begin on November 1, 2015, for customers with 12 months of interval data. The Settling Parties agree that, in addition to the normal process to default customers, customers subject to the change in the Schedule A-6 eligibility threshold will receive information by direct mail intended to explain the rate change and provide information on energy efficiency program opportunities and demand response options.

b. PG&E shall conduct a study of the following different potential eligibility thresholds for PG&E's next Phase 2 proceeding.

   - PG&E shall develop all information necessary for filing quality revenue allocation for hypothetical eligibility thresholds regarding Schedules A-1 and A-6 of 20 kW and of 50 kW.
   - PG&E shall develop billing determinants for the customers that are less than 20 kW; between 20 kW and 50 kW; and between 50 kW and 75 kW.
   - PG&E shall meet and confer with the Commission's Office of Ratepayer Advocates (ORA) no later than six weeks after this decision is adopted by the Commission to discuss an appropriate eligibility threshold. If ORA and PG&E cannot agree, PG&E will provide the information described above as part of its response to the ORA master data request.
   - As part of the above study, PG&E shall determine the customer type based on North American Industry Classification System code, where available and feasible, that fall within each of the hypothetical eligibility thresholds above (i.e., customers that are less than 20 kW; between 20 kW and 50 kW; and between 50 kW and 75 kW). In the size increments described above, PG&E shall develop billing data based on customer type, to the extent such information is available in PG&E's billing system. In conducting such analysis, PG&E will aggregate customer billing determinants by North American Industry Classification System code so parties can identify the

number and type of customers, including small businesses, in each size increment. PG&E will meet and confer with the Small Business Utility Advocates no later than six weeks after this decision is adopted by the Commission to discuss the matters in this paragraph and the progress in completing the analysis.

c. Schedule A-15 shall not be subject to a 75 kW eligibility threshold.

7.1.7.8. Elimination of Flat Rates

Until the next GRC Phase 2 proceeding, continue the requirement that current/existing non-Time of Use customers must have 12 months of interval data before they are transitioned to mandatory Time of Use rates.

7.1.7.9. E-CARE Rate Design

a. Continue to provide an annual average commercial CARE rate discount percentage that is commensurate with the annual average residential CARE rate discount percentage. The E-CARE discount will be billed on a cents per kWh basis at the rate value level appropriate to each applicable rate schedule.

b. Retain the current Schedule E-CARE zero minimum bill. However, if the Commission determines in the Residential Electric Rate Design Reform Proposal (Application 12-06-013) that the zero-minimum bill should not apply to residential rate schedules, PG&E shall file an advice letter to also eliminate the zero-minimum bill for Schedule E-CARE.

c. Update Schedule E-CARE discounts to reflect revised residential CARE discounts resulting from changes to residential rates in future proceedings.

7.1.8. Agricultural Rate Design Settlement

7.1.8.1. Summary

The Agricultural Settlement Agreement uses the revenue allocation agreed to in the MC/RA Settlement Agreement, and addresses certain rate design issues that were not resolved in that initial settlement. Specifically, any revenue loss from the transfer of customers to TOU rates or from any load aggregation proposals that may be adopted will not result in inter-class revenue transfers.

7.1.8.2. Collaborative Process for Agricultural Rate Design Prior to Next Phase 2

The parties have agreed to a specific collaborative process to be used to develop new agricultural rate design proposals.

7.1.8.3. Basic Agricultural Rate Designs and Illustrative Settlement Rates

Rates designed to collect the revenue allocated to the agricultural customer class under the Marginal Cost/Revenue Allocation Settlement Agreement shall be designed consistent with the illustrative settlement rates set forth in Appendix A to this Settlement Agreement. Appendix A of the Agricultural Settlement includes illustrative settlement rates for Schedules AG-1A/B, AG-4A/B/C, AG-5A/B/C, AG-RA/B, AG-VA/B, and E-37.

7.1.8.3.1. Customer Charge

The Agricultural Settling Parties agree it is reasonable for agricultural rate designs to increase all current fixed monthly customer charges by the agricultural bundled class average percentage change. Customer charges will continue to be billed on a daily equivalent basis.

7.1.8.3.2. Demand Charge

The Agricultural Settling Parties agree that it is reasonable to increase total bundled demand charges by an amount approximately equal to the agricultural bundled class average percentage change, while also achieving the capped schedule average total increase for Direct Access and Community Choice Aggregation customers. The changes to Distribution and Generation demand charges at the schedule level will be consistent with the revenue changes to the Distribution and Generation allocations at the overall agricultural class level contained in the Marginal Cost/Revenue Allocation Settlement Agreement.

