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505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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May 22, 2015

TO PARTIES OF RECORD IN RULEMAKING 12-06-013

Enclosed is the Alternate Proposed Decision of Commissioner Florio to the Proposed Decision of Administrative Law Judges (ALJ) McKinney and Halligan previously mailed to you. This cover letter explains the comment and review period and provides a digest of the alternate decision.

When the Commission acts on this agenda item, it may adopt all or part of it as written, amend or modify it, or set aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Public Utilities Code Section 311(e) requires that an alternate to a proposed decision or to a decision subject to subdivision (g) be served on all parties, and be subject to public review and comment prior to a vote of the Commission.

Parties to the proceeding may file comments on the alternate proposed decision as provided in Article 14 of the Commission's Rules of Practice and Procedure (Rules), accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3 opening comments shall not exceed 25 pages.

Comments must be filed pursuant to Rule 1.13 either electronically or in hard copy. Comments should be served on parties to this proceeding in accordance with Rules 1.9 and 1.10. Electronic and hard copies of comments should be sent to ALJ McKinney at jmo@cpuc.ca.gov, ALJ Halligan at jmh@cpuc.ca.gov,and Commissioner Florio's advisor Jessica Hecht at jhe@cpuc.ca.gov. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ MARYAM EBKE for
Karen V. Clopton, Chief
Administrative Law Judge

KVC:jt2

Attachment

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ATTACHMENT

DIGEST OF DIFFERENCES BETWEEN THE PROPOSED DECISION OF ADMINISTRATIVE LAW JUDGES MCKINNEY AND HALLIGAN AND THE ALTERNATE PROPOSED DECISION OF COMMISSIONER FLORIO

Pursuant to Public Utilities Code Section 311(e), this is the digest of the substantive differences between the proposed decision of Administrative Law Judges McKinney and Halligan, mailed on April 21, 2015, and the alternate proposed decision of Commissioner Florio, mailed on May 22, 2015.

The ALJs' Proposed Decision (PD) would adopt a residential rate structure that reduces the number of usage tiers from the current 4 down to 2, with lower rates for usage up to a customer's baseline quantity, and slightly higher rates for usage above that baseline, setting the difference between the tiers at a ratio of 1:1.2. The PD establishes a minimum bill amount of $5 for CARE customers and $10 for non-CARE customers, and endorses the concept of monthly fixed charges, to take the place of minimum monthly bill amounts in 2019. The PD also defines outreach, education, and other goals to be met over the next several years, after which utilities would be expected to transition to default time of use (TOU) rates for their residential customers.

The Alternate Proposed Decision (APD) of Commissioner Florio would instead approve the following:

- Transition by 2018 to a rate structure with three usage tiers, with a differential of 33% between the rates for each tier. The first tier rate would apply to baseline usage, with progressively higher rates for additional usage above baseline, and above twice baseline.
- Adopt a $10 minimum bill for non-CARE residential customers ($5 for CARE customers), as in the PD, but unlike in the PD there would be no transition to a monthly fixed charge in the foreseeable future.
- Extend to 2020 the transition period for reaching the statutorily mandated CARE discount rate of 35%.
- Establish a goal of implementing default TOU for residential customers in 2019, similar to the PD. Most TOU rates would include both a baseline credit and an excess consumption surcharge.
- Change the calculation of the Family Electric Rate Assistance discount to equal 20% off of Tier 2 usage for qualifying customers.
- Various additional changes to discussion and analysis consistent with these outcomes

(END OF ATTACHMENT)

Decision **ALTERNATE PROPOSED DECISION OF COMMISSIONER FLORIO (Mailed 5/22/2015)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

(See Service List for Appearances)

DECISION ON RESIDENTIAL RATE REFORM FOR PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY AND TRANSITION TO TIME-OF-USE RATES

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DECISION ON RESIDENTIAL RATE REFORM FOR PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY AND TRANSITION TO TIME-OF-USE RATES

1. Summary

California has long been a front-runner in developing and implementing innovative policies to make energy use cleaner and more efficient, and the current imperative to reduce Greenhouse Gas (GHG) emissions as rapidly as reasonably possible only heightens the necessity for maintaining and expanding on such policies. Also, in recent years, our residential ratepayers invested billions in the largest installation of advance metering infrastructure (AMI) in the country.

This decision marks the culmination of a three-year long examination of proposed rate reforms for the three major investor-owned utilities in California, a critical first step in the process of optimizing use of this installed AMI and new energy efficiency technologies. The policies that we adopt today both reaffirm our historical rate design principles and recognize new realities that require change. Meaningful incentives for conservation and energy efficiency remain the touchstone of our rate design approach. We also expect that the movement toward time-of-use (TOU) rates that we initiate today will reduce overall electricity costs for all customers in the long-term.

This decision balances the need for further rate relief for customers who have experienced high and volatile bills in the recent past with the essential principle that rates should be designed to encourage the most efficient use of energy possible. We further recognize the need for customer acceptance and understanding of rate changes as well as the other rate design principles developed in this proceeding. We direct Pacific Gas and Electric Company,

Southern California Edison Company, and San Diego Gas & Electric Company to take the next steps in residential rate reform. This reform is intended to make rates more understandable to customers, and to encourage residential customers to shift usage to times of day that support a cleaner more reliable grid, while maintaining strong conservation/efficiency signals.

We find that we need not choose between rates that encourage reduced use of energy (tiered rates) and those that encourage the shifting of usage from times of high demand to times when the system is less stressed (TOU rates). We can and must do both, and improve customer understanding and acceptance at the same time.

We find that the first step in rate reform must be a further gradual narrowing of the existing usage tier differentials and a reduction in the number of tiers, so that electricity prices are more understandable and less distorted due to historical restrictions. At the same time, we recognize the continued validity of tiered rates as an incentive to conservation and energy efficiency, and as a protection for small users, and adopt a three-tier structure with 33% tier differentials as our desired end state. We reject the imposition of fixed monthly charges that would require a reduction in usage rates and undermine conservation, while adopting a minimum bill that assures that all customers will make some contribution to system costs.

By statute, the Commission is tasked with ensuring that utility rates are "just and reasonable."[1] Historically, the determination of just and reasonable

[1] The Commission is also responsible for ensuring that every public utility furnishes and maintains "adequate, efficient, just and reasonable service, instrumentalities, equipment, and facilities" as necessary "to promote the safety, health, comfort and convenience of its patrons, employees and the public." California Public Utilities Code Section 451.

rates emphasized cost-causation among other factors. In recent years, changes in energy use to protect the environment have become increasingly important. Moreover, changes in the grid and technology have expanded the ability of energy producers and consumers to evaluate and respond to rates. These changes have also shifted costs to a subset of customers who are unable to employ new technologies. This makes protection of vulnerable customers of particular importance in any new rate design. In this proceeding, the parties developed 10 rate design principles by which to balance and compare existing and proposed rate designs.

For over a decade, lower-tier residential rates were frozen in compliance with legislation following the electricity crisis, resulting in residential rates that are distorted and do not reflect any conscious effort at a consistent design. Extremely high upper tier rates have caused excessive bill volatility for large customers, especially in hot climates. While we have made progress in recent years in bringing down those very high rates, the task is not yet complete and further adjustments are needed. At the same time, we have no intention of abandoning our historic commitment to inverted tier rates that provide a strong incentive for conservation and investments in energy efficiency. With the Governor calling for a doubling of energy efficiency achievements by 2030, we cannot regress to the rate designs of the distant past, as urged by the utilities here, which reflected a very different period in the history of the industry. In addition, the changing technology landscape and historically different usage patterns make time-variant pricing a viable and important element of future residential rate designs.

California's electricity needs have changed over the last decade and will continue to do so. Impacts on the grid that need to be considered include not just peak usage periods, but also the deepening afternoon valleys resulting from increased deployment of solar, and the need for flexible ramping capacity. Any default TOU rate must be flexible enough to address these changes while providing a degree of consistency for customers. The goal of this Commission is to ensure that default TOU is implemented in a meaningful way that benefits and empowers electricity customers. Developing appropriate rate designs in this new paradigm will be challenging, but this decision will provide sufficient time and guidance to accomplish our goal.

In balancing the ten rate design principles, we find that the most important action to be taken in the near term is to rationalize the tier structure while maintaining a strong conservation-oriented design. The most important tool for balanced rate design is a price signal that customers can understand and respond to in a way that reduces the costs and environmental impacts of energy use. Bringing the price signal in line with costs and policy considerations, while assuring that vulnerable customers continue to be protected, is the first step in fulfilling a maximum number of rate design principles.

To this end, this decision finds that the investor-owned utilities (IOUs) must promptly take the following actions:

(1) Continue the tier consolidation process (as described by this decision), including adjusting California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA); discounts to reflect tier moderation.

(2) Implement a minimum bill for summer 2015.

(3) Institute a special outreach program to educate lower tier customers on no-cost and low-cost conservation measures.

(4) Promptly begin the process of improving rate comparison tools and educational materials so that customers can more readily understand their energy bills.

(5) Promptly begin the process of designing TOU pilots, as well as study design for TOU opt-in rates.

In addition to the steps above, which should begin immediately, this decision sets a course for residential rate reform over the next few years, including the following requirements.

(1) The IOUs must evaluate opt-in and pilot TOU rates in preparation for widespread enrollment in TOU.

(2) The IOUs must file a residential rate design window (RDW) application no later than January 1, 2018 that proposes default TOU rate structure to begin in 2019, assuming that the statutory conditions have been met.

(3) The IOUs may continue to employ a minimum bill, but a fixed monthly charge that is not responsive to customer behavior will not be part of the residential rate design..

(4) The IOUs must provide regular updates on progress toward rate reform and the Residential RDW application, including presenting an annual update, regular workshops, and quarterly reporting.

A third phase of this proceeding is opened (i) to examine specific legal issues related to default TOU rates, (ii) to determine what information and supporting documentation should be included in the Residential RDW application in order for parties, the Commission and the public to evaluate the proposed rate changes, and (iii) to consider the restructuring of the CARE rate under Assembly Bill 327. A workshop will be held at the start of Phase 3 to determine the extent to which CARE restructuring should be included in the scope.

2. Background

2.1. Residential Rate Design in California

Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (Investor-Owned Utilities [IOUs]) file General Rate Cases (GRCs) approximately every three years seeking changes in revenue requirements.

A GRC is made up of two separate proceedings which are often compared to the making and serving of a pie. GRC Phase 1 sets the utility's revenue requirement (or the "pie"). The revenue requirement is the amount of revenue to be recovered in rates. This includes all current operation and maintenance costs, administrative and general expenses, fuel and purchased power expenses (determined in the Energy Resource Recovery Account (ERRA)), taxes, depreciation, interest payments, and a component for return on equity. During Phase 2 of each IOU's GRC, we determine the marginal cost for each service provided and the responsibility of each customer class for those costs. Then, the GRC Phase 2 addresses allocation of the costs in the pie to different customer classes (the "dividing of the pie"). GRC Phase 2 also sets the rate design for collecting each customer's allotted share of the pie served to their customer class. Importantly, this means that once the revenue requirement pie is set, the changes in GRC Phase 2 cannot increase the size of the pie. The IOUs may also file RDWs annually to request changes that were not addressed in the last GRC.

Rulemaking (R.) 12-06-013 will not change the total revenue requirement. It will also not change the revenue allocation between customer classes, or the amount of revenue requirement for which the residential class is responsible. Rather, this proceeding will change the rate design rules for residential customers that make up the entire slice of pie for which they are already responsible.

Each utility's current revenue requirement and the residential class' allocation of that revenue requirement have already been determined. Our review in the instant proceeding is limited to considering the appropriate rate design for the residential class. Historically, in setting electric rates, we have sought to design and set rate structures that are based on marginal cost and that allow each utility to recover its costs of service in a manner that ensures that costs specific to each class of customer are recovered from that same customer class. To the extent possible, and allowing for certain subsidies to promote certain societal programs, we have also sought to ensure that each customer pays for electric service in proportion to their use. Over the past 14 years, however, this has been challenging due to several limitations imposed on the Commission following the energy crisis of 2000-2001.

2.1.1. Common Rate Design Terminology

The terminology of rate design is arcane and full of acronyms. As a result, parties sometimes do not have a common understanding of a rate design term. For the most part, this can be resolved by agreeing to a common set of definitions such as the one in this proceeding.[2]

We have attached a list of common acronyms and definitions to this decision as Attachment A.

As a threshold matter, it is necessary for the reader to understand the following terms:

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[2] ALJ Ruling Requesting Rate Design Proposals, March 19, 2013, Attachments C and D.

- Opt-In Rate: A voluntary rate that the customer can choose to be on. The burden is on the customer to affirmatively choose the tariff.
- Opt-Out Rate: A voluntary rate the customer can choose to leave. The burden is on the customer to affirmatively leave the tariff. A voluntary default tariff can is also an opt-out tariff.
- Mandatory Rate: A rate that the customer cannot opt-out of.
- Default Rate: The rate the customer is automatically put on if the customer does not affirmatively choose a different tariff. For residential customers, this is a voluntary (not mandatory) rate.

In addition, however, there are some terms, such as "fixed costs" that are rightly the subject of litigation.

2.1.2. History of Residential Rates

2.1.2.1. Legislative Foundation for Inverted Block Rates

The utilities' total bundled rates have been tiered since lifeline rates were implemented in California in the mid 1970's. The Miller-Warren Energy Lifeline Act sought to provide California's residential customers with necessary amounts of gas and electricity (the "lifeline quantity") at a fair cost, while also encouraging conservation of energy. In adopting the Lifeline program, the Legislature found and declared as follows:

> (a) Light and heat are basic human rights, and must be made available to all the people at low cost for basic minimum quantities.
>
> (b) Present rate structures for gas and electricity serve to penalize the individual user of relatively small quantities, and at the same time encourage wastefulness by large users.
>
> (c) In order to encourage conservation of scarce energy resources and to provide a basic necessary amount of gas and electricity

> for residential heating and lighting at a cost which is fair to small users, the Legislature has enacted this act.[3]

While the statute has been amended numerous times over the years, the Legislature has never altered this fundamental statement of its intent.

The initial implementation of Lifeline rates consisted of two usage tiers, but by 1980 the Commission had added a third tier for PG&E.[4] In the PG&E GRC litigated during 1981, PG&E rate design witness Reynolds testified as follows:

> Q Do you have any opinion on whether the conservation effect of the three-tier versus the two-tier method, which one was better?
>
> A The evidence that I have seen to date from our elasticity studies, these have been presented for gas in the gas remand case, they are still being formulated, for the electric department, but the evidence strongly suggests that a three-tier approach does seem to induce conservation above and beyond elasticity developed based upon an average price variable.
>
> I think that's a significant to me indictor that this particular type of rate design is an effective conservation inducing tool.

The Commission agreed, stating that: "We are convinced that the three-tier structure by itself contributes significantly to conservation. We will therefore certainly continue it."[5]

The Commission conducted another in-depth review of PG&E's residential rate design in 1982, in the wake of significant dissatisfaction expressed by all-electric customers in the Sierra Foothills, where natural gas service was not

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[3] 1975 Statutes, chapter 1010, section 1.

[4] Decision (D.) 91721, 3 CPUC 2d 578 (1980).

[5] D.93887, 7 CPUC 2d 349, 493 (1980).

available. The Commission reached a number of significant conclusions on the tiering issue in D.82-12-113, including the following:

> TURN also established, through cross-examination, that 95% of the all-electric customers in climate band X (Sierra foothills) would have higher winter bills under a two- than under a three-tier structure because a higher second tier rate would be required to offset the revenue loss associated with elimination of the third tier. . . .
>
> One of the most important indirect effects of a rate design change is its impact on the cost-effectiveness and payback periods from the customer's point of view of various conservation measures. . . .
>
> Concerning rate stability versus conservation, one could question our retention of a three-tier rate structure and authorization of the balanced payment plan. We do not think that these two actions are mutually exclusive. We recognize that at very high usage levels, a three-tier structure can cause bills to vary significantly: its variability is unfortunately what makes it a good conservation signal. For some customers this represents an undue hardship which can be mitigated by the balanced bill payment plan. . . .
>
> The testimony of Dr. Wells, Dr. Action and PG&E witness Howard corroborate the view that a three-tier rate structure directly causes greater conservation than a two-tier structure. The testimony of Dr. Acton sponsored by Contra Costa County showed that in a large scale southern California experiment, price elasticity increased with higher usage levels. . ….
>
> Howard, in conducting studies at our direction the last few years, has used a method of calculating the conservation effects of rate structure without the very controversial use of elasticity data. Howard has shown that a two-tier structure has more of a conservation effect than a declining rate structure. He also testified that a three-tier would have more of a conservation effect than a two-tier structure. In A.82-06-08 Howard further developed the studies that he provided in A.60153. The further studies showed,

> and we found, that the three-tier conservation effect was about twice that of a two-tier structure.[6]

The Lifeline program was renamed and revised by the 1982 Baseline Act, which set baseline rates at 15 - 25% less than the system average rate (SAR).[7] The inverted rate relationship of the tier prices results from the same legislative mandate. In enacting the Baseline Act, the Legislature found and declared, among other things, as follows:

> (a) Rate structures for the furnishing of gas and electricity by public utilities should be designed to encourage conservation of scarce energy resources.
>
> (b) Inverted block rate structures are effective incentives to energy conservation and provide gas and electricity at a fair cost to all users.[8]

The establishment of baseline rates continued the inclining or inverted block structure in California: a tiered residential rate structure, with the upper-tier rates set progressively higher than the lower-tier rates, similar to graduated income tax rates. Inverted block structures charge ratepayers based on an increasing rate per kWh within each successive tier, or "block" of use. An inclining block rate promotes conservation, especially when most customers exceed the first tier and utilities can recover more of their costs in the upper tier(s).

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[6] D.82-12-113, 10 CPUC 2d 512, 522-24 (1982).

[7] The SAR is calculated by dividing the annual revenue requirement of the IOUs by their annual retail sales. This metric provides a normalized basis for assessing trends in utility costs. Because the value represents the average cost per kilowatt hour, it necessarily departs from the actual rates and trends experienced by different customer classes. The manner in which cost recovery is allocated across customers is considerably more complex.

[8] 1982 Statutes, chapter 1541 (AB 2443 Sher), section 1.

In 1988, six years after the Baseline Act, the Legislature enacted Senate Bill (SB) 987, which mandated a reduction in non-baseline residential rates and narrowed the differential between the tiers. It also enacted Pub. Util. Code § 739.7, which mandated that the "Commission shall reduce high non-baseline residential rates as rapidly as possible." Of note here, according to the Legislature's findings and declarations, SB 987 was focused on high winter *gas* bills, not *electric* bills:

> (1) The rates for gas service in excess of the baseline quantity are too high, and cause extremely high residential bills during cold weather.
>
> (2) The Public Utilities Commission should have greater flexibility in establishing rates for baseline service, in order to protect residential ratepayers from excessive rate increases and high winter gas bills.[9]

In the years following the adoption of SB 987, the Commission reduced electric tier differentials over time to as little as 1.15:1.[10] It is to that era that the utilities now encourage us to return.

In response to the dramatic reduction in tier differentials, in 1992, Assembly Bill (AB) 1432[11] was enacted. That act amended Section 739.7 to mandate that the Commission "shall retain an appropriate inverted rate structure," because "[i]t was never the intention of the Legislature that the Commission eliminate inverted residential rates. Inverted residential rates

[9] 1988 Statutes, chapter 212 (SB 987 Dills), Section 1.

[10] See D.96-04-050, 65 CPUC 2d 362, 431 (1996).

[11] 1992 Statutes, Chapter 1040 (AB 1432 Moore).

provide conservation incentives for residential customers and also provide reasonable rates for the domestic consumption of gas and electricity."[12]

2.1.2.2. AB 1890 and the Energy Crisis

Four years later, in 1996, AB 1890 restructured the electric industry in California. Rates were capped at the slightly above-cost levels in effect in 1996, with an additional 10% decrease in rates for residential and small business customers (funded by the issuance of bonds), with the situation to be re-evaluated in 2002. The utilities were meant to recover their stranded costs in the intervening years through innovation and reduction in costs, but wholesale market manipulation and the 2000-2001 energy crisis quickly created a gap between the wholesale costs to procure power and the retail rates the utilities were allowed to charge.

On February 1, 2001, AB 1X from the First Extraordinary Session (Ch. 5, First Extraordinary Session 2001) was enacted implementing measures to address the rapidly rising energy costs resulting from the 2000-2001 energy crisis. Among other things, AB 1X mandated that all residential electricity use up to 130% of baseline be capped at levels in effect on February 1, 2001, so the Commission was required to develop a rate design methodology that would enable the IOUs to fully recover their revenue requirements.

Consequently, in 2001, the Commission also replaced the then-existing two-tiered structure with a five-tiered structure,[13] as these statutory restrictions required the first two tiers to remain frozen as a customer protection. This required all future residential rate increases to be allocated to rates in non-CARE

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[12] *Ibid.*

[13] D.01-05-064.

Tiers 3 through 5, above the Tier 2 (130% of baseline) threshold. Consumption in Tiers 1 and 2 represent the majority of electricity usage in the state, so upper-tier rates increased to levels well above the residential average rate in order to recover costs, eventually leading to a steeply tiered structure.

To protect low-income households against these escalating costs, the Commission also froze rates for the California Alternate Rates for Energy (CARE) program at July 2001 levels, after increasing the CARE discount from 15 to 20%.

Over time, the rate tier differentials continued to widen. Between 2001 and 2010, the system average differential between the Tiers 2 and 3 expanded from about 5 cents to 15 cents, and the differentials between Tiers 3 and 4 and Tiers 4 and 5 expanded from about 4 and 2 cents per kilowatt-hour (kWh), respectively, to about 13 and 7 cents per kWh. Between 2000 and 2009, the Tier 5 rate nearly doubled, increasing from 24.5 cents per kWh at the height of the energy crisis to 44.3 cents per kWh at the end of 2009.

With the enactment of SB 695 in 2009,[14] Section 739.1 was amended and Section 739.9 was added to begin allowing limited annual Tier 1 and Tier 2 rate increases for both CARE (from 0 to 3%) and non-CARE customers (from 3 to 5%). In addition, D.10-05-051 consolidated Tiers 4 and 5 into a single Tier 4. Thus, the utilities have already realized some meaningful progress toward narrowing the disparity between upper- and lower-tiered rates.

As a result, as of January 2014, residential rates for lowest and highest tiers were as follows:

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[14] Exh. PG&E-04 at 1-5. SB 695 (Kehoe, 2009).

Utility/Date	Tier 1 (per kWh)	Tier 4 (per kWh)	Residential Average Rate (per kWh)
SCE 11/1/3[15]	13.2 cents	29.5 cents	17.6 cents
SDG&E 1/1/14[16]	15.0 cents	36.9 cents	21.1 cents
PG&E 1/28/14[17]	13.2 cents	36.4 cents	17.5 cents

2.2. Procedural History

2.2.1. The Order Instituting Rulemaking (OIR)

The Commission initiated this OIR, "to examine current residential electric rate design, including the tier structure in effect for residential customers, the state of time variant and dynamic pricing, potential pathways from tiers to time variant and dynamic pricing, and preferable residential rate design to be implemented when statutory restrictions are lifted."[18] At that time, the Commission was, and continues to be, interested in exploring improved residential rate design structures in order to ensure that rates are both equitable and affordable while meeting the Commission's rate and policy objectives for the residential sector. Currently, residential electricity rates have an "inclining block" structure consisting of multiple tiers based on usage. By statute, Tier 1 is equal to the "baseline quantity" which is defined as 50% to 60% of average residential consumption of electricity[19] As a customer's energy usage increases into higher tiers, the price paid for that energy also increases. This increase is made without regard to the cost to provide the increased amount of electricity.

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[15] Exh. SCE-03 at 16-17.

[16] Exh. SDG&E-03 at CF-15.

[17] Exh. PG&E-04 at 1-5.

[18] OIR at 1.

[19] Section 739.

On November 26, 2012, the assigned Commissioner issued the original Scoping Memo and Ruling. Over the next ten months, a variety of parties actively participated in the proceeding to examine residential rate structures. Those parties included: California Large Energy Consumers Association; Center for Accessible Technology (CforAT) and The Greenlining Institute (Greenlining); Distributed Energy Consumer Advocates; Office of Ratepayer Advocates (ORA);[20] Environmental Defense Fund (EDF); Interstate Renewable Energy Council, Inc. (IREC); Natural Resources Defense Council (NRDC); Pacific Gas and Electric Company (PG&E); SDG&E; San Diego Consumers' Action Network (SDCAN); Sierra Club; Solar Energy Industries Association (SEIA); The Vote Solar Initiative (Vote Solar); Utility Consumers' Action Network (UCAN), SCE; and The Utility Reform Network (TURN). PG&E, SDG&E and SCE are referred to collectively herein as the IOUs.

As part of the proceeding, the utilities each developed a "Rate Impact Calculator" designed to help parties understand the impact of different rate design proposals. The calculators were developed over a period of several months with the input of all interested parties. Although the final calculators do not provide all of the modeling abilities that the parties sought, the calculators represent a useful tool for comparing rate structures that has been used and cited by various parties. During the same period, the parties worked with the utilities to develop a customer survey to explore how well residential customers understand their rates. The bill impact calculators and the customer survey were

[20] The Office of Ratepayer Advocates was formerly known as the Division of Ratepayer Advocates (DRA). *See* Stats. 2013, Ch. 356, § 42.

moved into the evidentiary record pursuant to a later ruling. (*See*, Amended Scoping Memo and Ruling of Assigned Commissioner, dated January 6, 2014.)

On October 7, 2013, AB 327 (Perea, 2013) was signed into law, lifting many of the restrictions on residential rate design. With its passage, the utilities now propose residential rates that they assert are more reflective of cost, in keeping with the Commission's principle that rates should be based on cost-causation. AB 327 also contains limits designed to protect certain classes of vulnerable customers.

For purposes of today's decision, the relevant provisions of AB 327 are (1) setting the CARE effective discount rate between 30% and 35%, and (2) allowing an increase in rates for Tiers 1 and 2.

2.2.2. Phase 2

In light of the new rate structures permitted by AB 327, on October 25, 2013, the assigned Commissioner issued a ruling (October 2013 ACR) opening Phase 2 of this proceeding and inviting utilities to submit interim rate change proposals for summer 2014 in order to promptly stabilize and begin to rebalance tiered rates. Longer-term rate design was reserved for Phase 1.

The IOUs submitted their Phase 2 Proposals on November 22, 2013. A Phase 2 prehearing conference (PHC) was held on December 5, 2013. Parties filed protests to the Phase 2 Proposals on December 23, 2014 and the IOUs filed their replies on January 3, 2014.

On January 6, 2014, the assigned Commissioner issued the Amended Scoping Memo and Ruling (January 2014 Scoping Memo). The January 2014 Scoping Memo re-categorized Phase 1 as ratesetting, rather than quasi-legislative. The January 2014 Scoping Memo also presented the rate design proposal of Energy Division (Staff Proposal). The Staff Proposal was based on review of rate design proposals and other documents filed by parties during the course of this proceeding, the bill impact calculators provided by the IOUs, and additional research.[21] Importantly, the Staff Proposal demonstrates the considerable effort and thought that parties put into this proceeding prior to passage of AB 327. Although the Staff Proposal is part of the record, it was not subject to any type of cross-examination and serves only as a reference tool. The Staff Proposal should not be considered evidence that can be relied on for the truth of the statements therein.

At a Phase 2 PHC on January 8, 2014 the IOUs were instructed to simplify their Phase 2 Rate Change Proposals so that the proposals could be adequately reviewed and analyzed prior to summer 2014.

A Second Amended Scoping Memo and Ruling was issued on January 24, 2014 (January 24, 2014 Scoping Memo) and set the procedural schedule, including evidentiary hearings, for Phase 2.

As directed by the January 24, 2014 Scoping Memo, the IOUs filed their simplified Phase 2 Proposals on January 28, 2014. Over the next few weeks, the IOUs worked with other parties to arrive at settlements.

Over the course of the following months, partial settlements were reached between each of the three IOUs and many of the active parties to the proceeding.

The Phase 2 Settlement Rates (1) retained the current multi-tier rate structure, (2) retained current CARE discounts, or begin the gradual glide path toward the CARE effective discount maximum of 35%, and (3) did not institute new fixed customer charges.

[21] A revised Staff Proposal was filed on May 9, 2014 to incorporate corrections from parties. *See* ALJ Ruling Issuing Corrected Energy Division Proposal, Attachment B.

Although no party formally objected to the settlement, a one-day evidentiary hearing was held on March 27, 2015, 2014. The Phase 2 settlements were adopted in D.14- 06-029.

2.2.3. Phase 1

On February 13, 2014, the assigned Commissioner issued a Ruling (Phase 1 ACR) directing the IOUs to file rate design proposals for 2015 through 2018 (Phase 1 Testimony). The Phase 1 ACR also set a prehearing conference for March 14, 2014. The IOUs served their Phase 1 Testimony on February 28, 2014.

During the same period, on March 10, 2014, the assigned Administrative Law Judges (ALJs) issued a ruling on the Rate Design Element Inventory (Rate Design Element Inventory Ruling). ORA, SCE, SDG&E, TURN and UCAN filed comments on the Rate Design Element Inventory Ruling, and parties discussed the rate design elements included in the inventory at the March 14, 2014 PHC for Phase 1.

On April 15, 2014, Assigned Commissioner issued a Third Amended Scoping Memo and Ruling (Third Amended Scoping Memo) to finalize the Phase 1 schedule, set the Phase 1 scope, direct the IOUs to serve additional Phase 1 testimony and provide additional information regarding specific rate design elements to be evaluated in Phase 1. The Third Amended Scoping Memo scheduled evidentiary hearings for November 3 - 21, 2014. The Third Amended Scoping Memo also included a revised Rate Design Element Matrix that applies to both Phase 1 and Phase 2.

For the most part, the scope of this proceeding was defined by the objectives set forth in the OIR and the IOUs' rate design proposals. As we stated in the OIR, this rulemaking is intended to examine whether the current tiered rate structure continues to support the underlying statewide energy goals, facilitates the development of technologies that enable customers to better manage their usage and bills, and whether the rates result in equitable treatment across customers and customer classes. In addition, the Third Amended Scoping Memo identified the specific issues to be resolved in Phase 1 as follows:

1. Should the Commission adopt a Fixed Customer Charge?
2. Are the utilities' proposed Fixed Customer Charges reasonable, compliant with law and the optimal rate design principles developed in this proceeding?
3. Are the utilities' proposed reductions in baseline quantities reasonable, compliant with law and Rate Design Principles and in the public interest? Do they support Commission and state policies?
4. Is flattening tiers, including a reduction in the number of tiers and tier rate differentials, reasonable and consistent with law and Rate Design Principles? Does it support Commission and state policies?
5. Are the utilities' proposed opt-in tariffs and pilot programs for untiered TOU rates, reasonable, compliant with law and Rate Design Principles? Do they support Commission and state policies?
6. How should any revenue collection shortfalls be treated between customer groups on different tariffs?
7. In what type of proceeding should the Commission review residential TOU periods?
8. What requirements should be set for short-term outreach programs to communicate changes in rate design in the near-term (including untiered TOU pilot and opt-in outreach, changes to tiers and fixed charges, changes to the California Alternate Rates for Energy (CARE), Family Electric Rate Assistance (FERA), and medical baseline programs)? Where should funding for this outreach come from? What metrics should be used to evaluate the effectiveness of the outreach programs?
9. Does the two-tier minimum set in Section 739.9(c) apply to optional and default TOU rates?

10. At a minimum, what must IOUs do to comply with the Section 745(a)(5) requirement to provide each customer with a calculation of expected annual bill impacts under each available tariff? Should this service be offered starting in 2015 as a means of customer education and outreach regarding rate options?
11. In light of the changes to the tier-structure permitted by the passage of AB 327, what, if any, implementation steps are necessary to begin including greenhouse gas (GHG) costs in residential rates pursuant to the direction in D.12-12-033 that GHG costs should be included in residential rates once restrictions on lower tier rates are removed?
12. Is SCE's Phase 1 Proposal for 2015-17 reasonable under the law and the Rate Design Principles? Elements of SCE's Phase 1 Proposal include: changes to the Fixed Customer Charge; reduction in the number of tiers and the differential between tiers; changes to CARE, medical baseline and FERA programs necessitated by changes in the overall residential rate structure; corresponding changes to any other tariffs; and creation of memorandum accounts to track certain expenses related to the Phase 1 Proposal such as outreach expenses and TOU opt-in rate expenses.
13. Is PG&E's Phase 1 Proposal for 2015-17 reasonable under the law and the Rate Design Principles? Should PG&E's Phase 1 Proposal for 2015-17 be adopted? Elements of PG&E's Phase 1 Proposal include: Fixed Customer Charge; reduction in the number of tiers and the differential between tiers; untiered TOU pilot or opt-in rates; changes in the Baseline Percentage; changes to CARE, medical baseline and FERA programs necessitated by changes in the overall residential rate structure; corresponding changes to any other tariffs; and creation of memorandum accounts to track certain expenses related to the Phase 1 Proposal such as outreach expenses.
14. Is SDG&E's Phase 1 Proposal for 2015-17 reasonable under the law and the Rate Design Principles? Should SDG&E's Phase 1 Proposal for 2015-17 be adopted? Elements of SDG&E's Phase 1 Proposal include: changes to the Fixed Customer Charge; reduction in the number of tiers and the differential between

tiers; untiered TOU pilot and opt-in rates; changes in the Baseline Percentage; changes to CARE, medical baseline and FERA programs necessitated by changes in the overall residential rate structure; corresponding changes to any other tariffs; and creation of memorandum accounts to track certain expenses related to the Phase 1 Proposal such as outreach expenses and TOU pilot expenses.

15. Default TOU rates are permitted by law starting in 2018. SDG&E has proposed a default TOU rate for 2018 and has identified certain areas for further evaluation prior to implementation. Are there other factual issues that must be resolved before a decision is made to implement default TOU rates? What existing and new data, metrics and resources should be used to evaluate rates before authorizing default TOU rates and, if applicable, after implementation of default TOU rates? Are there specific conditions (for example, achieving minimum customer education and outreach requirements) that should be met prior to implementation of default TOU rates?

Pursuant to the Third Amended Scoping Memo, the IOUs served Additional Supplementary Testimony on May 16, 2014 and Additional Optional Testimony on June 13, 2014.

On July 11, 2014, the assigned ALJs issued an e-mail Ruling Requiring Additional Supplementary Testimony from SDG&E and PG&E regarding estimated load reduction associated with Energy Efficiency, Demand Response and Distributed Generation programs, and NEM Bill Impacts, respectively. On August 28, 2014, the ALJs issued a Ruling Requesting Briefing on Default TOU Pilots.

Intervenor Testimony was served on September 15, 2014 by ORA, TURN, UCAN, Vote Solar, CforAT/Greenlining, Sierra Club, EDF, NRDC, The Alliance for Solar Choice (TASC), Consumer Federation of California (CFC), SEIA and CALSEIA. On October 6, 2014, following the passage of SB 1090, which amended Public Utilities Code (Pub. Util. Code) Section 745, the ALJs issued a Ruling Requiring Additional Testimony and directing the IOUs to either identify the portions of their existing testimony concerning SB 1090 or serve additional testimony responsive to Section 745. Parties' Additional Testimony on SB 1090 issues and Rebuttal Testimony were concurrently served on October 17, 2014.

A PHC was held on October 23, 2014 to address witness scheduling and other issues in preparation for hearing. By email ruling on October 24, 2014, the ALJs granted TURN's request to present supplemental written testimony regarding the bill impact analysis of SCE's rate design proposals and limited surrebuttal testimony on regarding new information present in the rebuttal testimony served by ORA. TURN served supplemental testimony on October 30, 2014 and surrebuttal testimony on November 7, 2014,

Between November 3, 2014 and November 24, 2014, the Commission conducted 15 days of evidentiary hearings. On December 1, 2014, pursuant to an ALJ ruling issued November 19, 2014, the IOUs served supplemental testimony regarding rate design project timelines.

Opening and Reply Briefs were filed on January 5, 2015 and January 26, 2015, respectively.

2.2.4. Public Participation

In order to obtain public input regarding the Commission's rulemaking and the rate design proposals submitted by the IOU, the ALJs conducted public participation hearings (PPHs) throughout California in September and October, 2014. Sixteen PPHs were held between September 16, 2014 and October 14, 2014 in the communities of San Diego, El Cajon, San Francisco, Fontana, Temple City, Palmdale, Chico and Fresno. The PPHs were attended by a total of 870 people, with at least 370 people providing public comment. In addition to the PPHs, the

Commission's Public Advisor received more than twelve thousand letters and e-mail messages from IOU customers and community groups. The Commission also received numerous communications from civic leaders and elected officials. The comments from the public ranged from statements of total opposition to the IOUs requests and recommendations that the Commission deny the requests outright, to support for individual elements of the rate design proposals. Speakers and commenters were particularly opposed to the IOUs' proposals for fixed charges and expressed concern regarding the impacts on low-income customers. Support for the rate design proposals generally centered around the desire to reduce the highest tier rates.

We summarize a subset of the comments that were made most frequently:

> "I'm a member of the Area Agency on Aging Advisory Committee for Monterey County. . . . I'm here to ask you to not approve the changes in the rate structure or the CARE program for PG&E. I'm 70 years old. I live on a fixed income. I'm representing more than just me. I'm representing an awful lot of senior people in Monterey County. All my costs are going up, particularly my housing, my food, very basic costs. . . . I would like you to consider that the aging population, the senior population, is one of the fastest growing in the country."

> "SCE's request is ludicrous. At a time when the middle class is struggling to survive Edison wants to reduce the number of tiers thereby driving up the price for those who conserve electricity. And on top of this they want to increase the monthly charge to $10. Ridiculous, absolutely ridiculous. While the middle class struggles to keep its head above water they want more of our money. Thieves says I. You must stop this theft of the American family."

> "Now that PG&E is facing a big fine, suddenly it is demanding a huge 12-percent increase in gas charges for all individuals. And now double the monthly electric minimum and force electric customers into an expensive Tier 2 instead of a—for the present—moderate Tier 2? Who's making this decision? CPUC management

and PG&E management are not living on minimum wage, to say the least."

"Under the current rate structure, thousands of low-income seniors, particularly those here in East County, are subsidizing some of SDG&E's wealthiest customers who are fortunate enough to live in La Jolla and some of the other beach communities."

"Why do the CPUC and Governor Brown want to reward the customers who over-use our resources with lower kWh rates while penalizing us SCE customers who try to conserve and lessen unnecessary use of power resources? With R.12-06-013, SCE customers who conserve on their use of resources will pay ***more than 23% higher*** rates per kWh in Tier 1 and ***more than 28% higher*** rates in Tier 2. Mega users of SCE power in Tier 3, however, will pay ***24% less*** per kWh. Tier 4 users will pay ***18% less*** per kWh. Can anyone at the CPUC actually rationalize this SCE proposal as fair? **NO.** Does it truly create rate structure and renewable energy policies to better serve customers? **NO.** I see it as "**REWARD the rich** at the conservationists' expense!" Does that seem equitable? **NO.**"

"The worst scenario is that the low income seniors are going to be forced to start eating dog and cat food again. The worst scenario is that you're going to find some seniors in their apartments or wherever they live frozen to death. You're going to find that. You're going to find low income families chopping up their furniture just to keep the kids warm. This is what's going to happen. This is the future of seniors, low income families, and handicapable people."

"I feel that the current structure is for the rates is unfair. [sic] It assumes that if you are in Tier 1, you are not—you're poor. Many of the people that are in Tier 1 live closer to the coast. Therefore, they don't have the electrical rates for air conditioning and services that we do out on the East County. The truth is if you live in Tier 1, you probably live close to the ocean or do not need the air conditioning. I live in Ramona. And I am in Tier 3 and Tier 4. No matter how hard we conserve and try, we cannot get out of Tier 3 and Tier 4."

While we cannot accord the comments the same weight as evidence presented in sworn testimony of witnesses subject to cross-examination, we value the input and incorporate it into our deliberations. These comments provide valuable assistance in understanding the perspective of customers and others who are affected by our decisions.

3. Legal Review for Rate Design Proposals

3.1. Statutory Law

Rate designs must comply with a wide variety of laws designed to protect consumers, ensure reliability of the electricity grid, promote clean energy, and ensure safety. The rates approved in this decision must comply with long-standing laws and with the changes to law made by AB 327. The following statutes are of particular relevance in evaluating the rate change proposals.

- Section 451, which requires that rates be "just and reasonable."
- Section 382(b), as amended by AB 327, states that "electricity is a basic necessity" and that "all residents of the state should be able to afford essential electricity." Section 382(b) directs the Commission to ensure that low-income ratepayers are not "jeopardized or overburdened by monthly energy expenditures."
- Section 739 defines baseline quantity and, in Section 739(d)(1), requires that the Commission "establish an appropriate gradual differential between the rates for the respective blocks of usage."
- Section 739.1, which was amended by AB 327, addresses the CARE program. Section 739.1(c) requires the average effective CARE discount to be between 30-35% "of the revenues that would have been produced for the same billed usage by non-CARE customers."
- Section 739.9, which, pursuant to AB 327, replaced the prior Section 739.9, requires that any increases to electrical rates, including reductions in the CARE effective discount, "be reasonable and subject to a reasonable phase-in schedule relative to the rates and charges in effect prior to January 2014."

3.2. The Rate Design Principles

Rate design proposals must attempt to balance the sometimes conflicting Rate Design Principles (RDP) developed in this proceeding to evaluate residential rate design options. The initial Order Instituting Rulemaking (OIR) set forth a preliminary list of principles for optimal rate design. (OIR at 20-21.) The OIR list echoed Commission decisions, such as D.08-07-045, and was similar to the "Bonbright principles."[22] After extensive input from the parties, including a workshop and written comments, the RDP were adopted by the Commission in the Phase 2 Decision:

1. Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost;
2. Rates should be based on marginal cost;
3. Rates should be based on cost-causation principles;
4. Rates should encourage conservation and energy efficiency;
5. Rates should encourage reduction of both coincident and non-coincident peak demand;
6. Rates should be stable and understandable and provide customer choice;
7. Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals;
8. Incentives should be explicit and transparent;
9. Rates should encourage economically efficient decision-making;
10. Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding

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[22] The "Bonbright Principles" include rate attributes such as fair apportionment of costs among customers, encouragement of efficient use of energy, rate stability, and ability to meet revenue requirement under the fair return standard. *See*, Bonbright, James C, *Principles of Public Utility Rates*, Columbia University Press, New York NY, 1961.

and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

4. The Evidentiary Record; and Central Legal Issues

In the course of this proceeding, we have held two days of workshops and 15 days of evidentiary hearings and eight days of PPHs, and one all-party meeting. The exhibits admitted into the evidentiary record stand literally 3.5 feet tall. Numerous papers are cited in the evidentiary record. And yet, what is most surprising about this proceeding is the degree to which evidence does not provide a complete answer to even the most basic questions about changes to rate design for residential customers.

This lack of direct evidence highlights the degree to which our pursuit of reformed residential rates, particularly time-of-use (TOU) rates, has brought us to uncharted waters. As a result, a significant order of this decision will be to direct the IOUs to start mapping the transition to TOU rates.

Despite the aspirations of some purists, rate design, while requiring both understanding of economic principles and specialized knowledge of factors such as usage patterns, remains very much an art and not a science. It necessarily must balance numerous competing social, economic, and policy considerations. An important component of this decision is to direct the utilities to gather evidence on customer acceptance and to develop a comprehensive outreach strategy before implementing default TOU rates.

4.1. Customer Understanding of Electricity Rates

4.1.1. Hiner Study

In 2013, PG&E, SCE and SDG&E jointly commissioned Hiner & Partners to conduct a survey of their customers in order to develop a better understanding of customer knowledge of and preferences for various types of rate plans. The study surveyed 4,283 electric customers from the three IOUs, comprising several groups. The largest was a "Core" group, designed to be representative of the IOUs' populations, and was provided with educational information on rate structures. Additionally there was an "Unexposed" group, similar to the "Core" but not provided any educational information about the rate structures during the survey, and several "Supplemental" groups including Spanish speakers, solar customers and customers with high engagement in utility programs.

The Hiner study found that customers generally have a poor understanding of rates, stating that "customer awareness of existing rates is modest at best, especially about the tiered rates most currently have."[23] Before receiving educational information about rate plans, 58% of respondents in the "Core" group reported that they had heard about tiered rates and 40% were aware of TOU rates.

Only 50% of customers believed that they were currently on a tiered rate plan. 19% responded that they were currently on a TOU rate plan, however according to IOU data, as of April 2015, only 3.4% of PG&E's residential customers are on TOU rates, while SCE and SDG&E have 0.52% and 0.6% of residential customers on TOU rates respectively.[24] According to the study, "75% of customers have tried to save money by shifting their electricity use" and "despite most customers knowing they are not on a TOU rate, many believe they have saved money by shifting."[25] 21% of "Core" respondents were unsure of what type of rate plan they are currently on[26] and the most common answer

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[23] PG&E Rate Design Proposal, Appendix A, Hiner & Partners Key Findings at 7.

[24] April 2015 IOU Supplemental Filings.

[25] PG&E Rate Design Proposal, Appendix A, Hiner & Partners Key Findings at 11.

[26] *Id.* at 7.

when asked if their current rate plan includes a monthly service fee or demand charge was "not sure."[27]

Among "Supplemental" groups, SmartRate and PG&E solar customers were much more aware of TOU rates than the Core group[28] and Seniors were also more knowledgeable about existing rate plans.[29] The study found that Spanish speakers were less informed about current rates[30] and households with a disabled member have a similar knowledge of rate plans as the Core group.[31]

We find these results disappointing, particularly with respect to tiered rates, since the IOUs have been under direction since 2008 to work to improve their provision of information to customers in this regard. In that year AB 1763 (Blakeslee) was enacted, adopting Section 739(e) of the Public Utilities Code. The Legislature's findings and declaration, set forth in Section 1 of AB 1763, stated as follows:

> (a) The current tiered rate structure was designed to encourage customers to use less electricity. However, many customers lack an understanding of the tiered rates, and their personal consumption, necessary to make informed energy-saving decisions.
>
> (b) In order to realize California's energy efficiency potential, reduce peak demand, and encourage energy conservation, customers need to be provided with detailed information regarding their current and historic energy usage, the breakdown of the different costs of their usage, and specific recommendations of measures they can take to reduce their energy consumption.

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[27] *Id.* at 12.

[28] *Id.* at 37.

[29] *Id.* at 40.

[30] *Id.* at 36.

[31] *Id.* at 41.

The findings of the Hiner study suggest that the IOUs have been far less than successful in carrying out the Legislature's intent.

4.1.2. Customer Understanding

The level of customer understanding was further demonstrated at the 16 PPHs held in this proceeding and the voluminous public comments filed with the Public Advisors Office. Customers must have "confidence that rates are fair and reasonable."[32] CforAT argues at length that the comments of the public at the PPHs and in letters and e-mails filed with the Public Advisor's Office demonstrate that customers do not have an understanding of their bills or confidence that their rates are fair and reasonable.

We agree that residential customer understanding of rates should be a key objective of this proceeding.

4.2. Conservation and Rate Design

4.2.1. Overview

Energy conservation refers to reducing energy consumption through using less of an energy service. Energy efficiency refers to using less energy to provide the same service. California has many longstanding and more recent policies that support energy conservation and energy efficiency. In this proceeding, parties have categorized energy efficiency into (i) behavioral changes (such as turning out the lights) and (ii) investments (such as purchasing energy efficient appliances). In addition, rooftop solar photovoltaic (PV) can be used to reduce

[32] CforAT OB at 19.

the amount of grid-supplied energy used by a customer, but this is not the same as reducing overall energy use.[33]

The purpose of conservation includes reducing pollution and GHG, and reducing energy and infrastructure costs. In this proceeding we did not examine the degree to which California's existing programs for conservation and energy efficiency have been effective in achieving those goals, but these are areas of ongoing examination by the Commission. Indeed, Governor Brown recently announced a goal to double the amount of energy efficiency achieved in California by 2030.

Assuming that customers change the amount of energy they use based on the price of the energy, then the proposed rate design changes could increase or decrease conservation. For example, if the price of gasoline goes up, car owners drive less. The relationship between the price and changes in usage are not always easy to determine.

Conservation and energy efficiency are supported by RDP #4 (rates should encourage conservation and energy efficiency) and #5 (rates should encourage reduction of both coincident and non-coincident peak demand). These are very important principles, but they must also be balanced against the other eight RDPs. In addition, we are required by statute to make a specific finding on conservation before authorizing any fixed charge: that the fixed charge will not "unreasonably impair incentives for conservation and energy efficiency."

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[33] A customer who installs solar may actually increase usage to maximize perceived benefits from having their own energy source.

In this proceeding, parties focused on two tools for evaluating whether changes in rate design will change the incentives for conservation in a way that customers will respond to.

(1) Price Elasticity – the measure of how much customer demand for energy (kWh) will change in response to the price.

(2) Payback Period – the measure of the amount of time it takes to pay for an energy efficiency or PV investment.

Both measures were the subject of substantial testimony.

The utilities assert that their rate design proposals, including tier reduction and proposed fixed customer charges, will not impair incentives for customers to conserve energy or invest in energy efficiency measures. The utilities explain that while higher-usage customers have a greater incentive to conserve under steeply tiered rates, lower-usage customers have a lesser incentive to conserve. Because of this, they maintain that consumption may decrease slightly in the lower tiers under the new rate design proposals.

ORA, TURN, NRDC, and SEIA all argue that the utilities' proposals would negatively impact conservation incentives by decreasing the rates of those who have the most discretionary usage, higher-users, and increasing the rates of those whose discretionary usage is more limited. They also argue that the utilities' proposals would reduce the incentive for customers to invest in energy efficiency and demand response measures by increasing the payback periods associated with those investments.

4.2.2. Balancing State Policies

Among the many goals articulated in AB 327 is to give the Commission the ability to "address current electric rate inequities, protect low income users, and maintain robust incentives for renewable energy investments.[34] In addition, pursuant to Section 739.9(e)(2), prior to adopting any changes to residential rate design, the Commission must find that the rate design it adopts does not "unreasonably impair incentives for conservation and energy efficiency." This requirement is consistent with various policies and programs developed by the State of California and the Commission that seek to increase reliance on non-fossil based generation to reduce greenhouse gas emissions and promote conservation and energy efficiency.

The Commission's goals are articulated in part in Energy Action Plan and Energy Action Plan II, adopted on May 8, 2003, and October 2005, respectively and call for all strategies for increasing conservation and energy efficiency to minimize increases in electricity and natural gas demand and establish a goal of decreasing per capita electricity use through increased energy conservation and efficiency measures. The Energy Action Plan also identifies a "loading order" that places energy efficiency as "the resource of first choice for meeting California's energy needs." The loading order is codified in Pub. Util. Code Section 454.5(b)(9)(C).

4.2.3. Measuring Elasticity of Customer Demand

Each of the utilities' rate design proposals includes an assessment of the impacts of their rate design proposals on conservation of electricity by the residential class. A customer's price elasticity of demand can be measured by calculating the customer's percent change in consumption given a 1% change in price. Determining the price elasticity of demand for residential customers is

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[34] Letter to State Assembly Members regarding AB 327, from Gov. Edmund G. Brown Jr., October 7, 2013.

particularly difficult given the current tiered rate structure. Parties disagree on whether customers understand what their electric rates are at any given moment during the month, and whether they need to understand the rate structure in detail in order to respond to the intended signals. For this reason, parties did not agree on whether customers respond to a marginal price set by the highest tier of usage, or a marginal price tied to the average bill. Parties also disagreed on what price elasticity should be modeled.

In its Opening Testimony, PG&E presented the results of an Excel-based model evaluating the impact of its proposed rate design on conservation. PG&E compared the impact of its proposed 2018 rates to its 2014 rates under four scenarios, calculated the percentage change in prices between each tier, and then applied price elasticities to estimate changes in sales by tier. PG&E then summed the changes over all the tiers to estimate the effect on usage from its proposal.[35] In its first scenario, PG&E assumed a price elasticity of demand of -0.2 for all tiers. Given the uncertainty regarding the price elasticity assumption, however, PG&E also modeled four alternate elasticity assumptions. We refer to this approach as the PG&E method. Several parties, including ORA and TURN, criticized PG&E's approach on the basis that it not only assumes that customers know what tier they are in, but also assumes that customers know the price of each tier and when they move from one tier to another.

In Joint Rebuttal Testimony, PG&E and SCE witness Faruqui provided more detailed analysis of customer response to price for PG&E and SCE's rate proposals. Witness Faruqui used three different methodologies: (i) a

[35] Exh. PG&E-101 at 2-66.

Tier-Specific methodology, (ii) an Average Price methodology, and (iii) a Marginal Price methodology.[36]

Under the Tier-Specific methodology, the price change in each tier is assumed to affect the conservation in that tier. For each tier, the percentage change in price between each tier is multiplied by an estimated price elasticity to determine the percentage change in consumption in that tier. The change in consumption for each tier is then combined to obtain the overall net change in consumption attributable to the rate design change. Dr. Faruqui's Tier-Specific analysis assumes a price elasticity of -0.13 in the first tier and -0.26 in all other tiers. TURN disagrees with this methodology because it assumes that customers know the tier prices and what tier they are in.

The Average Price methodology assumes that customers respond to changes in their bill and increase consumption if their bill decreases and vice versa. Under this approach, each customer's bill under the new rate is compared to its bill under the old rate and then multiplied by an estimated price elasticity to obtain the percentage change in consumption. Dr. Faruqui's Average Price methodology uses a consumption-weighted average of the price elasticities used in the tier-specific methodology, resulting in a price elasticity of -0.18 for PG&E. For SCE, the average price elasticity was -0.17.[37]

The Marginal Price methodology offered by the joint PG&E/SCE testimony compares the new price of each customer's marginal (i.e., highest) tier to the old price of the marginal tier. The percentage change in price is multiplied

[36] The PG&E analysis was based on 12 months of consumption data from approximately 6,700 customers in calendar year 2011. The SCE analysis was based on 12 months of consumption data from 8,213 customers from calendar year 2013.

[37] Exh. PG&E-111 at 9.

by an estimated price elasticity to estimate the percentage change in the customer's total consumption. This approach assumes that customers respond to the actual price they avoid when reducing consumption.

Dr. Faruqui's Marginal Price methodology uses a price elasticity for the first tier of -0.13, and class consumption-weighted average of the tier specific price elasticities (-0.13 and -.26), resulting in a price elasticity of -0.18 for PG&E and -0.9 for SCE. Dr. Faruqui's Marginal Price methodology also uses income elasticity variables of 0.16 for PG&E and 0.15 for SCE, meaning that for a 10% bill increase in the inframarginal tiers, a customer's electricity consumption would decrease by 1.6 or 1.5% for PG&E and SCE customers, respectively.
Dr. Faruqui's analysis included the utilities proposed fixed charges converted to a levelized charge and added to the price of the first tier. Dr. Faruqui suggests that the marginal tier price method correctly models the way that customers would respond to changes in price if they accurately understand the actual impact of changes in usage on their bill.[38]

TURN and NRDC take issue with the Marginal Price methodology used by PG&E and SCE because it includes an income "expenditure" variable based on the assumption that customers also respond to the amount of money spent to reach the marginal tier according to their income elasticity – the higher the bill to reach the marginal tier, the less electricity will be consumed. Dr. Faruqui states that the application of an income elasticity variable means that "the same reduction in electric consumption would be realized through either a 10% increase in a customer's bill or a 10% decrease in overall household income."[39]

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[38] RT Vol 17 at 2357-2359, PG&E/Faruqui.

[39] *Id.* at 2362, 2368.

TURN points out that for a customer with an annual income of $60,000, the application of this income elasticity variable would mean that a $6,000 reduction in income would be assumed to result in a 1.6% reduction in electric usage. That same customer would be assumed to reduce their electric usage by the same amount (1.6%) if their bills increase by as little as $72 per year. According to TURN, assuming identical changes in consumption under scenarios presenting significantly different economic impacts to a customer is not reasonable. Dr. Faruqui acknowledged that he has not included this variable in his prior analyses of tiered rates and that he could not name a study that had used such a variable.[40] Dr. Faruqui also acknowledged that his methodology could lead to results that appear difficult to reconcile.[41]

We agree with TURN and others that the use of the "expenditure" variable is not appropriate for calculation of customer response to electricity prices. However, we find that, aside from the use of the expenditure variable, the Marginal Price methodology is an appropriate model for customer behavior. This conclusion does not rely on any assumption that customers necessarily understand the rate tiers, but rather the fact that it is the marginal rate that determines the *change* in a customer's bill from month to month as consumption varies. It is most often those changes in the monthly bill that capture customers' attention and lead to further action. If a customer reduces consumption in response to a high bill, it is likewise the marginal rate that will determine how much the customer saves. If that change is significant, the customer may pursue

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[40] *Id.* at 2371.

[41] *Id.* at 2368-69, 2371.

further actions to achieve greater savings. If the change is small, it is less likely that even the initial action will be sustained.

Under the joint PG&E/SCE analysis, PG&E's rate design proposals would result in a decrease in annual residential consumption of 0.6% using the Tier-Specific methodology, a decrease in consumption of 1.2% using the Average Price methodology, and an increase in annual residential consumption of 1.2% using the Marginal Price methodology. PG&E also finds that across all methodologies "reducing the CARE discount has the effect of reducing consumption since it represents an overall increase for the residential class."[42]

The joint PG&E/SCE analysis find that for SCE customers, consumption will decrease by 0.5% using the Tier-Specific methodology, decrease by 1.1% using the Average Price methodology, and increase by 1.8% using the Marginal Price methodology.

In addition to endorsing the approach and findings of Dr. Faruqui, SCE performed an analysis of conservation impacts based on changes in average bills. Using this approach, SCE determined that customers make decisions regarding conservation based solely on changes to the average bill. According to SCE, a $10 per month or 10% bill impacts essentially serve as proxies for when customers would notice a change. TURN contests this method, challenging its assumption that the customer remains uninformed about changes to its rate structure and typical usage level. Neither PG&E nor SCE analyzed the conservation impacts of rate design proposals submitted by any other party.

SDG&E performed a separate analysis of the conservation impacts of its residential rate design proposals using the tier-specific methodology built in to

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[42] Exh. PG&E-111 at 13.

the PG&E bill impact calculator. SDG&E did not conduct an analysis using the average rate or marginal tier methodologies. In its analysis, SDG&E used a -0.1 price elasticity for all tiers, assuming that customers would respond to changes in lower tier prices in the same manner they respond to higher tier prices.[43] [44] SDG&E calculated the impacts of including the proposed fixed charges using two different methodologies: a levelized or "all-in" approach similar to PG&E's and SCE's and a second approach that applied the fixed charge to all tiers.

Upon request from TURN, SDG&E also modeled the impacts of retaining a -0.1 price elasticity for the first tier and substituting -0.2 as the price elasticity for all other tiers to compare SDG&E's results to those of PG&E and SCE's. Applying these modified inputs to SDG&E's model results in a 0.27% increase in consumption for non-CARE customers.

Conservation Impacts: SDG&E Table[45]

	2015-2017 kWh Percent Change
SDG&E Scenario 1 (-0.1 elasticity, fixed charge in bottom tiers)	-0.36%
SDG&E Scenario 1 (-0.1 elasticity, fixed charge in all tiers)	-0.32%
SDG&E Scenario 2 (-0.2 elasticity, fixed charge in bottom tiers	-1.41%
SDG&E Scenario 2 (-0.2 elasticity, fixed charge in all tiers	-0.91%

43 RT Vol. 15 at 1955: 5-14, SDG&E/Willoughby.

44 SDG&E based its residential elasticity estimate on the residential sales models developed for the purpose of submitting residential sales forecasts to the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) process. *See* Exh. SDG&E-113.

45 Exh. SDG&E-113, Appendix A at 2-3.

SDG&E did not analyze the conservation impacts of the rate design proposals submitted by any other party.

Dr. Faruqui did not perform his own independent analysis on SDG&E's proposed rate reforms.[46] However, upon review of SDG&E's analysis, Dr. Faruqui finds that "SDG&E's rate design proposals would increase conservation incentives for the lower-tier sales, which constitutes nearly 70% of SDG&E's residential sales, and would reduce those incentives to some extent for upper-tier sales."[47] He admitted, however, that he "had not had an opportunity to review the underlying model in detail." Dr. Faruqui's testimony did not speak to how a customer can conserve lower tier energy unless and until the customer has eliminated all usage in the higher tiers.

Each of the IOUs acknowledges that under their proposals residential rates are expected to increase for both non-CARE and CARE residential customers whose usage terminates in Tiers 1 and 2 while decreasing rates for Tier 3 and Tier 4 customers. However, they maintain that those Tier 1 and Tier 2 customers may "seek additional engagement"[48] or ways to save or manage their energy use using existing EE and/or DR programs while customers whose usage terminates in Tiers 3 and 4 will see bill reductions, and those customers "may have reduced incentives to increase participation in EE or DR over what that participation is today."[49]

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[46] RT at 1953: 20-12.

[47] Exh. PG&E-111 at 21.

[48] SCE OB at 132.

[49] Exh. UCAN-104 at 24.

4.2.4. Other Estimates of Price Elasticity

Few if any parties dispute, and we find it reasonable to conclude, that customers in the low usage tiers[50] should be assumed to have lower price elasticity than customers in the higher usage tiers. This is simply logical, because much of that lower tier usage is by customers who also have usage in the upper tiers, usage that must be reduced "first" before any lower tier consumption. Dr. Faruqui's testimony finds that first tier usage represents "necessary essential use" with low elasticity, and usage beyond 200% of baseline is more discretionary.[51] Further, TURN asserts that elasticity may be less for small customers, or customers living in apartments or mobile homes.[52] NRDC and TURN both cite a study of British Columbia Hydro (BC Hydro) residential customers comparing the impact of a newly-introduced two-tiered rate with the existing non-tiered rate.[53] The study found that, under the tiered rate, consumption by the large customers fell. Specifically, the authors found a price elasticity of between -0.08 and -0.13 for large customers (i.e., those customers consuming above the 1350 kWh/bimonthly Tier 1/Tier 2 threshold).[54] However, as shown in the chart below, the study notes that with the introduction of a

[50] The term "small customers" is sometimes used in this proceeding and in AB 327. This proceeding did not address a definition for "small customers." For purposes of this discussion of elasticity we treat "small" and "low usage" as synonymous.

[51] Reporters Transcript (RT) Vol. 16 at 2236, Faruqui.

[52] Exh. TURN-201 at 39; Exh. TURN-207, Attachment WBM-6 (Michael Li, Ren Orans, Jenya Kahn-Lang & C. K. Woo, ARE RESIDENTIAL CUSTOMERS PRICE-RESPONSIVE TO AN INCLINING BLOCK RATE? EVIDENCE FROM BRITISH COLUMBIA, CANADA, June 2014); *accord* TURN OB at 6 n.5.

[53] Exh. TURN-207, Attachment WBM-6 (Michael Li, Ren Orans, Jenya Kahn-Lang & C. K. Woo, ARE RESIDENTIAL CUSTOMERS PRICE-RESPONSIVE TO AN INCLINING BLOCK RATE? EVIDENCE FROM BRITISH COLUMBIA, CANADA, June 2014).

[54] *Id*. at 227.

second tier in fiscal year 2010, customers with consumption below the 1,350 kWh/bimonthly Tier 1/Tier 2 threshold experienced very little rate variation, in real terms, throughout the study period (FY 2005 – FY 2012). Not surprisingly, average consumption of small users also remained virtually unchanged during the study period. Consequently, with little variation in either price or consumption the researchers could not estimate a price elasticity for small customers. The authors acknowledge that their analysis does not consider the effect that suppressing prices for Tier 1 customers may have had on their consumption.[55] If a flat rate had extended through 2012, small customers would have paid higher rates than they paid under the new tiered rate. Presumably the elasticity of small customers is not zero, and small customers would have consumed less than they actually did in 2010 through 2012. Without an estimate of this effect, it is not possible to conclude that the introduction of tiered rates by BC Hydro reduced consumption overall. However, the study did find that customers living in single-family detached houses have more elasticity than customers in town houses, apartments, or mobile homes.[56]

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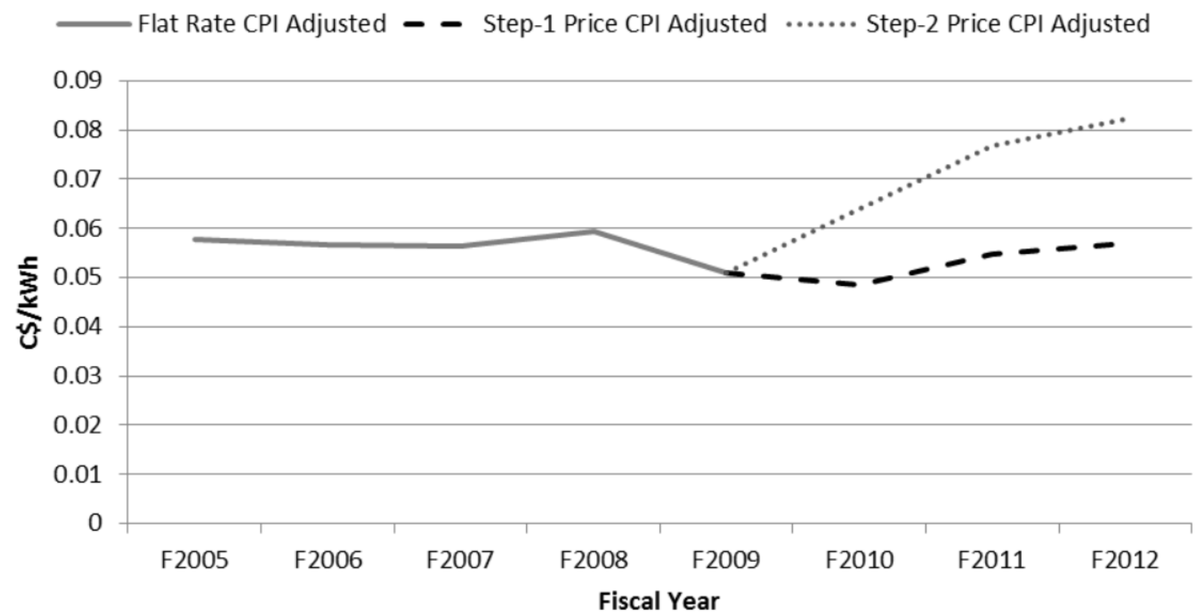
[55] *Id*. at 224 – 225.

[56] *Id*. at 14.

BC Hydro 2 Step Rate



TASC agrees that different elasticity assumptions should be applied to different tiers based on the fact that lower tier usage typically serves necessary energy needs while higher tier usage is more discretionary for most households.[57] TASC suggests that a more appropriate price elasticity for Tiers 1 and 2 is -0.08, the price elasticity coefficient used in the CEC's California Energy Demand 2014-2024 Final Forecast.[58] TASC reports that using this revised elasticity value in PG&E's scenario 1 results in significantly less conservation – an overall reduction of approximately -0.5%in usage - compared to the 3.9% reduction in usage estimated by PG&E.

CforAT cautions that efforts to encourage greater conservation among low-usage and CARE customers should not be used "as cover for reduced

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[57] Exh. TASC-105 at 9.

[58] *Id.* at 10.

conservation among high-usage customers." CforAT notes that the IOUs' primary argument that their proposals increase conservation is based on an assumption that the increased rates in their proposals will result in increased conservation by lower tier customers. CforAT argues that the IOUs ignore the fact that customers in Tiers 1 and 2 typically have less discretionary usage overall and may not be able to conserve. We agree with CforAT's point here.

CALSEIA, TURN, Sierra Club and others also disagree with the IOUs' assertions that as low- and medium-usage customers' bills increase, they may consider energy efficiency and solar options as a method of managing their bills. PG&E, for example, states that the number of residential customers for whom rooftop solar makes economic sense would actually increase as a result of PG&E's residential rate proposal. Based on their analysis of payback periods (discussed in more detail below) CALSEIA and Sierra Club maintain that the payback period for low and medium-usage customers remains higher than most people are willing to wait to break even on an investment. CALSEIA notes that customers with average usage of 250 kWh per month or 500 kWh per month who consider 50% offset solar systems in 2018 will have capital recovery periods of 10.8 -12.9 years under the IOUs rate proposals.[59] These parties also note that lower marginal tier prices will reduce the incentive for customers to buy new appliances (since it weakens the payback period) and thereby weakens the impact of improved appliance standards. Other parties note that a majority of low-usage customers are apartment dwellers and/or CARE customers, which limits their ability to install rooftop solar.

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[59] Exh. CALSEIA-106, Appendix A.

4.2.5. TURN Combined Methodology

Due to the limitations of the utilities' bill impact calculators and the unwillingness of the utilities to model other parties' conservation scenarios, TURN prepared its own conservation analysis. TURN developed a combined methodology based on its assertion that customers respond both to change in their bill and the price of incremental usage in the marginal rate tier.

TURN's approach includes a combination of average and incremental rates to reflect its position that customers respond both to changes in their bill and the price of incremental usage in the marginal rate tier. TURN used a -0.05 elasticity value for customers who remain in the first tier and a -0.2 elasticity value for customers above baseline.[60] TURN argues that a -0.05 elasticity value for customers who remain entirely in the first tier is reasonable.

Under TURN's analysis, PG&E's 2018 two-tier rate design would increase consumption by 4.88% under the marginal price approach, increase consumption by 1.44% under the average price approach (excluding the fixed charge) and increase consumption by 2.34% under the combined method incorporating both approaches.[61]

TURN applied the same analytical approach to its proposed three-tier rate structure (with no customer charge), and found that its proposal would increase load by 2.43% under the marginal price approach and decrease load by 0.24 %

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[60] Exh. TURN-201 at 40. Aside from an earlier discussion of price elasticity as low as -0.08 for large customers in the BC Hydro study, TURN does not include a rationale for choosing such a low price elasticity estimate for low usage customers.

[61] Exh. TURN-201 at 40-41.

under the average price approach, or produce a net increase of 1.09% under a method incorporating both approaches.[62]

Percentage Increase in Consumption (PG&E 2 Tier vs. TURN 3 Tier)

	PG&E 2 Tier Rate (excluding fixed charge)	**TURN 3 Tier Rate (excluding fixed charge)**
Marginal Price	4.88%	2.43%
Average Price	1.44%	-0.24%
Combined	2.34%	1.09%

As noted above, TURN disregarded PG&E's model because the elasticity estimates incorporated into the model assume that customers know what their rates are at any given moment. TURN also notes that the utilities' model produces illogical results by estimating that baseline usage could decline while usage in Tiers 3 and 4 simultaneously increase, explaining that "this is a physical impossibility." This is a critical observation.

TURN claims that under the Average Rate method with no customer charge, a 50-50 average and incremental rate, as well as the incremental rate method (and PG&E's elasticity method which TURN does not support), the TURN three-tier rate proposal is superior to PG&E's in terms of either not increasing consumption or increasing it less than PG&E's method.[63]

4.2.6. ORA TOU Analysis

ORA maintains that TOU rates better align customer energy efficiency and DG with the IOUs avoided costs. ORA used PG&E's Bill Impact Calculator model to estimate total and peak period load reduction under ORA's proposed TOU rate. The models used in PG&E's Bill Calculator are the Brattle Group's

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62 TURN OB at 6.

63 Exh. TURN-201 at 40.

3-period (Summer) and 2-period (Winter) PRISM models. After updating the consumption data to reflect PG&E's E-TOU rate design model, ORA assumed an elasticity of substitution of -0.2 and an own-price elasticity of -0.04, based on elasticity of substitution estimates reported in recent studies from -0.07 to -0.4 and own price elasticity assumptions reported from -0.02 to -0.1.[64] ORA then presented high and low case scenarios to show the extreme values for the two elasticity inputs using the rates.

ORA Table 7-2[65]

	Elasticity assumptions used in PG&E Conservation Tab		Low Case		High Case	
	Substitution Elasticity -0.2 Own-price Elasticity -.0.04		Substitution Elasticity -0.07 Own-price Elasticity -.0.02		Substitution Elasticity -0.4 Own-price Elasticity -.0.1	
Season	Consumption Change %	Change in usage (kWh/season)	Consumption Change (%)	Change in usage (kWh/season)	Consumption Change (%)	Change in usage (kWh/season)
Summer Peak	-11.34%	(396,073,648)	-4.22%	(147,480,267)	-22.00%	(768,321,131)
Summer Partial-Peak	-3.47%	(94,194,294)	-1.32%	(35,956,786)	-7.57%	(205,792,014)
Summer Off-Peak	3.44%	340,300,813	1.09%	108,206,485	6.09%	602,859,105
Summer Total	-0.93%	(149,967,130)	-0.47%	(75,230,568)	-2.30%	(371,254,040)
Winter Partial-Peak	-1.32%	(23,603,769)	-0.04%	(7,896,406)	-2.54%	(45,497,982)
Winter Off-Peak	0.04%	46,361,304	0.14%	19,244,617	0.77%	102,850,241
Winter Total	0.15%	22,757,535	0.08%	11,348,211	0.38%	57,352,259
Annual Total	-0.41%	(127,209,595)	-0.20%	(63,882,357)	-1.01%	(313,901,781)

[64] Exh. ORA-101 at 7-9 (citing Ahmad Faruqui & Sanem Sergici Arcturus: *International Evidence on Dynamic Pricing*, ELECTRICITY JOURNAL, VOL. 26, ISSUE 7: 55-56 (2013).

[65] Exhibit 101 at 7-10.

Based on this, ORA estimates that its proposed TOU rate for PG&E would result in a 0.4% decrease in total load consumption and an 11% decrease in peak load consumption.

4.2.7. Do Customers Understand their Rates?

ORA disagrees with the IOUs' assertion that customers only react to average bills and suggests that the average price methodology is not consistent with the goals of promoting a better understanding of rate design. We agree, and further observe that even without such better understanding, the "average price" approach is a static analysis that fails to take into account customer reaction to changes in bills from month to month. Those changes are determined by the marginal rate, not the average rate, except when there is an overall rate change.

Furthermore, ORA notes that of the methodologies analyzed by Faruqui, only the average price methodology shows the introduction of a fixed charge increasing consumption.[66] This result is borne out by the joint PG&E/SCE analysis, with the average price methodology showing decreased conservation associated with the introduction of, or increases to, the fixed charge. However, ORA maintains that this method inappropriately assumes that customers don't understand their rates.

ORA suggests that because the utilities have spent "billions of dollars on the mass-implementation of Advanced Metering and Smart Grid initiatives that provide easier access to more granular consumption data…" new rates should be introduced "assuming that the utilities will adequately inform customers about

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[66] ORA OB at 58.

their rate structures and choices."[67] ORA notes that while the utilities cite one paper by Kochiro Ito to support their assertions, this paper relies on studies and data from 1997 to 2007, well before the utilities invested in advanced metering and smart grid initiatives.

Because it disagrees with the IOUs regarding whether customers react to average bills, ORA finds the joint PG&E/SCE Tier-Specific and the Marginal Price methods more useful in estimating the conservation effects of ORA's rate design. ORA notes that for two out of the three joint PG&E/SCE methodologies, adding a fixed charge, or increasing an existing fixed charge will increase consumption. Based on the models, a fixed charge would result in a consumption increase nearly as large as collapsing the tiers and reducing the CARE discount. For SCE increasing the fixed charge will have a larger change than reducing baseline.

NRDC also maintains that customers react only to the highest tier and that no price changes in tiers other than the marginal tier will affect a customer's conservation decision.[68] NRDC argues that if customers are only responding to their total bill or average rate, they would not alter their consumption regardless of whether the utility's rate design was 20 cents/kWh or a fixed charge of $105/month plus 1 cent/kWh. NRDC argues that this outcome is implausible, and that it is more plausible that customers only respond to the highest tier price.

NRDC claims that Faruqui's calculations lead to a significant understatement of the usage increase for price decreases and an overstatement of the usage reduction for price increases.

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[67] *Id.*

[68] NRDC OB at 12.

CforAT states simply that "many customers simply pay their bills with no thought to the formula by which they are calculated, and nothing except potentially increased education efforts is likely to change this reality."[69]

4.2.8. Energy Efficiency, DR, DG Impacts

In response to the ALJs' request that the utilities quantify and discuss the impacts of any proposed rate design changes over the period 2015-2017 on customer participation and load impact in Energy Efficiency (EE), Demand Response (DR), and Distributed Generation (DG) program, the utilities generally responded that they did "not have an expectation of what the specific changes in customer participation and/or to load impacts to its EE, DR, and DG programs… it does expect that some customers will seek out ways to manage their usage."[70]

The IOUs explained that EE and DR program participation is driven by multiple factors such as advertising and rebate levels and therefore isolating the impact of rate changes would be difficult. ORA agrees, and suggests that we leverage the current evaluations conducted through the Commission's EE and DR program. For example, ORA notes that many EE evaluations focus on program attribution, or what is referred to as the Net-to-Gross (NTG) ratio.[71] In these evaluations, the evaluator focuses on the customer's motivation for participation in EE programs in order to better estimate the impact of the EE program itself on the participant's behavior. ORA suggests that the impact of rate changes could be included in the NTG evaluations.

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[69] CforAT OB at 18.

[70] Exh. SDG&E-105 at 7 (Willoughby).

[71] The net energy savings reflect the impact caused by the EE program after other factors that influenced the customers' decisions are netted out. The gross energy savings reflect the total conservation achieved regardless of what caused it.

While the utilities did not quantify the impact of their rate design proposals on EE, DR, and DG programs, several parties representing solar interests analyzed the impact of the utilities' proposals on the payback periods of certain EE upgrades.

UCAN maintains that over the next four years, lower-tier customers who have been protected or sheltered from the incentive to engage in EE and DR will face increasing incentives to do so, while upper–tier customers who have faced twice the price of lower-tier customers and have been clearly incentivized to engage in EE and DR programs, will face reduced incentives to engage in these programs. UCAN acknowledges that "there is clearly a trade-off between flattening the rate all way to 20% and reducing the current benefits of the tiered structure for conservation purposes versus preserving some conservation potential in the tiered structure …"[72]

TURN claims that not only will all the utilities' rate design proposals increase consumption by decreasing the higher tier rates, the impacts of the utilities' proposals could wipe out as much as three years' of conservation spending in increased usage.[73] To put the percentage increases or decreases into perspective, TURN explains that "PG&E's rate design will essentially cancel out 1 to 3 years' worth of the millions of dollars that PG&E spends on residential energy efficiency."[74] Under TURN's analysis, PG&E rate design proposals would increase overall residential class consumption between 514 - 1,071

[72] Exh. UCAN-101 at 25.

[73] Exh. TURN-201 at 1.

[74] *Id.* at 40.

Gigawatt hours (GWh) per year.[75] According to TURN, when compared to the energy efficiency program savings goal recently adopted for PG&E of 697 GWh in 2015, the effect of PG&E's rate design proposal in this proceeding would essentially negate PG&E's energy efficiency program efforts for 2015.[76]

We find this evidence quite disturbing, and will endeavor to prevent our rate design decisions from acting at cross-purposes to our efforts to promote energy efficiency using ratepayer funds. It would be counter-productive to reduce upper tier rates here, only to have to increase them again in order to recover the increased costs of energy efficiency incentives needed to offset the reduced cost-effectiveness of efficiency investments from the customer's point of view.

4.2.9. Payback Periods

The solar parties, along with NRDC and TURN maintain that understanding how rates impact payback periods informs whether a proposed rate design is consistent with the principle that rates encourage conservation and energy efficiency. In their view, payback periods are an important metric to evaluate the potential impacts of alternative rate designs because any rate–driven changes in monthly bill savings will necessarily affect a homeowner's interest in entering a solar lease or purchasing a new water heater or air conditioning (AC) system. As the price of a kilowatt hour rises or falls, so does the savings from conserving (or avoiding generation of) that kilowatt hour. Moreover, customers with the lowest payback periods are most likely to invest in a given technology. According to NRDC, even if tiered rates introduce cross-subsidies, state policy

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[75] *Id.* at 41 (Table 12).

[76] TURN RB at 6-7 (citing PG&E OB at 4, Exh. TURN-201 at 41, and D.14-10-046 at 10).

goals and legislation strongly endorse the energy efficiency benefits of tiered rates. They argue that the unambiguous loading order priority and the principle of conservation and efficiency in this proceeding support the argument that even if there is some remaining cross-subsidy, it is appropriately supported by explicit state policy goals.[77] These parties suggest that the Commission should retain a minimum of a three-tiered rate structure with a steeper differential between tiers. These parties assert that all California residents benefit from the positive health and environmental effects of increased renewable generation and the IOUs' proposed changes to residential rate design threaten the economic attractiveness of renewable technologies. We agree.

Sierra Club maintains that potential solar or EE customers generally discount future savings at a very high rate, meaning that they expect to recoup their investment in new technology very quickly. Sierra Club analyzed the impact of the proposed rate design changes on investments in energy efficiency and distributed generation using models designed to test the conservation impact on each of four common upgrades: 1) on-site PV; 2) upgrading a central AC unit upon the end-of-life of an existing unit; 3) changing 100% of the light bulbs in a residence to LED lamps; and 4) replacing an electric resistance water heater with an efficient electric heat pump, for electric only customers. Sierra Club finds that PG&E customers whose air conditioners could currently be repaid in six years or less would see their payback period increase by an average of 4.1 years under PG&E's proposed tiered rates, and 3.7 years under proposed TOU rates, and that the overall potential savings with a 10-year payback from

[77] NRDC OB at 11.

this measure or less are cut roughly in half under PG&E's proposed rates.[78] Sierra Club also finds that the utilities' tier flattening proposals would eliminate all the potential savings from installing LEDs that can be paid back in under two years, across all utilities and all proposed rates.[79] We consider these findings to be disturbing and quite instructive.

The solar parties emphasize that the residential rate tariffs and the net energy metering (NEM) tariffs work together to determine a customer's bill and accordingly, support or undermine a residential customer's solar investment.[80] As a result, changes to the residential rate structure necessarily affect the monthly savings provided by NEM. They argue that higher tiered rates that raise the marginal price for the average kWh of sales encourage conservation and energy efficiency in ways that flatter rates cannot and that large reductions in bills to large customers and large increases in bills to small customers would send a clear signal that California is not prioritizing energy efficiency.[81]

Sierra Club cites an National Renewable Energy Laboratory survey finding that "50% of non-adopters [homeowners who did not have PV] would require a payback period of 6 years or less to seriously consider adopting" and that solar market penetration curves flatten significantly as payback periods increase.[82]

CALSEIA measured the payback period for each of the utilities proposal for customers with different levels of consumption and with systems that offset

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[78] Sierra Club OB at 10.

[79] Exh. Sierra Club-101 (Corrected) at 21.

[80] Vote Solar OB at 7.

[81] NRDC OB at 8.

[82] Sierra Club OB at 7.

different proportions of usage. CALSEIA finds that the capital recovery period under the utilities' proposals are 9.2 years to 10.8 years for customers with 750 kWh or more of gross monthly consumption, compared to capital recovery periods of 5.6 years to 8.1 years under the current rate structure.[83] The capital recovery periods for customers with smaller usage would be longer.

CALSEIA also claims that the utilities' rate design proposals would reduce the monthly bill savings of existing solar customers by 26%-40%.[84] The utilities acknowledge these concerns, admitting that "[T]he average customer payback periods for customers installing new solar NEM facilities will increase slightly,"[85] and "SCE recognizes that payback period can provide information on customer adoption of solar."[86] This is true for both host-owned systems and Power Purchase Agreements (PPA). PG&E further acknowledges that "changes that negatively impact the payback period for host-owned systems also negatively impact PPA customers."[87] IREC agrees, noting that with the anticipated reduction in the Federal Investment Tax Credit from 30% to 10% after 2016, it will take roughly a 20% price decline by 2017 for customer-sited solar facilities to be as attractive to customers then as they are now, given no changes in rates; tier flattening and fixed customer charges would further limit the market."[88] Vote Solar claims that the Commission should not change the rate structures

[83] CALSEIA OB at 5.

[84] *Id.* at Table 2.

[85] Exh. PG&E-101 (Part 2) at D-32.

[86] Exh. SCE-106 at 107.

[87] RT Vol. 11 at 1267-1268, PG&E/Halperin.

[88] IREC OB at 6.

customers that solar customers relied on in making their investments. We give weight to this concern in our decisions herein.

CALSEIA, TURN, and Sierra Club disagree with the utilities' assertions that as low- and medium-usage customers' bills increase, they may consider energy efficiency and solar options as a method of managing their bills. PG&E, for example, states: the number of residential customers for whom rooftop solar makes economic sense would actually increase as a result of PG&E's residential rate proposal. CALSEIA and Sierra Club maintain that the payback period for low- and medium-usage customers remains higher than most people are willing to wait to break even on an investment. CALSEIA notes that customers with average usage of 250 kWh per month or 500 kWh per month who consider 50% offset solar systems in 2018 will have capital recovery periods of 10.8 - 12.9 years under the IOUs' rate proposals.[89] Other parties note that a majority of low-usage customers are apartment dwellers and/or CARE customers, which limits their ability to install rooftop solar.

4.2.10. Conservation and Fixed Charges

The impact of the proposed fixed charges on conservation effort was also actively debated in this proceeding. According to TURN and ORA, along with the solar parties, high fixed charges in particular will lead to energy efficiency programs that are less effective or more costly, or both.[90] ORA and TURN explain that the IOUs collectively spend more than a billion dollars a year on EE programs. According to ORA, a rate structure with a fixed charge will reduce customers' potential bill savings from investing in EE and DG and will lengthen

[89] Exh. CALSEIA-106, Appendix A.

[90] Exh. TURN-101 at 33.

the payback period for these investments, resulting in either higher rebates raising program costs or lower penetration of the programs or both. ORA maintains that this outcome is inconsistent with the Energy Action Plan, the SB 32 goals, and the requirements of Section 739.9(e)(2). We agree.

ORA suggests that the Commission should design the rate structure to promote conservation when possible to increase EE investment at no additional cost to ratepayers. In ORA's view, this is particularly important to low-income customers because higher volumetric energy rates help compensate for market barriers to customer energy efficiency due to split incentives and lack of access to capital. CALSEIA and TASC agree.

Regarding fixed charges, TASC also used PG&E's model to compare the effect of a fixed charge on conservation and found a 1.9 % reduction in usage,[91] nearly four times that of PG&E's proposal, when TASC assumed no monthly fixed charge.[92]

4.2.11. Discussion

Based on the studies and analysis presented in this proceeding, it is clear that the utilities' proposed rate design changes will reduce the structural incentives for conservation present in the existing rates, and extend the payback periods for efficiency and solar investments. The issue we consider here is whether the impacts associated with the proposed rate design changes are unreasonable, and whether they unreasonably impair incentives for conservation such that the proposals must be rejected. We find that they are and they do. In reaching this conclusion, we consider the evidence on price elasticity and

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[91] TASC OB at 12-14.

[92] Exh. TASC-105 at 12.

methodology as well as the impacts on payback periods, and consider generally whether the rate design proposals in this proceeding are consistent with law and the RDP.

The analyses used to determine the conservation impacts rely on varying assumptions about how customers respond to electricity prices. However, considered as a whole, the various analyses presented show that marginal rates – which determine the change in the customer's bill from month to month as usage varies and the payback period for efficiency investments - will have the greatest impact on increases or decreases in conservation. Because the utilities have made no efforts to compare the conservation impacts of their own proposals with those put forward by the other parties, it is not possible to fully compare parties' proposals against each other.

With the exception of ORA, most parties, including TURN, maintain that the joint PG&E/SCE tier-specific methodology presented by the utilities are based on unrealistic assumptions regarding consumer behavior and should not be relied upon. We agree. The PG&E model is also based on the PG&E Bill Impact Calculator and suffers from the same flaw. PG&E's witness Keane acknowledged that few customers actually know what usage tier they are in at any point during the billing cycle and that instead "customers notice and respond to significant changes in bills triggered by usage billed at high marginal tier prices.[93] [94]

TURN concludes that customers will either respond to average bills, or to the highest marginal tier price, and theorizes that customers react to a

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[93] RT Vol. 10 at 1056-1058, PG&E/Keane.

[94] Exh. TURN-201 at 37.

combination of average and marginal tier rates. TURN was only able to analyze the effect of conservation on PG&E's proposed rate design in detail due to the limitation of the utilities' bill calculator models and the fact that the utilities declined to assist TURN in preparing additional scenarios. However, TURN's conclusions make intuitive sense. A customer is most likely to notice changes in their bill from one period to the next. That same customer, to the extent they were concerned about high bills, would then be expected to notice the price of the next unit of output to evaluate whether they should or could conserve energy and reduce their bills.

Based on the analyses provided, we conclude that the marginal price methodology best represents our understanding of customers' response to tiered rates. We also agree that with TURN, TASC, NRDC, CforAT and other parties that customers with low usage (usage that currently does not exceed Tiers 1 and 2), are less likely to have discretionary electricity use that can be adjusted in response to higher rates.

The parties have provided compelling evidence that we cannot *assume* that customers who only have usage in the lower tiers are able respond to price changes at the same price elasticity as customers with higher usage. As TURN, TASC, Sierra Club and CforAT point out, customers in the lowest usage tier simply do not have as much ability to reduce consumption on their baseline usage as customers with higher tier usage. There will be exceptions of course, but most parties accept that baseline quantities, generally defined as 50-60% of average usage in each geographic zone, are calculated to represent the amount of electricity needed for essential usage that cannot be avoided without potential detrimental impacts to health and safety. Moreover, customers with usage in the upper tiers are completely unable to reduce their lower tier usage until all of that upper tier consumption has been eliminated. This makes their lower tier usage highly inelastic.

TURN correctly points out that the impacts of the rate designs proposed by the IOUs have the real potential to effectively offset or negate a significant portion of our energy efficiency program savings. Considering that California is already spending nearly a billion dollars a year of ratepayer money on these programs, and Governor Brown has proposed doubling efficiency gains by 2030, this is a matter of grave concern. It makes no sense to "drive with one foot on the gas pedal and the other on the brakes," which is exactly what the extreme tier flattening and fixed charges proposed by the IOUs threaten to do.

The Proposed Decision suggested, at page 61, that "over-investment in energy efficiency" could occur as a result of tiered rates. We find this assertion quite remarkable. California certainly does not have a problem of *too much* customer investment in energy efficiency – quite to the contrary, we continue to see *under*-investment in efficiency measures that otherwise appear to be fully cost-effective. Reducing upper tier rates and thereby increasing the payback periods on customer efficiency investments hardly seems like a prescription for achievement of the state's aggressive efficiency goals.

Given our finding that customers respond primarily to marginal prices, only those customers who remain in the first tier most months of the year may consume more than the socially optimal level. Since relatively few customers remain in the lowest tier most months of the year, excess consumption (if any) would occur for a much smaller share of the population. Likewise, because upper tier rates are higher than average rates and affect a substantial share of the population, tiered rates provide an incentive to this larger share of the population to increase conservation and energy efficiency investments.