7.1.8.3.3. Energy Charges

The Settling Parties agree to increase total bundled energy charges by an amount approximately equal to the agricultural bundled class average percentage change, while also achieving the capped schedule average total increase for Direct Access/Community Choice Aggregation customers. The changes to Distribution and Generation energy charges at the schedule level will be consistent with the revenue changes to the Distribution and Generation allocations at the overall agricultural class level contained in the Marginal Cost/Revenue Allocation Settlement Agreement. The increases to Public Purpose Program energy charges at the schedule level will be consistent with the revenue changes to the Public Purpose Program revenue allocated at the overall agricultural class level contained in the Marginal Cost/Revenue Allocation Settlement Agreement. While total customer charge and demand charge increases based upon the combined Distribution and Generation changes as applicable will generally approximate the class average bundled change, the total energy charge changes may deviate slightly more, but will be designed to be as uniform as possible subject to the revenue and rate design constraints applicable for bundled and Direct Access/Community Choice Aggregation customers.

7.1.8.4. Schedules AG-R and AG-V

Although PG&E received approval in D.11-12-053 to eliminate Schedules AG-R and AG-V to simplify and streamline the number of agricultural rate schedules beginning in March 2014, on February 6, 2014, there was a one-year deferral until March 2015. The Settling Parties agree that the elimination of these schedules should be further delayed pending further discussions about overall agricultural rates.

7.1.8.5. Schedule E-37 Elimination

Schedule E-37 shall be terminated for customers with 12 months of interval data beginning on November 1, 2017. Beginning November 1, 2017, or with each successive November 1, Schedule E-37 customers shall be transferred to their otherwise applicable commercial or industrial rate schedule. Customer notification shall utilize the standard customer notification process and billing system platforms and protocols as applicable to the general small and medium business annual November transition window for time-varying pricing.

7.1.8.6. Time of Use Revenue Neutrality

The settlement details the process whereby time of use rates remain neutral, i.e., do not otherwise change the revenue recovery by PG&E or impose costs on other customers.

7.1.8.7. Retain the 12-Month Interval Data Requirement for Transition to Mandatory Time of Use

The Settling Parties agree to retain the 12-month interval data requirement before an existing non-Time of Use customer must transition to service on a TOU schedule. Any change is deferred to PG&E's 2017 Phase 2 proceeding

7.1.8.8. Agricultural Internal Combustion Engine Conversion Incentive Rate

The Agricultural Internal Combustion Engine Conversion program, which provides rate discounts to customers who shift from diesel to electric generation for water pumping, expires for existing participants at the end of 2015. The Settling Parties believe there are numerous benefits to continuing this program. Therefore, the Settling Parties agree to address these issues expeditiously in 2015.

7.1.8.9. Peak Day Pricing Updates

The parties agreed to PG&E's proposals for Peak Day Pricing updates to Schedules AG-4A, AG-4C, and AG-5C. These proposals are limited to continuing the annual adjustments to Peak Day Pricing rate credits to conform rates to updated customer and sales forecasts and billing determinants, as proposed in Exhibit PG&E-7.

8. Disputed Issues

8.1. Summary

8.1.1. Adopting a Modified Settlement with Litigated Issues

In summary we adopt the settlements described above except for the specific adjustments we make below based upon the litigated outcome on these limited issues. Generally the Commission gives deference to settlements; more so when all-party, but only when the settlements comport with the settlement rules and are found to be in the public interest. Here we had a large number of parties who self-selected into a series of settlements (*see* Attachment 1). Most agreed with the outcome of every issue where they participated and the settlements collectively resolve the entire proceeding. But a small group of closely aligned parties aggressively litigated a number of issues for solar customers and the solar industry who would benefit as a result of favorable rates for solar customers. We note that a large and broadly representative group of intervenors has otherwise settled all issues, and we note that ORA as well as TURN, who both take a very broad perspective, would have settled all issues. Therefore we look for instances where these few narrow-interest parties raise compelling arguments that would lead us to altering the settlements.