While one could argue that the elasticity evidence in this proceeding is not entirely definitive, the same cannot be said for the evidence on payback periods. Simple math demonstrates that payback periods on efficiency and solar investments are determined by the customer's marginal rate, not the average rate. Thus, it is clear that the IOU proposals here will undermine such investments by lengthening the payback period for most customers.

Based on this, we find that as a whole the rate design proposals of the IOUs unreasonably impair incentives for conservation.

4.3. Income and Usage Correlation

The correlation between household income and electricity usage has been the subject of debate throughout this proceeding. Because there are many factors which influence usage, including climate and household size,[95] it is difficult to assess the particular impact that income has on usage. While there is agreement that there is some positive correlation between income and usage, parties disagree on whether this correlation is strong or significant.[96]

Determination of whether there is or is not a correlation can vary depending on whether one looks at data on a California-wide basis, on a climate zone basis, or on a household basis. Since the start of this proceeding there have been significant advances in geographic information system mapping that could improve our ability to assess the correlation between income and usage. For the present, we summarize the discussion of the issue in this proceeding, broken down chronologically. To provide context, this summary reaches back to the rate

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[95] TURN Proposal at 19; SCE OB at 10.

[96] PG&E Proposal at 37 ("While there is a positive correlation between income and usage, that correlation is weak").

design proposals and comments filed by parties in summer 2013 (prior to passage of AB 327).

4.3.1. 2013 Rate Design Proposals and Responses

TURN's original rate design proposal submitted on May 30, 2013 (TURN proposal) sets the stage for the debate.[97] In that proposal, TURN refers to an "established" correlation between income and usage, while granting that such correlation is imperfect.[98] To support its argument, TURN cites data from the CEC's 2009 Residential Appliance Saturation Study (RASS) showing that the average low-income household uses less energy than the average high-income household in California.[99]

In their proposal, TURN also breaks down the RASS data by income quartile to show that 8% of low-income households and 20% of moderate-income households are "high" energy users (defined as using over 8,350 kWh/year), compared with 41% of high-income households.

Apart from the RASS data, TURN also reviewed PG&E's and SCE's non-CARE rate data for municipalities across California. They found that those communities with the highest average electricity rates (and therefore highest average usage), tended to be communities with high median incomes, while those communities with the lowest average rates tended to have low median incomes.[100] For example, in the PG&E service territory, the communities of Atherton, Woodside, Ross, Hillsborough and Los Altos Hills had the highest

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[97] TURN does refer to an earlier CPUC literature review on the subject, published in June, 2012.

[98] TURN Proposal at 14.

[99] *Id.* at 15-16.

[100] *Id.* at 20-25.

average rates, and all show reported median income of $147,000 or above. On the other end of the spectrum, Arvin, Avenal, Lakeport, San Joaquin and Mendota pay the lowest average rates, and the highest median income among that group is less than $55,000. A similar pattern exists in the SCE service territory.

PG&E presented their own rate design proposal on May 29, 2013 (PG&E proposal). In their proposal they also refer to the CEC's RASS data. PG&E came to several conclusions based on their analysis of the RASS data pertaining to PG&E customers:

- Of the 865,000 non-CARE lower income households with annual incomes between $30,000 and $60,000, over one-third had high usage[101] and paid an average annual rate that exceeded the residential class average.
- Of the one million non-CARE moderate income households in the $60,000 to $100,000 annual income range, over half had high usage and paid an average annual rate that exceeded the residential class average.
- In contrast, over 40% of the nearly 1.1 million higher-income households with incomes exceeding $100,000 per year had low usage and paid an annual average rate below the residential class average.[102]
- Approximately 57% of PG&E's non-CARE customers using energy at Tier 3 rates and above were moderate or low-income customers.[103]
- Statistically there is a correlation coefficient of only 0.33 when comparing income and usage, which is "relatively weak."[104]

[101] PG&E defines high usage as 1/12 for each month with Tier 3 or above usage for each customer.

[102] PG&E Proposal at 37.

[103] *Id.* at 35.

TURN's response to the PG&E proposal pointed out that because the coefficient of 0.33 was calculated across all of PG&E's territory, it reflects variations in usage that may be due to climate rather than income and is therefore not an appropriate calculation.[105] TURN argued that once the RASS data were segregated by climate zone, the empirical relationship between income and usage became clearer.[106]

PG&E's response to the TURN proposal focused on TURN's analysis of average energy usage and median community income, arguing that comparing averages of usage and income was an unreliable method for determining if there was a significant correlation between those variables.[107] PG&E noted that TURN did not present individual household income-to-usage estimates to buttress its conclusions. PG&E pointed to its own rate design proposal as containing such household-level data, with more data points overall, leading PG&E to conclude that its results were "far more credible" than TURN's.[108]

PG&E also follows up on TURN's analysis of average usage and median income by community, and shows that there is usage variability among communities with similar median incomes. This leads PG&E to argue that "there is a wide range of average rates paid by households in every city. Even in the

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104 *Id.* at 38.

105 TURN Opening Comments of July 12, 2013, at 45.

106 *Id.* at 45-46.

107 PG&E Opening Comments of July 12, 2013, at 14 (citing a 2012 CPUC literature review stating that the correlation between income groupings and average electricity use may appear to be more significant than correlation between actual income and electricity use).

108 *Ibid.*

cities…with median annual incomes above $100,000, there are significant percentages of customers paying low average rates."[109]

Finally, PG&E calculates correlation coefficients for the income-usage relationship for individual communities in its territory using the RASS data. PG&E found that "the correlations are generally positive, but weak, with many in the range from 0.20 to 0.40. While there are a couple of cities with correlations above 0.50, there are also three cities with correlations below 0.10 (one of which is very slightly negative)."[110]

TURN's reply to PG&E's response seeks to refine the original TURN analysis on average community usage by grouping cities into three climate zones and then examining the relationship between usage and income. Calling the correlations "clear and robust," TURN argues that their reanalysis "shows the strongest correlations for cities with household incomes below $100,000 per year in the hot zone, significant correlations in the cool zone and weaker correlations in the mid zone."[111]

In its reply comments, TURN also points out that PG&E's criticism of its approach was focused on the average community-oriented comparisons and did not address TURN's other analysis showing that the high-income proportion of usage cohorts increased as usage increased.[112] TURN also reviewed city-level data provided by PG&E to determine correlations between average rates and median household income in each distinct climate area. This analysis found

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[109] *Id.* at 17.

[110] *Id.* at 19.

[111] TURN Reply Comments of July 26, 2013, at 25.

[112] *Ibid.*

correlations of 0.46 in the hot zone, 0.75 in the mid climate zone, and 0.65 in the cool climate zone.[113]

SDCAN's rate design proposal argued that the RASS data showed that the association between income and usage was "significant" and that the richest customers on average used more energy. SDCAN states that the causal link between income and usage is that richer households tend to have larger homes requiring more air conditioning and other energy-consuming amenities such as swimming pools.[114]

SCE's rate design proposal stated that the relationship between income and usage is "weak."[115] In their response to TURN's Proposal, SCE states that there is no perfect correlation between income and usage and that "inevitably" some low-income and middle-income customers would use as much energy as high-income customers.[116]

ORA's response to SCE's Proposal argues that SCE's CARE customers consume 16% less energy than its non-CARE customers and that low-income customers tend to use less energy than high-income customers on a per-person basis.[117] CforAT/Greenlining's response is similar, stating that 64% of PG&E's CARE customers and 60% of SCE's CARE customers have average usage that is captured by Tier 1.[118]

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113 *Id.* at 22-25.

114 SDCAN Proposal at 28.

115 SCE Proposal at 59.

116 SCE Opening Comments of July 12, 2013, at 18, 43.

117 ORA Opening Comments of July 12, 2013, at 46-47.

118 CforAT/Greenlining Opening Comments of July 12, 2013, at 3.

In SDG&E's rate design proposal, they assert that some low-income high-usage customers are subsidizing high-income low-usage customers in their territory under the current tiered rate structure.[119] CFC refers to an assumption that low-income customers are low-usage customers, but does not explicitly support the assumption.[120]

While not explicitly saying so, the CforAT/Greenlining rate design proposal implies that low-usage customers are likely to be low-income customers.[121] NRDC's rate design proposal describes the correlation between income and usage as "logical"[122] and states that in California usage is generally income-related.[123]

Sierra Club's rate design proposal included an analysis of the PG&E bill calculator model showing that high usage was associated with higher income with a correlation coefficient of 0.23.[124] In their response to PG&E's Proposal, Sierra Club states that "[s]ince the PG&E bill calculator shows that collapsing tiers results in a bill decrease for the wealthiest customers, it follows that the wealthiest customers are more likely to be the highest electricity users."[125]

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[119] SDG&E Proposal at 39.

[120] CFC Proposal at 8.

[121] CforAT Proposal at 65 ("[i]n a number of prior rate design proceedings, CforAT and Greenlining have expressed concern that the IOUs' efforts to reduce the rates charged to upper-tier customers would be accompanied by corresponding rate increases on low-income and/or low-usage customers, including customers who have the least ability to pay").

[122] NRDC Proposal at 39.

[123] *Id.* at 38.

[124] Sierra Club Proposal at 7.

[125] Sierra Club Opening Comments of July 12, 2013, at 14-15.

4.3.2. Staff Proposal position on the Income/Usage Relationship

On January 3, 2014, Energy Division submitted the Staff Proposal for Residential Rate Reform in Compliance with R.12-06-013 and AB 327 (Staff Proposal). The Staff Proposal granted that there was considerable debate concerning the correlation between income and usage.[126]

The Staff Proposal stated that while there was an "imperfect" correlation the fact remained that some low-income customers were in a high-usage cohort and some high-income customers were in a low-usage cohort. The Staff Proposal concluded that PG&E's approach to using household-level data was preferable to TURN's averaging approach, and that "the correlation of income with usage is not strong enough to support the generalized argument that low-income households are harmed by default TOU."[127]

IREC responded to the Staff Proposal's conclusions and stated that they generally supported TURN's position that there was a strong correlation between income and usage.[128]

4.3.3. Evidentiary Hearings and Briefs on Income/Usage

The debate concerning the relationship between income and usage continued during the evidentiary phase of the proceeding. We summarize here some of the arguments that were not duplicative of the arguments heard in earlier phases of the proceeding.

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[126] Staff Proposal at 37.

[127] *Id.* at 40.

[128] IREC Comments on Staff Proposal at 4.

TURN broke down the statewide RASS survey data, as supplied by the IOUs in their recent GRC Phase 2 proceedings, to calculate a general correlation between income and energy usage for SCE and SDG&E.[129] For SCE, their analysis shows that high tier usage generally increases with income, with some variability.[130] For SDG&E their findings are similar.[131]

TURN also uses data from PG&E's bill calculation model to show that "there is less variation in usage by income in hot climates, though customers under $30,000 to $60,000 use less than those above in most of the four hotter zones;"[132] and that "while the utilities tend to claim that income and usage are relatively unrelated, the bill calculation models for PG&E show that higher income customers tend to use more."[133] For example, TURN states that "in the largest [PG&E] region, Zone X, 38% of non-CARE customers earn over $100,000, and they use 90% more than non-CARE customers earning less than $60,000."[134]

TURN further refers to national-level data from the Bureau of Labor Statistics and the Energy Information Administration to argue that there is a positive correlation between income and energy usage.[135]

IREC states that the correlation between income and usage is "is almost certainly underestimated" by the IOUs.[136] While they do not independently

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[129] *See generally* Exh. TURN-207, attachments WBM-9 and WBM-10.

[130] *Id.* at 381-382.

[131] *Id.* at 443.

[132] Exh. TURN-201 at 20.

[133] *Id.* at 29.

[134] *Id.* at 19.

[135] *Id.* at 29.

[136] IREC OB at 16.

analyze a particular data set to arrive at an estimate of such correlation, they do critique PG&E's calculation. IREC states that while PG&E arrived at a relatively mild income-usage correlation coefficient of 0.33, it did not perform this analysis by comparing customers within climate zones or by striking NEM customers from the data set.[137] These omissions, in IREC's view, make PG&E's estimated correlation figure unreliable.

PG&E repeats many of its arguments from earlier phases of the proceeding and argues that the correlation between income and usage is weak, with a correlation coefficient of 0.33.[138] PG&E points to data that indicates that there are "significant numbers" of low-income households that consume large amounts of energy.[139] PG&E also refers to the CEC's RASS data as supporting a conclusion that household size helps to determine usage as well.[140]

Like PG&E, SCE grants that there is some correlation between usage and income, but they argue that there are many low-income households with high electricity consumption and many wealthy customers with low consumption.[141] SCE argues that the "proper correlation" to consider is between household size and usage, not between income and usage.[142] SCE further states that it is somewhat illogical to divide usage cohorts strictly, as customers may migrate

[137] *Id.* at 16-17.

[138] PG&E OB at 12; RT Vol. 12 at 1381: 1-21, PG&E/Quadrini.

[139] Exh. PG&E-101 at 1-11 & n.25.

[140] *See* Exh. PG&E-116.

[141] SCE OB at 115.

[142] *Id.* at 10.

between usage cohorts over the course of a year due to factors such as weather or employment status.[143]

TURN found higher correlation coefficients when comparing a community's average rate to that community's median income. While we believe that using household-level data rather than city-wide averages is a preferable method for quantifying correlations between income and usage, such data is not as readily available.

SDG&E argued during evidentiary hearings that there are working families and fixed-income seniors in their territory that are burdened by high-usage energy rates.[144] They further argue that in their territory there are high-usage as well as low-usage CARE customers.[145] While this may be true anecdotally, we do not believe that these outliers are truly reflective of the majority of customers.

The evidence leads us to conclude that while low-income and moderate-income ratepayers are not universally low or high users of energy, there is an apparent and meaningful correlation between usage and income that we must take into account in our decisions. It is clear that, on balance, the utilities' proposals will tend to benefit higher-income customers and disadvantage lower income. The fact that these conclusions are not universally true does not make them less important. Indeed, one could reasonably characterize the IOU proposals as a "rate design for the one percent."

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[143] SCE RB at 77.

[144] RT Vol. 13 at 1594-1595 SDG&E/Winn.

[145] SDG&E OB at 48.

4.4. GHG Reduction

Reduction in GHG emissions has frequently been cited as a reason to employ TOU rates.[146] Because California relies on natural gas peaker plants and older less efficient natural gas plants to supply energy during summer peaks, it seems intuitive that a shift in energy demand away from peak periods will also reduce GHG emissions. However, the California Independent System Operator (CAISO) system is interconnected to other states in the Western Electricity Coordinating Council (WECC) region.[147] When WECC-wide emissions are considered, the evidence that TOU rates will necessarily lead to GHG reductions is not so clear.

Parties who analyzed the potential of TOU rates to achieve GHG reductions reference two measures of emissions levels:

- "Emissions intensity" or "emissions rate," which is a measure of pounds of CO_2 per MWh of electricity generated.
- "Heat rate," which is a measure of the amount of fuel energy used to generate a unit of electricity. Heat Rate is typically expressed as Btu/kWh. A lower heat rate means a more efficient generator or pool of generating resources.

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[146] *See, e.g.,* Exh. SDG&E-117, SMUD SmartPricing Options Interim Evaluation at 1 of 195 (SMUD "has committed ... reduce the greenhouse gas emissions that contribute to global warming and lower the cost to serve our region."); D.08-07-045 (stating that "[b]y linking retail rates to wholesale market conditions, dynamic pricing can discourage customers from consuming polluting power. Conversely, if other time periods are dominated by non-emitting and low-cost resources such as nuclear, water and wind, dynamic pricing could signal to customers that the supply of power is clean."); Exh. EDF-102 at 13.

[147] WECC is the Federal Energy Regulatory Commission-approved non-profit entity that oversees reliability of the Western Interconnection's bulk electric system, which includes California. WECC includes 13 other western states, two Canadian provinces, and Baja, Mexico. https://www.wecc.biz/Pages/home.aspx.

During the 2013 portion of this proceeding, parties suggested that the appropriate way to measure the GHG emissions reduction from a TOU rate load shift would be to compare the heat rate for the peak period hour in which usage was decreased to the heat rate in the hour to which the use was shifted. For example, "a kWh shifted from 3:00 PM, when the marginal heat rate is 10,000 Btu per kWh, to say, 9:00 PM, when the marginal heat rate is 7,000 Btu per kWh, conserves 3,000 Btu of natural gas, and avoids the corresponding GHG emissions that would otherwise occur."[148] Energy Division's 2014 Staff Proposal applied this approach.

In contrast, TURN cited a study that examined whether GHG emissions reductions from changes in energy use could be part of a state implementation plan for California Air Quality Management Districts.

At the time of the evidentiary hearings, however, both ORA and TURN advocated WECC-wide analysis as the best way to determine if TOU rate structures could reduce GHG emissions. They argue that because WECC-wide dispatch is impacted by California's electric loads, changes in dispatch and the amount of incremental GHG in the western region of the United States should be taken into account when evaluating whether TOU rates can reduce GHG emissions.

As TURN explains, "electric systems in the WECC are interconnected and engage in substantial amounts of power transactions among each other. Load and generation in one portion of the WECC thus affect the generation used to meet load in other parts of the WECC. To assess the influence of changes in load

[148] DRA's Responses to the Residential Rate Design OIR Questions, June 5, 2013, at 24 n.40 (cited by Energy Division Staff Proposal at 53 n.87).

in California on incremental CO_2 emissions, it is thus important to assess these impacts over the entirety of the WECC."[149]

TURN and ORA both discuss WECC-wide studies of GHG emissions in their testimony that other organizations had conducted, because WECC-wide dispatch models are complex and time-consuming to run. Both ORA and TURN relied on models run for other purposes when calculating the impact of load shifts on GHG emission rates, and they agreed that this approach is less than optimal.

TURN witness Woodruff evaluated three existing production cost simulation modeling studies,[150] and concluded that "there is neither a strong nor consistent relationship between incremental CO_2 emissions in the Western United States and electric loads in California."[151] Witness Woodruff found that there was a positive link between load and emissions during annual peak hours – meaning that emissions decrease as load decreases, but the correlation was less strong at other times, and in the spring there was actually a negative correlation.[152] The 2020 PG&E study found that the highest average hourly incremental emissions (lbs/MW) occurred around midnight in the spring months. Witness Woodruff theorized that this high emissions level was the result of coal plants operating at the margin during these off-peak hours and

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[149] Exh. TURN-204 at 11.

[150] The three studies used were: (i) PG&E 2020 study performed in 2013; (ii) CAISO studies performed at the direction of the Commission in 2014 examining system conditions in 2022; and (iii) CAISO studies performed at the direction of the Commission in the Long-Term Procurement (LTPP) dockets for 2024

[151] TURN OB at 68 (citing Exh. TURN-204 at 2-4).

[152] *Ibid.*

increasing their dispatch to meet the new demand. He also reasoned that "increasing amounts of renewable generation in California (and elsewhere in the WECC) may serve to increase the amount of remaining coal generation that is dispatchable."

The WECC-wide model evaluated by ORA showed a correlation between load shift and emissions, but, unlike TURN's conclusions, it found that there was no indication of a GHG increase as a result of TOU rates.

Both ORA and TURN explained that the modeling studies they evaluated do not draw conclusions about how much energy customers will conserve as a result of TOU rates; instead, they only assume that customers will shift load from one time period to another.

ORA and EDF both argue that TOU rates will likely lead to overall reductions in usage, not just a shift from peak, but these load reductions were not modeled rigorously. EDF's assessment that TOU rates will lead to GHG reductions is based in part on an assumption that TOU rates will reduce total consumption. We believe a more rigorous method for forecasting load reduction is necessary before forecasts such as EDF's can be used to demonstrate GHG reductions as a significant goal of TOU rates. At this time we do not have adequate information on the extent to which customers might reduce total consumption under TOU rates.

SDG&E argues that an evaluation of the GHG emission impacts of TOU rates should be limited to plants under contract.

We agree with TURN and ORA that the California-based heat rate comparison method is not sufficient to evaluate the impacts of load shift on GHG emission rates in the west. Our discussion therefore focuses on the analysis of TURN and ORA. We note, however, that the GHG reduction impact of TOU rates is not limited to an incremental increase or decrease in emissions intensity at the time of load shift. TOU rates can also be structured to reduce GHG emissions in other ways, such as allowing a greater proportion of intermittent renewables to be integrated into the grid.

Parties argued that TURN's study is flawed for several reasons. EDF argued that TURN's study does not take into account the possible coal plant retirements expected from the Environmental Protection Agency (EPA) Clean Power Plan. TURN counters that some coal plant retirements are part of the model used. In addition, the EPA Clean Power Plan may change before it is approved.

TURN argues that ORA's model supports TURN's own argument that there is not a clear correlation between load shifting and GHG reduction.

For ORA's and TURN's studies, questions were raised about how modeling assumptions, such as forced outages (which are generated randomly using a methodology embedded in the production cost model) and coal plant retirements could have skewed the studies' results.

In sum, none of the models evaluated by parties provides a sufficient basis for finding that GHG emissions will increase or decrease due to load shifts caused by TOU rates in California. However, we agree with TURN's primary recommendation that the Commission should conduct more detailed analysis and modeling to clarify the impacts that load shifting will have on overall GHG emissions. Such analysis should also provide information sufficient to determine highly sensitive variables and assumptions that could skew the results. As information on TOU response becomes available, modeling of GHG reductions must also consider the potential for load reductions in addition to load shifts. Most importantly, we do not want to inadvertently increase GHG emissions by fostering increased reliance on out-of-state coal plants with higher GHG-emissions rates. We must also recognize California's challenge to integrate increasing amounts of renewable energy into the grid, the role that TOU rates may have in supporting efficient renewable integration, and the complex interactions between resources over which the Commission has significant influence, and those, like the composition of out-of-state baseload generators, over which we do not.

4.5. Expected Long-Term Cost Savings from TOU Rates

Long-term cost savings have also been cited as a benefit of TOU rates.[153] ORA argues that time-of-use rates will result in significant long-term cost savings due to deferral of system upgrades and the need for new generation.[154] ORA estimates that TOU rates (as proposed by ORA in May 29, 2013 filing) would result in a 2,400 MW peak load reduction, "which is equivalent to the size of one nuclear power plant."[155]

Likewise, EDF argues through their own analysis that there will be significant system cost savings on the order of $500 million a year if only half of customers take service on TOU rates.[156]

The amount of potential long-term cost-savings from TOU rates, as estimated by EDF and ORA, is significant. No other parties in this phase attempted to quantify cost-savings from TOU-induced load shifts. Several of the

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[153] D.08-07-045 at 2-3.

[154] Exh. ORA-201 at 1-3.

[155] *Id*. at 1-3 n.5.

[156] Exh. EDF-101 at 8.

solar parties cited potential long-term cost savings, but without mentioning specific studies or forecast amounts. The utilities did not attempt to measure cost savings of TOU rates in this proceeding.

TURN asserts that there are "no credible estimates of cost savings under default TOU rates."[157]

TURN argues that the estimates of ORA and EDF are "deeply flawed."[158] TURN contends that for the ORA and EDF predicted cost-savings to occur, there "would need to be significant customer response in the form of predictable load reductions that mirror both system and circuit-level peaks" resulting in the reduction of the need to build incremental new generating capacity. As a specific example, TURN points out that EDF's analysis assumes that all distribution circuit-peaks take place during the summer peak and does not account for the fact that some distribution circuits are winter peaking. EDF also did not break its cost savings estimate out by avoided generation, distribution, and transmission costs. During evidentiary hearings, EDF witness Fine acknowledged that the estimate of reduced generation needs on which EDF relied was a "very back of the envelope calculation."[159] In addition to arguing that the ORA and EDF estimates are flawed, TURN contends that any cost-savings estimates should include the estimated cost of TOU implementation, and costs that might result from unpredicted customer load shifts.[160]

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157 TURN OB at 63.

158 *Id.* at 64.

159 RT Vol 24 at 3747, EDF/Fine.

160 TURN OB at 63.

Finally, TURN contends that because the current Long Term Procurement Proceeding (LTPP) has not identified the need for additional generation in the immediate future, it is unreasonable to calculate avoided costs of generation when current forecasts do not show a need for additional generation in the immediate future. TURN's point is well taken, but we also believe that need for specific types of additional generation may change in future years.

The cost savings expected from avoided investment in distributed, generation and transmission is one of the most frequent arguments made in favor of default TOU. Quantifying these savings, however, remains theoretical. Therefore, we direct the IOUs to develop methodology for estimating these savings resulting from TOU. However, we do not rely on these specific figures of either EDF or ORA when directing IOUs to move toward default TOU. We expect that quantification of these savings may overlap with savings attributed to other Commission programs for demand side management, such as EE.

4.6. Implementation of Residential Time of Use Rates in other Jurisdictions

4.6.1. Overview

TOU rate designs are considered beneficial because they are potentially the most cost-based rate design, they can be designed to allow customers to respond when reducing load could reduce the need for additional infrastructure, they could potentially reduce overall GHG emissions by reducing the need to run peaker plants and less efficient fossil fuel plants on hot afternoons. By flattening the load curve, TOU rates could also improve grid reliability.

The Commission has previously found that "Dynamic pricing can lower costs by more closely aligning retail rates and wholesale system conditions, thereby promoting economically efficient decision-making."[161] Despite this finding for dynamic rates (which can include real-time pricing), California has yet to attempt wide-spread rollout of residential TOU rates. TOU rates are time-varying, but not dynamic. TOU rates have consistent peak and off-peak periods from day to day and are therefore easier for the average residential customer to understand and respond to.

Although we have long known that energy costs vary by time of day,[162] leading the Commission to adopt default TOU rates for Commercial & Industrial customers, TOU rates for residential customers were not possible until wide-spread installation of smart meters made it possible to track customers' usage by time. In fact, this capability was one of the primary reasons supporting the rollout of residential smart meters.[163] Because residential meters that efficiently track usage by time are relatively new, there are few existing examples of residential TOU programs on which to base assumptions about rate design, and even fewer examples of default residential TOU rates.

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[161] D.08-07-045 at 2.

[162] The electricity required by residential, industrial, and commercial consumers is not constant. Customer needs vary daily and seasonally, but in predictable patterns. During the peak load periods, many consumers simultaneously use large amounts of electricity. To meet loads during these periods, utilities must have extra power plants in reserve. These peaking power plants generally are more expensive to run than base-load units. Their costs also must be amortized over much fewer hours. This makes the cost of electricity produced during the peak period relatively higher. Any electricity that the utility procures in the market also reflects these economics. *See* Exh. ORA-101 at 1-6.

[163] *See, e.g.,* D.07-04-043 at 4 ("a first important step for achieving [demand response] is to 'issue decisions on the proposal for statewide installation of [advanced metering infrastructure] for small commercial and residential time-of-use (TOU) customers by mid-2006 and expedite adoption of concomitant tariffs for any approved meter deployment.'); *see also* Ruling Providing Guidance for the Advanced Metering Infrastructure Business Case Analysis, February 19, 2004, Appendix A at 3.

Parties supporting TOU rates include: SDG&E, UCAN, SEIA, Sierra Club, NRDC, EDF, and ORA. Although these parties differ on when and how default TOU should be rolled out to residential customers, they all agree that the benefits of TOU weigh in favor of default or wide-scale TOU being made available in the coming years.

UCAN notes that TOU rates are "efficient and equitable" to all customers.[164] TOU rates inform customers when costs are high and when costs are low, enabling customers to make economical usage and investment decisions. It is also equitable to all individuals because customers large and small receive the same price signals.[165] UCAN provided the following chart, which concludes that a TOU rate meets the RDP better than a tiered rate.[166]

R1206013 Rate Design Principles	Tiered Rate	TOU Rate
1. Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost.	Y*	Y*
2. Rates should be based on marginal cost.	N**	Y
3. Rates should be based on cost-causation principles.	N***	Y
4 Rates should encourage conservation and energy efficiency.	Y/N	Y/Y
5. Rates should encourage reduction of both coincident and non-coincident peak demand.	N/N	Y/[N][167]
6. Rates should be stable and understandable and provide customer choice.	Y/N/N	Y/Y
7. Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals.	Y*****	Y
8. Incentives should be explicit and transparent.	Y*	Y*
9. Rates should encourage economically efficient decision-making.	N	Y
10. Transitions to new rate structures should emphasize customer	Y/Y/Y****	Y/Y/Y****

164 UCAN OB at 33.

165 *Ibid*.

166 UCAN RB at 29-30.

167 Although UCAN argues that TOU rates can reduce non-coincident peak demand, we do not believe the TOU rate structures under consideration in this proceeding would be able to target non-coincident peak demand.

R1206013 Rate Design Principles	Tiered Rate	TOU Rate
education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.		

**The ability to make sure low income and medical baseline customers have access to electricity is not dependent to the rate structure since any rate can offer a discount on the energy prices, e.g., CARE. The same holds for incentives which can be explicit and transparent regardless of rate structure, DR or TOU. These incentives can be offered outside the rate as well but available to customers on the DR/TOU rate.*
***Tiered rates are not as easily based on marginal costs as TOU except for the customer charge. The energy charge can be based on marginal costs overall but not individual tier prices which are arbitrary.*
****Tiered rates are not as easily based on cost causation principles as TOU except for the customer charge. Actions by customers cannot be traced back to utility costs incurred or saved except on TOU.*
*****Cross subsidies are harder to avoid on a tiered rate structure which has the following characteristic: setting the lower tier rates lower results in higher upper tier prices to meet revenue requirement target. Any attempt to reduce or cap the lower tier price for policy reasons or to mitigate bill impacts results in cross subsidies to upper tier customers.*
******Both the tiered and TOU rate structure require customer education and outreach. Parties differ with respect to which is more understandable and that will depend on the quality of the educational efforts. Bill impacts can be mitigated in either case but TOU rates have a closer relationship to cost. Therefore, bill impacts will be easier to explain based on actual usage and utility costs and not just a consequence of tier structure. For example, doing laundry on weekends saves nothing on bill under tiered rate DR. But the same action on TOU can result in monthly savings based on the difference between on-peak and off-peak energy prices.*

While this comparison is interesting, we note that we are not confined to a binary choice between tiered rates and TOU. It is quite possible to capture the benefits of both approaches through a rate design that continues to encourage efficiency and conservation while adding an incentive to shift usage to times when demand and prices are lower. We intend to move toward such an approach by requiring that the majority of TOU rates include both baseline credits and excess consumption surcharges.

Many parties have concerns about a TOU rate structure, and are particularly concerned about default TOU rates. Concerns range from lack of customer acceptance, impacts on low-income customers, customer inability to respond to TOU price signals, locked-in TOU periods exacerbating load curve, and potential negative impact on economics of rooftop solar.

For a residential TOU rate structure to be successful, it must be understood and accepted by customers. In order to better understand how this can be accomplished, the next section summarizes residential TOU programs that have already been implemented and studied.

4.6.2. Other Residential Time of Use Programs

Time-of-use (TOU) rates have been a fixture in California energy policy for over 30 years. Beginning in the late 70s, TOU rates were made mandatory for the largest industrial customers, depending on their demand.[168] The passage of time and the advent of advanced metering saw mandatory TOU rates rolled out to smaller and smaller customers.[169] The ability to enable time differentiated rates and potentially reduce peak demand was cited by the Commission as a major benefit of smart meters and part of the justification for their expense.[170]

Beginning in 2011, the Commission ordered mandatory TOU for the rest of the non-residential rate classes,[171] citing that "dynamic pricing can lower costs, improve system reliability, cut greenhouse gas emissions, and support

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[168] D.85-05-059 (ordered three major utilities to implement mandatory TOU for customers with demands greater than 500 kW).

[169] D.01-05-064 modified by D.01-08-021 *and* D.01-09-062 (Commission required mandatory TOU rates for all customers with maximum demand greater than 200 kW who received new meters through a program funded by the CEC).

[170] D.03-06-032, Appendix A (California Demand Response: A Vision for the Future (2002-2007)).

[171] D.10-02-032, *modified by* D.11-11-008 (defaulted PG&E's small and medium non-residential customers to TOU rates); D.13-03-031 (same for SCE); and D.12-12-004 (same for SDG&E.

modernization of the electric grid."[172] Nearly all non-residential customers in California will be on mandatory TOU rates before the end of 2015.

Opt-in TOU rates for residential customers have a long history in California and have been offered by the three major utilities since the mid-80s. PG&E's first standard residential TOU tariff, E-7, was made available as an optional rate starting in 1986, for those who agreed to install and pay a monthly charge for an interval meter. As noted in the testimony of several parties (PG&E, SCE, SG&E, EDF, ORA, SEIA, UCAN, TURN), both opt-in and default residential TOU rates have been piloted around the world and examining the results of these programs can provide important insights on best practices.

Arizona Public Service (APS) is a model for utilities seeking customer adoption of opt-in rates, with over 50% of their residential customers on TOU rates as of 2015, an average of 5% peak load reduction and 76% of the customers satisfied with the utility's service.[173] They seem to have found the most success in targeting customers with larger than average bills. However, this level of enrollment took almost 20 years to achieve.[174] Salt River Project (SRP), also in Arizona, boasts high opt-in acceptance with 30% of its customers on a TOU rate as of 2015. SRP has offered TOU rates since 1980, but has drawn many new

[172] D.08-07-045 at 4.

[173] SEIA cites a 5% demand reduction from 40% of APS residential customers who are volumetric rates. SEIA 101 at 24.

[174] Chuck Meissner, Arizona Public Service, "Residential Time-of-Use Pricing," presentation from APSC Webinar, January 2014.

customers with its 'EZ-3' rate, which has a shorter peak period and a higher peak to off-peak ratio than its legacy rate.[175]

Many parties[176] have discussed Sacramento Municipal Utility District's (SMUD) SmartPricing Options pilot as a landmark study due to its scientific rigor and use of experimental design. The Final Evaluation, released in September 2014, found a 5.8 % peak load reduction from the customers chosen for the default pilot,[177] similar to the load reductions demonstrated by customers in Arizona Public Service (APS) territory and in the 2003 California Statewide Pricing Pilot,[178] which were both opt-in programs. Customers in the opt-in portion of the pilot were able to achieve 12% peak load reductions.[179] Most notably, the default portion of the pilot had only a 4 % drop out rate, smaller than the 5% of the opt-in participants who chose to leave the program.[180]

In Ontario, Canada, the Ontario Energy Board (OEB) embarked on the world's largest default TOU rollout by requiring all of the distribution utilities in the province offer default TOU rates by 2011. Currently 97% of residential customers in the province are on TOU rates. An evaluation of the program

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[175] Loren Kirkeide, *Effects of Three-Hour On-Peak Time-of-Use Plan on Residential Demand during Hot Phoenix Summers*, THE ELECTRICITY JOURNAL, VOL. 25, ISSUE 4 at 48-62.

[176] PG&E, SCE, SDG&E, EDF, ORA, SEIA, UCAN, and TURN.

[177] SmartPricing Options Final Evaluation, Nexant SMUD SmartPricing Options Pilot Evaluation, Executive Summary at 4.

[178] Charles River Associates, IMPACT EVALUATION OF THE CALIFORNIA STATEWIDE PRICING PILOT, March 16, 2005, at 1.1.

[179] SmartPricing Options Final Evaluation, Nexant SMUD SmartPricing Options Pilot Evaluation, Executive Summary at 4.

[180] *Id.* at 73.

found an average 3.3% reduction in summer on-peak usage since the change.[181] This was a multi-year effort, with the OEB focusing on increasing TOU enrollment starting in 2005 with opt-in rates and aggressive marketing campaigns by the OEB and the utilities.

Despite the long history of policy support for TOU rates in California, the various California pilot projects, and the near ubiquity of smart meters, adoption of TOU rates are still extremely low in California.[182] The only other jurisdiction to deploy large scale default TOU has been in Enel's service territory in Italy. The Italian Authority for Electricity and Gas made TOU rates mandatory in 2010. In order to transition people to the new rates, a 'transition' rate with a very small peak to off-peak differential was in place until 2012. As the differentials increased, response to the program also increased. However, the very small difference between the periods led to a smaller customer response, only about 1% peak load reduction.[183]

Two other smaller jurisdictions are cited by PG&E as providing insight into default TOU. In Washington state, Puget Sound started full-scale default TOU in 2001, but terminated the program in 2002 due to customer backlash. In Connecticut a planned default TOU rollout by United Illuminating resulted in 50% of customers ultimately opting out. The phased rollout started in 2008 by defaulting the largest residential customers first (over 4,000 kWh per month).

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[181] Brattle Group, IMPACT EVALUATION OF ONTARIO'S TIME-OF-USE RATES: SECOND YEAR ANALYSIS, December 16, 2014 at 37.

[182] PG&E 3.4%, SCE 0.52%, SDG&E 0.60% of customers on TOU rates, IOU Supplemental Filings April 1, 2014.

[183] Simone Maggiore & Ricera Sistema Energenico. "Impact of a mandatory time-of-use tariff on residential customers in Italy," presentation from Espoo, November 2012.

Fifty percent of customers opted out. Rollout of the program was terminated before customers below 2,000 kWh per month were defaulted to the rate.

Another approach to introducing TOU rates has been to offer consumer choice between rates. The two Arizona utilities each offer several different TOU structures to provide their customers with choice. Both have "traditional" seven-hour peak period rates, as well as three-hour peak period rates with higher price differentials between the periods. SEIA asserts that APS's success was due to offering a variety of TOU rate designs.[184] Salt River Project's (SRP) "EZ-3" rate, has experienced rapid growth since its introduction in 2005, despite the higher peak rate. A study between their seven-hour TOU and three-hour TOU found a much stronger peak reduction response from EZ-3 participants but SRP believes it is better to maintain both options to reduce peak across the whole period, especially considering "snapback" in usage at end of the shorter peak period.[185]

The price differential between on and off-peak rates has been shown to impact the amount of load shift or reduction from customers on TOU rates. Through analysis of 34 different TOU programs and pilots, the Brattle Group found that on-peak to off-peak ratio is positively correlated with peak load reduction (for example a ratio of 2:1 yields 4-5% peak load reduction and a 5:1 ratio should yield 9% reduction).[186] A steep price differential, however, will result in significant negative impacts on customers who do not shift load out of

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[184] Exh. SEIA-101 at 24.

[185] Loren Kirkeide, *Effects of Three-Hour On-Peak Time-of-Use Plan on Residential Demand during Hot Phoenix Summers*, THE ELECTRICITY JOURNAL, VOL. 25, ISSUE 4: 48-62

[186] Ahmad Faruqui & Sergici Sanem, *Arcturus: International Evidence on Dynamic Pricing*, ELECTRICITY JOURNAL, VOL. 26, ISSUE 7: 55-56 (2013).

peak periods. The SMUD pilot set on-to-off peak prices on a cost-basis, resulting in a price differential of about 19 cents. In contrast, the other default programs have had flatter on-to-off peak price ratios,[187] presumably as a means of gaining customer acceptance. Information on balancing these three principles (cost-causation, customer acceptance, and reduction in peak load) is not readily available for these existing programs, but will be important in designing any default TOU rate for residential customers in California.

Parties disagree about the conclusions to be drawn from these pilots. PG&E asserts that SMUD, APS and SRP are all located in areas with higher A/C saturation[188] than PG&E, and therefore there are no conclusions to be drawn about these pilots for PG&E. SDG&E concludes that "studies and experience in Canada, Arizona and California have shown that residential customers can successfully be transitioned to TOU with positive results through default rates."[189] ORA believes that the SMUD study showed that "most customers found TOU rates easy to understand"[190] while TURN believes the very same study shows that "customers placed on TOU rates didn't understand how they were being charged for their usage."[191] It is clear that there is disagreement about the inferences that should be drawn from the SMUD pilot. Nonetheless, the SMUD pilot represents the most significant and relevant experience with TOU pilot design available today. As such, the IOUs are highly encouraged to

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[187] 1.4:1 for Ontario at the beginning of the program and 1.03:1 for Enel at the beginning of its program.

[188] PG&E OB at 64.

[189] Exh. SDG&E-101 at CY-10-12.

[190] Exh. ORA-101 at 1-11.

[191] TURN OB at 61.

engage with SMUD to ensure that key lessons learned from the SMUD pilot are applied by the IOUs.

4.6.3. Comparison of Default TOU vs. Opt-In TOU

Parties have debated the load reduction potential of default time of use rates over those of opt-in time-of-use rates. PG&E, in particular, has asserted that opt-in programs create more system demand response.[192] There are several factors in this analysis. Firstly, as seen above, peak load reduction is a factor of the price differential between rates.[193] Currently, the few default options that have been implemented have had fairly small peak differentials, with the notable exception of SMUD.

Enrolling sufficient customers in opt-in TOU rates has been challenging for other utilities. APS, after 20 years, has a 53% enrollment rate. The IOUs in this proceeding have not predicted significant enrollment in opt-in TOU. The SMUD study revealed that although opt-in TOU customers individually tend to reduce more, in the aggregate, the default rate produced three times the load reduction.[194]

ORA provided the following summary of enrollment and load response.

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[192] PG&E Supplemental Filing, February 28, 2014 at 2-61 (Figure 2-19).

[193] Ahmad Faruqui & Sanem Sergici, *Arcturus: International Evidence on Dynamic Pricing*, ELECTRICITY JOURNAL, VOL. 26, ISSUE 7: 55-65 (2013).

[194] Exh. ORA-101 at 1-20.

ORA Table Summarizing Residential TOU Load Impacts[195]

Study	off-peak $	on-peak $	Price ratio	kW peak reduction/ participant	peak load reduction	Average Usage	Opt-in/ Default	Enabling Technology	Total Customers
APS	2.0	21.0	10.5	0.2	5%	3.8	Opt-in	no	1,200,000
EDF	4.6	5.8	1.3	1.0	45%	2.2	Opt-in	no	5,700,000
OGE	4.2	23	5.5	1.5	11%	5.0	Opt-in	yes	750,000
SRP	7.2	21.2	2.9	1.4	11%-13%	9.9	Opt-in	no	970,000
Enel	2.99	12.42	4.2	0.0	1%	0.6	Default	no	25,000,000
Hydro One	5.3	10.2	1.9	0.0	3%	1.2	Default	yes	4,500,000
PSE	4.7	6.25	1.3	0.1	4%	2.1	Default	no	945,000
UI	7.5	11.45	1.5	0.0	9%-10%	1.7	Default	no	325,000

While Ontario and Enel have shown modest peak load reduction effects, SMUD's default TOU rate has shown an average of 5.8% peak load reduction, which is comparable to peak load reductions found in optional programs with large peak differentials. This does not look particularly impressive when compared to the 12% peak load reduction from the opt-in participants, but according to SMUD, [w]hen the differential enrollment rates are factored into the equation, default plans offered to the same population of customers as opt-in plans are likely to produce much higher aggregate load reductions."[196]

Because SMUD was only able to recruit 17.5% of the targeted customers on to the opt-in TOU rate, the absolute load reduction provided by default TOU would be nearly three times greater than opt-in TOU due to the much larger number of participants. In the SMUD pilot, the dropout rate for the customers spending at least some time on the default TOU rate was 4%, which was lower than the dropout rate of 5% for opt-in TOU participants. The average peak

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[195] *Ibid.*

[196] SmartPricing Options Final Evaluation, Nexant SMUD SmartPricing Options Pilot Evaluation, Executive Summary at 4.

period load reduction for default TOU participants in SMUD's study was 5.8%. Opt-in customers provided a larger average reduction of 11.9%.

4.7. Specific Legal Issues Applicable to this Decision

4.7.1. Default TOU Pilots

AB 327 gave the Commission the authority to direct the IOUs to employ TOU rates starting no earlier than January 1, 2018. In 2014 testimony and workshops, parties raised the idea of implementing a default TOU pilot prior to employing default TOU. The assigned ALJs asked the parties to brief whether the express prohibition on default TOU prior to January 1, 2018 would apply to a pilot with limited enrollment. Parties consistently agreed that the statutory language prevents the Commission from authorizing a default TOU pilot prior to January 1, 2018. No party suggested an alternative interpretation of the language. Therefore, the assigned ALJs ruled that the January 1, 2018 restriction applies to default pilots.[197]

4.7.2. Requirement for a Baseline Tier for Default Residential Rate

The Commission is required to set a baseline quantity of electricity that represents the amount "necessary to supply a significant portion of the reasonable energy needs of the average residential customer."[198] The statute defines "baseline quantity" as "a quantity of electricity or gas allocated by the commission for residential customers based on from 50 to 60% of average

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[197] ALJ E-mail Ruling Setting Prehearing Conference, October 15, 2014, at 3.

[198] Section 739(b).

residential consumption of these commodities."[199] In establishing the baseline quantities, the commission shall take into account climatic and seasonal variations in consumption and the availability of gas service."[200]

Section 739.9(c) requires that the Commission "require each electrical corporation to offer default rates to residential customers with at least two usage tiers." The first tier shall include electricity usage of no less than the baseline quantity established pursuant to [Section 739(d)(1)]. But there is a clear exception for Section 745(c) (default TOU) rates.

Section 739(d)(1) requires the Commission to "require that every electrical and gas corporation file a schedule of rates and charges providing baseline rates. The baseline rates shall apply to the first or lowest block of an increasing block rate structure which shall be the baseline quantity. In establishing these rates, the commission shall avoid excessive rate increases of residential customers, and shall establish an appropriate gradual differential between the rates for the respective blocks of usage."

Parties raised several questions in connection with this requirement for a baseline tier.

First, some parties suggest that a baseline tier is required for default TOU. The clear language of Section 739.9(c), however, has an exception for the TOU rate structure as described in Section 745. Section 745, the time variant pricing exception including TOU rates, only requires a baseline tier for particular customers, such as medical baseline customers. Thus, based on the language of

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[199] The statute also requires that for all-electric customers the baseline be set at 60-70% of average residential consumption during the winter heating season.