We describe our resolution of the disputed issues in detail below. In summary, we modify schedule A-6 as proposed by PG&E. However, all current A-6 customers may continue to take service on the schedule in its unmodified form. We close the tariff to new customers as of December 31, 2016 in order to allow a transition period for customers who are contemplating taking service under the current eligibility rules. This will allow us to thoroughly evaluate the results of the comprehensive review of small and medium commercial customer rates that we order elsewhere in this decision. We determine that customers of any eligible class who are on a net-energy metering rate are also eligible to default to Peak-Day Pricing. Finally, we determine that a demand charge is still appropriate, and we adopt one herein to the extent it is consistent with the proposed settlement. We otherwise find any other objections to the settlements to be not persuasive and we adopt the balance of the settlements as filed unless specifically modified.

8.1.2. Subsequent Filing of a Detailed Analysis of Small and Medium Commercial Customers

Because of the continued litigation of certain issues regarding PG&E's small and medium commercial classes over this and prior proceedings, PG&E shall file a study in its upcoming GRC Phase 2 application, addressing these issues as detailed below.[5] PG&E shall prepare a comprehensive study taking into consideration all of the then-current rate design decisions, including this one, that affect the rates of small and medium commercial customers. In particular, we expect an exhaustive examination on the question of the relevant and appropriate demand charge or charges, if any, that should be imposed on small and medium commercial customers depending on their level and pattern of demand. We reiterate that this study should comprehensively analyze cost allocation and rate design within the small and medium commercial classes. We are determined that PG&E must use a sufficiently large data set for its analysis of these classes. This should limit parties arguing that the data is too limited to allow for a meaningful analysis and policy debate. We take note for example of the recent "Option R" decision, D.14-12-080, where there was a substantial disagreement over the sufficiency of the data set used in the proceeding. Further, PG&E must use a sufficient data sample – of both the number of customers and of data points of both demand and consumption – to adequately support a fair and reasonable rate design for these classes. This class study must also justify the appropriate demand limit for Schedule A-6.

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[5] PG&E states in comments on the proposed decision that it will file its GRC Phase 2 application on March 31, 2016. Based on the scoping memo in Rulemaking 14-07-002, we expect that the Commission will have adopted its new policy for Net Energy Metering prior to this date.

Comments on the proposed decision revealed that parties hold varied opinions regarding the appropriate scope and content of the study described above. To ensure that PG&E addresses these concerns while also delivering the comprehensive and exhaustive study we order herein, PG&E shall (1) schedule a "meet and confer" session with parties to this proceeding, to take place within 30 days of the effective date of this decision, and (2) file a Tier 2 Advice Letter 45 days from the effective date of this decision, providing a detailed plan for the study, including a description of the data that will be analyzed. This will afford interested parties the opportunity to influence study design and to comment upon a final proposal before PG&E begins its study. PG&E shall not proceed with its proposed study until the Advice Letter is approved by the Commission's Energy Division.

8.2. Size Limit on A-6 Eligibility

PG&E proposes to reduce eligibility for Schedule A-6 to maximum demands of 75 kW; the current maximum demand level is 500 kW. Customers with demands between 75 kW and 500 kW would instead take service on demand-metered Medium Light & Power (ML&P) Schedules A-10 or E-19.[6] According to PG&E, reducing the demand limit for Schedule A-6 is appropriate because Schedule A-6 is designed on a revenue neutral basis with Schedule A-1 and should therefore incorporate the same eligibility requirements. PG&E also notes that 20 kW is already the cutoff between the Small Light & Power (SL&P)

[6] Exhibit PG&E-1 at 4-5.

and ML&P classes for both Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E).[7]

PG&E describes Schedule A-6 as an almost entirely volumetric rate, with low customer charges, and no demand charges, while, in contrast, Schedules A-10 and A-10-TOU include modest demand charges and higher customer charges commensurate with the Medium Light and Power class.[8] According to PG&E,

> Schedule A-10 is more accurate than Schedule A-6 in accounting for these non-coincident loads because it has a demand charge that specifically charges for these non-coincident loads. In contrast, Schedule A-6 does not specifically charge for non-coincident loads and can only collect the costs on an average basis, which assumes that the entire class has typical usage. That assumption is inaccurate for solar customers[footnote omitted] who do not place "average" demands on the infrastructure because their load shape typically goes from positive to negative to positive during the summer. As a result, the average distribution costs that are rolled into the A-6 volumetric rates remain uncollected when solar production supplants usage. This makes volumetric TOU rates a poor choice for collecting non-coincident distribution costs.[9]

SEIA and CALSEIA oppose PG&E's proposal to reduce the demand limit on Schedule A-6, arguing that existing solar customers took service from PG&E on Schedule A-6 in good faith and in reliance upon the availability of the schedule when they elected to install solar. While we are sympathetic to this point, no customer is ever guaranteed that any rate schedule will remain unchanged indefinitely. We do not accept the proposal of SEIA and CALSEIA

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[7] PG&E Opening Brief at 6. PG&E's schedule A-1 is PG&E's "Small General Service" tariff.