[200] Section 739(a)(1).

the statute, we find that a baseline tier is not statutorily required for default TOU rates. There are, however, very good policy reasons why a baseline tier (or baseline credit and excess consumption surcharge) is desirable. These policy reasons are examined in the section on TOU Rates below.

Second, if a baseline tier is required by law, should the differential between tiers be set to take into account the amount of the fixed charge? The concept of including the fixed charge amount as part of the Tier 1 rate for purposes of calculating the tier differential is known as the "composite tier methodology." Based on the Commission's interpretation of the statute, we have consistently required the IOUs to use the composite tier methodology. Indeed, in D.89-01-055 we concluded that "revenues from any customer charge must, as a matter of law, be included in the baseline rate for purposes of Section 739(c)."

There are also sound policy reasons for doing so. Below is a chart comparing rates with and without using the composite tier differential method. It is clear that, if the utilities are not required to use the composite tier differential, the rates will essentially be flat, with no differential between the tiers. For example, under PG&E's scenario 1(B) from its April 2015 Supplemental Filing, a San Francisco customer would have a lower Tier 2 rate than Tier 1 rate. Because the law requires a baseline tier, we agree with long-standing Commission legal interpretation that the calculation should be made with the composite tier. Otherwise, we allow the utilities to effectively avoid the law.

Comparison of PG&E Scenario 1a (Fixed Charge with a composite tier differential) and Scenario 1b (Fixed Charge without a composite tier differential)

Summer 2018 San Francisco 30-day Non-CARE bill with usage of 130% of baseline	PG&E Scenario 1a	PG&E Scenario 1b
Monthly Service Fee (MSF)	$10.42	$10.42
Tier 1 Energy Charges	$33.60	$37.38
Tier 2 Energy Charges	$14.81	$13.42
Total Bill	$58.83	$61.22
$/kWh of Tier 1 + MSF	$0.210	$0.228
$/kWh of Tier 2	$0.235	$0.213
Actual Differential	$0.025	($0.015)

4.8. Bill Impact and Rate Modeling Assumptions

4.8.1. Adequacy of Modeling

The IOU's rate change proposals require complex utility rate design models to develop rates as well as bill impact models to evaluate the impact of the proposed rates on customers. At the start of this proceeding we directed the IOUs to develop rate impact calculators to assist parties in understanding and testing the impacts of different rate design scenarios. The bill impact calculators were used in evaluating the Phase 2 Settlement for 2014. However, as time passed, the data in the bill impact calculators has become stale. Parties and the assigned ALJs have also requested modeling that was outside the capacity of the bill impact models.

We acknowledge that the capacity and value of the bill impact calculator results are increasingly less reliable as time passes. The bill impact calculators have served a useful purpose of allowing us to compare different rate structures, but the results of the bill impact calculators are illustrative only and cannot be relied on to reflect what actual rates will look like.

To support their rate change proposals, the IOUs were directed to provide two sets of forecast rates. The first included no revenue requirement changes. The second set included a 2.1% annual increase to reflect forecast Consumer Price Index (CPI). The annual CPI was based on the average for the prior three years. However, during evidentiary hearings numerous parties objected that a 2.1% annual increase was not realistic. In addition, these parties pointed out that even if the average increase is 2.1%, it is likely that in some years the revenue requirement increase will be significantly higher than average.

In light of this, the assigned ALJs directed the IOUs to provide a significant amount of updated information for different rate design scenarios, ranging from three tiers with no fixed charge to two tiers without a fixed charge. This supplemental information also included examples of TOU rates assuming three hour and six hour peak periods. Because most parties found the rates modeled with a 2.1% annual increase to be of limited value, we did not require the IOUs to include an assumed increase in the April 2015 Supplemental Filing.

Portions of the April 2015 Supplemental Filing are added to the record. Because parties did not have an opportunity to respond to the April 2015 Supplemental Filing, we have given it limited weight. In addition, the April 2015 Supplemental Filing included updated electricity burden and energy burden calculations. After reviewing this data, we are concerned by the sample size and some of the results. We therefore have not relied on this data.

We find the April 2015 Supplemental Filing provides a reasonable approximation of different rate structures, sufficient to allow comparison. We also find that the April 2015 Supplemental Filing pertaining to post-2015 rate changes is useful for illustrative purposes but should not be relied on as an accurate prediction of actual rates.

For 2015, the IOUs included expected revenue increases. Therefore, the 2015 rates included in Appendix B are a reasonable estimate of the 2015 rates customers will face. This decision addresses concerns about unexpected or large revenue requirement increases by setting certain caps on rate changes after 2015.

5. Consolidation and Narrowing of Tiered Rates

While we have found that tiered rates promote conservation and energy efficiency and that tiered rates tend to benefit those with lower incomes, the current rate design remains relatively steeply tiered, even after several years of rate rebalancing, and has sometimes caused hardship for large users, especially during periods of extreme weather. This situation was not the result of intentional actions by this Commission, but rather reflects the result of legislative restrictions enacted long ago. Further, the size of the current second tier, covering only 30% of the customer's baseline quantity, is nothing more than the vestige of an historical legislative compromise.

Now that AB 327 has restored the Commission's discretion to determine an appropriate residential rate design, we must decide what a desired end-state rate design would look like and provide a glidepath toward that end state that avoids undue impacts in the process.

Parties in this proceeding almost universally support a change to the current tiered structure.

TURN recognizes that the current tiered rate structure needs to be reformed in the coming years and proposes a comprehensive reform that would establish three tiers of usage for each utility.

NRDC agrees with many parties that there are some real issues with the current rates that likely make them unsustainable.[201] ORA supports gradually reducing the number of tiers in the current tiered rate structure to two as part of a transition to default TOU.[202] UCAN also supports redesigning the current tiered rate structure to achieve rates "that are efficient, cost-based and fair to all customers"[203] SEIA, CALSEIA and IREC all recognize the need to change the current tiered structure and present proposals to reduce the number of tiers.[204] Vote Solar states that it supports the tiered rate proposals of SEIA, CALSEIA and IREC and TASC also supports SEIA's proposal.[205] EDF agrees that reforming the current tiered rate structure is necessary, stating that "maintaining status quo tiered rates does not solve the problem of ever growing peak demand."[206] CforAT proposes moving from the current four tiered rate structure to one with three tiers, however CforAT is concerned that "changes in rate design that increase Tier 1 costs and/or shift necessary usage out of Tier 1 risk non-compliance with affordability obligations."[207]

It is clear that a steeply tiered rate results in more volatile customer bills.[208] This volatility is felt most acutely in areas such as Central Valley where, prior to our recent actions to mitigate upper tier rates, a few hot summer days could

[201] NRDC OB at 16

[202] ORA OB at 1.

[203] UCAN OB at 7.

[204] Exh. SEIA-101 at ii; Exh. CALSEIA-101 at 4; Exh. IREC-101 at 2.

[205] Vote Solar OB at 2; TASC OB at 4.

[206] EDF OB at 4-5.

[207] CforAT OB at 53.

[208] Exh. PG&E-101 at 2-14.

cause a bill to double month over month.[209] At the same time, as the Commission noted over thirty years ago, bill volatility of reasonable magnitude provides the critical signal to customers to improve the efficiency of their energy use. Thus, as in many other areas, we must strive to achieve a balance that sends the necessary signals while avoiding overly harsh impacts.

Conservation in response to tiered rates can take a variety of forms, such as efficient behavior changes (like remembering to turn out the lights), or energy efficiency investments (such as buying Energy Star appliances or adding insulation). One major factor supporting tiered rates is that high-usage customers who are financially able to do so will purchase rooftop solar or make other significant purchases of energy efficiency technology in order to reduce overall consumption. At the same time, low-usage customers may have less incentive to conserve than they would under a flatter rate structure. The IOUs assert that there is also a potential for these low-usage customers to conserve more energy. This decision finds that the IOUs should provide educational materials to Tier 1 and Tier 2 customers who will be facing higher rates under our decision today so that they can respond to the new rates with no-cost and low-cost conservation strategies.

In sum, we find that tiered rates provide a price signal that encourages customers to conserve and invest in energy efficiency measures. Indeed, the record shows that the current steep tier differentials are used by vendors to market EE products and rooftop solar to high-usage customers. A knowledgeable customer who is aware of the price structure and has the wherewithal to track it, will be incented to use less overall energy.

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[209] *Id.* at 2-15.

5.1. Reasonable Number of Tiers

We find that a residential rate structure with at least three tiers and with a meaningful differential between the tiers should be available to all residential customers. This rate structure will maintain the price signal that increased usage means increased cost for the customer. There is also significant legislative direction that a tier structure should be maintained. Currently, each IOU has four tiers. The IOUs proposed to reduce the number of tiers to two.

The active parties in this proceeding are divided on whether two or three tiers are preferable. In addition to the three utilities, ORA, UCAN, and IREC support two tiers. NRDC, Sierra Club, CALSEIA, CforAT, TURN and SEIA support a three-tier structure. TURN prefers a three-tier structure, but also proposed an alternative two-tier structure.

NRDC and Sierra Club argue that a three-tier structure will incent additional conservation and support a steeper tier structure. NRDC argues that customers respond to the highest tier (not the average bill price), so a high tiered rate will incent more conservation.[210] Sierra Club and NRDC also point out that because high usage customers use large amounts of energy, they are the most likely to have opportunities to reduce usage, but low usage customers have fewer opportunities to save energy.[211] NRDC argues that its three-tier structure, "allows for lower bills for all customers with below-average usage, along with higher average conservation incentives, while still significantly reducing rates in the higher tiers from today's levels."[212]

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[210] NRDC OB at 12.

[211] *Id.* at 16.

[212] *Id.* at 17 (citing Exh. NRDC-101 at 32).

TURN argues that a three-tier structure with no customer charge will incent more conservation than a two-tier structure with a fixed charge.[213] We agree.

We find that a three-tiered structure will maintain the conservation and efficiency price signal inherent in current rates to the greatest degree possible while reducing the burden on high users of the current steeply inverted four-tier rates. This approach will also generally benefit lower income customers more than higher income.

5.2. Reasonable Tier Differential

Parties provided a wide range of proposals for how to set the tier differentials in either a two- or three-tiered rate. In this proceeding, the term "tier differential" refers to the percentage difference in price between two tiers. For example, a 20% differential means that the second tier price is equal to 120% of the first tier price.

The utilities have proposed a 20% end state differential and make several arguments to support this proposal. As a group, the IOUs do not provide a rationale or methodology for selecting 20%. SCE does assert that according to its calculations, a 20% differential is reflective of cost. For the most part, however, the IOUs appear to rely on a selected set of prior Commission decisions (mainly from that late 1980s and early 1990's) and on the Section 739(d)(1) requirement for "gradual" tier differentials.

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213 TURN OB at 2; *id.* at 6 (finding that PG&E's proposed 2018 rate, including fixed charge, would increase load by 1.44 under the average price approach and that TURN's proposed three-tier rate without a fixed charge would decrease load by .24% under the average price approach).

The utilities cite Section 739(d)(1), which states that the tier differential should be "gradual." PG&E argues that, based on its version of history, a 1.2 to 1 ratio would be appropriately gradual,[214] and that steep tiers are inequitable.[215]

Several parties, such as ORA and UCAN, find the 1.2:1 ratio acceptable, but argue that it may take a longer than 2018 to reach this differential. UCAN also recommends the 1.2:1 ratio only if it is paired with a program of direct incentives for conservation (which would increase revenue requirements). ORA supports the 1.2:1 differential only if default TOU is implemented as an incentive for conservation during peak periods.

Other parties, including TURN, SEIA, TASC, IREC, Vote Solar, Sierra Club and NRDC argue for a steeper differential. TURN argues that regardless of the number of tiers, the differential should be 40 – 50%,[216] and proposes a 1:1.6 differential for its two-tier rate. NRDC argues that a high top tier is necessary because customers only respond to the highest price (not the average price).[217]

Aside from SCE's estimate that a 20% differential is representative of cost, only two parties, SEIA and IREC, provided analysis tying their proposed tier differentials to cost. SEIA and IREC provide extensive arguments against the 20% tier differential.

Although the utilities have justified the 20% differential in part on their version of history, SEIA points out that there has been a "[d]ramatic shift in

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214 PG&E RB at 9 (stating that prior to the 2000-2001 energy crisis, the ratio was set at 1.15 to 1).

215 *See generally, e.g.*, PG&E OB at 21.

216 TURN RB at 19-20.

217 NRDC OB at 13. This decision addresses the average cost method and marginal tier method in Section 2 and finds that the average cost method is the more appropriate measure for residential customers.

policy since there were 2 tiers with 15% differential."[218] SEIA cites a plethora of Commission and state programs and policies that have been enacted that support the "increasing importance of renewable energy and energy efficiency technologies" including RPS in 2003, California Solar Initiative (CSI) in 2006, Energy Action Plan in 2003, and AB 32 (California Global Warming Solutions Act of 2006). SEIA argues that using 1980s and 1990s decisions as a roadmap for establishing tier differentials is "illogical."[219] We agree. This State will never reach its ambitious GHG reduction goals by relying on the policies of the 1980's and 1990's.

IREC argues that "gradual" tiering is only relevant if there are at least three tiers.[220] For a two tier rate, there is only one differential. There must be a second differential to make a comparison and determine if the two, when looked at together, are gradual. Based on this, IREC proposes a much steeper differential.

SEIA and IREC each propose a steeper differential where the highest tier is based on a "marginal cost" calculation.[221]

SEIA proposes a three-tier rate structure with tier differentials of 1.7 to 1.35 to 1.0, where "each IOU's marginal capacity costs would be allocated to upper tiers, with more being allocated to the third tier than the second tier."

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[218] SEIA OB at 4-6.

[219] *Id.* at 6.

[220] IREC OB at 13.

[221] SEIA OB at 12-13 ("peak-related *marginal* usage is generally in higher tiers.").

SEIA seeks to use marginal utility "capacity" costs as the basis for a high-usage tier. The capacity component is defined as "generation capacity and primary distribution capacity."[222]

SEIA asserts that marginal capacity costs should not be allocated to baseline usage – not because a customer whose energy use is limited to baseline quantity does not incur such capacity costs but because "peak-related *marginal* usage is generally in higher tiers."[223] SEIA argues that this rate would be cost-based "because it collects in the upper tiers the marginal capacity costs that are driven by customer usage during peak periods when system demand peaks."[224] SEIA uses load factor, a ratio that compares the ratio of a customer's average demand to their peak demand, to argue that high usage customers "peakier" load profiles. More specifically, SEIA asserts that these customers have lower load factors and demand more power than others during peak periods and therefore demand more services *at the margin* from the IOU. These customers should, according to SEIA, pay higher tier rates to account for the marginal strain they put on an IOU's generation and distribution system. SEIA supports this conclusion with a finding for SCE territory that the load factor for a single family home in a mild coastal zone was 0.44, but that this load factor dropped to 0.30 in moderate or hot inland zones.[225]

IREC proposes a tier differential based on another marginal cost calculation. IREC's proposal would be a two-tier rate, with an approximately 2:1

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[222] Exh. SEIA-101 at 39.

[223] SEIA OB at 12 (emphasis in original).

[224] *Ibid*.

[225] Exh. SEIA-101 at 38 (referring to SCE data that is not in the record).

differential.[226] IREC argues that the utility's upper tier in a two-tier system should recover marginal generating capacity costs and overall generation costs. Unlike SEIA, IREC only focuses on marginal generation capacity costs, and does not appear to include distribution costs in its calculation of a high-usage tier rate. IREC's proposed baseline tier would recover all other costs and the tier differential ratio would reflect the difference between the two.[227]

IREC's rationale is that once the generation and marginal generation capacity costs are averaged for each utility, they equal a higher tier rate that is 110% - 120% larger than the rate that recovers all other utility costs. IREC argues that the approximately 2:1 ratio therefore reflects marginal pricing and maintains appropriate conservation incentives.[228]

IREC refers to this methodology as "long-run" marginal pricing because it accounts for the procurement costs of an entire marginal power plant or resource, rather than simply a unit of energy purchased at the margin. IREC argues that this will lead to cost signals that will reduce future procurement that would occur if prices were set only on the basis short-term marginal costs.[229]

SEIA and IREC have different rationales for their proposals for steep tier differentials. SEIA connects high usage to high demand, and therefore higher marginal demand costs, meaning that it would be appropriate to charge high-usage customers more to cover those increased demand costs. IREC takes a more abstract view and simply reasons that if the marginal cost of electricity (the

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[226] IREC calculates the differential assuming a 50% baseline for all three IOUs, but if the IOUs have different baselines the differential would need to be recalculated.

[227] IREC OB at 12.

[228] Exh. IREC-101 at 14-17.

[229] IREC OB at 10-12.

higher tier cost) is higher than the cost of building a new plant, then there will be less incentive to build more plants and therefore "long-run" marginal costs will decline.

Both SEIA and IREC argue that their proposals are cost-based. Certainly making higher-usage rates more expensive should in theory create a disincentive for marginal procurement of various kinds. This would theoretically limit utility costs over time. High marginal generation costs are driven to some degree by peaky less efficient demand curves. The appropriate size of the tier differentials is, like most of rate design, a matter of art rather than science. Looking back over the history of the last forty years of inverted rates in California, one can observe that when the tier differentials have grown very large, customers who consume larger amounts of energy experienced considerable bill volatility and demand relief, as happened with natural gas rates in southern California in the winter of 1987-1988 and with electric rates in the Central Valley in the late 2000's. Likewise, when tier differentials become compressed, small customers become dissatisfied and demand relief. Finding the point at which conservation incentives are maximized but larger users are not overly burdened is necessarily a matter of judgment. This is the paradox of bill volatility – month to month changes in bills as usage varies are necessary to provide a key element of the energy efficiency price signal, but if that signal grows too strong, customer hardships lead to an adverse reaction.

A three-tier rate with 33% differentials between the tiers will continue to encourage overall conservation and investments in energy efficiency while reducing bill volatility as compared to the very steep differentials of the recent past. Further, since usage is clearly positively correlated with income, low- and moderate-income customers will generally (though not universally) benefit from the retention of meaningful tier differentials.

We determine that a three-tier rate with 33% tier differentials is reasonable, complies with state law, and is consistent with the RDPs. However, we must consider all aspects of the rate design changes approved in this decision. For example, as discussed in Section 4.7.2, if a fixed charge or minimum bill is implemented, the differential between Tier 1 and Tier 2 must be calculated using the composite tier method.

5.3. Reasonable Glidepath for Consolidation of Tiers

The reduction in tier differential and the number of tiers will have to be carefully coordinated to minimize undue burdens on lower tier customers. The largest bump in rates will come for Tier 2 customers when Tiers 2 and 3 are combined. This transition will be difficult for all three utilities, especially SDG&E.

In addition, the illustrative rates reviewed in this proceeding do not include actual revenue requirements increases. A large revenue requirement increase allocated to the residential class at the same time as tiers are being narrowed could also result in an increase that is not reasonable for lower tier customers.

However, the glidepath to reach an approved end-state cannot be determined until the end-state number of tiers and tier differentials have been approved, and the time period for reaching the end state has been set. Then the options for glidepaths (including the timing of tier consolidations) can be evaluated. Although all three IOUs will be on a glidepath to the same target tier differential, the timing of the tier reductions and tier differential changes will be different. The glidepaths are examined in the context of each IOU's separate proposal in Section 11.

5.4. Baseline Quantities and the Amount of Usage in Each Tier

The Commission is required to set a baseline quantity of electricity that is "necessary to supply a significant portion of the reasonable energy needs of the average residential customer."[230] By statute, this baseline quantity must be equal to 50 and 60% of the "average residential consumption" in each geographic area.[231] Baseline quantities are set differently for each Climate Zone and are designed to take into account seasonal variations in consumption.[232]

During the period that the AB 1X rate freeze on lower tiers was in place, adjustment of the baseline percentage was one of the few means of reducing rate pressure on high use rates. For example, because Tier 1 is set at 100% of baseline, if the baseline quantity is reduced from 60% to 55%, the number of customers in Tier 1 will be reduced. With the passage of AB 327, the Commission now has discretion to adjust the lower tier rates. With that discretion, the need to adjust baseline quantities has become less important.[233] Indeed, in this proceeding some parties (Vote Solar) parties took no position on baseline, and others professed no preference (IREC). Other parties, such as ORA, argue that further

[230] Section 739(2)(b).

[231] The statute requires that for all-electric customers the baseline be set at 60-70% of average residential consumption during the winter heating season.

[232] Section 739(a)(1).

[233] Recall that reductions to 50% were driven by the need to reduce pressure on upper tier rates while AB 1X restrictions were still in place. (SEIA OB at 17.) This is no longer necessary.

reductions are not necessary now that tiers can be modified to more accurately reflect cost.[234]

SCE and SDG&E asked for reduced baseline quantities.[235] PG&E asked that no changes to baseline quantities or guidelines be made in this proceeding.

Table Showing Current and Proposed Baseline Percentages

	Current	**Proposed**	**Difference**
PG&E	52.5%	52.5%	None
SCE	53%	50%	3%
SDG&E	Between 52% and 55% for Basic customers	50%	2% - 5%

Several parties ask that the baseline quantities be adjusted to the 55% midpoint between 50% and 60%.[236] CforAT states that the baseline quantity is the best representation we have of "amount of energy sufficient to meet basic needs." CforAT acknowledges that baseline formula is not perfect (for example, it does not take into account household size), but finds that baseline quantity is the best available estimate of essential usage.[237] Therefore, CforAT argues that baseline be set in the middle of the statutory range of 50-60%.[238]

SEIA would also set the baseline quantity at mid-point (55%) through gradual transition, arguing that the midpoint gives the Commission the most flexibility to adjust up or down as necessary as conditions change.

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[234] ORA OB at 25.

[235] SCE OB at 20-23.

[236] CforAt OB at 2.

[237] CforAT OB at 52 (citing SCE, PG&E, and SDG&E statements in agreement).

[238] *Id.* at 54.

ORA argues that a decrease to 50% would run the risk that in between GRCs the calculated baseline would fall below the statutorily required minimum baseline.

We agree that changes to baseline quantity are best addressed in each utility's periodic Phase 2 GRC revenue allocation and rate design proceedings. The need to lower baseline to decrease pressure on upper tier rates is gone. We also agree that, as tiers are flattened, low usage customers should not be subject to the additional rate and billing impacts that would result from reducing baseline quantities.

SCE currently has a baseline allowance of 53% for standard service in all climate zones. As part of this proceeding, SCE proposes to reduce its baseline allowance to 50% in 2016.[239]

Considering SCE's proposed rate change as a whole, we believe that a decrease in baseline allowance is not warranted at this time. Currently, SCE's baseline is within the middle range for baseline allowances. We find that tier flattening between now and 2018 will have a more significant bill impact on lower usage customers than additional incremental baseline adjustments. We therefore deny SCE's request to reduce SCE's baseline quantity.

SDG&E seeks consolidation of Tiers 1 and 2, so that the consolidated Tier 1 includes usage up to 130% of baseline, arguing that the decrease to the baseline quantity will be offset. We do not see any reason to maintain different rate structures among the major utilities. Baseline quantities should not be changed at this time, but in its next GRC Phase 2 each utility should adjust its baseline quantities to 55%, the midpoint of the statutory range.

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[239] SCE OB at 64.

Our adoption of a three-tier rate design also requires us to determine the size of the second tier. From the data provided by the utilities, we have observed that setting the second tier equal to the applicable baseline quantity (same size as Tier 1) would appear to result in between 15% and 20% of usage falling into the top tier. We believe that this is a reasonable amount of upper tier usage.

If we were to set a higher usage cutoff between Tiers 2 and 3, there would be very little usage in the upper tier, requiring us to either raise baseline and Tier 2 rates or else set an even higher rate (more than 33% above Tier 2) for the limited consumption remaining in the third tier. We are reluctant to set a higher Tier 3 rate, because of the significant bill volatility problems that such a structure might re-create. Also, we must keep in mind that by allowing Tier 1 and Tier 2 rates to remain lower than what might otherwise be the case with fewer Tier 3 sales, a customer with only a small amount of usage in the top tier will still be better off than if the tiers were priced closer together. Only a customer with substantial upper tier usage (well more than twice baseline) will be worse off than under a flatter structure.

We also see value in having a larger number of customers experience the Tier 3 rate at least occasionally. As we have noted, it is the change in bills from month to month that is most likely to capture the customer's attention and incent positive action toward greater energy efficiency and conservation. The occasional high bill, brought about by increased consumption, is the very signal that we seek to promote. Thus, by setting the size of Tier 2 equal to the baseline quantity, we can expose more customers to the higher price without burdening them with excessively high bills on a consistent basis.

5.5. Seasonal Rates

Several parties, including SCE, SDG&E, and SEIA, advocate seasonally differentiated tiered rates. Tiered rates differentiated by season are a type of TOU rates that is based on time of year rather than time of day.

Currently, SCE's and PG&E's current residential tiered rates do not include any difference in charge based on season; customers are charged the same rate regardless of the time or season they use energy.

SDG&E recently began seasonally differentiating its high tier rates (Tiers 3 and 4).[240] SDG&E proposes to expand seasonal pricing to Tiers 1 and 2.

SCE proposes to adopt seasonally differentiated tiered rates for the first time and would use these rates for the interim period between the end of 2018 and "the earliest time the IOUs could undertake default TOU pilots."[241] SCE argues that implementing seasonally differentiated tiered rates as a predecessor to default TOU (should it be ordered) would assist customers with the transition by allowing them to grow "accustomed to seeing higher rates in summer and lower rates in winter."[242] SCE contends that seasonally differentiated rates were adopted as part of the transition to mandatory TOU rates for its commercial customers (SCE's 2009 GRC Phase 2) and recommends a similar path be taken for residential customers.

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[240] Exh. SDG&E-107 at CF-26 (stating that seasonal rates reflect the difference in cost of service between summer and winter and that D.14-01-002 approved SDG&E's uncontested proposal to limit the summer/winter total rate differential to 75% of the summer/winter commodity differential).

[241] SCE OB at 154.

[242] SCE RB at 88.

SDG&E proposes to seasonally differentiate rates in all tiers to "better reflect the costs of providing commodity services."[243] SDG&E proposes to transition to a two-tiered, seasonally differentiated rate structure. Currently, the commodity component of SDG&E's Tier 3 and 4 rates is seasonally differentiated, with higher rates in the summer and lower rates in the winter. Due to lower tiers being subject to legislative caps prior to AB 327, Tier 1 and 2 rates do not have any seasonal differentiation. D.14-01-002 set the "summer/winter total rate differential at 75% of commodity rate differential for residential tiered rate schedules."[244] SDG&E's current Tier 3 summer rates are 0.3 cents higher than winter; Tier 4 summer rates are 0.35 cents higher.

SEIA supports the move to seasonally differentiated rates and recommends that the Commission "encourage PG&E and SCE to explore seasonally-differentiated IB rates in future GRC Phase 2 cases" to reflect the significant seasonal dimension of the IOUs' marginal costs.[245] SEIA argues that seasonally differentiated tiered rates would provide customers with the appropriate price signals to reduce usage during summer months and would bring rates closer to the utilities' cost of service.

On the other hand, ORA opposes further exploration of seasonally differentiated rates at this time. ORA argues that, since PG&E and SCE don't currently have seasonally differentiated rates and SDG&E's residential rates are already the highest among the three IOUs, adding seasonal differentiation to

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[243] Exh. SDG&E-107 at CF-26/Fang.

[244] D.14-01-002 at 37.

[245] Exh. SEIA-101 at 38 (referring to SCE data that is not in the record).

lower tiered rates would cause SDG&E's summer rates to be significantly higher than the other utilities.[246]

Additionally, ORA contends that higher summer generation costs can be better reflected by TOU rates.

SDG&E and SCE argue that seasonally differentiated rates in all tiers would be way for customers to learn about and understand time-differentiated rates. But, ORA argues that, since about 40% of SDG&E's customers never experience usage outside of Tiers 1 and 2, and therefore aren't familiar with seasonally differentiated rates, adding this complexity will cause unnecessary confusion at a time when other significant rate changes will be going into effect.[247]

We agree conceptually with SDG&E, SCE and SEIA that residential rates should include a seasonal component to reflect predictable differences in costs across the year. However, the dynamics of the grid are changing and the traditional summer peak period may no longer be the most critical period from a system reliability standpoint. Rather than adopt a change now only to find ourselves required to shift course later (with resulting customer confusion impacts), we will defer making any changes toward seasonal rates at this time, and allow the utilities (and other parties) to make proposals in their GRC Phase 2 as appropriate. As noted by SDG&E in its testimony, seasonal rates are already in place for its customers using Tier 3 and Tier 4 amounts of energy and those differentials may remain. All of the utilities may explore seasonally differentiated rates in their next applicable GRC Phase 2.

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[246] Exh. ORA-101 at 5-11.

[247] ORA OB at 23.

6. Residential Time of Use Rates

6.1. Overview

Earlier in this decision we examined existing opt-in and default residential TOU programs. We found there are benefits from existing programs, and many potential benefits for California if a well-designed default TOU rate is implemented. For example, TOU rates may reduce the cost of infrastructure by reducing the need for peaker plants.

It is also well-documented that the larger two IOUs, have been very slow to explore the value of residential TOU rates despite its priority as a state policy goal.

We can no longer allow the larger two IOUs to prevent California from transitioning to an improved rate design for residential customers. Therefore, we direct the IOUs to move quickly to prepare themselves and their customers for the potential implementation of TOU rates. Specifically, the IOUs should quickly and thoroughly evaluate all areas of transition to default TOU, including but not limited to: load shift and load reduction, customer acceptance, appropriate parameters of residential default TOU, customer classes who are not able to respond and should remain on tiered default rate, and measure of environmental and cost savings from load shift and load reduction.

Based on the potential benefits demonstrated by the evidentiary record, we approve default TOU rates in principle, to be implemented on a schedule that provides sufficient time and resources to assure that legal requirements are met and to design a rate that is acceptable to customers while achieving reductions and shifts in load that benefit the entire state.

It has been said that rate design is more art than science, and we agree. Nonetheless, for a default TOU rate to be successful, the design should be based to the extent possible on empirical evidence that supports both measurable benefits of TOU on the grid, and the acceptance and understanding of TOU rates by the residential customer.

6.2. Customer Acceptance Concerns

6.2.1. Identifying Customer Segments Prior to Authorizing Default TOU

The first step in customer acceptance is to identify different types of customers within the residential customer class, including those who are explicitly exempted from default TOU by statute. Section 745 provides three separate rules regarding customers.

Section 745(c)(1) requires three specific groups of customers to be identified because they are not subject to default time-of use rates without their affirmative consent: (i) medical baseline customers; (ii) customers requesting third-party notification pursuant to Section 779.1(c); and (iii) customers who cannot be disconnected without an in-person visit.[248] The IOUs should have records that make identifying these customers straightforward.

Section 745(c)(1) also allows the Commission to identify additional customer groups to be made exempt from default TOU. Further analysis, as described below, is necessary before the Commission can identify additional

[248] Section 745(c)(1) provides: "Residential customers receiving a medical baseline allowance pursuant to subdivision (c) of Section 739, customers requesting third-party notification pursuant to subdivision (c) of Section 779.1, customers who the commission has ordered cannot be disconnected from service without an in-person visit from a utility representative (Decision 12-03-054 (March 22, 2012)), Decision on Phase II Issues: Adoption of Practices to Reduce the Number of Gas and Electric Service Disconnections, Order 2(b) at 55), and other customers designated by the commission in its discretion shall not be subject to default time-of-use rates without their affirmative consent."

customer groups. But, based on the record as discussed below, we believe that careful analysis to identify these potential other customer groups is warranted.

By statute, the Commission must also identify "senior citizens" and "economically vulnerable customers" in hot climate zones so that the Commission can ensure that TOU rates do not cause unreasonable hardship for them.[249] Identifying these two groups of customers will be more difficult. The statute does not define seniors, and the utilities do not track the age of their customers. The term "economically vulnerable customers" could be interpreted to mean CARE and FERA customers, or it could be defined to include other low-income customers who do not qualify for these programs. In addition, not all ratepayers eligible for CARE or FERA have identified themselves by signing up for the programs. The statute also does not define "hot climate zones."

Once senior citizens and economically vulnerable customers in hot climate zones have been identified, the next step will be to determine if these customers will face unreasonable hardship from TOU rates. After that step is completed, the Commission could decide whether to add these customers to the exempt list pursuant to Section 745(c)(1), or could direct the IOUs to take other measures to eliminate the "unreasonable hardship."

Section 745(d), added by SB 1090 in 2014, requires consideration of evidence related to customer groups that are similar, but perhaps not identical, to

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[249] Section 745(c)(2) requires that the Commission "ensure that any time-of-use rate schedule does not cause unreasonable hardship for senior citizens or economically vulnerable customers in hot climate zones."

those identified by Section 745(c)(2). Section 745(c)(2) customers appear to be a subset of Section 745(d) customers.[250]

Table Comparing Section 745(c)(2) and Section 745(d) Customers

745(c)(2)	745(d)
Senior citizens in hot climate zones	
Economically vulnerable customers in hot climate zones	
	Customers located in hot, inland areas
	Customers living in areas with "hot summer weather"

As with Section 745(c)(2), identifying Section 745(d) customers is the first step in an analysis that must be performed in connection with implementing default TOU. After identifying the customers, evidence must be gathered regarding the "extent to which hardship will be caused" by default TOU (a) assuming no change by hot, inland area customers during peak periods, and (b) assuming no change by customers in areas with hot summer weather during the summer or during peak periods. This evidence must then be "explicitly" considered before the Commission can require or authorize an electrical corporation to "employ" default TOU.

[250] Section 745(d) provides "The commission shall not require or authorize an electrical corporation to employ default time-of-use rates for residential customers unless it has first explicitly considered evidence addressing the extent to which hardship will be caused on either of the following: (1) Customers located in hot, inland areas, assuming no changes in overall usage by those customers during peak periods. (2) Residential customers living in areas with hot summer weather, as a result of seasonal bill volatility, assuming no changes in summertime usage or in usage during peak period."

Several parties provided insight into additional potentially vulnerable customer groups that might need to be exempted from default TOU without the customer's affirmative consent.

CforAT cites customers in hot climates who cannot reasonably avoid air conditioner usage, such as "people with disabilities, seniors who do not work outside of their home, people with infants."[251] CforAT provided extensive evidence on how customers with difficulty affording energy may not be able to shift their energy use.[252]

In addition to segmenting customers by income, usage, location, air conditioning requirements, there are other customer characteristics that cannot be controlled for that do impact customer acceptance levels. For example, at one extreme there are customers who will be interested in adopting TOU rates because they are interested in new technology and energy efficiency. At the other extreme, there are customers who will not be happy with any change in rate structure.

Creative data mining, such as identifying customers who are structural winners or losers, or customers with load profiles that show it is unlikely that they will be able to shift use, should be done now rather than waiting until the next decade. For example, ORA asserts that for small commercial customers the IOUs were required to proactively contact the top 10% most impacted customers and provide them with information and integrated solutions to reduce their

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251 CforAT OB at 77 (citing Exh. CforAT-101 at 53).

252 Exh. CforAT-101 at 51.

energy usage.[253] In moving toward default TOU rates, the IOUs must start to identify statutorily required customer groups (senior citizens), customers explicitly exempted by statute, and vulnerable customers who may need to be categorized as exempt or be provided with additional outreach. The IOUs must also start identifying customer segments that will benefit or be interested in participating in TOU rates.

6.3. Customer Protections Included in TOU Rate Structure

6.3.1. Optional, not Mandatory, TOU Rate

Consistent with our statutory obligations pursuant to AB 327, it is important to remember that any default TOU rate derived from this decision will be optional and it is essential that the IOUs provide a menu of well-designed optional tariffs, including tiered rates, for residential customers to opt into. Most parties in this proceeding have advocated this "menu" of options, to promote customer choice,[254] and we agree that a menu of choices for customers is part of the goal of this proceeding and AB 327. This decision does not endorse mandatory TOU for residential customers.

[253] ORA OB at 83 (apparently referring to D.10-02-032 at 79 (requirement to contact 10% most impacted customers unaffected by subsequent modification of decision in D.11-11-008)).

[254] *See, e.g.,* RT Vol. 23 at 3666 (EDF witness Fine testifying that "a variety of tariff options and programs should be available to meet the variety of needs of customers."); *see also* SEIA OB at 27 (SEIA recommending menu of TOU options); ORA OB at 28 ("customer choice is at the heart of Rate Design Principle #6.").

6.3.2. Mild Differential between On-Peak and Off-Peak Rates

ORA points out that TOU rates can be structured to initially have a mild differential, which will avoid adverse bill impacts.[255] This structure is similar to the "TOU-Lite" rate adopted by settlement for the roll out of mandatory TOU to small commercial customers.

The Commission has previously authorized TOU-Lite rates: a tariff that is intended to be revenue neutral with other tariffs for the same customer class and has on and off peak rates set to a specified differential instead of attempting to reflect actual difference in the cost of energy by time period. The purpose of this mild differential is to be an introductory rate that allows for customers to learn and understand the new rate structure before they are subject to differentials that could produce significant rate shock for the unaware.

The residential TOU rates being developed in this proceeding are not an attempt to match real-time prices in the wholesale market. Like tiered rates, they are a methodology for allocating responsibility for the recovery of the residential class' revenue requirement among residential customers. Like tiered rates, TOU rates can provide a price signal that allows customers to make energy decisions that align with grid needs. SCE and PG&E argue that ORA's proposal for default TOU rates in 2018 does not provide enough detail or guidance. For example, how would the mild differential be set, and when would it be adjusted closer to peak period cost?[256] We agree that ORA does not provide a sufficiently detailed TOU rate proposal for us to adopt at this time. Furthermore, before a rate could

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[255] Exh. ORA-101 at 1-1 (citing PG&E's Schedule A-1 for small business customers starting with a 4 cents/kWh differential).

[256] SCE OB at 154.

be approved, we would need to understand bill impacts. Most importantly, we would need to meet the requirements of Section 745 for avoiding hardship to certain customer groups. Rather, ORA's proposal is a framework for moving toward implementation of default TOU rates that are based on evidence and supported by state policy goals.

During the TOU-Lite transition period, we would expect to see less load-shifting than we would with more fully cost-based price differentials. The IOUs pointed this out, and we do not disagree. However, during the transition, it is more important to ensure customer acceptance of the new rate structure and understanding of the directional price signal. The TOU-Lite structure will be more acceptable to customers, less volatile, and avoid other potential issues. The shift toward more fully cost-based price differentials may be made later, as informed by data and experience gathered during the course of pilot implementation and ongoing review of the glidepath transition.

6.3.3. Baseline Credit in TOU Rates

A baseline credit should be part of the default TOU rate, and any other TOU rate option other than those explicitly designed to encourage increased use of electricity instead of another fuel (e.g.; electric vehicle charging; conversion of equipment from diesel or natural gas). An analysis of the legal requirements contained in Section 4.7.2 (Requirement for a Baseline Tier for Default Residential Rates) found that the baseline credit is not required for default TOU by law. However, the strong policy reasons for implementing a baseline credit are particularly applicable to default TOU. In addition, for both opt-in and default

TOU, a baseline credit will make the TOU rate structure more comparable to the opt-in tiered rate.[257]

There are several reasons to include a baseline credit in optional and default TOU rate designs. The most important is that, because the baseline amount takes into account the climate zone in which the customer lives, including a baseline credit allows the TOU rate to be differentiated by climate zone. Second, a baseline credit will provide more opportunity for low usage customers to benefit from a TOU rate. Without a baseline credit in the TOU rate, these customers would likely opt for a tiered rate that includes a baseline credit. Similarly, without a baseline credit, the TOU rate rewards large customer who switch to TOU even without load shift.[258]

PG&E and SDG&E support untiered (no baseline) opt-in TOU. PG&E argues that tiered TOU rates are harder for customers to understand.[259] Introducing a baseline credit also means that customer will not be rewarded as much for reducing at peak times. While we agree with these parties that it appears to create a two-rate structure, one cannot draw an apples-to-apples comparison between the current four-tier rates and a simple baseline credit, because the latter is not a whole rate structure. Rather, the baseline credit should be viewed as an adjunct or overlay to a TOU rate that provides some incremental measure of relief to customers who need it based on climate zone. In this sense, we support the baseline credit concept as a supplemental customer protection.

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[257] *See, e.g.*, DRA [ORA] Residential Rate Design Proposal, May 29, 2013, at 37, 45, and 48; *see also* Revised Energy Division Staff Proposal on Residential Rate Reform, May 8, 2014, at 12-13, 23 (published by ALJ Ruling Issuing Corrected Energy Division Proposal, May 9, 2014).

[258] TURN OB at 46 (citing TURN 201 at 60 and CforAT RB at 15).

[259] PG&E RB at 74.

As we have noted above, without a baseline credit, a TOU rate rewards large customers who switch to TOU even without any load shift. Given that we are adopting a three-tiered rate structure, it is important that most default and opt-in TOU rates include *both* a baseline credit for total usage within the baseline allowance *and* an excess consumption surcharge for total usage above second tier levels. This approach will help ensure that customers do not choose between TOU and non-TOU rates simply to achieve a personal bill reduction. Absent such features, both large and small customers will naturally migrate to the rate schedule that most benefits them, resulting in large revenue shortfalls for the class as a whole. That is not our intent.

To the contrary, we seek to maintain the conservation and efficiency benefits of tiered rates, while adding the incentive for load shifting created by TOU rates. However our current tiered TOU rate options present customers with a complex and confusing rate schedule that differs both by tier and by TOU, resulting in a plethora of different rates. This can be greatly simplified by presenting the default rate schedule as a TOU rate structure (revenue neutral to the Tier 2 rate), with a line item per-kwh discount for baseline usage and a per-kwh surcharge for above Tier 2 usage.

There is not a clear statutory requirement for a baseline credit in optional TOU rates. However, because we find that policy reasons support the baseline credit in default TOU, and because a baseline credit will allow for the best comparison of optional rates with a future default TOU rate, baseline credits and excess consumption surcharges must be incorporated into default TOU and optional TOU rates offered by the IOU. The only exceptions to this requirement may be made for some (but not all) pilots,[260] and for TOU rates specifically targeted at shifting usage to electricity from other more carbon-intensive energy sources such as gasoline.

Because a baseline credit is required by this decision for default TOU, each IOU must offer TOU rates and pilots with a baseline credit. This approach is supported by SEIA[261] and ORA.

TURN supports keeping a baseline credit in any TOU rate to reduce the risk of large users opting in and thereby lowering their bill without making change to their usage. Whether a large user is actually able to accomplish this depends on other aspects of the rate structure and how the baseline credit is calculated. To prevent this, we require an excess consumption surcharge, except as noted above, in order to deter large Tier 3 users from shifting rate schedules with no intention of shifting load.

To calculate the baseline credit rate, ORA proposes to take the difference between the weighted average of non-baseline and the baseline rate.[262] PG&E agrees with this calculation of baseline credit.[263] Sierra Club did propose an alternate method of simply setting the credit at 10 cents.

There are different ways to apply the baseline credit to a TOU rate schedule. ORA proposes (and SCE has in place) a methodology that applies a

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[260] Each IOU must design and propose pilots that test both baseline credits and excess consumption charges, but may also propose additional pilot options that include one element or the other.

[261] SEIA OB at 27.

[262] ORA OB at 67.

[263] PG&E RB at 77-78.

straight credit to a TOU rate.[264] SCE applies a straight credit, but mandates a ceiling for the credit equal to one cent less than the super-off-peak rate. TURN's proposal would raise all TOU rates by equal percentages to recover the revenue paid out as a credit.[265]

Alternatively, SEIA and ORA also suggest that the rate be presented as an untiered rate with an excess usage charge for all usage over baseline.[266]

Because we are adopting a three-tiered rate structure, we will adopt a baseline credit for all Tier 1 usage equal to the difference between baseline and Tier 2 rates. Similarly, the excess consumption surcharge will equal the difference between Tier 2 and Tier 3 rates. The underlying TOU rate structure will then be set to be revenue neutral against Tier 2 rates. This approach will minimize rate schedule arbitrage and ensure that all customers receive both conservation and time-of-use price signals.

We find that the baseline credit and excess consumption surcharge on default TOU rates, on most available TOU optional rates, and on most TOU pilot rates, is an essential element of wide-scale TOU adoption for residential customers.

6.3.4. Bill Protection for Default TOU

By statute, one year of bill protection is required for customers defaulted to TOU rates. ORA states that such protection will prevent customers from being harmed in the first year of a new rate. If, at the end of the year, a customer

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[264] Exh. ORA-101 at 3-17; ORA OB at 67, 69, 72; Exh. SEIA-101, Attachment RTB-3 (describing SCE's methodology).

[265] Exh. TURN-201 at 60.

[266] *Id.* at 28; Exh. ORA-101 at 1-12.

would have been better off on the previous rate plan, the customer will be credited the difference on their bill. ORA recommends that this bill protection be made available on a semi-annual (rather than annual) basis for customers.[267] We agree that this proposal merits consideration and direct the utilities to consider this option in their design of default TOU rates. A semi-annual true-up may be especially important if we ultimately decide to employ seasonally-differentiated rates.

SDG&E proposes that its bill protection will include a monthly "shadow bill." A shadow bill will allow customers to see how their electricity bill under the new rate differs from the bill they would have had under the old rate.[268] A shadow bill is required by statute and we find that an accurate shadow bill is an important part of customer education and outreach for default TOU.