[8] *Id.* at 9.

[9] *Id.* at 15.

for a new schedule, A-8, because this appears to be the old A-6 with a new label. We conclude that PG&E's testimony has demonstrated the need to change Schedule A-6, at least prospectively. Therefore we will close Schedule A-6 to all new customers with demands above 75 kW.[10]

In comments on the proposed decision, SEIA and CALSEIA argued that the proposed decision's direction that Schedule A-6 should be closed "as of the effective date of this decision" was unfair in that it did not take into account the customers who are in the midst of installing solar projects and based their decision to do so on their expectation of taking service on Schedule A-6. SEIA and CALSEIA present reasonable arguments for the creation of some sort of transition period for these customers so that they may complete their investments as planned. CALSEIA suggests a 14-month transition period, while SEIA suggests an 18-month period, where the customer will be eligible for the rate schedule irrespective of whether the customer commences service under that schedule before the termination of the transition period, so long as the customer submits a written request to PG&E for service under the rate schedule anytime within the 18-month period.[11] PG&E dismisses these suggestions, and simply requests that the proposed decision be clarified to state that PG&E should treat any customer who has requested to switch to Schedule A-6 prior to the effective date of the final decision as an "existing customer."

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[10] The proposed decision ordered PG&E to create two A-6 tariffs, one being the current A-6, and another called "A-6-N". In comments on the proposed decision, PG&E recommended that the Commission should instead simply allow the changed eligibility requirements for new A-6 customers to be set out in the tariff. We agree that this is a more straightforward approach and have changed the proposed decision accordingly.

[11] SEIA Opening Brief at 3.

We are convinced by CALSEIA and SEIA that the proposed decision's creation of a cutoff in eligibility coincident with the effective date of this decision was too abrupt, given the realities of solar project development as described by CALSEIA and SEIA. Instead, we create a transition period for prospective customers that shall terminate on December 31, 2016. Any customer who sends PG&E a letter (via certified mail with a return receipt to establish a delivery record) requesting a rate change on or before the cutoff date shall be allowed to take service on Schedule A-6. We select this cutoff date for two reasons. First, this period should be sufficient for any eligible customers who are contemplating or in the midst of developing a solar project, to make an informed decision based on the certainty of the availability of that rate. Second, the study we direct PG&E to undertake regarding its small and medium commercial customers should be completed well before that date, so the likely otherwise available rate options and the rationale for these options (if PG&E prepares a thorough and credible study) should be clear to the affected customers.

8.3. Peak Day Pricing

In D.06-05-038, the Commission directed the utilities "to incorporate default critical peak pricing tariffs for large customers into their next comprehensive rate design proceeding or other appropriate proceeding if directed by the Commission."[12] This rate is intended to offer a rate inducement to reduce load on the days when demand and therefore marginal cost are the highest. As such it is a demand response mechanism that can be layered onto rates for customers who already have a specialized rate design which encourages

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[12] D.06-05-038 at 16.

them at all times to minimize peak consumption and for solar customers to maximize the net energy produced and delivered into the grid. With respect to the assertion by SEIA and CALSEIA that Peak Day Pricing should be added on top of Net Energy Metering, we agree they have a statutory right to the option. (Pub. Util. Code § 2827.)[13]

We find that Peak Day Pricing is a ratesetting device intended to encourage conservation on those peak days when energy costs spike upwards. Peak Day Pricing is an available default rate, so it can in fact be used here in conjunction with Net Energy Metering.[14] We therefore adopt this position to the extent that it modifies the otherwise proposed settlement for any eligible Net Energy Metered customer.

8.4. Demand Charge vs. All-Volumetric Rates

PG&E defends its proposal to shift customers with demands between 75 kW and 500 kW to rate schedules that feature demand charges, by arguing

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[13] Pursuant to D.10-02-032, as modified by D.11-11-008, small and medium agricultural customers are only defaulted to TOU. They do not default to PDP.