6.3.5. Outreach and Education for TOU Rates

Without adequate customer outreach and education, the protections set forth above will not be meaningful.[269]

An important part of the roll out of default TOU and optional rates is a robust bill comparison tool. Section 745 requires a shadow bill be provided to customers prior to any default TOU rate. But we believe the need for a shadow bill or bill comparison tool goes beyond preparing customers for default TOU.

Currently, neither SCE nor SDG&E have an online bill comparison tool that will allow customers to compare rates based on their actual interval data.

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[267] ORA OB at 80.

[268] Exh. SDG&E-102; Exh. CAW-7.

[269] ORA at 79 (discussing need to "execute effective outreach and education programs" for both tiered and TOU rates).

PG&E does have an online bill comparison tool available to individual residential customers based on their actual usage.[270] It is essential that the bill comparison and online web tools available to customers are accurate, useful, and customer-friendly. We have concerns that these bill comparisons are not effective. In addition, a web-based tool will only reach the customers who use the web and are interested enough to take the steps to try the bill comparison. Although we support having such a web-based tool available at any time for customers to explore rate options, we believe that to properly educate customers about their rate options a paper bill comparison should be provided to customers twice per year beginning in 2016. We therefore instruct the utilities to immediately begin developing this tool (if it does not already exist) and begin design of rate comparisons.

In the Section 9 (Marketing, Outreach and Education), we discuss measurable goals for ensuring that all outreach and education for rate reform are effective.

6.4. Concerns About the Changing Load Curve

Energy uses and generation sources evolve over time, and have been doing so even more rapidly in recent years due to increases in distributed generation and renewable resources, as well as the proliferation of new technologies that allow customers to monitor their energy usage. Put succinctly: "It is widely acknowledged that system conditions are changing rapidly with the

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[270] SDG&E was developing this tool in connection with its Smart Pricing rate (Schedule TOU-DR-P) and it should be available now. SDG&E Supplemental Testimony of Caroline Winn at 3. PG&E My Energy also includes this ability. Exh. PG&E-155 at 2. SCE does not have this capability and does not currently have plans to implement it. SCE estimates it would take 18 months to implement it. Exh. SCE-126 at 2-3.

addition of major quantities of intermittent renewable resources including the rapid penetration of rooftop solar."[271] The Commission is well-aware of these anticipated changes, as well as the possibility of unexpected changes, in the load curve.[272]

AB 327 requires default TOU periods that are "appropriate" for the next five years. There are excellent policy reasons for requiring a five-year forward-looking design for TOU periods for default TOU rates. A constantly changing TOU period would cause customer confusion. It would also make it difficult for customers to evaluate investments in energy efficiency improvements and rooftop solar.

Many parties in this proceeding have made the assumption that a default TOU program would take the form of a rate with a single on/off/part peak structure applicable to all customers who do not specifically opt out. This single on/off/part peak structure would be set in a GRC and, because of AB 327, would hold constant for five years. In essence, customers on the default rate could move en masse with on/off peak periods designed to cover the exact time periods that were identified five years ago.

This assumption misses the entire point of adopting TOU.[273] TOU should be a flexible customer-empowering tool to make the load curve more

[271] TURN OB at 59.

[272] The possibility of shifts in usage periods was dramatized in the famous "duck curve" in 2012 – the year this proceeding was opened. While historically the state has focused on reduction of the afternoon peak, the duck curve showed that an increasingly steep incline in the evening could soon become a larger problem. The duck curve is emblematic of the risk of solving for yesterday's problem.

[273] As EDF put it, "one place where this conversation has been stilted is a failure to think about the rate diversity of customers." RT PGE RB at 72. Vol 23 at 3666, EDF/Fine.

manageable. As EDF describes it, using TOU to "increase customers' ability to be an active part of the grid will be critical to ensuring that California achieves its emission reductions, renewables and other landmark clean energy policies."[274]

Although it would be unrealistic to expect vast numbers of residential customers to accept a multi-period complex TOU structure today, there are structures and mechanisms that can be developed that will allow customer understanding of TOU, customer acceptance of the rate, and useful tools to assist in smoothing out the load curve.

Rate design has never limited itself to relying on soon-to-be-outdated data. Policy has long required utilities and the Commission to use creative approaches to develop reasonable and just rates that support state policy goals.

A wide-scale TOU rate for residential customers must be flexible enough to account for load shifts from year to year, while providing customers with certainty required by AB 327. This can be accomplished through the menu of rate options proposed by many parties, as well as a mechanism for regularly updating TOU periods while providing customers the certainty of a specific TOU period for five years. Default TOU periods and rate structures should take into account the most accurate peak and off-peak periods as determined through the GRC or RDW process on a five-year forward-looking basis.

Options for design of TOU rates that must be considered going forward include:

- a default TOU rate with mild differential intended only to minimize the impact of residential customers on peak periods;

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[274] Exh. EDF-102 at 21.

- tranches of optional TOU rates with complementary TOU periods that considered together address grid needs, but do not impose unreasonable hardship on individual customers; and
- changing the default rate for new customers in each GRC to reflect new TOU periods, but allowing already enrolled customers the option to keep their legacy TOU period structure for the five year period suggested by AB 327.[275]

Each of these rate designs may pose challenges, but the record does not reflect any reasons not to explore them.

EDF envisions a menu of TOU rate options, including options to provide needed ramping resources to "manage intermittent renewables and the sunset."[276] EDF does not suggest a mechanism for these periodic adjustments to TOU periods and rates, but does suggest that using the current three-year GRC Phase 2 schedule would not be sufficient.[277] EDF cites the NEST thermostat as an example of emerging technologies that can "push new programming from a central desk without requiring the customer to be aware of peak price changes.[278] This suggests that with adequate education and enablement tools customers could respond to changes in TOU periods without needing to carefully track TOU period changes. Although this does not seem practical for the average residential customer in the immediate future, it does point to a promising future

[275] Through its experience with the Power Charge Indifference Adjustment (PCIA), the Commission already has experience with rates that are vintaged by year. Similarly, the California Air Resources Board (ARB) uses vintaging of cap and trade GHG allowances as part of its AB 32 compliance program.

[276] RT Vol. 23 at 3697, EDF/Fine.

[277] RT Vol. 23 at 3698, EDF/Fine.

[278] RT Vol. 23 at 3699, EDF/Fine.

for a menu of TOU rates that can make meaningful needed impacts on the load curve.

Having a menu of alternative TOU and non-TOU rates for customers to choose from, and encouraging customers to be on the rate that is best suited for their energy use, would also reduce the percentage of energy use tied to a default TOU rate. This lets customers who are the most educated about rates take advantage of new and innovative rates and technologies to reduce use during periods with high prices (including real time pricing or matinee rates for customers who have the enthusiasm and interest).

Residential rate structures in other jurisdictions already offer a variety of TOU rate options with different TOU periods. For example, Salt River Project offers a variety of TOU rates, including one with a 1 – 8 p.m. peak and one with a 3 – 6 p.m. peak. APS offers three different TOU rates and two different TOU periods, Electricité de France has multiple TOU rates available with different TOU periods.[279]

EDF points out that if TOU periods are not adjusted over time, rates will not accurately reflect cost.[280] This argument also applies to allowing multiple TOU rates to co-exist at the same time. However, although there is tension between creating a strictly "cost-based" rate and allowing for changing TOU periods, a balance can be achieved between cost-causation and the goal of increasing reliability by having residential rates that reduce the peaks (or valleys) in the load curve.

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[279] Exh. PG&E-101 at 2-59 n.69(a).

[280] Exh. EDF 102 at 21.

As discussed above, TOU rates are not the same as real-time pricing, and they should not be assumed to reflect real time energy costs. Rather, they are rates created from averaging prices and costs over extended periods of time.[281] Rates are both cost-based and policy-based. TOU rates represent the average of hourly marginal costs over defined groups of hours with similar load characteristics, and can be set by a differential that sends a price signal. As such, unlike real-time pricing, the TOU approach both reflects costs and addresses the other RDP and the statutory requirements for residential TOU. This rate can be designed in a way to collect sufficient revenues from customers on TOU to cover their costs as a group and be revenue neutral with rest of residential class.

The process of identifying peak and off-peak periods for the purpose of setting TOU periods was intentionally removed from this proceeding. We note that to date the IOUs have allocated marginal generating capacity costs and recommended time periods based on their analysis of Loss of Load Expectation, Loss of Load Probability, and top 250 hours. The LTPP already forecasts load curves for the purpose of assuring sufficient generation resources. Furthermore, the IEPR, released every two years by the CEC, with input from the CPUC and CAISO, forecasts future peak and total loads in order to provide more detailed analysis of load curves in the future.[282] We expect that going forward the IOUs will refine the process for identifying TOU periods for their residential rates. TOU periods will be identified in GRC Phase 2 or RDW proceedings for each

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[281] *See, e.g.*, RT Vol. 12 at 1374, PG&E/Quadrini, (stating that TOU rates are difficult to get immediate customer engagement because time of use is "over a very long period of time. And everything's averaged . . .").

[282] The CAISO has identified recommended TOU periods to address operational needs for 2020, but determining residential rate designs that are acceptable to customers remains subject to the protections of ratesetting proceedings at the Commission.

utility, and the method for selecting these hours will be based on the methodology for identifying peak/off peak periods adopted in that proceeding.[283]

We direct the IOUs to explore options and return with reasonable proposals as part of their Residential RDW application.

6.5. Concerns That Wide-Scale TOU Will Not Support Existing Economic Structures for Solar or IOU EE Programs

6.5.1. Energy Efficiency and Other Utility Programs

Some parties have expressed concern that EE and other demand side programs will be negatively impacted by TOU rates that reduce the monetary incentive for participation. For example, TOU rates could be in competition with a DR program. Another example is the difficulty in determining whether behavior changes incented by TOU rates or by EE behavior programs paid for by ratepayers.

Utilities have already invested ratepayer money in the technology necessary for TOU rates. They have been studying default and residential TOU for years at ratepayer expense.[284] As ORA points out, TOU rates will "better align" EE and DG benefits with IOUs' avoided costs."[285]

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[283] SEIA argues that TOU periods should be determined in GRC Phase 2 proceedings. "TOU periods are not just used for rate design, but are also integral assumptions used in calculating marginal costs and in allocating revenues among customer classes." SEIA OB at 33. It's important for Commission to have actual historical data, not just forecasts for setting TOU periods. *Ibid.*

[284] ORA OB at 85 (asking whether ratepayers should continue to fund such studies if they do not provide "lessons learned.").

[285] Exh. ORA-201 at 1-2.

These special programs should not be the primary driver for rate design.[286] However, by requiring that most TOU rates include a baseline credit and excess consumption surcharge, we can best assure that such rates do not undermine the other resource programs that we implement and that ratepayers pay for in the revenue requirement.

6.5.2. Existing NEM and Rooftop Solar

Consistent with Pub. Util. Code Section 2827, the Commission established NEM tariffs in 1995 to encourage the installation of distributed generation on the customer side of the meter. Customers who install and operate small (1 megawatt or less) renewable generation facilities that meet certain technical requirements were allowed to participate in a NEM tariff.

The NEM tariff is an overlay to the customer's otherwise applicable tariff. Under the NEM tariff customer-generators receive a financial credit for power generated by their on-site system that is fed back into the power grid. The financial credit is used to offset the customer-generator's electricity bill. The majority of NEM customers use on-site photovoltaic solar generators to provide some or all of their electricity, and feed power back to the power grid when they generate more than they need at a given time. The net surplus electricity compensation rate established by the Commission represents the amount paid by the utilities per kWh to procure power at peak times.[287]

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[286] ORA OB at 85 (asking, "why should ratepayers continue to fund such studies?" if they do not provide some "lessons learned.").

[287] On October 11, 2009, Governor Schwarzenegger signed into law AB 920, requiring California utilities to compensate NEM customers for electricity produced in excess of on-site load over a 12-month period ("net surplus compensation").

Among other things, AB 327 requires the Commission to adopt a reasonable transition period for customers who took service under NEM tariffs before July 1, 2017 or prior to reaching the statutory net metering trigger level. D.14-03-041 established a transition period of 20 years from the date of interconnection of the customer's solar PV system.

In this proceeding the utilities have proposed to close certain existing optional tiered tariffs. PG&E proposes to close E-6 and EL-6 to new participants on January 1, 2015, and to eliminate E-7, EL-7, E-8 and EL-8 on January 1, 2016 and replace them with a new opt-in TOU rate schedule, E-TOU. E-7, EL-7, E-8 and EL-8 have been closed to new customers since 2008 and 2003, respectively. Customers on closed schedules E-6, EL-6, E-7, and EL-7 would be migrated to E-TOU and customers on closed schedules E-8 and EL-8 would be migrated to E 1/EL-1. SDG&E has two TOU rates that may be used by NEM customers: 1) DR-TOU, a three-tiered TOU rate with three TOU periods, and 2) DR-SES, a non-tiered rate with three TOU periods. SDG&E proposes new optional TOU rate schedules that are flat rates with three summer TOU periods. SDG&E's new tariff would also add a third winter tier and a Demand Differentiated Monthly Service Fee (DDMSF) instead of the existing small minimum bill. SCE's original proposal to eliminate its existing opt-in TOU rate schedule, TOU-D-T has been superseded by our recent decision, D.14-12-048, approving a settlement agreement in SCE's rate design window proceeding. Pursuant to D.14-12-048, SCE will keep TOU-D-T open until the effective date of the decision addressing SCE's 2018 GRC application.

Vote Solar, and SEIA argue that because the residential rate tariffs and the NEM tariff work jointly to determine a customer's bill, the Commission should require the utilities to retain all existing TOU rate schedules. They maintain that all TOU tariffs that are currently open to new customers should remain open and that the existing rate structures for these tariffs should be maintained (i.e., customer charges should not be added and tier differentials should not be adjusted).[288]

These parties argue that because solar customers made investments based on these rate structures and rate differentials, customers that are currently on TOU rates should be grandfathered onto those rate structures. Vote Solar argues that making significant changes to rate structures, by, for example, adding a new demand charge or customer charge, could have significant impacts on the customer's PV investment.

SEIA suggests that the Commission keep E-6 open to new customers and keep E-7 available to existing NEM customers and "evolve" both of these tariffs over a period of time to a simpler rate structure. SEIA supports gradual changes to E-7 to make it more revenue neutral with E-1, and changes to the tier structure of E-6 and E-7.

Under this proposal, rate schedules that are already closed, such as PG&E's E-7 and E-8, would remain closed, but existing customers could remain on those schedules with the existing rate schedules and rate structures unless they chose to migrate to another tariff. To the extent that the Commission decides to close currently open TOU tariffs, Vote Solar requests that the Commission grandfather those existing NEM customers that are currently taking service under the tariff and that grandfathered customers should be permitted to continue service on closed TOU rates for a period consistent with the payback

[288] Exh. Vote Solar-101 at 4.

period established by D.14-03-041.[289] This approach would allow grandfathered customers to remain on their existing TOU rate schedule for 20 years from the original year of interconnection of the renewable distributed generation system. Vote Solar emphasizes that the "rate levels" of any grandfathered tariffs would change only with adjustments in overall revenue requirements, and that the "rate structures" would remain the same for the life of the grandfathered TOU tariff.

Vote Solar also suggests that PG&E's proposal to close E-7 and E-8 is an impermissible collateral attack on prior Commission decisions, in violation of Section 1708 and would be unfair to NEM customers already grandfathered on those rates. They maintain that although E-7 and E-8 rates are not considered revenue neutral, and are therefore subsidized rates, the rate principles identified by the Commission in this proceeding permit cross-subsidies where they are supported by explicit state policy goals. According to Vote Solar, residential customers should continue to be allowed to benefit from the policies and rate differentials provided by the Commission and the state at the time these customers made their decision to invest in residential solar.[290]

Finally, Vote Solar recommends that we adopt a "solar friendly" TOU option in addition to the utilities' proposed TOU rate options. The "solar friendly" TOU rate structure would consist of a "volumetric rate structure without a customer charge or minimum bill." Vote Solar's "solar friendly" option would also have a tiered rate structure with significant rate differentials between the top tier and lower-tier rates. The rate structure should be "revenue

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[289] Vote Solar OB at 14.

[290] *Id.* at 22.

neutral with the default tariff."[291] Vote Solar suggests that this solar friendly tariff would encourage investment in PV and encourage these customers to select a TOU rate.

The utilities generally, and PG&E and SDG&E specifically, maintain that the Commission should permit them to close the existing tiered TOU tariffs. PG&E maintains that customers under both E-6 and E-7 are not fully covering their cost of service.[292] PG&E proposes to restructure E-6 in 2015 by adding a fixed customer charge and reducing the number of tiers from four to three. PG&E would then close E-6 in 2016, and customers would have the option of moving to its new E-TOU rate.

PG&E argues that the solar parties' proposal relies on the false assumption that customers have a reasonable expectation that their public utility rates will never change in the future.[293] PG&E maintains that its E-6, E-7 and E-8 are far below cost and heavily subsidized by other customers.[294] PG&E explains that under the existing tiered TOU rates, low-usage customers' peak rates can actually be smaller than the off-peak rates paid by upper-tier usage customers, even though the cost to provide service to each is the same.

The solar parties describe E-6 as a "revenue-neutral" rate, but note that any undercollections are picked up by the larger residential class (E-1). However, they suggest that the undercollection may not be a subsidy because the E-6

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[291] Exh. Vote Solar-101 at 18.

[292] PG&E RB at 80.

[293] PG&E OB at 70.

[294] *Id.* at 71.

population is considered lower cost to serve.[295] PG&E states that although E-6 was designed to be revenue neutral with the E-1 tariff, this is different from being cost-based.[296] E-6 was designed as if all residential customers were on E-6. In reality, there are a significant number of solar customers on E-6 who pay less than other customers, meaning E-6 is not revenue neutral on a customer basis, only on a class basis.[297]

The utilities' existing, optional TOU rates are similar to the existing default rates in that they are comprised mostly of volumetric rates with significant differentiation between upper and lower tiers and no or little minimum bill or fixed charge. At the time these optional TOU rates were developed and approved, various elements of tiered rates were required by law.

We find the solar parties' contentions regarding customers' reliance on existing rates and rate structures to be reasonable up to a point. D.14-03-041 recognized that customers who invest in renewable generation systems and participate in NEM tariffs should have an opportunity to recoup their initial investment and allowed these customers to retain the benefit of the existing NEM tariff for 20 years. D.14-03-041 also specifically acknowledged that the rates and charges paid by a customer are dependent on the underlying residential tariff and confirmed that the instant proceeding "is expected to result in significant changes to the residential rate structure."[298] While we are initiating such changes today, we do not want to inadvertently disadvantage the very customers who

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[295] Vote Solar OB at 18.

[296] PG&E RB at 82.

[297] *Id.* at 83.

[298] D.14-03-041 at 17.

have responded most strongly to this state's energy policy initiatives, usually expending substantial personal resources in the process. Rates and rate structures change periodically, typically gradually, through periodic revenue requirement and revenue allocation proceedings, but occasionally abruptly, as the Commission found necessary in D.01-05-064. We are endeavoring to avoid abrupt changes here through a variety of approaches, but recognize that individual hardships may nonetheless occur. We seek to avoid that outcome to the greatest degree possible.

We are sympathetic to the challenges faced by individual customers who have elected to install rooftop solar. As Vote Solar and others point out, these individual TOU customers may have made the investment in solar assuming that the TOU rate would not change. Rooftop solar installations are often designed to maximize generation during the TOU rate peak periods that were in place at the time of installation. In keeping with the RDPs of customer acceptance and energy efficiency, we believe the impact of changing or closing TOU tariffs should be mitigated. This is consistent with Section 745's recommendation that default TOU periods be designed to be appropriate for at least five years.

Given the number of significant changes we are adopting, including tier flattening and increased use of minimum bills, and given the need for customer acceptance, we also find that the transition period for PG&E E-6 and E-7 tariffs and SDG&E's DR-TOU tariff should be at least five years from January 1, 2016. E-8 has been closed for well over five years and may be eliminated in 2016. The minimum bill approved for the default tariff must also apply to existing TOU rates, including E-6 and E-7. Further, those residential PG&E customers with pending interconnection requests selecting an E-6 rate will be allowed to take service on E-6 in the case where the processing of the interconnection request is finished after E-6 is officially closed.

A summary of the changes to the optional rates appears below.

Rate Schedule	Change made by this Decision
PG&E Schedule E-6	Closed to new customers on 1/1/16. Transition period toward elimination of at least five years begins on 1/1/16.
PG&E Schedule E-7	Transition period toward elimination of at least five years begins on 1/1/16.
PG&E Schedule E-8	Eliminated on 1/1/16. Existing customers transferred to E-1 on that date.
SDG&E DR-TOU	Closed as of January 2015 pursuant to D.12-12-004. Transition period toward elimination of at least five years begins on 1/1/16.

6.5.3. Revenue Shortfall and Structural Winners

6.5.3.1. Structural Winners and Losers

In this proceeding, the term "structural winner" refers to a customer who will see a reduced electricity bill by moving to TOU, without making any change in the time or quantity of their electricity use. Given that the current tiered rate structure relies on upper tier customers for a significant portion of the residential revenue requirement, there may be many customers who could be structural winners on TOU rates.

In fact, structural winners will have a positive experience on TOU, making for greater customer acceptance. PG&E intends to market first to high usage customers who are more likely than low-usage customers to benefit from the TOU structure.

On the other hand, too many structural winners will mean an undercollection that needs to be recovered from somewhere.

6.5.3.2. Revenue Shortfall

A revenue shortfall occurs when the revenues collected from a group of customers is less than the revenue that was forecast. The revenue shortfall will be amortized and included in future rates to make up for the undercollection. A revenue shortfall between classes can result when, for example, residential customers as a whole use less power than predicted. Depending on the structure of the rate when implemented, the undercollected amount could then be recovered from just the residential class in future years, or it could be recovered from all customer classes.

In this proceeding we are primarily concerned with revenue shortfalls between different groups of customers within the residential class. The opt-in TOU rates are purportedly designed to be revenue neutral to the residential class, but, because historically the revenue collection has been premised on collecting more from high-usage customers, it is possible that high-usage customers will shift to TOU and low-usage customers will remain on the tiered rate. Our decision to require baseline credits and excess consumption surcharges in most TOU rates will mitigate this potential, but cannot eliminate it entirely.

CforAT describes the revenue shortfall problem as follows: "Customers on TOU may pay less because (a) they are structural winners, or (b) they are able to shift load. In either case, these customers are paying less, resulting in reduced revenue for IOU. Even though reduced peak usage as a result of changed behavior is expected to reduce system costs in the long-run, in the meantime must collect the shortfall in some other way."[299] Revenue shortfall between

[299] CforAT OB at 73.

tariffs arises "most starkly" when the TOU rate differs substantially from tiered rates.[300]

PG&E states that its proposed "E-TOU is designed to be revenue neutral in the sense that it is designed as if the entire residential population is on it. That makes it revenue neutral to the entire population."[301] However, PG&E estimates a revenue shortfall of $300 million if all residential customers who benefit from being on E-TOU switched. TURN asserts that PG&E E-TOU is therefore NOT revenue neutral.[302]

PG&E's potential $300 million revenue deficiency assumes that TOU customers do not change their usage patterns. If TOU customers shift load patterns to use less energy during peak periods, the revenue deficiency for PG&E would be even larger.

SDG&E estimated potential for $132 million in undercollections for non-CARE customers.[303] If there was a shift in customer usage, the figure would be larger.[304] SCE did not provide a specific estimate, but does state that it expects migration to TOU could result in a revenue deficiency.

Regardless of how one defines "revenue neutral rate," we find these estimates of possible revenue deficiencies should be addressed. Our requirement for baseline credits and excess consumption surcharges other than in very specific and narrow circumstances, will accomplish that to some degree. We

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300 SCE OB at 155.

301 TURN OB at 52 (citing RT Vol. 12 at 1369, PG&E/Quadrini).

302 *Ibid.*

303 *Id.* at 51-52 (citing RT Vol. 14 at 1791-92, SDG&E/Fang).

304 *Ibid.*

further direct the utilities to focus on reducing the potential for undercollection when designing TOU rates.

First, the IOUs should model a range of revenue deficiencies which can then be used to set a TOU rate that is more likely to meet its allotted revenue requirement.

Second, as discussed above, a baseline credit will make the TOU rate more appealing to low-usage customers.

In the event there is an undercollection, the recovery must be apportioned fairly. Until the magnitude of undercollection is better understood, any undercollection directly resulting from rate design changes should be spread to the entire residential class. An "undercollection" of fuel and purchased power costs resulting from reduced usage probably does not have to be recovered at all, because those variable costs will also be reduced through lower consumption.

SEIA proposes a "virtuous cycle" in which if there was an undercollection from the TOU customer group, the undercollection would be recovered from non-TOU residential customers. This would encourage enrollment in TOU, and would penalize the customers who remained on tiered rates.

CforAT argues that this would punish the very customers who are the least able to make adjustments to their time of use.[305] CforAT argues that many of these customers are low-income for whom it is already difficult to afford electricity. Even if low-income and low-usage are only somewhat correlated, there is still a group of low-usage low-income customers who may not be able shift load for TOU rate.

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[305] CforAT OB at 73.

SCE does not support "virtuous cycle" proposal.[306] SCE argues that before a "large-scale movement to cost-based TOU" it is essential to reform the tier structure.[307] Otherwise, customers who are under the currently "punitive" high tiers, will be the ones to be incented to move to TOU rates, resulting in significant undercollection from tiered rate customers as a group. The revenue shortfall solution adopted in SCE RDW Application (A.) 13-12-015 will recover shortfalls from within the entire residential class over an appropriate period of time."[308] This is consistent with ORA's position, that "flattening or reducing the differential for residential tiered rates is helpful to prepare for default TOU rates."[309] PG&E also agrees with ORA that undercollection should be made up by the entire residential class.[310]

Although we agree that a virtuous cycle would make the TOU rate more attractive, we agree with SCE, ORA and CforAT that recovery from the entire residential class is the only fair solution until such time as the IOUs can demonstrate a reduced risk of undercollection.

6.5.4. Impact of Load Reduction on Cost Savings and GHG Reduction not Demonstrated

Intuitively, TOU is assumed to reduce peak usage, thereby moderating the peak periods during which expensive, and potentially higher polluting, generation resources must be brought online. This in turn should result in reduced purchased power and infrastructure costs, and potentially GHG

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306 SCE RB at 87 n.328.

307 SCE OB at 150.

308 ORA OB at 65 (citing D.14-12-048).

309 RT Vol. 22 at 3475, ORA/Kao.

310 PG&E RB at 79.

emissions, because California will be able to make better use of the cleanest energy sources.

As we noted at the beginning of this decision, there are few studies that actually evaluate and document these expected benefits.

For example, no studies were cited in this proceeding that demonstrate a clear correlation between reduced peak use and reduced GHG emissions. Indeed, TURN's analysis suggests that GHG emissions could increase as a result of increased use of out-of-state coal to support shifts in energy use.

Similarly, the estimates of long-term cost-savings rely on many assumptions and further study would be necessary for a decision could rely on specific cost-savings estimates.

We certainly agree with parties that the available evidence on these issues is disappointingly inconclusive. However, this is not a reason to put off large-scale roll out of TOU. Instead, we direct the IOUs, as part of their 2018 Residential RDW application, to prepare better studies of the potential for cost savings and GHG reduction. To ensure that the studies are truly useful to the Commission, other parties, and the public, we direct the utilities to design the studies in consultation with Energy Division and interested parties, as part of Phase 3 of this proceeding.

6.6. TOU Pilots and Optional Tariffs

6.6.1. What Should be Studied in TOU Pilots and Optional Tariffs?

Throughout this proceeding, in written testimony, briefs and other filings, and in evidentiary hearings, parties have identified many categories of information to consider for residential TOU. Here is a partial list.

- Peak period length and times for the on-peak period.[311]
- Most effective way to communicate and implement TOU programs.[312]
- Customer adoption and retention rates.
- Costs of educating customers and responding to inquiries.
- Effective means of educating and recruiting customers for TOU optional rates.
- Pattern in usage shift owing to migrations from tiered rates to TOU rates.[313]
- Estimating revenue shortfall.[314]
- Opt-in pilot should use randomized treatment design to simulate benefits of a default pilot.[315]
- Cost estimates for outreach, education, marketing, billing and IT modifications.
- Quantify variability of bill and load impacts across key geographic, demographic and segments as well as for varying rate designs and outreach messaging.[316]
- Section 745 requirements.
- Different peak period hours and price-ratio combinations to test differences in customer acceptance and engagement under each variation.[317]

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[311] SDG&E RB at 27.

[312] ORA OB at 70.

[313] *Id.* at 71 (citing SCE OB on legality of pre-2018 default pilot).

[314] CforAT OB at 4-5, 72-79.

[315] ORA OB at 71 (citing SDG&E OB on legality of pre-2018 default pilot).

[316] *Id.* at 72 (citing PG&E opt-in pilot description).

[317] PG&E OB at 63; *id.* at 67 (citing Exh. PG&E-109 at 5-7; RT Vol. 12 at 1423 PG&E/Mandelman).

- Model range of revenue deficiencies based on different assumed levels of adoption and levels of migration between optional and default tariffs.[318]
- Comparing TOU opt-in structures and acceptance by Climate Zone.[319]
- Identify customers to be categorically exempted from default TOU.
- Time period over which a mild TOU differential become more cost-based.
- Load reduction in relation to relatively low (44%) AC saturation.[320]
- Marketing message to gain engagement with diverse customer segments.[321]
- Effectiveness of marketing, education and outreach for non-English speakers.
- Lessons to reduce costs for wider-scale outreach and operations.[322]
- Test system operationality.[323]
- Effective marketing, education and outreach for customers with and without AC.
- Test comparative rate presentation to develop most effective presentation.

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[318] TURN OB at 53.

[319] RT Vol. 12 at 1423, PG&E/Mandelman.

[320] PG&E OB at 65.

[321] *Ibid.*

[322] *Ibid.*

[323] *Ibid.*

- Long-term implications of different rate structures on the load forecasts used in distribution planning and on the procurement of new generation resources.[324]
- Long-term revenue requirement implications of different rate structures both in terms of stranded assets and future new investments.
- Tradeoffs between energy bill consequences and incentives for private investment in Distributed Energy Resources.

6.6.1.1. Default TOU Pilots Generally

AB 327 authorized default TOU as early as 2018, provided that certain requirements are met. ORA, Sierra Club, and EDF contend that default TOU should start in 2018, without a separate TOU Pilot.

However, a number of active parties argue for a two-year default pilot prior to any large-scale implementation of default TOU.[325] These parties state that a default TOU pilot would allow further study of the topics above. Their proposal would also significantly delay any move to default TOU without any assurance of progress being made toward an improved rate design.

While the timeline proposed by these parties would prevent default TOU from being implemented earlier than 2022 (or more likely, 2023), the parties did not offer any specific objectives or criteria for evaluating TOU during this period of time. The timeline included one year to design a pilot, an advice letter for

324 Exh. EDF-101 at 26..

325 *See* Joint Motion for Admission of Joint Exhibit 101 into Evidence filed December 2, 2014; *see also* SCE OB at 151; PG&E OB at 7, 63-66; SEIA OB at 34-35; TURN OB at 53-55, 82-85; UCAN OB at 5, 33-37; CforAT OB at 4-5, 77-79; Vote Solar OB at 25-26; CUE OB at 4-5; IREC OB at 27-28; TASC RB at 23; *cf.* SDG&E OB at 59-62 (although SDG&E did not support all aspects of the specific proposal of the first 10 parties to the joint proposal).

approval, and then another nine months during which no activity was specified, but no progress would be made toward better understanding default TOU.

We find that this proposed timeline is not reasonable. However, we recognize that agreement between diverse parties on an approach to default TOU design has significant value. We find that a collaborative approach, such as that recommended by the parties, will benefit the design and roll out of default TOU.

We therefore authorize and direct a working group to develop study parameters and pilot design on a more expedited schedule. We expressly authorize the working group to select a consultant, to be paid by the IOUs, to advise on and document the study parameters and pilot designs. We expect parties, including ORA, to work together to form the working group and report back at the first Phase 3 PHC. We expect the process of pilot design to be completed in 2015, and submitted for approval by each utility through a Tier 3 advice letter. As discussed below, the pilot design should include both opt-in pilots for immediate implementation and default TOU pilots to be implemented in 2018 as permitted by statute.

6.6.1.2. Is Default TOU Pilot Required by Statute?

SB 1090, passed in 2014, added new conditions to be met prior to authorizing or requiring default TOU. The Commission must consider "the extent to which hardship will be caused on . . . customers located in hot, inland areas, assuming no change in overall usage by those customers during peak periods [and] [r]esidential customers living in areas with hot summer weather, as a result of seasonal bill volatility, assuming no change in summertime usage or in usage during peak periods."[326]

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[326] Section 745(d).

TURN asserts that this language should be interpreted to require a default pilot prior to any "commitment to transition to default TOU rates."[327] The language of the statute requires the findings to be made prior to *authorizing or requiring* the utilities to *employ* TOU rates. The statute does not preclude the Commission from ordering the IOUs to file default TOU rates, provided that the SB 1090 analysis is completed before default rates are authorized or required to be employed.

TURN correctly points out that, "At this time, there is no basis for the Commission [to] conclude that these requirements have been satisfied . . ."[328] but this is not the finding we must make before taking the next step toward default TOU. If TURN were correct, and the Commission had to make these additional findings before any step toward default TOU, this would effectively prevent any step toward default TOU. If this is what the legislature intended, they would have drafted the statute with more clarity. We understand the legislature's intent in passing SB 1090 is to require a study to prevent hardship to customers in hot areas before any wide-scale default TOU rates are implemented.

The record for this proceeding includes only limited information on the SB 1090 findings as well as other important areas that should be studied before the utilities employ default TOU. We agree with TURN that it is important to study these impacts and determine how to mitigate them before default TOU is employed. On the other hand, we do not believe that the Legislature intended SB 1090 to create an infinite loop that would prevent default TOU from ever being implemented. Rather, the legislature seeks to protect customers by having

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[327] TURN OB at 53.

[328] *Ibid.*

certain studies done before default TOU is implemented. We direct the utilities to take steps toward implementing default TOU rates, including performing the statutorily-required studies and studies that will provide important information about customer acceptance and response to TOU rates.

TURN cites SDG&E's witness Winn stating that a default pilot would be useful to make sure that time of use was implemented properly, and that because of SB 1090 SDG&E was seeking to implement default TOU only after default TOU pilot.[329] TURN cites SDG&E witness Winn and Willoughby as "needing insight from 2018 pilot."[330]

Similarly, SDG&E's witness George said that the SMUD study should not be relied on as the basis of default TOU.[331] George cites the need to test demand response in the absence of selection bias.[332]

Selection bias will primarily address shifts in load, or other changes in load, that are a response to the new TOU rate. As has been shown, customers who opt-in to TOU rates are often more responsive than customers who are defaulted. However, the amount of load flattening that can be achieved by residential TOU will take time to assess. The immediate goal of default TOU is customer acceptance and education.

Despite the arguments of several parties, we are not convinced that a default TOU pilot is necessary. Had these parties demonstrated that there were significant benefits of a default pilot compared to the current optional rates and

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[329] SDG&E OB at 60 (citing RT Vol. 13 at 1573-74, SDG&E/Winn).

[330] RT Vol. 15 at 1972, SDG&E/Willoughby.

[331] RT Vol. 16 at 2139-2144, 2181, SDG&E/George.

[332] SDG&E OB at 61.

pilots, then further consideration of their argument might be warranted. As ORA points out, these parties do not provide any details or explanations of how such data would be developed or used to meet Section 745.[333] In addition, these parties do not address the fact that their proposal will be expensive and cause a delay in implementation of default TOU. Although we agree with their arguments that a default TOU pilot could provide additional data, the record does not show that the additional data would be beneficial or necessary.

For example, it is not necessary to have default pilot to determine if TOU rates would impose a hardship on certain customer groups.[334] SB 1090 requires evidence to be gathered that *assumes no change in usage*. None of the parties advocating a default TOU pilot prior to default TOU have explained how information gathered from the pilot could provide information that is more informative on the SB 1090 findings than analysis of existing usage data. The utilities already have the data necessary to evaluate how customer bills would have differed if they had been on TOU instead of tiered rates. In contrast, an attempt to use a default TOU pilot to obtain this data would be skewed by customers who change their usage pattern as a result of knowing they are on a TOU rate. Thus the best data to use is the data that already exists.

After careful review, we find that only a few of the recommended study topics would require a default TOU pilot. These topics can and should be studied on an ongoing basis once default TOU is implemented. We expect that the design of TOU rates will need to be monitored and updated on an ongoing basis, and these studies will assist with that process. Notably, systems

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333 ORA RB at 27.

334 *Id.* at 28.

operability, customer retention rates and load shift will be best studied once default TOU rates are in place. The 2018 default TOU pilot will provide an opportunity to begin studying these areas in advance of full rollout.

However, because we agree there are benefits to default TOU pilots, we require each IOU to include a default TOU rate in its design of pilots approved by this decision. The purpose of this default TOU pilot will be primarily to study aspects of TOU that are directly impacted by the self-selection bias, and to fine-tune customer education and test system operability prior to full rollout of default TOU. The default TOU pilot will begin in 2018 and study of participants may continue for several years, even as full rollout of default TOU is implemented, so that the Commission and the IOUs can benefit from lessons learned from customers participating in the default TOU pilots.

We agree with TURN that the determination of whether default TOU rate structure complies with statute is a "fact-specific analysis"[335] that cannot be completed on the record of this proceeding. We therefore find it is imperative that the IOUs promptly take the next steps to propose default TOU rates and to develop benchmarks and prepare evidence to properly evaluate the proposals.

PG&E points out that the language of Section 745 needs to be clarified before we can determine if findings are made. Specifically, uses terms like "senior citizen" "hardship" and economically vulnerable customers" and "hot climate zones."[336] Clarifying these terms will not happen through a default TOU pilot. Rather, this needs to be done by the Commission through this proceeding

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[335] TURN OB at 54-55.

[336] PG&E RB at 85-87.

at an earlier date. PG&E recommends it be done through the "collaborative workshop process."[337] This issue will be addressed in Phase 3.

6.7. Default TOU Progress Reporting

Despite the installation of sufficient AMI technology over the last five years, PG&E and SCE have established a pattern of avoiding wide deployment of residential TOU. Despite the fact that this proceeding to examine time-variant rates was opened more than two years ago, and prior proceedings[338] stated that it is Commission policy to encourage time-variant pricing, and despite the fact that in 2012 the legislature passed AB 327 which expressly permits implementation of default TOU, the utilities have taken remarkably few steps in that direction

In this proceeding, we directed the IOUs to provide us with a roadmap for the years from 2016 through 2018. Only SDG&E proposed default TOU for 2018. By the time of evidentiary hearings, SDG&E had determined that it would not seek authorization of default TOU in this proceeding. No party provided evidentiary support for specific TOU structures.

During Evidentiary Hearings and in briefs PG&E and SCE estimated that it would take a minimum of 18 months to design a default TOU, and an additional 24 months to implement it. Meanwhile, IOUs could implement a fixed charge in 30 days. In a world where the NEST programmable thermostat was the most hyped tech holiday gift for 2014,[339] the argument that it takes three years to

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[337] *Id*. at 86.

[338] *See*, e.g., D.08-07-045; R.02-06-001; A.07-12-009.

[339] http://www.extremetech.com/extreme/194595-extremetechs-2014-holiday-gift-guide-high-tech-futuristic-gift-ideas-for-geeks-and-nerds.

design a pilot that could lead to increasing participation in TOU to meaningful levels is not reasonable.

The parties propose two different timelines for default TOU: (i) default TOU starting in for all customers in 2018 (ORA), and (ii) default TOU starting after a default TOU pilot and additional hearings (most other parties).

We agree with ORA that the record does not reflect any basis for delaying default TOU past 2018. Additional procedural steps are necessary, however, before default TOU rates can be employed. Based on this, we find that default TOU rates should begin in 2019 if the findings required by Section 745(d) can be made by that time.

The potential benefits of TOU are well-documented, as is the fact that enrollment in an opt-in TOU rate is slow, making default TOU the strongest option for demand response. But the details of implementing default TOU in California need further study and refinement. We are confident that California's IOUs can accomplish the needed study and propose appropriate default TOU rates for 2019.

We therefore direct the IOUs to begin preparing a residential rate design window application to be filed January 1, 2018 with the goal of review and approval no later than December 1, 2018.

Based on the record in this proceeding, however, the IOUs will need much collaborative assistance to help them meet that goal.

We believe that the utilities must be held to a strict timeline for evaluating default TOU, and that the IOUs must do more than file regular progress reports. As described in the Next Steps section, progress towards default TOU must be considered in the overall context of residential rates. For this reason, we direct the IOUs to hold an annual residential rates forum to report on the status of residential rate reform in their service territory. The annual Residential Electric Rate Summit (RERS) will be held each fall, beginning in 2015.

6.8. Opt-In TOU Rates Proposed in This Proceeding

6.8.1. Existing Opt-In TOU Tariffs and Pilots

As discussed above, the utilities already have optional TOU rates for residential customers. Many of those existing TOU rates include a complex system of tiered and TOU rates for different times of the day and month. As a result, current tiered TOU rates may be confusing and can result in counter-intuitive rates. PG&E provides an example of its current tiered TOU rate, which for Summer has three different time periods and twelve different rates that may apply, depending on time and usage tier level. In this proceeding we initially directed the IOUs to offer untiered TOU rates.

Example of the Twelve Separate Rates with Current TOU[340]

Summer Energy Rate	Peak	Part-Peak	Off-Peak
Baseline Usage	0.287	0.175	0.101
101 – 130% of BQ	0.305	0.193	0.119
131%-200% of BQ	0.478	0.366	0.291
Over 200% of BQ	0.518	0.406	0.331

On the other hand, a basic TOU rate structure with a baseline credit and/or an excess consumption surcharge can be considered a tiered rate because the customer pays several different rates: a lower rate for low usage kWh, a standard rate, and/or a higher rate for high kWh usage. Parties have argued both that any tiering is confusing for the customer and that a baseline credit is not confusing. As discussed above, we find that a baseline credit and excess

[340] *Ibid.* (Table 2-11).

consumption surcharge are important parts of TOU rate design. TURN's testimony included a mock TOU bill that includes a baseline tier and two higher tiers.[341]

Figure 2: Exemplary Bill Format for TOU Rate with Baseline Credit Based on SDG&E Bill

ELECTRIC CHARGES Amounts ($)

Electricity Delivery (Details below) 500 kWh

SUMMER USAGE	Baseline	1-30% over Baseline	31-100% over Baseline	More than 100% over Baseline		
kWh used	336	101	63			
kWh used	$.03919	$.05996	$.18655			
Charge	$13.17	$6.04	$11.79		=	**$31.00**

DWR Bond Charge 500 kWh x $0.00515 = **$ 2.58**

Electricity Generation (Details below) 500 kWh

SUMMER USAGE	On-Peak	Semi-Peak	Off-Peak	Peak Shift Period Adder		
kWh used	114	147	239	13		
kWh used	$.08500	$.07146	$.05570	$0.91000		
Charge	$9.69	$10.51	$18.84	$11.83	=	**$45.34**

Total Electric Charges **$78.91**

TAXES AND FEES ON ELECTRIC CHARGES Amounts ($)

use same format as SDG&E's existing bills; Attachment RWH-6 bills are formatted similarly to existing bills[2]

The bill structure that we envision would be even simpler than TURN proposes, roughly corresponding to the bottom portion of the TURN example by time period, with line items for the baseline credit and excess consumption surcharge.

Each of the IOUs already has some options for residential customers to enroll in TOU rates. Changes to these existing TOU rates and periods and for new TOU rate options are currently under review in other proceedings, and some new TOU rates have been approved while R.12-06-013 has been pending.

[341] Exh. TURN-201 at 62.

Given the priority to study these optional TOU rates in order to design better default TOU rates, it is essential that the utilities now establish a consistent approach to studying, implementing, and (as appropriate) closing optional TOU rates.

Based on the record in this proceeding, we direct the utilities to adhere to the following TOU opt-in rate design guidelines going forward:

(1) Offer a menu of different residential rates designed to appeal to a variety of residential customers, with different time periods and rate differentials.

(2) Include a baseline credit and/or an excess consumption surcharge in all opt-in TOU rates except those designed to encourage switching to electricity from other more carbon-intensive fuels (e.g., electric vehicle (EV) rates), and in a limited number of pilots.

(3) Changes to TOU periods should be made in rate design windows or GRC Phase 2 proceedings.

(4) TOU tariffs should include a legacy provision that allows subscribers to remain on their existing TOU tariff (with its original TOU periods) for at least five years. When TOU tariffs are closed, they must be discontinued gradually. The discontinued tariff should be closed to new customers. Existing customers (legacy tariff customers) should be permitted to remain on their TOU tariff for at least five years, with the ultimate duration of the tariff to be determined in future proceedings.

(5) SDG&E's DDMSF TOU pilot proposal should not be implemented until further study of standard TOU rates is accomplished.

6.8.2. PG&E Proposed Opt-In TOU Rate and Proposed TOU Pilot

PG&E proposes to introduce a new opt-in TOU rate without tiers: Schedule E-TOU (for non-CARE households) and Schedule E-TOU CARE (for

CARE households).[342] PG&E states that it wants E-TOU to be a non-tiered rate as it "provides more accurate price signals, better incents load shifting and is easier for customers to understand."[343]

There would only be two periods (peak and off-peak) during two seasons (summer and winter). PG&E proposed to use the same TOU periods as Schedule E-6. E-TOU would be a seasonally differentiated rate, with different rates and peak periods for Summer and Winter.