[14] Net Energy Metering was designed to specifically comply with legislation that set specific parameters for compensating customers whose on-site generation provides energy to the grid. The legislative purpose was to stimulate investment in renewal generation. D.11-06-016 states:

> "Assembly Bill (AB) 920 amends Pub. Util. Code § 2827 and requires the Commission to establish a program to compensate net energy metering … customers for electricity produced in excess of on-site load at the end of a 12 month true-up period. In enacting AB 920, the Legislature stated that [a net energy metering] program combined with net surplus compensation … is one way to encourage substantial private investment in renewable energy resources, stimulate in-state economic growth, and reduce demand for electricity during peak consumption periods. " (Section 2827(a).)

that demand charges serve two key purposes.[15] First, they appropriately reflect cost causation. Capacity-related costs are the result of the infrastructure such as generators, transmission lines, substations, circuits and final line transformers that must be put in place so that electricity can be generated and distributed to customers. These infrastructure costs are not driven by kWh sales volumes. Instead, facilities must be sized so that they are sufficient to meet each customer's kW demands during all time periods, including those periods in which demand is the highest. Because kW demand, not kWh usage, is the driver of these costs, volumetric rates (i.e., rates in units of cents per kWh) do not properly capture these costs. Second, demand charges are a tool to help reduce demand by providing an incentive for customers on Time of Use demand schedules to limit their demands during particular periods when generation costs are highest.

It is, according to PG&E, a long-established California ratemaking practice that each utility's most fully cost-based tariffs apply to service the largest electric customers.[16] The Commission's policy supporting demand charges for large customers dates back to the mid-1970s. (PG&E cites to D.87745, D.89711, and D.85-08-017.) Thus, for decades, the Commission has used demand charges to collect capacity-related costs, since doing so is consistent with cost-based rate design. Marginal distribution and generation capacity costs are measured in units of dollars per kW. Rate design based on marginal costs establishes demand charges (in units of dollars per kW) for these services. The rates applicable under Schedules A-10 and E-19 are closer to fully cost-based in this regard. PG&E

[15] PG&E Opening Brief at 9-10.

[16] I*d.* at 10.

argues that neither the passage of time nor the evolution of the solar market has changed these rate design principles.

AB 327 directed the Commission to develop a successor tariff to the current Net Energy Metering structure, and to develop a transition period for customers interconnecting prior to the transition date. By D.14-03-041, the Commission set that transition period at 20 years from interconnection. However, this means that existing Net Energy Metering customers will remain on current Net Energy Metering, that is, they will be exempt from standby and most interconnection charges, and will receive a full retail credit for all exports. That decision did not exempt such customers from rate changes for the next 20 years. PG&E argues the decision noted that under its own study of the cost shifts associated with Net Energy Metering:

> "the analysis suggests that [Net Energy Metering] generation currently results in a net cost of $79 to $252 million, with these additional net costs subsidized by other ratepayers (i.e., those not participating in Net Energy Metering), reaching costs of $370 million to $1 billion per year in 2020 with a complete build out of systems to the 5 percent Net Energy Metering program transition trigger level. The report also notes that the costs of Net Energy Metering are largely a function of retail rate designs, and that any future changes to the rate structure would have a significant impact on the results."
> (D.14-03-041 at 7.)

PG&E also argues that the Commission stated in D.14-03-041 that it intended to address the Net Energy Metering cost shift associated with existing customers through changes in rate design, clearly indicating that existing Net Energy Metering customers will not be exempt from rate changes.

Thus we find that the continued reliance on demand charges as provided in the Small Commercial Rate Design Settlement Agreement and the Medium

Commercial Rate Design Settlement Agreement is reasonable. We were not persuaded by the solar industry advocates to create a new schedule without a demand charge, and thereby shift costs to other customers. As we noted earlier, as part of the study of the small and medium commercial classes that we order PG&E to submit in its upcoming GRC Phase 2 application, questions regarding demand charges can be further analyzed with respect to whether they would or should apply to all customers in these classes.

9. Comments on Proposed Decision

The proposed decision of Administrative Law Judge Long in this matter 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 July 13, 2015, by PG&E, ORA, SEIA, CALSEIA, Small Business Utility Advocates, and Marin Clean Energy. Reply comments were filed on July 20, 2015 by PG&E, SEIA, Small Business Utility Advocates, California Farm Bureau Federation, and the California Large Energy Consumers Association.