Summer Peak: 1 pm – 7 pm, weekdays (except holidays)

Summer Off-Peak: all other Summer hours.

Winter Peak: 5 pm – 8 pm, weekdays (except holidays)

Winter Off-Peak: all other Winter hours.[344] [345]

The E-TOU schedule would include a $5/month service fee, and E-TOU CARE would include a $2.50/month service fee.[346]

PG&E proposes a price differential between periods that is equal to the difference in the marginal costs per kWh for each respective time period.[347] PG&E states that this is the same methodology used for E-6. The table below shows an illustrative 2015 rate. For non-CARE rates, the differential between

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[342] Exh. PG&E-101 at 2-52.

[343] *Id*. at 2-53.

[344] *See* A.14-11-014.

[345] PG&E filed its rate change proposal in this proceeding in February 2014. Currently, PG&E has a rate design window pending in which it requests that the TOU periods for E-TOU (once E-TOU is approved) be modified to have a peak period of 4-9 p.m., weekdays, with a summer period of June – September.

[346] Exh. PG&E-101 at 2-5.

[347] *Id*. at 2-53.

summer peak and off-peak is approximately 1.75:1, and for Winter the rates are 1.1:1.

Illustrative E-TOU Rates[348]

Non-CARE	**Monthly Service Fee**	**On-Peak Rate**	**Off-Peak Rate**
Summer	$5	$0.319	$0.182
Winter	$5	$0.183	$0.169
CARE	**Monthly Service Fee**	**On-Peak Rate**	**Off-Peak Rate**
Summer	$2.50	$0.207	$0.118
Winter	$2.50	$0.119	$0.110

PG&E did not include a definition of summer and winter in its testimony, but review of E-6 Tariff shows that the current definitions are: Summer: May 1-October 31st and Winter: November 1-April 30th.[349]

PG&E did not provide details on the methodology used to arrive at the "marginal costs per kWh."

PG&E describes the E-TOU rate as "revenue neutral" but did not provide details on how undercollections from E-TOU would be collected. As noted above, given the current steeply tiered rate structure, undercollections could be significant.

The E-TOU is fully untiered and does not include a baseline credit. As discussed above, we find that a baseline credit and an excess consumption surcharge are essential aspects of residential TOU given the migration risk caused by the current steeply tiered default rate. In addition, it is essential that all IOUs begin studying residential TOU rates with a focus on TOU periods, duration of TOU periods, customer acceptance and customer response. Finally, the baseline credit is a means to make TOU a reasonable alternative to the default

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348 *Ibid.*

349 PG&E Schedule E-6 at Sheet 4.

tiered rates for low-usage customers, and the excess consumption surcharge helps to deter opportunistic tariff shifting with no system benefit.

We agree with PG&E that its E-TOU rate will support movement of more customers to time-variant rates.[350] Based on the evidence in this proceeding, we agree that a two-period TOU rate will be the most understandable and acceptable to residential customers. Therefore, we believe that PG&E E-TOU proposal, as modified, is reasonable, fair and consistent with the law.

We approve PG&E's proposed E-TOU rate with the following modifications:

- A minimum bill rather than a fixed charge.
- E-TOU and other optional rates must include a baseline credit and/or excess consumption surcharge, except for those designed for customers switching to electricity from other fuels (e.g., EV rates), and in a limited number of pilots.
- Undercollections can be made up from the residential rate class as whole over a reasonable amortization period.
- Time periods offered must remain available to customers for a minimum of five years after enrollment, but can be modified through RDW or GRC process for future customers.
- So that we can better understand the degree to which the E-TOU rate reflects costs, going forward PG&E must provide documentation of marginal cost of kWh it is using in setting the TOU rates.
- Enrollment can be capped if migration from default rates to E-TOU suggests that a significant revenue shortfall is likely. PG&E must file a Tier 2 Advice Letter to request a cap.

PG&E proposes a two-phase TOU pilot. The first phase would be an optional rate, beginning as early as 2016, and the second phase would be a

[350] PG&E OB at 55.

default rate.[351] PG&E states that it will use the pilots to study "how PG&E's 4.7 million residential customers might respond to mass market implementation of TOU rates (whether opt-in or default), and thus what rate structure, communications and operational preparations are advisable to achieve a widespread and successful PG&E TOU program in the future."[352]

For PG&E's TOU pilots, we direct them to be designed to allow study of TOU as further determined through the workshop process set forth in Section 11. The pilot design should include only opt-in TOU prior to 2018.

6.8.3. SDG&E Proposed Opt-In TOU Rate and TOU Pilots

SDG&E proposes a new, optional, untiered TOU rate beginning in 2015. Unlike the other TOU rates discussed in this decision, the SDG&E Opt-In rate would consist of a volumetric TOU rate designed to recover commodity costs **and** a DDMSF for the recovery of distribution and demand costs. Demand differentiated rates are used in the commercial setting, but SDG&E is the only party to propose that demand-differentiated rates should be used for residential customers.

SDG&E argues that including a DDMSF would result in a rate that is more reflective of cost. If customers' response to the DDMSF price signal as SDG&E hopes, it would result in reductions of coincident and non-coincident demand.[353]

SDG&E's proposed DDMSF would be a fixed $/month adder and would vary by the level of a customer's non-coincident demand (for example, 0-3kW =

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[351] *Id.* at 63.

[352] *Ibid.*

[353] SDG&E OB at 53.

$X, 3-6kW = $Y, etc.). SDG&E proposes to apply the DDMSF to a customer's monthly hourly maximum demand. SDG&E proposes to institute a super-off-peak exemption for the DDMSF, explaining that "demand during the super off-peak period would be excluded from the determination of maximum demand for the application of DDMSF."[354]

SDG&E argues that its proposed optional TOU rate would provide a more accurate price signal than either the default TOU rate or the optional tiered rate and would lead to greater reductions in coincident and non-coincident demand. SDG&E also contends that the optional TOU rate would give customers more ways to reduce their bills; in addition to reducing usage, customers could also shift the time of day they use electricity and/or level out load.

As shown in the table below, SDG&E's illustrative DDMSF could be over $70 for some residential customers. The corresponding volumetric rate would be much lower. Several parties argue that this type of high monthly service fee would be too large, and the methodology too complex for residential customers to readily accept it.[355] To understand the calculation of the demand charge a customer must understand the difference between energy (kilowatt hours) and capacity (kilowatts). TURN points out that even SDG&E witness Winn admitted that few residential customers understand the difference between energy and capacity.[356]

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[354] Exh. SDG&E-108 at CF-48/Fang.

[355] TURN OB at 47.

[356] *Id.* at 48-49 (citing RT Vol. 13 at 1565-70, SDG&E/Winn).

Table CF-12: SDG&E Proposed DDMSF for Optional and Experimental TOU Proposals[357]

Max kW range	Customer Costs ($/month)	Distribution Demand Costs ($/month)	Proposed Monthly Service Fee ($/month)
Up to 3kW	$14.56	$13.29	$27.84
3kW up to 6kW	$14.56	$33.97	$48.53
6 kW and above	$14.56	$65.15	$79.71

We commend SDG&E for its willingness to explore the variety of TOU rates, at this time the focus of residential TOU must be on studying rate designs with volumetric TOU rates as set forth in AB 327. The rate component variables for study at this time are price differential between periods, number of periods, and the duration of the time periods. For this reason, we do not authorize SDG&E to start DDMSF pilots at this time. Instead, we direct SDG&E to first focus on pilots that will allow it to study the impact of volumetric TOU rates without a separate demand charge. We are, however, open to considering a structure similar to DDMSF in the future, after default TOU rates have been introduced.

In its 2015 RDW (A.14-01-027), SDG&E proposed changes to its current TOU periods, specifically to "change the current off-peak period to a super off-peak period previously available only to EV rates."[358] According to the A.14-01-027 Testimony of David Barker (which was submitted as an Appendix to SDG&E's Supplemental Testimony in this proceeding), SDG&E's proposed TOU periods are:

[357] Exh. SDG&E-108 at CF-2/Fang.

[358] Exh. SDG&E-107 at CF-43/Fang.

Summer on-peak: 2 p.m. – 9 p.m. non-holiday weekdays

Winter on-peak: 5 p.m. - 9 p.m. non-holiday weekdays

Super off-peak: 12 a.m. – 6 a.m. daily

Semi-peak: All other times

SDG&E also proposes to add two experimental TOU rates in 2015, in order to study customer response to different TOU structures. These rates will have shorter summer on-peak periods (four hours as opposed to seven hours); Experimental TOU A has a proposed summer on-peak from 2 p.m.-6 p.m. and Experimental TOU B has a proposed summer on-peak from 5 p.m.-9 p.m. The off-peak periods for summer and winter would be the same across all three optional TOU rates.[359]

SDG&E's proposed rates for its experimental TOU rates would be the same as its optional TOU rates and would include the DDMSF, except with a higher summer on-peak period rate to "reflect the recovery of equivalent costs through the shorter" period.[360]

Proposed Optional and Experimental TOU Rates with 2015 RDW TOU Periods[361]

TOU Period	Optional TOU - Proposed Rate (cents/kWh)	Experimental TOU – Proposed Rate (cents/kWh)
On-Peak: Summer	17.9	27.9
Semi-Peak: Summer	15.2	15.2
Super Off-Peak: Summer	11.1	11.1
On-Peak: Winter	11.3	11.3
Semi-Peak: Winter	10.0	10.0

359 Exh. SDG&E-111 at LW-4/Willoughby.

360 Exh. SDG&E-108 at CF-3/Fang.

361 *Id.* at CF-4/Fang.

Super Off-Peak: Winter	8.7	8.7

SDG&E proposes to recover any undercollection from the pilots and opt-in TOU from the residential class as a whole. For the reasons set forth above, we agree that this is the appropriate treatment of revenue undercollections at this time. In order to mitigate the risks of too many high-usage customers migrating to these optional TOU rates, we direct SDG&E to monitor enrollment. SDG&E should filed a Tier 2 advice letter to cap the opt-in and pilot rates in the event that significant undercollection is likely.

SDG&E's proposed TOU rate is more complex than the PG&E opt-in TOU rate. Like PG&E's E-TOU, it is seasonally differentiated, and it does not include a baseline credit. Unlike PG&E's E-TOU, it has more than two time periods. As noted, the record shows that customers generally prefer simpler rates. Nonetheless, because the purpose of this TOU pilot is to study customer acceptance and response, we agree that more than three TOU periods may be acceptable. We direct SDG&E to take the steps necessary to offer this TOU pilot to its customers as early as possible. However, we approve it with the following modifications/clarifications:

- No DDMSF or other fixed charge; minimum bill only.
- Opt-in tariffs must include a baseline credit and/or excess consumption surcharge, except for those designed for customers switching to electricity from other fuels (e.g., EV rates), and in a limited number of pilots.
- Undercollections can be made up from the residential rate class as whole over a reasonable amortization period.
- Time periods offered must remain available to customers for a minimum of five years after enrollment, but can be modified through RDW or GRC process for future customers.

- So that we can better understand the degree to which residential TOU rates reflect costs, going forward SDG&E must provide documentation of marginal cost of kWh it is using to set the TOU rates.
- Enrollment can be capped if migration from default rates to the opt-in TOU rate suggests that a significant revenue shortfall is likely. SDG&E must file a Tier 2 Advice Letter to request a cap.

For SDG&E's pilots, we direct them to be designed to allow study of TOU as further determined through the workshop process set forth in Section 11. The pilot design should include both opt-in and default TOU.

6.8.4. SCE Proposed Opt-In TOU Rate and TOU Pilots

A new, optional, untiered TOU rates became effective for SCE residential customers in 2015.[362] [363] The new rate has three time-of-use periods which do not differ by season.

On-Peak	Super Off-Peak Period	Off-peak
2-8 weekdays except holidays	10 pm to 8am	All other hours

The new rate, TOU-D, has options for both low usage and high usage customers. Option A, for low-usage customers, includes a small customer charge equal to that of SCE's default residential rate and a baseline credit.

The baseline credit is set using customers' baseline zone allocations (in kWh) multiplied by a cent-per-kilowatt value established as the difference

[362] *See* A.13-12-015 (2013 Rate Design Window).

[363] Exh. SCE-101 E-33.

between the average of the non-baseline energy rate(s) of the default rate, and the Tier 1 energy rates.[364]

Option B, for higher usage customers such as EV owners, has less differentiated summer and winter peak periods, no baseline credit, and a $16 monthly fixed charge. SCE stated that these features will provide seasonal bill stability for Option B customers. CARE customers who choose TOU-D will receive a 30% discount off their total bill.

A.13-12-015 was settled by the parties. The settlement addressed the concern regarding deficiency from customers moving from SCE's default residential rate to TOU-D by setting an initially cap open enrollment on TOU-D to 200,000 customers. SCE is permitted to seek a higher enrollment cap in a future Rate Design Window or GRC Phase II.[365]

For consistency with SDG&E and PG&E opt-in TOU, we direct SCE to modify TOU-D and other optional rates or pilots to be consistent with our directives to PG&E and SDG&E above.

SCE did not propose an opt-in TOU pilot for 2015. We therefore direct SCE to develop a TOU pilot on the terms similar to PG&E's and SDG&E's proposed pilots.

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[364] A.13-12-015, Joint Motion for Approval of Settlement Agreement, August 14, 2014, Appendix A (Settlement Agreement Resolving SCE's 2013 Rate Design Window Application § 4(e)(iii)(c)).

[365] *Id.* at § 4(e)(iii)(a).

7. Monthly Service Fee

7.1. Generally

7.1.1. A Fixed Monthly Charge is Not Reasonable

Currently, virtually all of a utility's costs are collected in volumetric rates. NEM customers and vacation home owners may not have volumetric usage and thus may not pay anything to support the costs of the system. This problem can be resolved with a minimum bill.

Parties generally agree that the cost of providing electric service has both fixed and variable elements. No party in this proceeding denies that utilities have fixed costs, or the existence of customer-related fixed costs. Instead, the debate centers on how the utilities should recover these fixed costs. Currently, for residential customers, the vast majority of the utility's costs, including those that do not vary with usage, are collected through variable energy charges. In this proceeding, each of the utilities has proposed a new or increased "fixed charge" or "monthly service fee" designed to collect certain fixed costs from all residential customers. The utilities maintain that the proposed fixed charges would better link cost recovery to cost causation, reduce cross subsidies, and ensure some degree of cost recovery from all customers.

7.1.2. The History of Fixed Charges in California

PG&E and SDG&E currently have minimum bills in place for residential customers as approved by prior Commission decisions. For PG&E, the current residential minimum bill is $4.50/month[366] and for SDG&E it is $0.17/day

[366] D.11-05-047 at 18 (referring to the minimum bill somewhat confusingly as a "minimum charge").

(approximately $5/month).[367] SCE does not have a minimum bill but does have a small fixed charge.

As TURN points out, the Commission has regularly considered the question of fixed charges in the past and almost always rejects them for residential IOU customers due to their interference with conservation and efficiency signals. This issue came to a head over twenty-five years ago in 1987, when the Commission authorized a fixed charge of $4.80 for SDG&E customers.[368] The decision was reversed less than a year later[369] with the Commission citing many customer complaints about the charge. SCE was granted the ability to assess a fixed charge, but it currently equals less than $1/month.[370]

In D.11-05-047, the Commission rejected PG&E's proposal for a $3 fixed charge, holding in part that because a fixed charge "cannot be avoided by a customer's reducing usage or being more energy efficient, the customer charge offers no conservation price signal." In D.14-06-007, the Commission rejected SDG&E's proposal for a $5 fixed charge for its residential gas service, even though SDG&E made the same cost causation argument that they make now. The Commission held that "SDG&E's argument that a $5 per month charge sends a significant 'cost causation' signal for fixed costs is not persuasive when weighed against the dilution of conservation and energy efficiency price signals."

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[367] Exh. SDG&E-107 at CF-27, CF-28.

[368] D.87-12-009.

[369] D.88-07-023.

[370] Exh. PG&E-111 at 16; Exh. NRDC-101 at 46; *see generally* D.96-04-050.

7.1.3. Change in Law Regarding Fixed Charges

Pub. Util. Code Section 739.9(e) gives the Commission the authority to adopt new, or expand existing, fixed charges for the purpose of collecting a reasonable portion of the "fixed costs" of providing electric service to residential customers. Fixed charges are defined in the statute as "any fixed customer charge, basic service fee, demand differentiated basic service fee, demand charge, or other charge not based upon the volume of electricity consumed."[371] Our authority is currently limited by Section 739(f) to a maximum fixed charge for non-CARE customers beginning January 1, 2015 of $10 per month and a maximum $5 per month fixed charge for CARE customers. Beginning January 1, 2016, the maximum allowable fixed charge may be adjusted by no more than the annual percentage increase in the CPI for the prior calendar year.

Section 739.9(e) provides the following direction to the Commission:

> (e) The Commission may adopt new or expand existing, fixed charges for the purpose of collecting a reasonable portion of the fixed costs of providing electric service to residential customers. The Commission shall ensure that any approved charges do all of the following: 1) reasonably reflect an appropriate portion of the different costs of serving small and large customers; 2) not unreasonably impair incentives for conservation and energy efficiency; and 3) not overburden low-income customers.

The statute does not require the Commission to approve any new or expanded fixed charges.[372]

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[371] Section 739.9(a).

[372] *Id.* at (g).

7.2. Calculating Fixed Costs

Currently, there is no agreed-upon method for identifying and calculating the IOU's fixed costs. Parties concede that there are fixed costs associated with providing residential electric service, but disagree on policy bases as to the level of those costs and whether those costs should be recovered by fixed charges. For the most part, the parties' arguments regarding which cost elements should be considered fixed costs generally reflect how such an allocation would impact their rates. The utilities argue for a fairly broad interpretation of fixed costs while the solar parties generally argue for a narrow interpretation of fixed costs, as that would load more costs into the volumetric rates, which their constituents avoid.

We periodically evaluate various proposals for calculating the utilities' fixed costs during part of each electric utility's GRC cycle. First, we establish the utilities' revenue requirements, that is, the amount of revenues to be recovered in rates. This includes all current and operation and maintenance costs, administrative and general expenses, fuel and purchased power expenses, taxes, depreciation, interest payments, and a component for return on equity. Those revenue requirement amounts for each of the three electric utilities are determined in Phase I of their GRCs.

Next, during Phase 2 of each electric utility's GRC, we determine the marginal cost for each service provided and each customer class' responsibility for those costs. We then allocate the authorized revenue requirement between the customer classes and set the actual rates or prices for each tariff. As we consider the proposed fixed charges in this proceeding, each utility's current revenue requirement and each utility's residential class' allocation of that revenue requirement have already been determined. Our review in the instant proceeding is limited to considering the appropriate rate design for the residential class.

Historically, in setting electric rates, we have sought to design and set rate structures that are based on marginal cost and that allow each utility to recover its costs of service in a manner that ensures that costs specific to each class of customer are recovered from that same customer class. To the extent possible, and allowing for certain subsidies to promote certain societal goals, we have also sought to ensure that each customer pays for electric service in proportion to their use.

Many of the GRCs and cost allocation proceedings in the last two decades have been settled. In most recent proceedings in which marginal customer costs have been litigated, including PG&E GRCs D.92-12-057, and D.97-03-017; SDG&E GRC D.96-04-050; SoCalGas/SDG&E Biennial Cost Allocation Proceeding D.00-04-060 the Commission has adopted the new customer only (NCO) method of calculating customer costs. In these decisions, we have consistently found that it is more efficient to charge customers an up-front amount that reflects the cost of the equipment because customer-hookup equipment is not available to other customers at different locations if one customer reduces his or her use of the meter and another customer increases their load. Although customers continue to benefit from the equipment after it is installed, for purposes of establishing marginal costs that simulate pricing in a competitive market, we have found that the relevant unit of output is new customer hookups, as the only time the cost of customer access is marginal is when the customer is deciding to connect to the system.

In this proceeding, each of the utilities proposes a monthly service fee of $5 and $2.50 for its non-CARE and CARE rates beginning in 2015, increasing to $10 and $5, respectively, for non-CARE and CARE by 2017.[373] In 2017 and 2018, the monthly service fees would be adjusted according to the year-over-year change in the California CPI. These charges would replace any current residential minimum bill amounts.

Each of the utilities proposes a slightly different methodology for calculation of the fixed charge or "monthly service fee" (referred to herein as a fixed charge). Their calculations generally follow the methodologies used by each of the utilities in their most recent GRC Phase 2 applications.

7.2.1. PG&E Fixed Cost Calculation

PG&E's proposal in its last GRC, and its proposal in this proceeding, is based on the NCO method, also called the one-time hookup method for calculating marginal customer costs. The NCO method relies on forecasts of customer counts and assigns the cost of new hookups to each customer class based on the number of new customers and estimated replacements for that class. Ongoing costs are assigned based on the total number of customers in that class. PG&E calculates the marginal customer costs noted above and multiplies them by the Equal Percentage of Marginal Cost Multiplier (EPMC) in order to recover the full revenue requirement, no more and no less.[374] The EPMC process in utility revenue allocation is essentially the markup (or mark down) of the marginal cost to reflect the embedded cost revenue requirement.

PG&E maintains that its methodology for calculating fixed costs includes categories of costs that do not vary with usage, including "customer access and

[373] PG&E proposes to increase its monthly service fee to $10 and $5 for, respectively, non-CARE and CARE, in 2016; SDG&E's and SCE's proposals are more gradual, reaching the maximum in 2017.

[374] Exh. PG&E-109 at 1-35, 1-36.

revenue cycle service costs such as the costs of connecting a customer to the grid and maintaining that connection and service to the account—metering, preparing and sending bills, processing payments, providing service and contact center resources, and other grid-related costs."[375] PG&E also includes the maintenance of existing infrastructure such as transformers, services, and meters for existing customers in its calculation of fixed costs, as well as general capacity-related costs associated with generation, transmission, and distribution assets.[376]

PG&E states that its fixed costs to serve residential customers are approximately $11.49 per residential customer per month.[377]

PG&E suggests that AB 327's $10.00 limit on the maximum allowable fixed monthly charge makes the issue of which costs are fixed somewhat moot in this proceeding because even if you define fixed costs to include just the EPMC-adjusted residential marginal customer costs, they would exceed the statutory limitation of $10. As support, PG&E refers to its estimate of marginal cost for the residential customer class submitted in its 2014 GRC Phase II proceeding, in which it estimated that its EPMC-adjusted marginal customer cost is $198.09 per customer-year, or $16.51 per customer month.

SCE and SDG&E's proposals for calculating customer costs are generally based on the rental method, consistent with the proposals filed in each of their recent GRC applications. The rental method includes calculating an annualized capacity value, or "rental charge" for customer hookups, which is then assigned to each class on the basis of the total number of customers in the class. The

[375] PG&E OB at 30.

[376] *Id.*

[377] PG&E OB at 31.

capacity value is calculated by applying a real economic carrying charge to customer access equipment investment costs. This Commission has not adopted the rental method in a contested proceeding for many years.

7.2.2. SCE Fixed Cost Calculation

SCE and SDG&E's proposals for calculating customer costs are generally based on the rental method, consistent with the proposals filed in each of their recent GRC applications. The rental method includes calculating an annualized capacity value, or "rental charge" for customer hookups, which is then assigned to each class on the basis of the total number of customers in the class. The capacity value is calculated by applying a real economic carrying charge to customer access equipment investment costs.

SCE argues that Section 739.8 places no requirement of customer-specificity when calculating what "fixed costs" might be, and that the statute requires no specific focus on marginal customer-related costs when calculating the "fixed costs" of an IOU.[378]

In SCE's opinion, fixed costs should reflect customer, and portions of generation/transmission capacity and grid-related fixed costs of service, i.e., costs that do not vary with customer usage.[379] SCE offers several different methodologies to determine the average fixed cost per residential customer, each of which results in average fixed costs greater than $10/month.[380] SCE's marginal customer cost methodology (which includes the cost of the final line

[378] SCE OB at 83.

[379] Exh. SCE-101 at 27.

[380] SCE OB at 84.

transformer, service drop, meter and panel, and customer services (i.e., call center)) results in a cost of $13.30/customer/month.[381] For comparison, SCE also applies an EPMC scalar to its marginal customer cost estimate from a 2013 settlement adopted in D.13-03-031 to reach a cost of $17.30/customer/month.[382] SCE argues that certain costs of distribution infrastructure should be included in the calculation of fixed costs, including the financing costs associated with the distribution grid, and the cost for components of the distribution grid such as poles, conductors, and transformers that are required to serve customers. When factoring in these components, SCE arrives at a figure of $76/customer/month.[383]

Finally, to estimate the average fixed costs for low-usage or no-usage customers, SCE provided an estimate of what its costs of distribution and transmission would be if no one was actively drawing any energy. SCE states that a zero-demand state represents 38% of its distribution costs and therefore 38% of SCE's distribution costs should be considered "fixed" and divided amongst all SCE customers accordingly.[384] When calculating the fixed cost per customer in this manner, SCE obtained fixed customer costs of $17 per month; fixed distribution service costs of $10 per month; and fixed generation capacity/transmission costs of $8 per month.[385] SCE argues that because each of

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381 *Ibid.*

382 *Ibid.*

383 SCE OB at 85.

384 Exh. SCE-101 at 28.

385 SCE OB at 85.

its methodologies results in a figure in excess of $10/month, the $10/month fixed charge should be imposed.[386]

SCE currently has a fixed charge of approximately $1 per month, which recovers approximately 1% of SCE's residential revenue requirement. SCE's increased fixed charge would recover approximately 8% of SCE's residential revenue requirement. The increased fixed charges would offset, on a dollar-for-dollar basis, customers' variable energy rates, reducing seasonal bill volatility and provide an appropriate price signal to customers.

7.2.3. SDG&E Fixed Cost Calculation

Currently, SDG&E's residential customers are subject to a minimum bill of approximately 0.14 and 0.11 cents per day for non-CARE and CARE customers. SDG&E proposes to replace this minimum bill with a monthly service fee of $5 per month in 2015, increasing to $7.50 in 2016 and $10 in 2017, with an annual CPI adjustment occurring in 2018 and later. Although in SDG&E's opinion, a distribution rate structure designed to reflect clear and accurate prices signals would consist of a monthly service fee to recover distribution-related customer costs along with a non-coincident demand charge to recover demand-related distribution costs,[387] in this proceeding SDG&E proposes only the monthly service fee, and would continue to recover the residual distribution and demand costs through the volumetric ($ per kWh) distribution rate.

Using figures from its 2012 GRC Phase 2 application, SDG&E estimates the average distribution customer costs for residential customers to be $10.64 per

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[386] *Id.* at 83-84.

[387] SDG&E's preferred non-coincident demand charge would recover demand-related distribution costs through a dollar per kW charge structure based on distribution usage, differentiated by customer class and voltage level.

month and distribution demand costs to be $5.85 per kW per month. Updating for current revenues, SDG&E calculates average distribution customer costs of $14.56 per and distribution demand costs of $8 per kW per month.

SDG&E explains that its fixed customer cost estimate of approximately $15/month is a conservative estimate, and that the number could have been closer to $40/month if it had exercised the full discretion allowed under AB 327.[388] SDG&E also suggests that the appropriate forum to address specific methodologies for determining fixed costs and charges is in each utility's GRC Phase 2 proceeding.[389]

SDG&E recommends that the fixed charge revenues be used to reduce the upper tier rates until a 20% differential is reached between the upper tier and the lowest tier. SDG&E would exclude master-metered customers from the fixed charge, because the cost of service to master-metered customers differs from separately-metered customers because the cost is dependent upon the number of customers behind each meter. SDG&E would retain the current minimum bill charge for master-metered customers but would increase the current minimum bill from $0.17 per day to $0.30 per day for non-CARE customers. Master-metered CARE customers would continue to see a minimum bill of $0.17 per day in 2015 with annual CPI adjustments beginning in 2016.

7.2.4. Party Positions on Fixed-Cost Calculation

Several parties including ORA, TURN, and IREC disagree with the IOUs' proposed methodologies for calculation of fixed customer costs. These parties

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[388] Exh. SDG&E-109 at CF 23-24.

[389] *Id.* at CF-24.

maintain that customer-specific costs should only include maintaining or replacing the meter, billing, customer accounts, and customer service and that it is inappropriate to include any load-carrying or demand-related costs in a fixed cost methodology.[390]

They further argue that customer-related fixed costs that vary with the size and/or usage of the customer should be excluded from a fixed charge.[391]

TURN argues that while marginal customer costs vary by utility, if calculated using the NCO method previously used by the Commission, marginal customer costs would be less than the $10 per month claimed by the IOUs. For example, TURN's recent PG&E GRC Phase 2 testimony estimated PG&E's fixed customer costs of $60 per customer year.[392]

In the same case, PG&E claimed that customer costs were $70 per customer year. In this proceeding, PG&E calculates a $10 per customer month cost, by adding the EPMC scalar to the $70 per customer year figure, plus about $103 per customer in non-marginal costs.[393] Similarly, NRDC notes that PG&E's GRC Phase 2 fixed cost estimate per customer was $6.49/month in 2014 dollars, and that this was arguably an "overestimate" as shared service drop costs were included.[394]

SDG&E also justifies its proposed $10 fixed charge based on its litigation position in its 2012 Phase 2 GRC. As with the PG&E estimates,

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390 UCAN OB at 25; IREC OB at 19; OB at 16.

391 NRDC OB at 40.

392 Exh. TURN 204 at 49.

393 PG&E RB at 30-31.

394 Exh. NRDC-101 at 52.

other parties challenged SDG&E's position. In that proceeding, UCAN estimated marginal customer costs of $89.10 per customer year ($7.42 per month) and ORA estimated $77.68 per customer year ($6.47 per month).[395]

We are not persuaded that collecting customer-related "fixed costs" through a monthly fixed charge is reasonable. We also agree with TURN that the record is not sufficient to reach definitive findings on the exact definition and amount of fixed customer costs. We find that the evidence in this case is insufficient to determine which costs are customer-related, and of among the universe of customer-related costs, which costs should be considered marginal.

7.3. Analysis of Fixed Charges for Residential Rates

7.3.1. Party Positions on Fixed Charges in Residential Rates

Regardless of which methodology is used to calculate the amount of fixed costs that could be recovered through a fixed charge, many parties oppose any rate structure with a fixed charge. These parties point out that fixed charges to reflect fixed costs are permitted, but not required, by statute. The IOUs point out that Fixed Charges to reflect fixed costs would bring rates closer to being cost-based. Parties who favor fixed charges point out that not only are they cost based but they are used by many other utilities. Opposing parties argue that, implementing a new fixed charge is universally unpopular with ratepayers. Moreover, in light of the significant bill impacts from tier flattening, it is not

[395] Exh. TURN-207, Attachment WBM-10 at 444.

reasonable to implement new or increased fixed charges until the impacts of tier flattening are complete.

The utilities argue that their proposed fixed charges will bring rates more in line with its costs to serve, and reduce intra-class subsidies, and reduce bill volatility. In addition, California's small electric utilities and many municipal utilities and investor owned utilities across the country already use a fixed charge to recover a portion of fixed costs.

While no intervenor denies that utilities have fixed costs, with the exception of UCAN, each of the non-utility parties is opposed to the imposition of a fixed charge. The non-utility parties oppose fixed charges for several reasons. First, ORA argues that most competitive markets do not recover fixed costs using fixed charges. Instead, they generally mark up the volumetric prices they charge to cover fixed overhead, which is analogous to what the EPMC markup does in the case of distribution costs.[396] ORA's Opening Testimony referred to a paper written by the Regulatory Assistance Project, regarding how competitive markets work which finds: "In competition, a consumer who does not consume a product or service does not nevertheless pay for the mere ability to consume it. Thus, as a general matter, prices should be structured so that, if a consumer chooses not to purchase a good or service, he or she has no residual obligation to pay for some portion of the costs to provide that good or service."[397]

These parties also contend that that fixed charges are inconsistent with marginal cost ratemaking because fixed charges, as proposed by the utilities,

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[396] ORA OB at 29.

[397] *Id.* at 32.

represent sunk costs and do not reflect the marginal cost that a customer would incur for the next increment of electricity purchased.

In contrast to the IOUs' arguments regarding cross-subsidies, CFC, along with TURN, argue that fixed charges require both large and small residential users to pay the same fixed cost and note that the Commission has, in the past, adopted different customer charge amounts for small and large customers. CFC agrees with IREC and others that, to the extent that smaller users tend to be the least well-off, the fixed charge is a regressive charge.

CFC also supports the conclusion of Sierra Club and ORA that fixed charges are a disincentive to rooftop solar and other renewables.[398]

According to ORA, a significant problem with fixed charges is that there is no meaningful way for customers to respond to a fixed charge other than by terminating service.[399] Because customers can respond to variable rates by reducing consumption, ORA, NRDC, maintain that variable rates are more efficient.[400]

ORA is correct that customers cannot avoid these costs unless they terminate service, and unless that customer does terminate service, the utility cannot avoid incurring these costs either.

Sierra Club also argues that the proposed fixed charges would violate the requirement of AB 327 by "unreasonably impairing" incentives for conservation and energy efficiency. Sierra Club points out that the Commission has rejected lower proposed fixed charges for impairing conservation incentives as recently

[398] CALSEIA OB at 16.

[399] ORA OB at 28.

[400] RT Vol. 17 at 2337, NRDC/Chernick.

as 2011 and 2014. In 2011, in D.11-05-047, the Commission rejected PG&E's application for a residential fixed charge on the basis that because a "fixed charge cannot be avoided by a customer's reducing usage or being more energy efficient," it offers no conservation price signal.[401] Subsequently, in D.14-06-007, the Commission rejected SDG&E's request for a $5 fixed customer charge for residential gas service, holding that SDG&E's argument that the "$5 per month charge sends a "significant "cost causation signal for fixed costs is "not persuasive when weighed against the dilution of conservation and energy efficiency price signals.[402]

NRDC witness Chernick calculates that for every $1/month increase in the fixed charge, the average energy rate would be reduced by about $1. - $/MWh, or about 1%, which means that "a $10 month fixed charge would reduce the average energy charge by about 10-11%; assuming roughly proportional distribution of the rate reduction across tiers, the reduction in the conservation incentive would be similar."[403]

CforAT argues that the utility proposals for fixed charges should all be rejected because none of the utilities has met it burden to show that its proposal is just and reasonable.

7.3.2. Differentiating Fixed Charge for Small and Large Customers

Although § 739.9(e) does not define "small" or "large" customers, in the context of fixed charges for residential customers, "large" and "small" most

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401 D.11-05-047 at 33.

402 D.14-04-007 at 41.

403 Exh. NRDC-101 at 49-50.

likely refers to a customer's usage level or type of dwelling. The utilities each propose to differentiate fixed charges by providing a 50% fixed charge discount to CARE customers, regardless of the usage characteristics of the individual customer. They suggest that because CARE customers generally use less energy than non-CARE customers, providing a lower fixed charge for CARE customers is a reasonable and practical means of complying with Section 739.9(e)(1).

Sierra Club, CforAT and CFC also object to a fixed charge, arguing that fixed charges would disproportionally impact low-income customers in both TOU and tiered rates because any fixed or customer charge will represent a larger percentage of their bill relative to a higher usage customer.

These parties also suggest that if fixed charges are not differentiated by customer size, fixed charges will result in a cross-subsidy of single-family homeowners by apartment dwellers and residents of multi-family buildings.

7.4. Fixed Charges as a Reflection of Cost Causation

The testimony in this case sometimes confuses "fixed costs" with marginal customer-related costs. The two are, of course, quite different. This Commission has for over 30 years used marginal costs (sometimes referred to as "economic costs") as the basis for revenue allocation and rate design. Fixed or sunk costs are irrelevant to a marginal cost analysis, which focuses on the forward-looking (avoidable) costs of the next unit of consumption of a product or service. In contrast, utility revenue requirements are based on an embedded (or accounting) cost framework, in which the cost of past plant investments is recovered over time through depreciation rates and a return on the undepreciated balance of those investments.

Fixed costs are not considered in a marginal cost analysis because they do not change based on increases or decreases in current consumption. They become relevant only when adjusting the revenues that would be collected through marginal cost pricing to match the embedded cost revenue requirement. This Commission has long employed Equal Percent of Marginal Cost (EPMC) for performing these adjustments.

The IOUs appear to be concerned that we are in a period when marginal costs may be less than embedded costs, thus requiring large upward adjustments to marginal-cost based rates in order to recover authorized revenue levels. This may or may not be true, depending upon one's perspective.

Today the driving issue behind many of our energy policies is GHG reduction. The costs of mitigating GHG emissions are only partially reflected in utility costs, through the IOUs' cost of purchasing allowances under the Cap and Trade program. The carbon price reflected in those allowances is modest, approximately $12 per ton. Yet numerous studies have indicated that the true "social cost of carbon" is much higher. Indeed, many of our "complementary policies" such as the RPS, CSI, Self-Generation Incentive Program (SGIP), and energy efficiency and electric vehicle incentives serve to depress the price of allowances by securing GHG reductions in other ways, rather than through a direct response to the market price of carbon emissions. This may be sensible policy for a wide number of reasons, but it does mean that the current market price for electricity does not fully reflect the true cost of emitting carbon.

If GHG costs were fully reflected in the market price of allowances, marginal energy costs would be considerably higher than they are today. Likewise, approving rate designs that would recover those higher costs in volumetric energy rates would substantially mitigate the problem of the embedded cost revenue requirement exceeding the revenues that could be recovered by pricing based on marginal costs. We are not suggesting that we are prepared to take this step today, nor have we developed an adequate record on the true cost of GHG emissions. But it is important to keep this reality in mind when considering whether or not to adopt a fixed charge as part of the residential rate design.

Further, our techniques for measuring marginal distribution costs are crude at best, typically involving a regression analysis of forecasted increases in load versus forecasted distribution plant investments. There is no reflection of locational cost differences in rates, and the many varied services provided by the distribution system have not been unbundled into separate charges. Through our Distribution Resource Planning proceeding, we are beginning the process of examining the distribution system and the services it provides in much more granular detail. This process may very well lead to more granular pricing of distribution products and services in the future. But a fixed monthly charge merely because of the status of being a utility customer is unlikely to be part of that evolution.

One of the fundamental principles of rate design that we seek to balance is that rates should reflect marginal costs, so that customers receive bills roughly consistent with how the utility will incur costs to serve those customers. Currently, for PG&E, SDG&E and SCE, the vast majority of costs are collected through volumetric, or variable energy charges. The Commission has previously considered fixed charges for the large electric IOUs several times in recent years, but has generally declined to adopt them based on a combination of legal and policy reasons. With the passage of AB 327, there is no longer a legal impediment to adopting fixed charges, so our primary consideration here are the relevant policies in favor or against fixed charges.

The utilities maintain that there are certain fixed costs that should be collected separately to provide more accurate price signals to consumers and eliminate the cross-subsidies present in an all-volumetric rate design.

PG&E argues that an all-volumetric design means that low-usage customers are not paying their fair share of the fixed costs that they impose on PG&E's system, while high-usage customers pay an unfairly high share of such costs.[404] SDG&E states that fixed charges would send more accurate price signals to consumers and would end cost-shifting from low-usage to high-usage customers, encouraging more efficient investments in DR and EE technology, and therefore increasing overall benefits to the environment and consumers.[405]

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[404] Exh. PG&E-101 at 2-6.

[405] Exh. SDG&E-106 at CY-3-4.

We note that these are primarily embedded cost arguments that do not consider the marginal costs of increased or decreased consumption.

The utilities suggest a broad interpretation of the categories of costs that do not vary with customer usage, including customer access and revenue cycle service costs, such as metering, preparing and sending bills, processing payments and providing service center resources and other grid-related costs. The utilities also suggest that capacity-related costs associated with generation, transmission and distribution assets are driven by customers' coincident and non-coincident demands on the electric system. Each of these costs are currently collected through volumetric rates. Non-bypassable costs associated with programs like CARE and FERA, and those that provide incentives for energy efficiency such as SGIP and CSI are also collected through volumetric rates.

The utilities argue that where certain costs are fixed and cannot be avoided, adopting a rate structure to recover these costs through monthly service fees, rather than through volumetric rates, best reflects cost causation and is more equitable. The utilities acknowledge that fixed charges are not necessary for revenue stability or cost recovery, but maintain that fixed charges would provide bill stability for customers.

Other parties, including ORA and TURN, maintain that the current approach – where fixed costs are collected through volumetric rates – is more consistent with the majority of the rate design principles and marginal cost ratemaking and should be retained. They maintain that fixed charges would violate most of the rate design principles articulated in this proceeding, because the fixed charges would be the same regardless of the amount of electricity used, would provide no incentive to conserve, and are not based on cost causation. In particular, they argue that fixed charges are antithetical to the Commission's conservation and energy efficiency efforts. They also argue that fixed charges have a disproportionally negative impact on low-income customers, and would create a new cross-subsidy, with low-income, low-use, multifamily customers subsidizing higher usage customers. These same parties emphasize that customers overwhelmingly oppose fixed charges.

7.5. Discussion

As discussed above, while we have occasionally supported fixed charges previously, most commission decisions over that last thirty years have rejected such charges for electricity on a variety of grounds. Even when fixed charges have been adopted, we have reduced the amounts requested by the utilities in recognition of certain marginal cost differences identified by ORA.[406] At those times, we found that it would only be appropriate to include the "marginal cost of billing, accounting, and other ongoing customer-related services."[407]

In this proceeding, the utilities each have proposed to set fixed charges at the maximum amount permitted by AB 327. TURN and other parties maintain that the IOUs' estimates of their fixed customer costs are too high. As noted above, in presenting their proposed fixed cost calculations, each of the utilities relied, in part, on their litigation positions from previous Phase 2 GRC proceedings to justify their customer cost amounts.

However, as is noted by TURN and ORA, due to the limitations imposed on the Commission by AB 1X, recent Phase 2 GRC proceedings have focused primarily on marginal customer costs for purposes of revenue allocation rather than residential rate design. In addition, many of these proceedings have been

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[406] D.96-04-050 at 115.

[407] *Id.* at 113.

resolved through settlements. As a result, the marginal cost figures ultimately approved by this Commission in the GRC decisions have often been reverse engineered from settled revenue allocation outcomes with very little true agreement as to the actual fixed costs of serving residential customers.

More recently, we have expressed concern regarding the potential impacts of a fixed charge on conservation incentives. In D.11-05-047 and D.14-06-007, in particular, we declined to approve proposed fixed charges in part due to concerns that such charges would reduce the incentives for conservation. We see no basis in the record of this proceeding to deviate from our policy. The utilities maintain that their proposed fixed charges would not unreasonably impair conservation in part based on their findings that customers respond primarily to average prices as opposed to specific elements of the individual bills. TURN agrees that there would be limited impacts on conservation with a fixed charge if customers are only affected by their average bills, but TURN suggests that the Commission should not assume that customers cannot be educated.

Our approved structure cannot be fully compliant with all of the principles set forth in the scoping memo, and we must balance the competing rate design principles. In this area, we give significant weight to the need to avoid the dampening impact on conservation incentives because customers would not be able to avoid the fixed charge. Any fixed charge would reduce the payback period for conservation investments by customers whose tier rates would be reduced.

We are also extremely concerned regarding customer acceptance of a fixed charge. As noted by many parties, the Commission has considered, and rejected, fixed charges in prior proceedings due to its concerns about customer acceptance (*see* D.89-12-057 and D.93-06-087). In this proceeding, the record demonstrates that customers have expressed their opposition to fixed charges in comments, at PPHs, through customer surveys, and in previous rate proceedings. The findings of the Hiner study commissioned by the utilities to obtain "customer input into alternative electric rate plans as part of the Residential Rates OIR," also demonstrate that customers strongly disfavored rate options with fixed charges[408] and that "a monthly service fee was the most important attribute of rate plans for the participants and that participants had a strong preference for rate designs that did not include a fixed charge." PG&E witness Pitcock agreed that the Hiner Study revealed that "a monthly service fee was not favorable."[409]

Furthermore, there is nothing on the record to demonstrate that customers are likely to understand that a new fixed charge would represent only a change in rate design, as opposed to an additional charge. To the contrary, the record demonstrates that customers tend to believe that the fixed charge would be an additional charge. Utility witnesses Pitcock, Garwacki, and Winn each acknowledged customer opposition to fixed charges at the PPHs but claimed that customers were "misinformed" and did not understand fixed charges. Since the majority of customers' bills will increase as a result of the rate redesign we are undertaking, it is reasonable to conclude that customers would interpret any bill increase to be at least partially related to a fixed charge.

As is reflected in RDP #10, we want to ensure that customers understand and accept residential rate structures, and that rates are stable and understandable. As noted by many parties, in the past, the Commission has rejected rate elements that might otherwise have been considered reasonable,

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[408] Exh. TASC-102 at 18-19 (concerning Hiner study).

[409] RT Vol. 12 at 1458, PG&E/Pitcock.

when they have resulted in widespread customer hostility. The record in this case demonstrates that customers are concerned about fixed charges. In light of this concern, and in the interest of adopting a roadmap that includes stable and understandable rates, we find that it is reasonable to reject the imposition of fixed monthly charges for residential customers.

As many parties have noted, the Commission previously adopted, and then rescinded, a customer charge for SDG&E. In that decision, the decision to institute a customer charge was purportedly based on a "commitment to cost-based rates and equal percent of marginal cost (EPMC) revenue allocation."[410] An overwhelmingly hostile response to the customer charge motivated the Commission to repeal the charge. In the decision repealing the charge, the Commission determined that "considerable weight must be given to the ability of residential customers to both understand the principles behind the rates they are charged and accept those principles as reasonable."[411] Consumer acceptance and understanding is incorporated into the rate design principles in this proceeding, including principles 6 and 10.