Pursuant to Rule 14.3 (c), comments shall focus on factual, legal or technical errors in the proposed decision and in citing such errors shall make specific references to the record or applicable law. Comments which fail to do so will be accorded no weight. Comments proposing specific changes to the proposed or alternate decision shall include supporting findings of fact and conclusions of law.

Substantively, comments and reply comments focused on the areas of the proposed decision that addressed PG&E's A-6 rate, the eligibility of NEM customers for PG&E's PDP rate, and the requirement that PG&E conduct a study of its small and medium commercial classes and associated rate design. The proposed decision has been revised in each of these areas to address parties' comments. Our reasoning for doing so is provided in each section of the decision.

In addition to the substantive changes described above, the proposed decision has been revised to correct typographical errors and clarify wording throughout the document.

10. Assignment of Proceeding

Michael Picker is the assigned Commissioner and ALJ Douglas M. Long is the presiding officer.

Findings of Fact

1. There is a full and complete record composed of all filed documents and all exhibits received into evidence, as well as the transcripts of all hearings.
2. The parties engaged in extensive discovery, litigation, and settlement.
3. The parties to the settlements adopted in this decision had a sound and thorough understanding of the application, and all of the underlying assumptions and data included in the record and could make informed decisions in the settlement process.
4. The adopted settlements are between competent and well-prepared parties who were able to make informed choices in the settlement process.
5. The schedule in the Marginal Cost and Revenue Allocation Settlement for holding a workshop on Agricultural Class Balancing Account Study cannot be met. PG&E has proposed, and no party has objected to, a revised schedule with the workshop to occur within 6 weeks of the decision, with the draft report due by September 30, 2015, and the final report completed by December 30, 2015.
6. The schedule in the Small Commercial Rate Design Settlement for conferring with the Office of Ratepayer Advocates and the Small Business Utility

Advocates on certain small light and power eligibility thresholds and analysis cannot be met. PG&E has proposed that the deadlines for these meetings be changed to no later than six-weeks after the decision. PG&E has conferred with the parties and there are no objections.

7. The A-6 rate was adjusted by settlement but opposed by some parties.

8. Closing A-6 to new customers would not harm existing A-6 customers.

9. Peak Day Pricing would encourage further conservation by Net Energy Metering customers.

10. Demand charges allocate infrastructure costs to customers.

11. Net energy metering customers contribute to the need for infrastructure recovered in demand charges.

12. A detailed study of the small commercial and industrial class would determine the reasonable cost allocation and any need for demand charges.

Conclusions of Law

1. Applicant alone bears the burden of proof to show that its proposals are reasonable.

2. The revised schedule presented in PG&E's comments on the proposed decision for the Agricultural Class Balancing Account study workshop and report is reasonable.

3. The revised schedule presented in PG&E comments on the proposed decision for conferring with the Office of Ratepayer Advocates and the Small Business Utility Advocates over topics specified in the Small Commercial Rate Design Settlement is reasonable.

4. The rate design and cost allocation settlements are reasonable because they fairly balance intervenor interests and provide sufficient revenue to safely provide reliable service.

5. The adopted settlements provide sufficient information for the Commission to discharge its future regulatory obligations.

6. It is reasonable to close the existing A-6 tariff to new customers with demand above 75 kW, while also creating a transition period to allow customers considering taking service on the A-6 tariff to complete their decision-making process.

7. Peak Day Pricing is a default rate option that should be available to net energy metering customers.

8. Demand charges fairly allocate infrastructure costs to customers.

9. Net energy metering customers contribute to the need for infrastructure recovered in demand charges and should pay demand charges.

10. A data rich and detailed small commercial and industrial customer class cost study would determine the reasonable allocation of costs and any need for demand charges in rates.

11. Any pending motions are unnecessary to resolve this proceeding and should be denied.

12. The proceeding should be closed.

O R D E R

IT IS ORDERED that:

1. The July 16, 2014 Motion of Pacific Gas & Electric Company (PG&E) and other settling parties to Approve a Settlement Agreement on Marginal Cost and Revenue Allocation Issues, is granted. PG&E shall make any necessary filings to implement the specific terms of the Settlement Agreement as one or more Tier 1 advice letters.