Based on the record in this proceeding, it is very clear that customers are unlikely accept the need for a fixed charge. Combining a new fixed charge with other significant rate design changes would only exacerbate the issue. Certain parties agree, for example, UCAN acknowledges that "introducing a customer charge, though a reasonable way to recover customer-related costs, could still be

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[410] D.88-07-023 at 2-3.

[411] *Id.* at 5.

ill-timed when SDG&E's low-usage customers' bills are increasing so rapidly over the next four years... "[412]

Accordingly, we reject the imposition of fixed monthly charges for residential customers for the foreseeable future. At the same time, we would be willing to entertain proposals similar to SDG&E's proposed DDMSF at some point in the future, following the adoption of default TOU rates, if the customer understanding issue can be adequately addressed. Since the DDMSF would vary based on the demand the customer places on the system, it is avoidable through customer action, something that is not true for a fixed monthly customer charge (unless the customer chooses to disconnect from the utility entirely, which is not something that we want to encourage).

7.6. We find that a minimum bill is reasonable.

As an alternative to the fixed charge, the minimum bill charge is a mechanism that is designed to recover a minimum level of revenue, recognizing that some costs are still incurred to maintain service even in the event that a customer does not use energy. As noted by several parties, AB 327 authorizes the Commission to consider minimum bills as an alternative to fixed charges.[413] The majority of parties who opposed the fixed charge proposal generally recommend adoption of a minimum bill instead.

For example, although it is committed to a rate design based on marginal costs, ORA acknowledges that a rate design based entirely on variable energy

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[412] UCAN RT at 6.

[413] § 739.9(h) ("The commission may consider whether minimum bills are appropriate as a substitute for any fixed charges.").

rates may under-recover the utilities' fixed costs.[414] Therefore ORA recommends that the best way to charge marginal costs while assuring the recovery of certain fixed costs is through a minimum bill applied to all residential customers.[415]

For customers with no or very low usage, the minimum bill would function like a customer charge and collect a portion of the utilities' costs, assuring that each customer pays something for the continued ability to take energy from the grid. Customers who use more energy (and whose bills exceed the minimum bill amounts) pay no minimum bill but instead pay through volumetric rates. SDG&E and PG&E already have minimum bills in place for residential customers. PG&E has a residential minimum bill of $4.50 per month and SDG&E has a minimum bill of $0.17 per day or approximately $5 per month.

Because minimum bills apply only to that percentage of customers whose usage is less than the minimum kWh of usage, the minimum bills collect less revenue. A minimum bill therefore allows the continued recovery of most utility costs through the volumetric rate, providing a price signal for the customer to limit its consumption.

7.6.1. Amount of Minimum Bill

ORA recommends that the size of the minimum bill be determined in subsequent GRCs or rate design proceedings. TURN believes that it would be reasonable to set a minimum non-generation bill in the range of $8-$10 for non-CARE customers, with 50% off that amount for CARE customers, noting that this would collect about 100-150 kWh of non-generation costs at baseline rates from non-CARE customers.

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[414] ORA OB at 44.

[415] Exh. ORA-101 at 2-17.

ORA agrees that certain ongoing variable costs such as billing, maintenance and customer services could be recovered in a fixed charge, but recommends that they be recovered through a minimum bill instead because most competitive markets do not recover such costs using fixed charges.[416] However, the parties disagree on whether Section 739.9 sets a cap on minimum bills. Several parties, including ORA,[417] argue that, because minimum bills were seen by the Legislature as an alternative to fixed charges, they should therefore be subject to the $5 CARE and $10 non-CARE caps.[418] Although the foregoing argument is conclusory, IREC quite reasonably suggests "[i]t would be illogical to read the statute to carefully prescribe what the Commission may do in regard to fixed charges, but then [leave] the Commission's discretion unfettered through an alternative, minimum bill approach."[419] While we do not agree with IREC and ORA, the IOU response is too clever by half.[420] We instead find that the plain language of the statute is subject to only one reasonable interpretation.

Section 739.9(a) defines "fixed charge" broadly, but without mention of minimum bills; Subdivision (e) sets out narrower criteria for permissible fixed charges. By contrast, subdivision (h) provides that the Commission "may consider whether minimum bills are appropriate as a *substitute* for any fixed

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416 *See, e.g.*, ORA OB at 29.

417 *See, e.g. id.* at 27; SEIA OB at 25; Sierra Club OB at 21; IREC OB at 23.

418 ORA OB at 27.

419 IREC OB at 24.

420 *See* SCE RB at 47-50 and especially at 48-49, where SCE propounds a granular distinction between a "minimum charge *mechanism*" and a "fixed charge *mechanism*," based on a purported "catch-all" definition of minimum bills in § 739.9(a). The other IOUs and intervenors did not substantively address this issue.

charge;" not whether minimum bills may *qualify* as a fixed charge under Section 739.9(a).[421] From this statutory scheme, we infer that the Legislature's unstated premise is that fixed charges are different from minimum bills. Accordingly, Section 739.9(h) does not authorize the Commission to uncritically apply fixed charge provisions—such as the section 739.9(f) maximums—to minimum bills. Rather, subdivision (h) contemplates the use of minimum bills where the *effect* of the substitution would be commensurable and similar to the intended effect of a fixed charge, as defined by Section 739.9(e) and related subdivisions. Moreover, IREC wrongly supposes that the failure to apply the fixed charge caps to minimum bills will result in "unfettered" Commission discretion.[422] We do not read subdivision (h) to abrogate all other constraints. For example, Section 739.1 would still apply. We therefore find that the Section 739.9(f) caps on fixed charges are not applicable to minimum bills. As dictum, however, we observe that the Legislature's choice of fixed charge caps may reasonably limit the range of permissible minimum bills.

7.6.2. Approval of Minimum Bill

To ensure maximum customer understanding of the preferred rate structure change, encourage customer adoption and increase the likelihood of success, today's decision adopts a minimum bill provision as part of a gradual transition to a rate structure that includes TOU rates and fewer tiers.

The minimum bill would ensure that all customers contribute some amount toward the cost of the system to which they remain connected. It also avoids the potential negative impact on conservation associated with a fixed

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[421] Emphasis added.

[422] IREC OB at 24.

charge, and it protects lower-usage customers. An approach employing a minimum bill will allow us to monitor any conservation and energy efficiency impacts associated with the tier flattening separate from any potential impacts associated with a fixed charge.

As we set a rate structure for residential rates for the foreseeable future, including a shift to a more moderate three- tiered system and the increased use of TOU rates, we recognize rates and bills will increase to some extent for lower users and decrease for the highest users relative to current rates, all other elements remaining the same. For this reason it is particularly important that we not be exacerbate these bill increases through the imposition of a fixed monthly charge.

Finally, although we are rejecting the implementation of any fixed per-customer charges for the foreseeable future, we find that it is reasonable to adopt a minimum bill of $10 for all three utilities ($5 for CARE, FERA and medical baseline customers). SCE's current fixed charge shall be eliminated and replaced by the minimum bill.

Although we find that the statutory limits on fixed charges do not apply to minimum bills, given the disagreement regarding the appropriate amount of marginal customer-related costs, it is reasonable to adopt a minimum bill amount for all three utilities that is consistent with the statutory limit for fixed charges. Future proposed minimum bill amounts shall be subject to review by the Commission and the parties through the utilities' GRC Phase 2 applications, and should take into consideration the level of variable customer-related costs such as metering, billing and customer service.

Table: Adopted Minimum Bill for CARE Customers (per month)

	PG&E	SCE	SDG&E
2015	$5.00	$5.00	$5.00
2016	$5.00	$5.00	$5.00
2017	$5.00	$5.00	$5.00
2018	Annual CPI adjustment or GRC Phase 2 outcome	Annual CPI adjustment or GRC Phase 2 outcome	Annual CPI adjustment or GRC Phase 2 outcome

Table: Adopted Minimum Bill for Non-CARE Customers (per month)

	PG&E	SCE	SDG&E
2015	$10.00	$10.00	$10.00
2016	$10.00	$10.00	$10.00
2017	$10.00	$10.00	$10.00
2018	Annual CPI adjustment or GRC Phase 2 outcome	Annual CPI adjustment or GRC Phase 2 outcome	Annual CPI adjustment or GRC Phase 2 outcome

This minimum bill shall remain in effect and subject to review in each electric utility's GRC Phase 2. Each utility's application for a default TOU tariff shall include a proposal for the appropriate level of a minimum bill charge associated with the default tariff(s) as well as any optional rates that are available.

7.7. Zero Minimum Bill

PG&E proposes to retain a zero minimum bill amount that would apply to delivery charges on all residential rate schedules to ensure no negative bills (as with PG&E Schedules E-7, AL-7 and EL-8).

Marin Clean Energy (MCE) recommends that the Commission reject PG&E's request. MCE notes that the Commission adopted Rules of Conduct for Electrical Corporations Relative to Community Choice Aggregation Programs ("Code of Conduct") in D.12-12-036. Rule 18 of the adopted Code of Conduct states: "[a]n electrical corporation shall not, through a tariff provision or otherwise, discriminate between its own customers and those of a CCA in matters relating to any product or service that is subject to a tariff on file with the Commission. … This restriction does not apply to optional rates, programs and services authorized or approved by the Commission that are only available to bundled service customers."[423]

The Zero Minimum Bill (ZMB) provision, which states "total delivery charges cannot be less than zero," currently exists on several PG&E rate schedules, including E-7, E-8, EL-7, EL-8 and CARE-eligible commercial E-CARE rates where there is the potential for the non-generation portion of the charges to sum to a total negative charge (i.e., a credit). The ZMB applies to both bundled and CCA customers under these existing rate schedules. According to MCE, for bundled customers, the ZMB has less of an effect because any non-generation-related bill credits are carried over and applied against the bundled customers' generation-related charges. However, for unbundled customers on these rate schedules, if these customers' delivery charges are negative, PG&E employs this ZMB provision to zero-out the non-generation portion of the bill. MCE maintains that by refusing to carryover the excess credits associated with the delivery charges of an unbundled customer's bill toward their generation charges, PG&E is increasing the bills of some unbundled customers and shifting these customer's excess credits to other customers.

In this proceeding, we approve an increase in the minimum bill amount for CARE and non-CARE residential rate schedules. In light of this decision, PG&&E has not sufficiently justified the need to retain the ZMB. Moreover, to the extent that the ZMB would only affect those customers taking service from a

[423] MCE OB at 5.

Community Choice Aggregator (CCA), we agree with MCE that application of the ZMB is inconsistent with Rule 18 of the Code of Conduct concerning CCAs.

8. CARE, FERA, Medical Baseline

8.1. CARE

AB 327 mandates that the IOUs maintain an average effective CARE discount between 30 and 35%. Any utility that currently has an average effective discount greater than 35% is instructed to reduce its discount level to between 30 and 35% on "a reasonable phase-in schedule." PG&E and SDG&E both currently have effective CARE discounts above 35%. In summer 2014 PG&E and SDG&E began a gradual reduction to the statutory level and propose to continue the glidepath over the next four years to reach the statutory level by 2018.

IOU Proposed Transitions for Average CARE Effective Discount

	PG&E[424]	SCE[425]	SDG&E[426]
2013	47%	31%	30%
2014	48.4%	32%	39%
2015	43.2%	31%	38%
2016	39.8%	32%	36%
2017	37.3%	32%	34%
2018	34.7%	32%	34%

PG&E, SCE and SDG&E all proposed to implement a fixed charge for CARE customers at a 50% discount off the non-CARE fixed charge and on the same transition schedule. SCE and SDG&E proposed the same amounts and timeline; while PG&E moves to $5/month a year earlier.

[424] Exh. PG&E-109 at 2-4 (Table 2-1).

[425] Exh. SCE-101 at ii/Garwacki (Table 1).

[426] Exh. SDG&E-109, Attachment C/Fang.

IOU Proposed Fixed Charges for CARE Customers (per month)

	PG&E[427]	SCE[428]	SDG&E[429]
2015	$2.50	$2.50	$2.50
2016	$5.00	$3.75	$3.75
2017	Begin annual CPI adjustment	$5.00	$5.00
2018	Begin annual CPI adjustment	Begin annual CPI adjustment	Begin annual CPI adjustment

PG&E's and SCE's CARE rates currently have three tiers (as opposed to four tiers in their non-CARE rates) and both utilities provide a discount off the corresponding non-CARE volumetric rate for each tier. PG&E and SCE proposed to continue providing the CARE discount in the same manner but have proposed to redefine the CARE tier boundaries in 2015 in order to align them with non-CARE tiers (see table below). After 2015, both utilities propose to transition CARE rates to a two-tiered rate structure by 2018 on the same schedule that they have each proposed for non-CARE rates.

PG&E and SCE's Proposed Change to CARE Tier Definitions in 2015
(% of Baseline Quantity)

	Current CARE Tiers	Proposed 2015 Care/non-CARE Tiers[430] [431]
Tier 1	0-100%	0-100%
Tier 2	100-130%	100-200%
Tier 3	Over 130%	Over 200%

SDG&E's current CARE rate is structured differently from the other utilities'. SDG&E's CARE volumetric rate is provided at a discount off the

[427] Exh. PG&E-109 at 2-4 (Table 2-1).

[428] Exh. SCE-101 at ii/Garwacki (Table 1).

[429] Exh. SDG&E-109, Attachment C/Fang.

[430] PG&E OB at 6 (Table 1).

[431] Exh. SCE-101 at ii/Garwacki (Table 1).

corresponding non-CARE rate for each tier (similar to PG&E and SCE), but, in addition to discounted volumetric rates, SDG&E's CARE rate also includes a flat 20% discount off of energy charges.

Unlike PG&E and SCE, SDG&E proposed to simplify its CARE rate structure by removing the discount from volumetric rates (with the exclusion of the exemption from DWR-BC, CSI and CARE charges) and providing it as a line-item discount off a bill calculated at standard rates, beginning in 2015. SDG&E argues that by providing the CARE discount as a line-item bill discount, "all tiers will receive a more equitable discount level and more accurate information regarding the costs associated with their electricity demand."[432]

8.1.1. Party Positions on CARE

As discussed in Section 5, the non-utility parties (with the exception of UCAN) oppose fixed charges for both CARE and non-CARE customers. ORA and CforAT both expressed concern that PG&E's proposal to reduce its CARE discount to 35% by 2018 will result in unacceptably large bill impacts to CARE customers. ORA argues that PG&E CARE customers have already experienced a significant increase in rates, asserting that between May 2014 and January 2015, PG&E's CARE Tier 1 rates increased by 24%, Tier 2 rates increased by 22% and Tier 3 rates increased by 18%.[433] ORA proposes a longer transition period in which PG&E reduces its CARE discount by 1-2% per year until it reaches the mandated 35%, with reductions "subject to bill impact evaluations in the rate design proceedings."[434]

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432 Exh. SDG&E-107 at CF-36.

433 ORA RB at 5.

434 ORA OB at 52.

CforAT argues that none of the IOUs' proposals give adequate consideration to what low-income customers can actually afford to pay and that the utilities fail to show that their proposals will allow for affordable supplies of electricity to meet basic needs. CforAT contends that, according to the chart provided in PG&E's Opening Brief,[435] "40% of low-income households would see a bill increase of between $5 and $10 in 2016, about 35% would see a similar increase in 2017 and 39% would see a similar increase in 2018."[436] CforAT asserts that CARE discounts should be calculated as a line-item discount off of standard rates and argues that Tier 1 rates "should be set so that, in conjunction with a 35% line-item discount, CARE customers with usage within Tier 1 have a mean energy burden that does not exceed 5%."[437]

PG&E acknowledges that most CARE customers would see bill increases as a result of its proposals, but argues that CARE rates must be gradually increased in order to comply with the effective discount range mandated by AB 327 and that these increases are reasonable and "modest for the vast majority of CARE customers."[438]

ORA is not opposed to SDG&E's proposal to apply a line-item CARE discount in the future; however, because ORA proposes to decrease the non-CARE upper tier rates more slowly than SDG&E's proposal, applying a line-item discount would result in the CARE Tier 3 rate initially increasing and then decreasing as the non-CARE tier rate differential is decreased. ORA proposes to

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[435] PG&E OB at 37 (Figure 5).

[436] CforAT RB at 20.

[437] CforAT OB at 64.

[438] Exh. PG&E-109 at 2-7.

hold the upper tier CARE rate at its current level through 2016. ORA also proposes to reduce SDG&E's effective CARE discount from 38% to 36% in 2017 (as opposed to 2016) because of the other major changes in rate design that will be taking place in 2015 and 2016.[439]

TURN proposes to implement a CARE discount off corresponding non-CARE rates that is allocated unevenly across three tiers. Tier 1 rates would be established at a 40% discount, Tier 2 rates at a 30% discount and Tier 3 rates would collect any residual discount to achieve an average effective discount of 35%. TURN argues that this structure provides "the largest discounts for basic and essential usage while encouraging conservation via higher prices for upper tier usage."[440]

TURN also asserts that the Commission should adopt an average effective CARE discount of the maximum 35% for all utilities. This would require SCE to increase its proposed average effective discount of 32%. TURN argues that offering the maximum discount permitted is reasonable considering the significant bill impacts to CARE customers of SCE's rate design proposals.[441] We agree and therefore adopt a glidepath that will move each IOU to a 35% CARE discount by 2020.

SCE argues that TURN's proposal to provide greater discounts to Tier 1 rates should not be considered because it would restructure the CARE discount and is therefore outside the scope of this proceeding.[442] SCE also contends that

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[439] ORA OB at 53.

[440] TURN OB at 41.

[441] *Id.* at 42.

[442] SCE OB at 98.

TURN provides no basis for its proposal to require SCE to increase its effective CARE discount to 35% and it should be rejected. TURN contends that if the Commission will not consider its proposal to change the structure of the CARE discount, then it should also not consider SDG&E's proposal to convert the CARE to a line-item discount.

8.1.2. Discussion of CARE Rate Adjustments

We approve a CARE discount glide path for both SDG&E and PG&E that will reduce the discount to 35% by 2020. We anticipate increasing SCE's discount to 35% as well. Bill impact tables based on Scenario 3d, a modeled scenario similar to the reform glidepath approved in this decision show that CARE customers in SCE's territory will see small changes in their bills. The majority of SDG&E CARE customers will see an increase under $5. However, PG&E CARE customers with high usage will see significant increases under Scenario 3d. PG&E's CARE discount is currently significantly above the statutory limit. With each percentage discount decrease, the actual dollar amount increase for high usage customers is significant. When the discount has been reduced to meet the statutory limit, approximately 25% of PG&E CARE customers will see an average monthly bill increase of over $30 by 2018, and approximately 10% will see an increase of over $50.

Moreover, given these concerns regarding impacts of CARE rate changes, we find that is reasonable to minimize the risk of significant financial impacts on CARE customers by limiting the minimum bill for these customers to 50% of the minimum bill for non-CARE customers.

We agree that SDG&E's proposal to remove the CARE discount from volumetric rates (with the exclusion of the exemption from DWR-BC, CSI and CARE charges) and apply it as a line-item discount off a bill calculated at standard rates, beginning in 2015, will simplify the CARE rate structure. We therefore approve this approach for SDG&E and encourage the parties to consider this approach for the other utilities in Phase 3 or in future proceedings.

Other structural changes to the CARE program, such as a discount that ranges from 30% to 40% depending on usage (suggested by TURN), or a discount that differs by income (suggested by CforAT/Greenlining), is outside the scope of today's decision. Phase 3 of this proceeding will include a workshop on CARE rate restructuring to determine if these proposed structural changes should be included in Phase 3.

Table Showing PG&E Proposed Glidepath for CARE rates with minimum bill (no fixed charge) under Scenario 3d, through 2018 (2019 and 2020 to be determined)[443]

	May 2014	March 2015		December 2015		2016		2017		2018	
	Rate	Rate	% Change YOY[444]	Rate	% Change YOY	Rate	% Change YOY	Rate	% Change YOY	Rate	% Change YOY
0 – 100% of BQ[445]	$0.086	$0.109	26.7%	$0.116	6.4%	$0.112	-3.4%	$0.111	-0.9%	$0.116	4.5%
100 - 130% of BQ	$0.099	$0.123	24.2%	$0.131	6.5%	$0.146	11.5%	$0.156	6.8%	$0.162	3.8%
130 – 200% of BQ	$0.140	$0.167	19.3%	$0.131	-21.6%	$0.146	22.5%	$0.156	6.8%	$0.162	3.8%
Over 200% of BQ	$0.140	$0.167	19.3%	$0.167	0%	$0.185	10.8%	$0.223	20.5%	$0.232	4.0%

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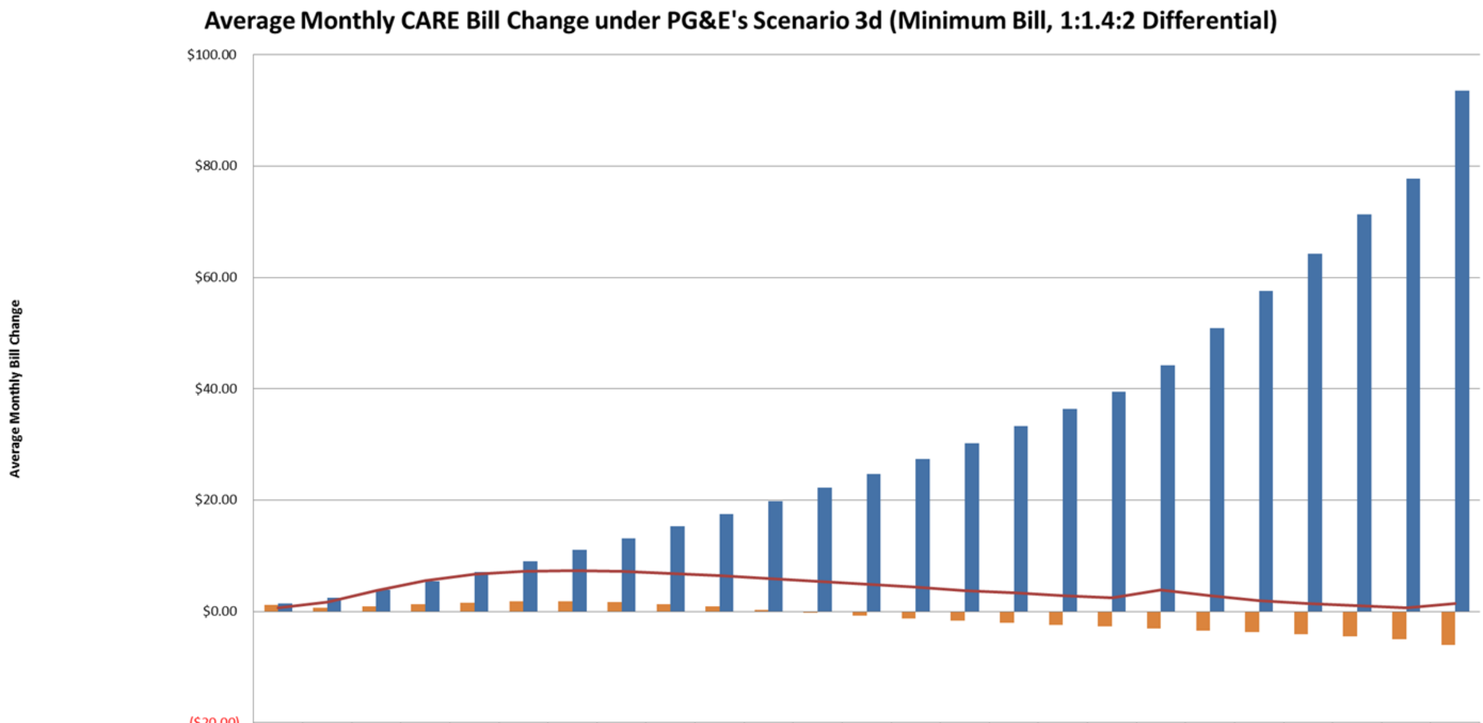
443 PG&E Supplemental Filing of 4/1/15, Appendix A at 9, Scenario 3d. The PG&E bill impact graphs are based on PG&E's Scenario 3d, a minimum bill scenario that closely matches the rate reform that we order in this Decision. Because the ordered reform is somewhat different than the scenario modeled by PG&E, the billing impacts will not be exactly the same. The reform we order today will lessen the immediate bill impacts on low-usage customers and stretch out the bill reductions seen by high-usage customers over a greater number of years. Nevertheless, the graphs below give us some indication of the billing impacts of the ordered rate reform. Because PG&E did not model CARE rates or billing impacts for 2019-2020, we do not have PG&E billing impact data for those years.

444 Includes revenue requirement increases throughout 2015 – the rest of the rates do not assume any revenue requirement increases to show the effect of rate reform in isolation from revenue requirement increases.

445 BQ = Baseline Quantity.



	LOW -< 50	50 -< 100	100 -< 150	150 -< 200	200 -< 250	250 -< 300	300 -< 350	350 -< 400	400 -< 450	450 -< 500	500 -< 550	550 -< 600	600 -< 650
Average 2015 Bill Change	$1.11	$0.65	$0.92	$1.24	$1.55	$1.79	$1.83	$1.67	$1.32	$0.86	$0.32	($0.24)	($0.76)
Average 2014-2018 Bill Change	$1.48	$2.49	$3.89	$5.40	$7.06	$8.95	$11.00	$13.13	$15.31	$17.54	$19.84	$22.24	$24.74
% of Total PG&E CARE Customers	0.63	1.67	3.70	5.50	6.64	7.21	7.30	7.18	6.85	6.42	5.95	5.35	4.85

	650 -< 700	700 -< 750	750 -< 800	800 -< 850	850 -< 900	900 -< 1000	1000 - < 1100	1100 - < 1200	1200 - < 1300	1300 - < 1400	1400 - < 1500	1500 - < 2000
Average 2015 Bill Change	($1.26)	($1.68)	($2.08)	($2.42)	($2.70)	($3.06)	($3.48)	($3.74)	($4.09)	($4.53)	($4.93)	($6.06)
Average 2014-2018 Bill Change	$27.44	$30.25	$33.24	$36.32	$39.49	$44.21	$50.90	$57.56	$64.28	$71.33	$77.71	$93.51
% of Total PG&E CARE Customers	4.38	3.78	3.31	2.87	2.46	3.88	2.79	1.99	1.44	0.99	0.69	1.46

Title

Table showing SCE Proposed Glidepath for CARE rates with $5 minimum bill under Scenario 3d (no fixed charge), 2016-2020 to be determined[446]

Scenario 3d – Minimum Bill of $5 – CARE rates[447]						
	Jan 2014	Jan 2015	2015 w/ Pending RRQ[448]		EOY 2015	
	Rate	Rate	Rate	% Change	Rate	% Change
0 – 100% of BQ[449]	$0.088	$0.097	$0.105	8.2%	$0.11225	6.9%
100 -130% of BQ	$0.110	$0.125	$0.137	9.6%	$0.16071	17.3%
130 – 200% of BQ	$0.200	$0.200	$0.216	8.0%	$0.16071	-25.6%
Over 200% of BQ	$0.200	$0.200	$0.216	8.0%	$0.22959	6.3%

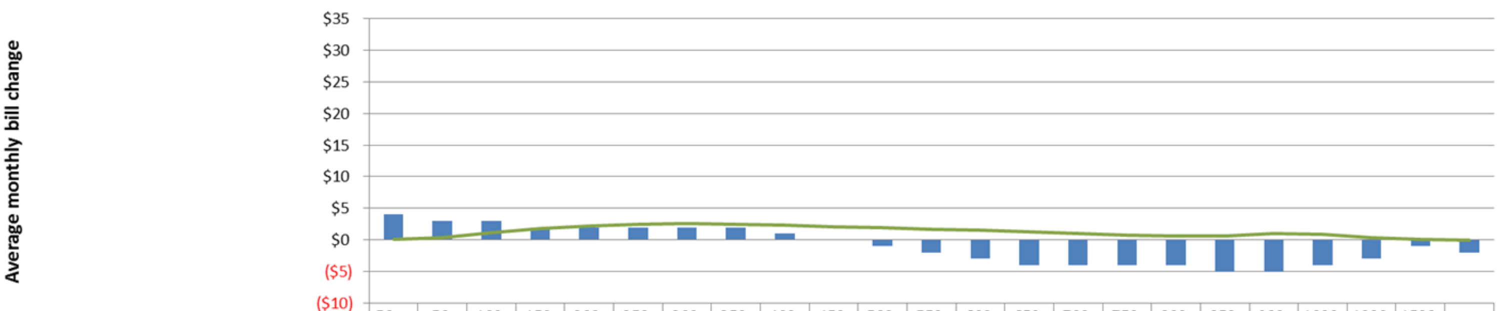
[446] SCE Supplemental Filing of 4/1/15, Scenario 3d. The SCE bill impact graphs are based on SCE's Scenario 3d, a minimum bill scenario that closely matches the rate reform that we order in this Decision. Because the ordered reform is somewhat different than the scenario modeled by PG&E, the billing impacts will not be exactly the same. Nevertheless, the graphs below give us some indication of the billing impacts of the ordered rate reform. The graph use 2015 rates under the current four-tiered structure, calculated with 100% of SCE's 2015 pending revenue requirement added, as the base and show bill impacts to the end of 2015 as well as cumulative impacts through the end of 2018. Because SCE did not model CARE rates or billing impacts for 2016-2020, we do not have SCE billing impact data for those years.

[447] SCE Supplemental Filing of April 1, 2015, Attachment B, Scenario 3d.

[448] These rates were provided by SCE in its April 1, 2015 Supplemental Filing and represent 2015 rates under the current four-tiered structure with 100% of SCE's 2015 pending revenue requirement added.

[449] BQ = Baseline Quantity.

Change in Average Monthly CARE Bill under SCE's Scenario 3d ($5 Minimum Bill, 1:1.4:2 Differential)



Average Monthly Usage in kWh	50 or Less	50-100	100-150	150-200	200-250	250-300	300-350	350-400	400-450	450-500	500-550	550-600	600-650	650-700	700-750	750-800	800-850	850-900	900-1000	1000-1200	1200-1500	1500-2000	2000+
Average $ Change 2015	$4	$3	$3	$2	$2	$2	$2	$2	$1	$0	($1)	($2)	($3)	($4)	($4)	($4)	($4)	($5)	($5)	($4)	($3)	($1)	($2)
% of Total Residential Customers	0.06	0.4	1.1	1.86	2.16	2.42	2.54	2.52	2.35	2.13	1.98	1.7	1.51	1.28	1.03	0.81	0.68	0.63	0.97	0.93	0.39	0.11	0.02
Cumulative % of Total Residential Customers	0.06	0.46	1.56	3.42	5.58	8	10.54	13.06	15.41	17.54	19.52	21.22	22.73	24.01	25.04	25.85	26.53	27.16	28.13	29.06	29.45	29.56	29.58

Scenario 3d – Minimum Bill of $5 – CARE rates[450]						
	Jan 2014	Jan 2015	2015 w/ Pending RRQ[451]		EOY 2015	
	Rate	Rate	Rate	% Change	Rate	% Change
0 – 100% of BQ[452]	$0.088	$0.097	$0.105	8.2%	$0.11225	6.9%
100 - 130% of BQ	$0.110	$0.125	$0.137	9.6%	$0.16071	17.3%
130 – 200% of BQ	$0.200	$0.200	$0.216	8.0%	$0.16071	-25.6%
Over 200% of BQ	$0.200	$0.200	$0.216	8.0%	$0.22959	6.3%

450 SCE Supplemental Filing of April 1, 2015, Attachment B, Scenario 3d.

451 These rates were provided by SCE in its April 1, 2015 Supplemental Filing and represent 2015 rates under the current four-tiered structure with 100% of SCE's 2015 pending revenue requirement added.

452 BQ = Baseline Quantity.

Table showing SDG&E Proposed Glidepath for CARE rates with $5 minimum bill under scenario 3d (no fixed charge) 2019 and 2020 to be determined[453]

	Jan-14	Feb-15		Dec-15		2016		2017		2018
	Rate	**Rate**	**% Change YOY**	**Rate**	**% Change YOY**	**Rate**	**% Change YOY**	**Rate**	**% Change YOY**	**Rate**
0 – 100% of BQ	$0.100	$0.112	12.00%	$0.119	6.25%	$0.123	3.36%	$0.126	2.44%	$0.126
100 - 130% of BQ	$0.116	$0.131	12.93%	$0.171	30.53%	$0.176	2.92%	$0.181	2.84%	$0.181
130 – 200% of BQ	$0.176	$0.199	13.07%	$0.171	-14.07%	$0.176	2.92%	$0.181	2.84%	$0.181
Over 200% of BQ	$0.176	$0.199	13.07%	$0.248	24.62%	$0.256	3.23%	$0.263	2.73%	$0.262

[453] SDG&E Supplemental Filing of 4/1/15.

Average Monthly CARE Bill Change under SDG&E's Scenario 3d(Minimum Bill, 1:1.4:2 Differential)

	0 to 25 kWh	25 to 50 kWh	50 to 75 kWh	75 to 100 kWh	100 to 150 kWh	150 to 200 kWh	200 to 250 kWh	250 to 300 kWh	300 to 350 kWh	350 to 400 kWh	400 to 450 kWh
Avg $ change 2015	($1.52)	($0.57)	($0.26)	($0.25)	($0.31)	($0.37)	($0.36)	($0.14)	$0.37	$0.85	$0.99
Avg $ change 2015-2018	$0.92	$0.63	$0.36	$0.40	$0.52	$0.78	$1.20	$1.97	$3.06	$4.18	$5.00
% of Customers	0.10	0.20	0.50	1.40	6.00	9.40	11.30	11.40	10.40	9.20	7.70
Cumulative % of customers	0.10	0.30	0.80	2.20	8.20	17.60	28.90	40.30	50.70	59.90	67.60

	450 to 500 kWh	500 to 600 kWh	600 to 700 kWh	700 to 800 kWh	800 to 900 kWh	900 to 1000 kWh	1000 to 1500 kWh	1500 to 2000 kWh	2000 to 3000 kWh
Avg $ change 2015	$0.81	$0.58	$1.41	$3.56	$6.37	$9.44	$17.12	$35.03	$58.80
Avg $ change 2015-2018	$5.50	$6.30	$8.60	$12.29	$16.66	$21.26	$32.70	$58.68	$91.07
% of Customers	6.30	9.20	5.90	3.70	2.40	1.50	2.80	0.50	0.20
Cumulative % of customers	73.90	83.10	89.00	92.70	95.10	96.60	99.40	99.90	100.10

Average Monthly Usage in kWh

8.2. FERA

In 2004, the Commission issued D.04-02-057, ordering PG&E, SCE and SDG&E to implement a program to provide rate relief to low-middle income customers with larger households. Under the current FERA program, residential customers who meet established income and household size requirements are charged the Tier 2 rate (covering usage from 100-130% of baseline) for energy usage in Tier 3 (covering usage from 130-200% of baseline). We recognize that, because the current program is predicated on existing tier definitions, transitioning to a three-tiered rate structure requires modifications to the current FERA program.

PG&E and SCE both proposed to transition FERA to a percentage discount off a bill calculated at standard rates. Under their proposals, eligible customers would receive a discount regardless of which tier(s) their energy usage falls in. PG&E and SCE employed similar methodologies to calculate the amounts of their proposed line-item FERA discounts. Both utilities calculated the average discount that all FERA program participants have received over the last five years and proposed to establish that percentage as the FERA discount. Using this methodology, PG&E's proposed line-item discount is 12.5% and SCE proposed a 10% line-item discount.[454] SDG&E did not include any changes to the FERA program in its original proposal, however they support SCE's proposal for a line-item discount of 10%.[455] The IOUs contend that their proposals would simplify the structure of the FERA discount and allow all eligible customers to benefit from the program, regardless of the amount of energy they consume.

Additionally, SCE proposed to recover any revenue loss resulting from providing the FERA discount from non-CARE customers in the residential class. This would be a change from SCE's current method of recovering FERA-related revenue losses from all customer classes. SCE argues that, because the FERA discount is only provided to residential customers and there is no statutory requirement to recover its costs outside the residential class, any revenue shortfall should be recovered from non-CARE residential customers.[456]

Several parties opposed the IOUs' proposed modifications to the FERA discount. ORA and TURN both support providing FERA as a line-item discount off a bill calculated at standard rates; however both parties contend that the IOUs' methodology of calculating the amount of the discount is unfair. ORA and TURN assert that the IOUs' methodology understates the average discount for customers who actually receive a benefit from the FERA program. They argue that, because the IOUs' calculations include program participants with usage only in Tiers 1 and 2 (and, therefore, do not receive any discount), the resulting

[454] Exh. PG&E-101 at 2-22; SCE RB at 53.

[455] Exh. SDG&E-109 at CF-42/Fang.

[456] Exh. SCE-101 at 45.

discounts are significantly less than the average discount received by customers with Tier 3 usage.

ORA proposed a 20% line-item FERA discount, arguing that the disparity between the IOUs' proposed FERA discount (10%-12.5%) and CARE discounts (30%-35%) is too wide considering how close the qualifying income ranges of the two programs are.[457] TURN proposed a 15% line-item FERA discount, justifying it as the midpoint between CARE and non-CARE rates.[458] TURN stated that it would not oppose the 20% discount proposed by ORA but feels that 15% is also reasonable. SCE refutes ORA and TURN's contention that the FERA discount should be established relative to the CARE discount, arguing that the Commission never intended the two discounts to be linked.[459] SCE also argues that TURN's proposed 15% discount, which equates to the maximum discount an SCE customer could achieve under the current structure, is not a reasonable basis for establishing a discount for customers at all usage levels.

CforAT also opposed the IOUs' FERA proposals, recommending that the Commission adopt CforAT's three-tiered rate proposal and maintain the existing FERA structure. CforAT argued that the IOUs' proposed FERA discounts are not based on an evaluation of what eligible customers can afford to pay for basic energy needs. CforAT echoes ORA and TURN's argument that, because the current benefits of the FERA program are not spread equally, using the average effective discount is not a reasonable methodology to determine a flat discount. CforAT is also concerned that by transitioning the FERA program to a line-item

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[457] ORA OB at 54.

[458] TURN OB at 43.

[459] SCE RB at 55.

discount, the IOUs' proposals would significantly impact how the benefits of the discount are distributed among eligible customers. CforAT argues that customers who currently receive a significant FERA discount, due to their usage being very close to the upper limits of Tier 3, will experience a reduction in benefits and this can't be "'offset' by the fact that other households would see a greater benefit."[460]

We do not believe that the proposals for flat percentage line item discount off the entire bill accurately capture the purpose of the FERA program. FERA was designed for low-to-moderate income households that do not qualify for CARE but consume more than the baseline amount of electricity due to family size. As such, a discount on Tier 2 usage is the more appropriate approach, once Tiers 2 and 3 are combined under the adopted glidepath. Therefore, once those tiers are combined, FERA customers should receive a 20% discount on all Tier 2 usage. Until that change occurs, FERA customers should continue to be charged second tier rates for third tier usage. In addition, FERA customers should be subject to the same minimum bill as CARE customers.

We agree with SCE that any undercollection due to the FERA discount should be funded by the non-CARE residential class and not from all customer classes. We direct the IOUs to make this change as part of their advice letter filing for 2015 rates.

8.3. Medical Baseline

The Medical Baseline program provides eligible customers of the three IOUs with a higher baseline allocation to cover additional energy needs required by medical equipment. PG&E and SDG&E also currently provide discounted

[460] CforAT OB at 67.

rates to their Medical Baseline customers, while SCE does not. All three utilities proposed to maintain their existing, higher medical baseline allowances.

SDG&E's Medical Baseline customers are currently exempt from the Department of Water Resources Bond Charge (DWR-BC) and pay reduced rates in addition to receiving a higher baseline allowance. SDG&E's non-CARE Medical Baseline customers pay the CARE rate prior to the existing 20% line item discount (current SDG&E CARE rates are structured as a lower volumetric rate with an additional 20% line item discount on the bill).

In 2001, D.01-09-059 adopted rate increases for SDG&E's customers in order to recover the Department of Water Resources (DWR) revenue requirement, but exempted CARE and Medical Baseline customers from these increases.[461] SDG&E explains that at the time of this D.01-09-059, its CARE discount was provided only through a 20% line-item discount, meaning that CARE customers paid the same volumetric rates as non-CARE customers. In implementing D.01-09-059, SDG&E left CARE rates unchanged (a DWR-BC charge was not added) and began charging Medical Baseline customers the CARE volumetric rates. At the time of implementation, this meant that non-CARE Medical Baseline customers were simply paying their previous non-CARE residential rate with an exemption from the DWR-BC charge; however as additional rate discounts were adopted for CARE customers in subsequent years, these discounts "have inadvertently been provided to non-CARE Medical Baseline customers."[462]

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[461] D.01-09-059 at 56 (Conclusion of Law 20).

[462] Exh. SDG&E-110 at CF-43/Fang.

SDG&E proposes to gradually remove this discount by transitioning non-CARE medical baseline customers to non-CARE rates over four years. Under this proposal, rates would increase by 25% of the differential between non-CARE and Medical Baseline rates each year.[463]

PG&E Medical Baseline customers currently pay Tier 3 rates for their Tier 4 usage, which is currently equivalent to a 4 cent/kWh discount for usage over 200% of baseline. PG&E proposes to maintain this level of discount by providing a 4 cent/kWh discount on usage over 200% of baseline for these customers.

SCE does not propose any changes to its existing Medical Baseline program, which simply allocates a higher baseline to eligible customers.

8.3.1. Discussion

TURN is concerned that PG&E's proposal to provide its Medical Baseline discount as a 4 cent/kWh discount on usage over 200% of baseline would result in declining block rates in 2018 if a two-tier default rate is adopted. Medical Baseline customers would be charged less for usage above 200% of baseline than for usage up to 100% and usage between 100-200%. TURN asserts that this would violate the inclining block rate requirement in Pub. Util. Code Section 739.7. TURN recommends that the Commission increase the tier differential in a two-tiered rate or adopt TURN's proposed three-tier rate and apply the 4 cent/kWh to Tier 3.[464]

PG&E argues that very few non-CARE Medical Baseline customers exist who have monthly usage in excess of 200% of the higher baseline allocated to

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[463] SDG&E OB at 52.

[464] TURN OB at 45.

them and that TURN's proposal to adopt a three-tiered rate structure would be "an extreme response to a situation that affects so few customers and so little usage."[465] PG&E states that a Medical Baseline customer would have to use more than 1,700 kWh/month in order to exceed 200% of baseline;[466] however PG&E does not provide any data regarding the number of customers who currently fit this description. PG&E proposes that the Commission provide a "lower credit to all medical baseline usage exceeding 100% of baseline in 2018 that, at the very least, provides the same total benefit currently provided to medical baseline customers."[467]

CforAT argues that the IOUs' proposals to leave the Medical Baseline program relatively unchanged are not sufficient to ensure that these customers have access to affordable electricity under their proposed changes in rate design. CforAT asserts that increases in lower-tier rates would result in higher bills for all Medical Baseline customers and that the utilities have not adequately considered or analyzed the impacts of their proposals on Medical Baseline customers.[468] CforAT is opposed to SDG&E's proposal to transition non-CARE Medical Baseline customers to non-CARE rates. ORA supports maintaining all existing Medical Baseline discounts at current levels.

Given the limited scope of this proceeding, for purposes of today's decision, we find that no changes should be made to the Medical Baseline program, except as necessary to ensure Medical Baseline customers continue to

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[465] PG&E RB at 43.

[466] *Id.* at 44.

[467] *Ibid.*

[468] CforAT OB at 71.

have access to these special rates. We find the proposals of the utilities are reasonable and should be sufficient to maintain the same approximate discount that Medical Baseline customers are currently receive. We therefore approve the IOUs proposals, with the exception of SDG&E's proposal to discontinue the CARE discount currently provided to Medical Baseline customers. Even though this CARE discount is in addition to the required Medical Baseline discount, we find that any changes that would reduce the discount should be examined in SDG&E's GRC.

9. Volumetric GHG Rate Offset

Under the ARB economy-wide GHG Cap-and-Trade Program, ARB annually grants the state's electric IOUs an allocation of GHG allowances, which the utilities are required to sell in ARB's quarterly allowance auctions. These mandatory allowance sales generate substantial proceeds that "must be used exclusively for the benefit of retail ratepayers of…electric distribution [utilities], consistent with the goals of AB 32,"[469] the Global Warming Solutions Act of 2006.

In D.12-12-033 and subsequent implementing decisions, the Commission adopted a framework of rules regarding how the electric IOUs should distribute these proceeds in accordance with ARB's Cap-and-Trade Regulation and the parameters of Pub. Util. Code § 748.5. We required the three large electric IOUs to distribute these proceeds in the following manner: 1) compensate emissions-intensive trade-exposed entities in a manner similar to ARB's Industry Assistance program; 2) offset GHG costs in the electricity rates of small businesses through a volumetrically calculated credit known as the small

[469] California Cap on GHG Emissions and Market-Based Compliance Mechanisms, Title 17, California Code of Regulations, Section 95892.

business California Climate Credit; 3) neutralize GHG costs from residential electricity rates through a volumetrically calculated rate adjustment; and 4) return all remaining proceeds to households as an equal, semi-annual bill credit known as the residential California Climate Credit.

The issue relevant to the present proceeding is whether it is appropriate to discontinue the volumetric GHG rate offset for residential customers. Under the Cap-and-Trade Program, owners and operators of large sources of GHG emissions (including electric utilities and power plants) must submit compliance instruments – GHG allowances and a limited number of offsets – to ARB to account for their emissions. This requirement has the effect of creating a cost to emit carbon pollution, and this cost results in both an increase in the cost to produce electricity from fossil-fueled resources and in wholesale electricity prices. The electric utilities' revenue requirements increase correspondingly, and at present all customers, except residential customers, experience these GHG costs in their electric rates.