2. The July 24, 2014 Motion of Pacific Gas & Electric Company (PG&E) and other settling parties to Approve Residential Rate Design Supplemental Settlement Agreement, is granted. PG&E shall make any necessary filings to implement the specific terms of the Settlement Agreement as one or more Tier 1 advice letters.

3. The July 25, 2014 Motion of Pacific Gas & Electric Company (PG&E) and other settling parties to Approve Large Light and Power Rate Design Settlement Agreement, is granted. PG&E shall make any necessary filings to implement the specific terms of the Settlement Agreement as one or more Tier 1 advice letters.

4. The August 29, 2014 Motion of Pacific Gas & Electric Company (PG&E) and other settling parties to Approve Streetlight Rate Design Supplemental Settlement Agreement, is granted. PG&E shall make any necessary filings to implement the specific terms of the Settlement Agreement as one or more Tier 1 advice letters.

5. The March 30, 2015 Motion of Pacific Gas & Electric Company (PG&E) and other settling parties to Approve the Amended E-Credit Rate Design Supplemental Agreement, is granted. PG&E shall make any necessary filings to implement the specific terms of the Settlement Agreement as one or more Tier 1 advice letters.

6. The September 5, 2014 Motion of Pacific Gas & Electric Company (PG&E) and other settling parties to Approve Medium Commercial Rate Design Settlement Agreement, as modified in Section 8 of this decision, is granted. PG&E shall make any necessary filings to implement the specific terms of the Settlement Agreement as one or more Tier 1 advice letters.

7. The September, 5, 2014 Motion of Pacific Gas and Electric Company (PG&E) and other settling parties to Approve Small Commercial Rate Design Settlement Agreement, as modified in Section 8 of this decision, is granted. PG&E shall make any necessary filings to implement the specific terms of the Settlement Agreement as one or more Tier 1 advice letters.

8. The December 2, 2014 Motion of Pacific Gas & Electric Company (PG&E) and other settling parties to Approve Agricultural Rate Design Settlement Agreement, is granted. PG&E shall make any necessary filings to implement the specific terms of the Settlement Agreement as one or more Tier 1 advice letters.

9. Pacific Gas & Electric Company (PG&E) shall make any necessary filings to implement the specific terms of this decision as one or more Tier 1 advice letters. Specifically:

a. The current A-6 tariff is closed to new customers with demand above 75 kW, subject to a transition period;

b. A transition period is created such that any customer who sends PG&E a letter (via certified mail with a return receipt to establish a delivery record) requesting a rate change on or before December 31, 2016 shall be allowed to take service on Schedule A-6; and

c. Net-energy metered customers shall be eligible for Peak-Day Pricing as a default rate option.

10. Pacific Gas & Electric Company (PG&E) shall file a data-rich analysis of the Small and Medium Commercial classes in its upcoming General Rate Case Phase 2 application. PG&E shall (1) schedule a "meet and confer" session with parties to this proceeding, to take place within 30 days of the effective date of this decision, and (2) file a Tier 2 Advice Letter 45 days from the effective date of this decision, providing a detailed plan for the study, including a description

of the data that will be analyzed. PG&E shall not proceed with its proposed study until the Advice Letter is approved by the Commission's Energy Division.

11. Any pending motions are deemed denied.
12. Application 13-04-012 is closed.

This order is effective today.

Dated August 13, 2015, at San Francisco, California.

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
LIANE M. RANDOLPH
Commissioners

Attachment 1

Application 13-04-012, PG&E 2014 GRC Phase 2 Proceeding: Party Status by Settlements – April 6, 2015

APPLICATION 13-o4-012,PG&E 2014 GRC II PROCEEDING:PARTY STATUS BY SETTLEMENTS April6,2015

Party	MARGINAL COST AND REVENUE ALLOCATION SETILEMENT	LARGE LIGHT AND POWER RATE DESIGN SETILEMENT	RESIDENTIAL RATE DESIGN SUPPLEMENTAL SETILEMENT	E-CREDIT RATE DESIGN SUPPLEMENTAL SETILEMENT	MARCH 30,2015 E-CREDIT RATE DESIGN AMENDED SUPPLEMENTAL SETILEMENT	STREETLIGHT RATE DESIGN SETILEMENT	MEDIUM COMMERCIAL RATE DESIGN SETILEMENT	SMALL COMMERCIAL RATE DESIGN SETILEMENT	AGRICULTURAL RATE DESIGN SETILEMENT
PG&E	YES	YES	YES	YES	YES	YES	YES	YES	YES
AECA	YES	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	YES
BODEAN	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	OPPOSE	OPPOSE	DID NOT PARTICIPATE
CAL-5EIA	NOT OPPOSED	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	WITHDREW	OPPOSE	DID NOT PARTICIPATE
CAL-SLA	YES	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	YES	WITHDREW	YES	DID NOT PARTICIPATE
CFBF	YES	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DIDNPT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	YES
CLECA	YES	YES	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE

APPLICATION 13-04-012,PG&E 2014 GRC II PROCEEDING: PARTY STATUS BY SETTLEMENTS April6,2015

Party	MARGINAL COST AND REVENUE ALLOCATION SETTLEMENT	LARGE LIGHT AND POWER RATE DESIGN SETTLEMENT	RESIDENTIAL RATE DESIGN SUPPLEMENTAL SETTLEMENT	E-CREDIT RATE DESIGN SUPPLEMENTAL SETTLEMENT	MARCH 30,201S E-CREDIT RATE DESIGN AMENDED SUPPLEMENTAL SETTLEMENT	STREETLIGHT RATE DESIGN SETTLEMENT	MEDIUM COMMERCIAL RATE DESIGN SETILEMENT	SMALL COMMERCIAL RATE DESIGN SETTLEMENT	AGRICULTURAL RATE DESIGN SETTLEMENT
CLFP	YES	DID NOT PARTICIPAT	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPAT	DID NOT PARTICIPATE
CMTA	YES	YES	DID NOT PARTICIPATE	WITHDREW	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPAT	DID NOT PARTICIPATE
DACC	YES	NOT OPPOSE	DID NOT PARTICIPATE	YES	YES	DID NOT PARTICIPATE	WITHDREW	WITHDREW	DID NOT PARTICIPATE
EPUC	YES	YES	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPAT	YES
EUF	YES	YES	DID NOT PARTICIPATE	YES	YES	DID NOT PARTICIPATE	YES	YES	DID NOT PARTICIPATE
FEA	YES	YES	DID NOT PARTICIPATE	YES	YES	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPAT	DID NOT PARTICIPATE
MCE	NOT OPPOSED	DID NOT PARTICIPAT	YES	DID NOT PARTICIPATE	*DID NOT PARTIC/PATE*	DID NOT PARTICIPATE	WITHDREW	YES	DID NOT PARTICIPATE
MMID	NOT OPPOSED	DID NOT PARTICIPAT	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPAT	DID NOT PARTICIPATE

APPLICATION 13-04-012, PG&E 2014 GRC II PROCEEDING: PARTY STATUS BY SETTLEMENTS April6,2015

Party	MARGINAL COST AND REVENUE ALLOCATION SETTLEMENT	LARGE LIGHT AND POWER RATE DESIGN SETTLEMENT	RESIDENTIAL RATE DESIGN SUPPLEMENTAL SETTLEMENT	E-CREDIT RATE DESIGN SUPPLEMENTAL SETTLEMENT	March 30,2015 E-CREDIT RATE DESIGN AMENDED SUPPLEMENTAL SETTLEMENT	STREETLIGHT RATE DESIGN SETTLEMENT	MEDIUM COMMERCIAL RATE DESIGN SETTLEMENT	SMALL COMMERCIAL RATE DESIGN SETTLEMENT	AGRICULTURAL RATE DESIGN SETTLEMENT
ORA	YES	DID NOT PARTICIPATE	YES	WITHDREW	DID NOT PARTICIPATE	DID NOT PARTICIPATE	WITHDREW	YES	DID NOT PARTICIPATE
SEIA	NOT OPPOSED	NOT OPPOSED	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	OPPOSED	OPPOSED	DID NOT PARTICIPATE
SBUA	YES	YES	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	WITHDREW	YES	DID NOT PARTICIPATE
CCSF	NOT OPPOSED	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	YES	DID NOT PARTICIPATE	DID NOT PARTICIPAT	DID NOT PARTICIPATE
TURN	YES	DID NOT PARTICIPATE	YES	YES	YES	DID NOT PARTICIPATE	WITHDREW	YES	DID NOT PARTICIPATE
WMA	YES	DID NOT PARTICIPATE	YES	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPATE	DID NOT PARTICIPAT	DID NOT PARTICIPATE

(END OF ATTACHMENT 1)