In D.12-12-033, we reasoned that it was appropriate, at that time, for the three large electric IOUs to use allowance proceeds to offset all volumetric GHG costs that the IOUs would otherwise have included in upper tier rates. Though this approach violated our fundamental objective of preserving a carbon price signal in rates, we found that it was temporarily justified because statutory restrictions prevented the equitable allocation of costs, including carbon costs, among residential customers, and we wished to avoid adding to the disproportionate cost burden born by upper tier customers. We did not allow PacifiCorp or Liberty Utilities to use allowance proceeds in this manner, because neither utility was subject to the same historic statutory limits on ratemaking; thus, their residential customers have experienced full GHG costs in rates since we authorized the utilities to begin introducing both allowance proceeds and GHG costs in rates in April 2014.[470]

AB 327 lifted the statutory restrictions that effectively prevented the utilities from including carbon costs in lower tier rates. The Commission envisioned that such a statutory change would trigger the introduction of GHG costs in residential rates and the discontinuation of the volumetric GHG rate offset. In D.12-12-033 we found that "future changes to the current residential tiered-rate structure that result in the reduction or elimination of the existing differences in cost burden between lower-tier and upper-tier residential rates would appear to eliminate the need to offset GHG costs in residential rates."[471] We further concluded that, should the difference between lower and upper-tier residential rates be substantially reduced or eliminated, "the carbon price signal should be fully reflected in residential rates, and all remaining revenue should be returned on a non-volumetric basis."[472]

Because it is now permissible to include GHG costs in both lower and upper tier rates, and this proceeding continues the process of narrowing the tiered rate differentials, we directed parties to brief whether the residential volumetric GHG rate offset should continue. If the volumetric GHG rate offset is eliminated, GHG costs will be reflected in residential customers' electricity rates, as is currently the case for the residential customers of PacifiCorp and Liberty Utilities. Additionally, if we discontinue permitting the utilities to use allowance proceeds for the residential volumetric credit, the size of the Climate Credit will

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[470] D.12-12-033 at 108-109, 114.

[471] *Id.* at 179 (Finding of Fact 107).

[472] *Id.* at 114.

be correspondingly larger – residential customers will still receive the same total amount of allowance revenue; they will simply receive it all as the California Climate Credit, which will not affect rates or mute the carbon price signal.[473]

Aside from the IOUs, parties (ORA, TURN,[474] NRDC, SEIA and Sierra Club) argued that the volumetric credit should be eliminated and that the equal-per-account Climate Credit should be used as the mechanism to return all allowance proceeds to residential customers. As CALSEIA contends, in D.12-12-033 the Commission declared its intent to distribute GHG allowance proceeds equally per account, thereby preserving the "incentives the Cap-and-Trade program is intended to provide."[475]

The IOUs argue that the volumetric credit should not be eliminated at this time. SCE argues that while AB 327 lifted the rate freeze on the lowers tier, the volumetric return should continue until the "completion of tier-flattening,"[476] which, according to SCE's Phase 1 Opening Brief, is signaled by a two-tiered rate differential of 30%.[477] PG&E argues that eliminating the volumetric return will "make residential electric bills more volatile," and thereby derail ARB's plan to smoothly and moderately transition to carbon price signals under its own schedule for phasing out the free allowances.[478] SDG&E contends that the

[473] It is important to note that the allowance proceeds are held by the IOUs on behalf of their ratepayers, and therefore the Climate Credit should not be treated as a reduction in a customer's bill for purposes of calculating rate impacts and energy burdens. *See*, Phase 2 Decision.

[474] TURN RB at 56.

[475] CALSEIA RB at 8 (citing D.12-12-033 at 59).

[476] SCE RB at 92.

[477] SCE OB at 164.

[478] PG&E OB at 79.

Commission should address the allocation of GHG proceeds in a separate proceeding.[479]

As noted by NRDC and others, the volumetric credit "mute[s] the carbon price signal in upper-tier residential rates."[480] This defeats one of the goals of the Cap-and-Trade Program and also the Commission's primary policy objective in D.12-12-033 to ensure that rates reflect a carbon price signal. AB 327 enables the Commission and the electric utilities to reflect GHG costs in electric rates in an equitable manner across rate tiers, and this decision sets forth a process for the utilities to flatten rate tiers and eliminate the distortions that D.12-12-033 concluded were the sole basis for justifying the residential volumetric GHG rate offset.

For these reasons, we find that the volumetric credit for upper tier residential customers should be eliminated starting January 1, 2016. The IOUs' 2016 ERRA Forecast filings should reflect that the residential volumetric GHG rate offset will be eliminated in 2016.

ORA also proposed a specific methodology for allocating embedded GHG compliance costs to customers. ORA supports recovering GHG costs using an equal cents per kilowatt hour adder that would be applied to the rates for all tiers or TOU periods."[481] By eliminating the volumetric credit, the GHG costs will be reflected in residential rates in the same manner that similar other procurement-related costs recorded in ERRA will be recovered in rates. It is unnecessary to establish separate rules that would result in GHG costs being apportioned to rate

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479 *See* SDG&E OB at 66.

480 NRDC OB at 47.

481 ORA OB at 90.

tiers in a manner different from other procurement-related costs tracked in ERRA.

10. Marketing, Education and Outreach (MEO)

10.1. Summary

In this proceeding we have repeatedly raised the importance of providing adequate marketing, education and outreach to customers so that they can understand and respond appropriately to their electricity rates. RDP #10 provides in part that "[t]ransitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates." Customer understanding is also an essential part of Section 745.

MEO is a large topic and is raised by numerous other utility programs. In some proceedings, MEO has been handled in separate applications.[482] In others, the Commission has unilaterally directed the IOUs to use a specific state-wide administrator. Historically, each utility has handled its own MEO.

In this proceeding, parties have identified a need for outreach and education on a local level, as well as the need for consistent state-wide messaging.

In the February 13, 2014 scoping memo we required the IOUs to address plans for outreach, but stated that "the specific details of outreach programs are likely beyond the scope of Phase 1, but it is necessary to have some information on utility plans in order to make this determination."

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[482] *See, e.g.*, A.13-08-025, et al.

For example, PG&E's MEO proposal includes plans for (i) general awareness outreach, (ii) direct outreach to most impacted customers, and (iii) hard to reach customers.[483]

Based on the information provided, we find that there is a sufficient basis for the IOUs to move ahead with MEO plans related to summer 2015 and 2016 rate changes, but that a more robust review is necessary for long-term MEO plans to inform residential customers about their electric rates.

10.2. 2015 Outreach

Because 2015 rate changes occurring in the next few months, we direct the IOUs to quickly begin outreach to the most impacted customers. The IOUs took steps for the summer 2014 rate reform to inform impacted customers, and the IOUs have described similar outreach plans for 2015 rate changes.[484] We direct the IOUs to implement these outreach plans for 2015 rate changes. To the extent applicable, PG&E should work with ORA as agreed to in Exhibit Joint ORA-PG&E 1.

10.3. Long-Term Outreach

In testimony and in briefs, the IOUs are generally enthusiastic about MEO to improve customer understanding of their rates and to develop innovative MEO strategies. However, at least two significant problems remain: (i) lack of robust bill comparison tools, and (ii) weak metrics to track customer understanding.

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[483] PG&E OB at 71-73.

[484] *See, e.g.,* SCE OB at 156.

Section 745(c) has specific requirements for bill comparison that must be met before default TOU is implemented. The bill comparison tools currently available, and the plans for more robust tools, differ substantially for each IOU.

SCE does not currently have any bill comparison tool available to customers. In its opening brief SCE argued at length that customers are not interested in a bill comparison tool. SCE therefore has no immediate plans to develop a customer-facing bill comparison tool. SCE estimates that it will take 18 months to develop such a tool once directed to by the Commission.

SDG&E recently rolled out an online tool to allow customers to compare tariff options. This tool is part of SDG&E's Smart Pricing Program and is intended to empower the customer, not burden the customer.[485] The tool became available after evidentiary hearings. SDG&E states that it "plans to provide personalized tailored solutions and communications based on its understanding of customer preferences[.]"[486]

PG&E currently has an online site, MyEnergy, where customers can view their past usage and compare which residential rate will be most cost-effective for their usage profile, save them the most money, and customers can review past usage. During evidentiary hearings, however, TURN's cross-examination of PG&E witness Pitcock revealed that the website provided potentially misleading information on reasons for bill increases. PG&E states that this problem has been addressed, and PG&E is constantly improving the tools available on MyEnergy.

We find that the bill comparison tool is an essential piece of the MEO for residential customers. We commend PG&E and SDG&E on already developing

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485 SDG&E OB at 63.

486 *Ibid.*

these tools, and we direct SCE to immediately begin to develop a similar tool that provides individual customers with bill comparison information tailored to their individual usage.

However, the confusing information from the MyEnergy website identified by TURN during evidentiary hearings has raised a significant concern about the quality of educational materials for individual customers on the IOU websites. As TURN puts it "PG&E offers an example of how customer education efforts can serve to mislead rather than inform."[487] We therefore direct the IOUs to include a live demonstration of their website and bill comparison tools as part of an annual residential rate reform summit to be held at the Commission.

A second concern is the availability and quality of metrics to measure customer understanding. The IOUs propose several metrics commonly used to evaluate marketing campaigns such as click-through rates. Click-through rates, however, will not help us evaluate whether customers understand their electric bills. It is worth noting, again, that the Hiner study had one finding that all parties agree with: customers generally do not understand their electricity rates.

ORA proposes the following metrics which are taken from D.13-12-038 (Decision on Phase 2 Issues: Statewide Marketing, Education, and Outreach Plans for 2014 and 2015) and Resolution E-4381 (Pacific Gas and Electric Company requests approval of its proposed metrics for its Peak Day Pricing and Time-of–Use customer education and outreach activities for non-residential customers).[488] ORA's list includes:

- The extent of customer exposure to advertising.

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[487] TURN OB at 87.

[488] ORA OB at 88-89.

- Website activity: length of time, number of pages visited.
- Number and quality of key strategic partners that IOUs are able to coordinate with.
- Percent of escalated customer complaints received.
- Increase in the number of Californians that understand the benefits of modifying their energy use and know where to go to learn more about energy and energy management options.

ORA and PG&E stipulated to a joint exhibit "to represent their consensus view of development of the detailed outreach plan on a collaborative basis involving Commission staff and stakeholders."[489] PG&E notes that this collaborative process would include performance metrics and coordination with third-party marketers, such as Center for Sustainable Energy (CSE), under the Statewide MEO decision (D.13-12-038). Although we commend ORA and PG&E for their agreement to a collaborative process, we do not make specific finding at this time as to the extent to which marketing should be coordinated with CSE. SCE agrees that the workshop process would be beneficial.[490]

TURN recommends that the IOUs be directed to "track awareness through approaches that measure the accuracy of customer responses to specific questions that remain relatively constant over a series of years. This type of approach would allow the utilities and the Commission to better understand whether customer awareness is improving, declining, or remaining constant."[491]

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[489] PG&E OB at 74 (citing Joint Exhibit ORA-PG&E-1).

[490] SCE RB at 91.

[491] TURN OB at 90.

TURN also points out that metrics should play a role in evaluating whether expenditures are reasonable.[492]

We agree that the metrics suggested by ORA and the IOUs will be useful, but a metric to evaluate customer understanding, as suggested by TURN, must be one of the primary measures for assessing MEO success.

We find that the IOUs must move quickly to (i) improve bill comparison tools and (ii) develop a metric that will measure changes in customer understanding year over year. The bill comparison tool should not be limited by the timing or other requirements of Section 745(c).

The development of this long-term MEO program will be addressed in Phase 3 and will include workshops and/or working groups, as well as regular updates to the Commission.

10.4. Tier 1 and Tier 2 Customer Education on Conservation Opportunities

For over a decade, low tier residential rates were frozen in compliance with legislation. As a result, Tier 1 and Tier 2 customers did not experience any increases in the cost of electricity for over ten years, and only modest increases since then. This decision will raise rates for these customers so that they pay a greater portion of the utility's costs. Because these customers will have the significant bill impacts from the rate changes approved in this proceeding, we find that special additional educational materials should be provided to these customers to assist them in responding to rate increases.

The IOUs posit that as these customers begin to pay closer attention to the cost of electricity, they will be motivated to conserve energy. Other parties

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[492] *Ibid.*

suggest that these customers' conservation options may be limited by financial obstacles. An educational campaign should be focused on these low tier customers to inform them of affordable means to reduce energy use by behavior modification or inexpensive energy efficiency tools, such as products to control vampire plug loads.

In addition, outreach to low-income customers should promote the energy efficiency improvement opportunities provided through existing Commission programs. This outreach should be coordinated with the state-wide marketing of these programs as appropriate. For example, The Energy Savings Assistance (ESA) program, available to participants including those living in single-family, multi-family, and mobile homes with household incomes at or below 200% of the Federal Poverty Guidelines. The program provides weatherization measures and services including 1) Appliances: refrigerators, microwaves, clothes washers, 2) Water Conservation: water heater blankets, pipe insulation, low flow shower heads, 3) Enclosure: insulation, air/envelope sealing, weather stripping), 4) Heating, Ventilation and Air Conditioning: furnace repairs/replacements, air conditioning, infiltration, 5) Lighting, 6) Energy Education, and 7) Other miscellaneous measures such as smart strips and pool pumps. For program year 2014, the Commission approved a cumulative IOU ESA program budget of approximately $390 million. The Single-Family Affordable Solar Homes (SASH) and Multifamily Affordable Solar Housing (MASH) programs provide rebates for the installation of solar PV systems on low-income properties. The SASH program provides rebates for eligible low-income homeowners, while the MASH program provides rebates for eligible low-income multifamily housing. On January 29, 2015, the Commission adopted D.15-01-027, implementing AB 217 (Bradford, 2013), which extended the MASH and SASH programs until 2021, authorized an additional $108 million in program funding, and set a capacity goal of 50 MW of solar PV installed at low-income customer housing across both programs.

We direct the IOUs to begin developing these materials and to work with other parties (such as ORA) to form an MEO Working Group. This campaign directed at energy savings for Tier 1 and 2 customers should begin as soon as possible, but in no event later than January 2016. In the long-term, this campaign should be modified based on lessons learned to help this group of customers take advantage of existing direct incentive programs.

10.5. Cost Recovery

Because Phase 1 is not addressing details of the IOUs' specific long-term outreach proposals, the IOUs provided limited information on the expected cost of their MEO plans. As more specific MEO programs are developed, it will be useful for the utilities to provide more detailed budget forecasts.

In the meantime, the IOUs have requested memorandum accounts to track expenditures related to outreach. These memo accounts would be subject to reasonableness review, with the burden on the utility to show that the expenditures were incremental, verifiable and reasonable.

We agree that memorandum accounts are needed at this time to track expenditures and we therefore authorize the IOUs to implement, via advice letter, the requested memo accounts.

11. Approvals of IOU Rate Changes

11.1. Summary

AB 327 expanded the permissible residential rate structures to include flattening of the existing tiered rates, potential monthly fixed charges of up to $10, and default TOU rates starting no sooner than 2018.

The proposals of the utilities can be divided into immediate ranges to be implemented for 2015 (2015 Rates) and long-term rate design plans through 2018 (Roadmap).

All three utilities proposed to flatten tiered rates and implement a fixed charge on a glidepath beginning in 2015 and continuing through 2018. In conjunction with the structural changes to the tiers, the utilities proposed adjustments to related residential schedules like CARE, FERA and SmartRate. SDG&E and PG&E also propose specific glidepaths to reduce the CARE discounts to meet the statutory range of 30% – 35%. No utility proposed default TOU for 2018.[493] The utilities did propose to have pilots and opt-in rates to study TOU.

In addition, the utilities proposed marketing, outreach, and education programs to educate customers about their options for electricity rates.

In reviewing the rate change requests, it is essential to look at the bill impacts of the requested rate changes on a cumulative basis. Our analysis considers the 2015 rate changes and the rate directions for the Roadmap. In addition, we consider the impacts of the significant rate reform made in summer 2014 as part of the cumulative impact analysis.

As discussed in the preceding section of this decision, our analysis is based on the 10 RDPs, AB 327, and other statutory requirements. To avoid repetition, we've grouped the RDP as follows for this analysis.

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[493] SDG&E initially proposed default TOU, but by the time of evidentiary hearings in November SDG&E had modified its proposal.

Cost Of Service RDP	Affordable Electricity RDP	Conservation	Customer Acceptance
2 Rates should be based on marginal cost; 3 Rates should be based on cost-causation principles 7 Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals; 8 Incentives should be explicit and transparent; 9 Rates should encourage economically efficient decision-making;	1 Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost;	4 Rates should encourage conservation and energy efficiency; 5 Rates should encourage reduction of both coincident and non-coincident peak demand;	6 Rates should be stable and understandable and provide customer choice; 10 Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

11.1.1. Affordability Requirements

11.1.1.1. Overview

Affordability of essential amounts of electricity is of particular concern. RDP #1 sets forth the principle that low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) can be met at an affordable cost. Section 382(b), sets a statutory requirement that low-income ratepayers not be "jeopardized or overburdened by monthly energy expenditures."

Recognizing the paramount importance of affordability, this decision retains the requirement that Tier 1 cover baseline quantities of electricity and preserves (while moderating) the inverted tier structure, thereby protecting low usage customers from drastic bill increases while still reducing the bills of high users.

This decision also preserves significant assistance to low-income customers. It makes necessary changes to FERA and medical baseline programs to reflect changes in the tier structure, but maintains the overall protections for these customer groups. This decision also continues the transition to the legislatively-mandated CARE discount range of 30%-35% in compliance with Section 739.1

11.1.1.2. Affordability of Changed Rates

Affordability analysis is framed by state law including Section 451 (requiring just and reasonable rates) and Section 382(b) (requiring reduced rates for certain low-income customers and endeavoring to provide essential electricity at an affordable cost).

The burden is on the IOUs to justify proposed rate changes by showing they meet the law, including affordability requirements. The bill impact and energy burden analyses provided by the IOUs support our finding that the rates approved for 2015, and the direction of rates during the Roadmap period, are affordable.

CforAT argues that none of the rate designs proposed by the IOUs are just and reasonable.[494] Instead, CforAT states that its preferred rate design would consist of a three-tier structure with baseline quantities set at 55% of average. Tier 1 rates should be set at a level which, in conjunction with a CARE discount of 35%, results in a mean energy burden for CARE customers that does not exceed 5%. Furthermore, they suggest that rates for Tier 2 and Tier 3 be held in a constant ratio to each other, and that there be no increased customer charge. A high-usage surcharge should apply to non-CARE customers with usage over 400% of average.[495]

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[494] CforAT OB at 1.

[495] CforAT OB at 2-4.

The design proposed by CforAT would not meet all the legal requirements and Rate Design Principles; however, we agree with the concept of a high-usage surcharge, albeit beginning at a somewhat lower usage level.

11.1.2. Affordability Requirements

CforAT uses a 5% energy burden (combined gas and electricity) as a benchmark for "high energy burden." This benchmark is used by the Low Income Needs Assessment (LINA).[496] However, neither the Commission nor state law have adopted a specific benchmark or test to determine whether a customer's energy burden is "high" and whether energy burden by itself can be used to evaluate affordability of electricity. The LINA study found that the mean energy burden for low income households is already 8%.

11.2. Default Rate Structure

11.2.1. Generally

The record in this proceeding shows that further flattening of tiered rates is reasonable up to a point. By retaining a three-tier structure with 33% tier differentials, and ensuring that the IOUs educate customers about the distinction between tiers, the new rates will continue to promote conservation. Reduction in the number of tiers may make the tiered rate more understandable to customers.

The record also reflects that fixed charges will be an unreasonable rate design for the foreseeable future. Such charges would undermine affordability

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[496] The full name of the LINA Report is the "Needs Assessment for Energy Savings Assistance and the California Alternate Rates for Energy Programs," prepared by Evergreen Economics, December 2013. An earlier low income needs assessment known as the KEMA Report" is also referenced. The full name of the "KEMA Report" is the "Final Report on Phase 2 Low Income Needs Assessment" prepared by KEMA for the Commission, September 7, 2007. Portions of the LINA Report are included in the evidentiary record within Exh. CforAT-01 (Revised Prepared Testimony of Henry J. Contreras Addressing Affordability Issues for Vulnerable Customers for Summer 2014).

of service for low usage customers. For example, PG&E's Supplemental Response estimated the cumulative bill impacts between 2014 and 2018 for those customers using less than 300kWh/month in a scenario where a 1:1.2 ratio is achieved by 2018 with a $10 fixed charge introduced in 2016. PG&E's calculations show that average bill increases for these customers would range between 46% and 169% over that four-year period.[497]

By rejecting a fixed charge we continue to keep volumetric rates higher, and therefore more likely to incent conservation.

We therefore evaluate and approve modified 2015 Rates and a Roadmap rate structure for each utility separately below.

Each utility proposed its own timeline based on current rate structure, with the goal of achieving two tiers with a 20% differential by 2018.

UCAN and ORA argued that the glidepath towards tier flattening should be slower to avoid rate shock. The statute does not require a set timeline. Because this decision makes flattening of tiered rates the first step in rate reform, and holds other reforms until AFTER this step is complete, we believe that 2018 is an appropriate target for the moderate tier flattening that we approve here. ORA proposed system of caps tied to revenue increases, but we aren't going to do that because it creates uncertainty in roll out of other rate reforms, and make ratesetting unnecessarily difficult for the next few years.

11.2.2. PG&E

PG&E proposes to flatten its current four-tiered structure to two tiers with a 20% differential between the tiers by 2018. Reduction in the number of tiers would be accomplished in two steps: first, reducing from four tiers to three tiers

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[497] PG&E Supplemental Response of April 3, 2015, Vol. 1 at 4.)

in 2015 by combining the usage levels for Tier 2 and Tier 3; second, by reducing to two tiers in 2018 by collapsing the top two tiers into Tier 2.[498] Except as otherwise noted, the tables below reflect the data filed by PG&E as part of the April 2015 Supplemental Filing. Note that these illustrative rates therefore do not include any revenue requirement increases beyond 2015. PG&E states that it expects to have $0 in residential revenue requirement changes in 2015.

11.2.2.1. Recovery of Fixed Costs in Rates

For non-CARE customers, 2018 illustrative rates <u>with a fixed charge</u> and calculated with a composite tier set at a 1:1.2 differential would be $0.160 for Tier 1 and $0.235 for Tier 2 (representing all usage over 100% of baseline in 2018).[499] For non-CARE customers, 2018 illustrative rates <u>without a fixed charge</u> but with a $10 minimum bill applied to Tier 1 would be $0.195 for Tier 1 and $0.235 for Tier 2 (representing all usage over 100% of baseline).[500]

Including a fixed charge in 2015 keeps PG&E's Tier 1 rates roughly 8% lower than they would be in a minimum bill scenario in 2015. However, a fixed charge actually results in greater average bills for the vast majority of low-usage customers by the end of 2015 despite the lower Tier 1 rate. The same result holds for cumulative bill impacts between 2014 and 2018.

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498 PG&E OB at 15.

499 PG&E Supplemental Filing of April 1, 2015, Appendix A at 4, Scenario 1a.

500 *Ibid.*

Table comparing PG&E's proposed 2015 Non-CARE Rates: fixed charge vs. minimum bill[501]

Summer 2015 Rate Change with a Fixed Charge and with composite tier differential	**March 2015**	**EOY 2015**	**Summer 2015 Rate Change without a Fixed Charge and with a Minimum Bill**	**March 2015**	**EOY 2015**
Fixed Charge	$0	$5	Minimum Bill	$0	$10
0 – 100% of BQ	$0.164	$0.164	0 – 100% of BQ[502]	$0.164	$0.179
100 -130% of BQ	$0.187	$0.223	100 -130% of BQ	$0.187	$0.223
130 – 200% of BQ	$0.275	$0.223	130 – 200% of BQ	$0.275	$0.223
Over 200% of BQ	$0.335	$0.310	Over 200% of BQ	$0.335	$0.310

PG&E proposes a monthly service fee that would begin in 2015 at $5.00 for non-CARE customers and $2.50 for CARE customers, and during the Roadmap Period would increase to the maximum permitted by statute.

As noted throughout this decision, the bill impacts associated with consolidating and narrowing tiers will be significant throughout the transition period. During this time, customers should be able to focus on understanding and responding to the change in tiered rates. We therefore reject fixed charges for the foreseeable future. Instead, we find that a minimum bill set at $10 for non-CARE customers and $5 for CARE customers, should be implemented with the 2015 summer rate change. Revenue from the minimum bill should be applied to Tier 1. The minimum bill amount will increase as follows:

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[501] PG&E Supplemental Filing of April 1, 2015, Appendix A at 4 (Scenario 1a); *id.* at 8 (Scenario 3a).

[502] BQ = Baseline Quantity.

Table: PG&E Adopted Minimum Bill for Non-CARE Customers (per month)

	PG&E non-CARE	PG&E CARE
2015	$10.00	$5.00
2016	$10.00	$5.00
2017	$10.00	$5.00
2018	Annual CPI adjustment or GRC Phase 2 outcome	Annual CPI adjustment or GRC Phase 2 outcome

11.2.2.2. Consolidation of Tiers (PG&E)

In April 2015 Filing, PG&E inexplicably reduced the glidepath for the minimum bill scenarios to end in 2017 instead of 2018, as shown below. Instead of reaching the tier structure by 2018, the transition would be completed in 2017. PG&E did not offer an explanation for the change in transition period.

The most significant bill impact for lower tier customers will occur when Tiers 2 and 3 are consolidated, regardless of whether a fixed charge is included in the rate structure or not. As the table below demonstrates, PG&E's proposed collapse of Tiers 2 and 3 in 2015 results in an increase of the price of Tier 2 by 19.25%.

To reduce the rate shock of such an increase, we direct PG&E to reduce the differential between Tiers 2 and 3 before combining these tiers. This approach is also recommended by ORA.[503] ORA also points out that the Tier 2 customers were already impacted by a large rate increase in summer 2014.

[503] ORA OB at 7.

Table showing PG&E Proposed Glidepath for Non-CARE rates with minimum bill (*no fixed charge*).[504]

	May 2014	March 2015		December 2015		2016		2017		2018	
	Rate	Rate	% Change YOY[505]	Rate	% Change YOY	Rate	% Change YOY	Rate	% Change YOY	Rate	% Change YOY
0 – 100% of BQ[506]	$0.136	$0.164	20.6%	$0.179	9.15%	$0.172	-4.0%	$0.165	-4.1%	$0.165	0%
100 - 130% of BQ	$0.155	$0.187	20.6%	$0.223	19.25%	$0.233	4.5%	$0.233	0%	$0.232	-0.4%
130 – 200% of BQ	$0.320	$0.275	-14.1%	$0.223	-18.9%	$0.233	4.5%	$0.233	0%	$0.232	-0.4%
Over 200% of BQ	$0.360	$0.335	-6.9%	$0.310	-7.5%	$0.315	1.6%	$0.333	5.7%	$0.332	-0.3%

11.2.2.3. Revenue Requirement Increases (PG&E)

The final variable for determining a smooth glide path and avoiding sharp year over year rate increases is the treatment of revenue requirement changes during the transition period. For the April Supplemental Filing, the IOUs were not required to include an assumed or forecast revenue requirement increase beyond 2015. Therefore setting specific rules for treatment of future increases is of paramount importance.

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504 PG&E Supplemental Filing of April 1, 2015, Appendix A at 9 (Scenario 3d). The PG&E bill impact analysis herein is based on PG&E's Scenario 3d, a minimum bill scenario that it similar to the rate reform that we order in this Decision. Because the ordered reform is somewhat different than the scenario modeled by PG&E, the billing impacts will not be exactly the same.

505 Includes revenue requirement increases throughout 2015 – the rest of the rates do not assume any revenue requirement increases to show the effect of rate reform in isolation from revenue requirement increases.

506 BQ = Baseline Quantity.

PG&E proposed that (i) for revenue requirement increases, all rates (non-CARE and CARE, in every tier) would increase on an equal cents per kWh basis in order to collect the incremental revenue amount; and (ii) for revenue requirement decreases, the non-CARE Tier 1 and 2 rates, as well as all CARE rates, would remain at their then-current levels and non-CARE Tier 3 rates would be decreased so at to collect the lower revenue amount.[507]

In contrast, ORA proposes that for rate changes in 2016 or later, the cumulative change in rates applicable to baseline usage (Tier 1) should either (i) be limited to the change in the residential class average rate (RAR) plus 3% over a given 12-month period, OR (ii) allow tiers to move on an equal percent basis but cap the Tier 1 rate at RAR plus 3% relative to May 1 rates.[508]

ORA argues that without such a cap, increases on lower tier rates could be unacceptably high and lead to rate shock. ORA also argues that applying increases on an equal percent basis, instead of an equal cent basis as proposed by PG&E, is necessary because an equal cents basis would cause lower tier customers to face disproportionately high rate increases.[509] ORA cites several past settlements and Commission decisions that align with its proposals.

ORA proposes that any revenue requirement decreases be treated the same across all tiers. We agree.

Based on the changes we are making to PG&E's proposed rate design, and the principles of rate reform, we find that the following revenue requirement

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[507] ORA OB at 10 (citing Exh. PG&E 101 at 2-69).

[508] *Id.* at 6.

[509] *Id.* at 10-11; 13.

treatment, containing aspects of ORA's and PG&E's proposals, as well as a cap applied for the Tier 1 rate increases, is reasonable:

- Revenue Requirement Increases: allow tiers to move on an equal percent basis, except that Tier 1 increases are capped at RAR plus 3% relative to May 1 rates for the first two years, and at RAR plus 5% thereafter.

- Revenue Requirement Decreases: any revenue requirement decreases be treated the same across all tiers.

- The glidepath should be no steeper than necessary to reach a 33% differential by 2018. The glidepath shall continue until the later of (i) January 1, 2018 or (ii) the year the 33% differential tier ratio is achieved.

After reviewing the tier consolidation glidepath proposed by PG&E for a tiered rate with a minimum bill, we have determined that the bill impact on Tier 2 customers in 2015 would be too severe. Extending the glidepath by additional years would not mitigate this initial bill impact for Tier 2 customers. We therefore direct PG&E to update its rate for the following glidepath. The Tier 1 advice letter containing the updated tariff sheets for summer 2015 should also include the forecast rates for the new glidepath. The tier differentials for years 2015 – 2018 in the table below are suggested, and each IOU is directed to use these suggested differentials as a guideline for its glidepath.

Approved Glidepath for Tier Consolidation (PG&E)

	Current	**2015**	**2016**	**2017**	**2018**	**2019**
Number of Tiers	4 tiers	4 tiers	3 tiers	3 tiers	3 tiers	3 tiers
Usage covered			Baseline 101 – 200% BQ Over 200% BQ	Baseline 101 – 200% BQ Over 200% BQ	Baseline 101 – 200% BQ Over 200% BQ	Same as 2018
Suggested Tier Differential		1:1.18:1.5:1.91	1:1.23:1.81	1:1.23:1.5	1:1.33:1.77	Same as 2018

Based on this, we approve the continued tier narrowing on the glidepath approved above and a minimum bill of $10 for summer 2015.

PG&E must retain the four-tier structure for the remainder of 2015. In its advice letter filing, PG&E should include a revised glidepath that (i) extends to 2018, (ii) narrows the ratio between Tiers 2 and 3 in 2015 but does not combine Tiers 2 and 3 until 2016 at the earliest, (iii) uses the suggested 2015 -2018 tier differentials above as a guideline, and (iv) applies revenue requirement changes as described above.

As discussed above, we direct PG&E to explore seasonal tiered rates.

11.2.2.4. Energy Burden Analysis

As we noted in this proceeding's Phase 2 Decision: "[e]nergy burden is the ratio of the customer's cost for electricity and gas compared to the customer's income."[510] We further noted that "CforAT/Greenlining use a 5% energy burden (combined gas and electricity) as a benchmark for 'high energy burden.' This benchmark is used by the Low Income Needs Assessment (LINA) Report, but neither the Commission nor state law has adopted a specific benchmark or test to determine whether a customer's energy burden is 'high' and whether energy burden by itself can be used to evaluate affordability of electricity."[511]

We continue to employ the energy burden metric as an assessment of the general affordability of the rate design reforms. While we do not specifically hold that a 5% mark is the appropriate threshold for determining affordability, we continue to use it as a guideline for examining the impacts of rate reform on the affordability of energy.

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[510] Phase 2 Decision at 46.

[511] *Id.* at 47.

Generally, the average energy burdens for non-CARE customers in cool and moderate climate zones remain under 5%. Customers with the highest usage continue to have the highest energy burdens. However, the energy burden data provided by PG&E may not be reliable given that some of the sample sizes are as small as six customers. There are other affordability metrics in the evidentiary record that demonstrate reducing rates for high tier customers will reduce some energy burdens.

In light of this, we approve changes for 2015, but direct PG&E to update forecast energy burdens for 2015 and the remaining years using a reasonable sample size. This information must be included in the Tier 1 AL implementing summer 2015 rates.[512]

11.2.2.5. Adjustments to CARE and FERA programs (PG&E)

As discussed in Section 7, we approve a proposed glidepath for CARE to a 35% average discount by 2020. We are also approving a minimum bill for CARE customers. As with the non-CARE rates, PG&E only provided illustrative rates for the minimum bill scenario with a glidepath ending in 2017. As with the non-CARE rates, we direct PG&E to extend the glidepath until 2020, and not to combine Tiers 2 and 3 in 2015. As discussed in Section 7, we will modify FERA in light of the reduced number of tiers.

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[512] Original data from PG&E's Supplemental Filing, April 3, 2015, Energy Burden for Scenario 3a at 1-10. We note that PG&E's data is somewhat suspect given the very small sample sizes for some of their usage cohorts. For example, for CARE customers in the "Other" climate group the usage cohorts with burdens > 5% had sample sizes between 1 and 11. We have doubts about the significance of statistics divined from such small samples.

11.2.2.6. Adjustments to SmartRate (PG&E)

SmartRate (Schedule E-RSMART) is PG&E's optional demand response program for residential customers. It is an "overlay" rate, meaning that it applies certain supplemental charges and credits to the underlying rates that the customer would be charged under any of the applicable residential tariffs.[513] Specifically, SmartRate participants pay higher prices for power during certain hours in the summer (Smart Day event hours). In turn, credits are applied to the participating customer's usage during other parts of the day. Specifically, there are two separate credits applied to usage from June through September (other than Smart Day event hours). The "participation credit" applies to only usage above 130% of baseline. Currently, 130% of baseline is the boundary between Tier 2 and Tier 3. Because PG&E's rate restructuring approved in this decision will make changes to tier usage amounts, the "participation credit" will have to be modified. For this reason, PG&E proposes that the participation credit apply to all usage above 100% of baseline. Because the participation credit would apply to an increased number of kWh, PG&E asks that the credit be reduced from 1 cent/kWh to 0.75 cents/kWh for customers on existing tariffs. PG&E asks that its E-TOU rate proposed in this proceeding apply a smaller credit of 0.5 cents/kWh. PG&E argues that these changes will preserve the approximate magnitude of the currently effective SmartRate participation credit, and that the reductions reflect the increased number of kWh that will now be eligible for credits under SmartRate.

No parties commented on PG&E's proposal. In light of the other rate changes approved in this decision we agree with PG&E that SmartRate should be

[513] Exh. PG&E-101 at 2-22.

adjusted. PG&E's proposal is reasonable and consistent with the law and RDP. We therefore approve PG&E's proposed reduction of the SmartRate discount, concurrent with the combination of Tiers 2 and 3.

11.2.3. SCE

Like PG&E, SCE proposes to flatten its current four-tiered structure to two tiers with a 20% differential between the tiers by 2018. Reduction in the number of tiers would be accomplished in three steps beginning with a move to three tiers as part of summer 2015 rate reform. Except as otherwise noted, the tables below reflect the data filed by SCE as part of the April 2015 Supplemental Filing. Per the March 30, 2015 ALJ ruling requesting supplemental information, we assume the illustrative rates shown here include projected revenue requirement increases through 2015, but not beyond. SCE's expected 2015 rate increases are listed in Attachment B.

SCE Proposed Tier Flattening Glidepath

Current	2015	2016	2017	2018
4 tiers	3 tiers	3 tiers	2 tiers	2 tiers
	Baseline 101 – 200% BQ Over 200% BQ	Same as 2015.	Baseline Non-baseline	Same as 2017

11.2.3.1. Recovery of Fixed Costs in Rates

For SCE non-CARE customers, 2018 illustrative rates with a fixed charge and calculated with a composite tier set at a 1:1.2 differential would be $0.17 for Tier 1 and $0.24 for Tier 2 (representing all usage over 100% of baseline). For SCE non-CARE customers, 2018 illustrative rates without a fixed charge but with a $10 minimum bill applied to Tier 1 would be $0.20 for Tier 1 and $0.24 for Tier 2 (representing all usage over 100% of baseline).

Table comparing SCE's proposed Summer 2015 Non-CARE Rates: Fixed Charge vs. Minimum Bill[514]

Summer 2015 Rate Change with a Fixed Charge and with composite tier differential	January 2015	EOY 2015	Summer 2015 Rate Change without a Fixed Charge and with a Minimum Bill	January 2015	EOY 2015
Fixed Charge	$0.94	$5	Minimum Bill	$0.94	$10
0 – 100% of BQ	$0.149	$0.151	0 – 100% of BQ[515]	$0.149	$ 0.164
100 -130% of BQ	$0.193	$0.247	100 -130% of BQ	$0.193	$ 0.25
130 – 200% of BQ	$0.257	$0.247	130 – 200% of BQ	$0.257	$ 0.25
Over 200% of BQ	$0.312	$0.329	Over 200% of BQ	$0.312	$0.333

SCE proposes a monthly service fee that would begin in 2015 at $5.00 for non-CARE customers and $2.50 for CARE customers, and during the Roadmap Period would increase to the maximum permitted by statute.

Unlike the other two utilities, SCE currently has a fixed "basic charge" of $0.031 per day, which equates to approximately $0.94 per month, for non-CARE customers, and $0.024 per day, equating to approximately $0.73 per month, for CARE customers. SCE requests an increase in the monthly service fee that beginning in 2015 to $5.00 for Non-CARE customers and $2.50 for CARE customers, and during the Roadmap Period the monthly service fee would increase to the maximum permitted by statute. SCE also requests a minimum bill that would be the same for all customers (CARE and non-CARE).

As noted throughout this decision, the bill impacts of consolidating and narrowing tiers will be significant throughout the transition period. During this time, customers should be able to focus on understanding and responding to the

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[514] SCE Supplemental Filing of April 1, 2015 (Scenario 1a; Scenario 3a).

[515] BQ = Baseline Quantity.

change in tiered rates. As discussed earlier, we reject additional fixed charges for the foreseeable future. As a result, customers will be able to focus on changes to the tiered rates without the added complication of new or increased fixed charges. Instead, we find that a minimum bill set at $10 for non-CARE and $5 for CARE customers, should be implemented with the 2015 rate change.

We do approve a minimum bill, starting as early as 2015, at the amounts set forth below. Revenue from the minimum bill should be applied to Tier 1.

SCE Adopted Minimum Bill (per month)

	SCE non-CARE	SCE CARE
2015	$10.00	$5.00
2016	$10.00	$5.00
2017	$10.00	$5.00
2018	Annual CPI adjustment or GRC Phase 2 outcome	Annual CPI adjustment or GRC Phase 2 outcome

11.2.3.2. Consolidation of Tiers (SCE)

For lower tier customers the most dramatic bill impact resulting from tier collapse will occur when Tiers 2 and 3 are consolidated, regardless of whether a fixed charge is included in the rate structure or not. When compared with January 2015 rates, SCE's proposed collapse of Tiers 2 and 3 in 2015 would result in an increase in the Tier 2 rates by 22% under fixed charge scenario 1g (which maintains tiers and a differential similar to those ordered in this decision), and an increase in the Tier 2 rates by 23.4% under minimum bill Scenario 3d. When compared with rates under the current four-tiered structure calculated with 100% of SCE's pending 2015 revenue requirement added, the price of Tier 2 rates would increase by 12.1% under fixed charge scenario 1g and by 13.4% under minimum bill scenario 3d. The illustrative rates shown here include projected revenue requirement increases through the end of 2015, but not beyond.

To reduce the rate shock of such an increase, we direct SCE to reduce the differential between Tiers 2 and 3 before combining these tiers.

Table showing SCE's Proposed Glidepath for Non-CARE rates with $10 minimum bill no fixed charge[516] [517]

	Jan 2014	Jan 2015	2015 w/ Pending RRQ[518]		EOY 2015		2016		2017		2018	
	Rate	Rate	Rate	% Δ	Rate	% Δ	Rate	% Δ	Rate	% Δ	Rate	% Δ
0 – 100% of BQ	$0.132	$0.149	$0.162	8.7%	$0.14677	-9.4%	N/A	N/A	N/A	N/A	N/A	N/A
100 - 130% of BQ	$0.165	$0.193	$0.210	8.8%	$0.23809	13.4%	N/A	N/A	N/A	N/A	N/A	N/A
130 – 200% of BQ	$0.274	$0.257	$0.277	7.8%	$0.23809	-14.0%	N/A	N/A	N/A	N/A	N/A	N/A
Over 200% of BQ	$0.304	$0.312	$0.337	8.0%	$0.34013	0.9%	N/A	N/A	N/A	N/A	N/A	N/A

11.2.3.3. Revenue Requirement Increases (SCE)

The final variable for determining a smooth glide path and avoiding sharp year over year rate increases is the treatment of revenue requirement changes during the transition period. For the final set of bill impact modeling in Phase 1, we did not include an assumed or forecast revenue requirement increase.

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516 This table is based on SCE's April 8, 2015 Supplemental Filing's minimum bill Scenario 3d. Because the ordered reform is somewhat different than the scenario modeled by SCE, the billing impacts will not be exactly the same. This table includes revenue requirement increases through the end of 2015; rates after 2015 do not assume any revenue requirement increases to show the effect of rate reform in isolation from revenue requirement increases.

517 SCE Supplemental Filing, April 1, 2015, Attachment B, Scenario 3d. Note that SCE did not provide modeled rates for 2016-2018 in their run of Scenario 3d.

518 These rates were provided by SCE in its April 1, 2015, Supplemental Filing and represent 2015 rates under the current four-tiered structure with 100% of SCE's 2015 pending revenue requirement added.

SCE did not propose a specific treatment for revenue requirement changes occurring during the transition period. No other party had specific suggestions for treatment of SCE revenue requirement changes.

Based on the changes we are making to SCE's proposed rate design, and the principles of rate reform, we find that the following revenue requirement treatment, containing aspects of ORA's proposal for PG&E discussed in Section 11.2.2.3, as well as a cap applied for the Tier 1 rate increases, is reasonable:

- Revenue Requirement Increases: allow tiers to move on an equal percent basis, except that Tier 1 increases are capped at RAR plus 3% relative to May 1 rates for the first two years, and at RAR plus 5% thereafter.
- Revenue Requirement Decreases: any revenue requirement decreases be treated the same across all tiers.
- The glidepath should be no steeper than necessary to reach a 33% differential by in 2018. The glidepath shall continue until the later of (i) January 2018 or (ii) the year the 33% tier differential is achieved.

After reviewing the tier consolidation glidepath proposed by SCE for a tiered rate with a minimum bill, we have determined that the bill impact on Tier 2 customers in 2015 would be too severe. Extending the glidepath by additional years would not mitigate this initial bill impact for Tier 2 customers. We therefore direct SCE to update its rate for the following glidepath. The Tier 1 advice letter containing the updated tariff sheets for summer 2015 should also include the forecast rates for the new glidepath.

The tier differentials for years 2015 – 2018 in the table below are suggested, and each IOU is directed to use these suggested differentials as a guideline for its glidepath.

Approved Glidepath for Tier Consolidation (SCE)

	Current	2015	2016	2017	2018
Number of Tiers	4 tiers	4 tiers	3 tiers	3 tiers	3 tiers
Usage covered			Baseline 101 – 200% BQ Over 200% BQ	Baseline 101 – 200% BQ Over 200% BQ	Baseline Over 100% BQ
Tier Differential			1:1.5:2	1:1.6:1.9	1:1.33:1.77

Based on this, we approve a minimum bill of $10 for non-CARE customers and $5 for CARE customers starting as soon as practicable after the adoption of this decision, with tier narrowing as described here between 2016 and 2018. We find that a fixed charge is not appropriate, for the reasons described above.

11.2.3.4. Energy Burden Analysis

In their April Supplemental Response, SCE calculated the estimated electric energy burden for both CARE and non-CARE customers by monthly usage cohort in four different climate groups: Cool (Zones 6, 8 and 16), Warm (Zones 5 and 9), Inland (Zones 10, 13 and 14) and Very Hot (Zone 15). These electric energy burdens represent the estimated percentage of annual income that an average customer in a given usage class pays for electricity over the course of a year.

We examined the number and percentage of customers who are projected to see electric energy burdens of 5% or more by the end of 2015 under SCE's Scenario 3d, which is similar to the rate reform ordered in this decision. This analysis does not look beyond the end of 2015, because SCE did not model energy burdens (or rates) for Scenario 3d beyond the end of 2015. By the end of 2015, 6.1% of SCE's non-CARE residential customers would have an electric energy burden of 5% or more. By the end of 2018, 0.5% of SCE's CARE residential customers would have an electricity energy burden of 5% or more.

We find that these estimates of electricity burden are reasonable and consistent with affordability requirements.

11.2.3.5. Adjustments to Baseline Allowance; Seasonal Rates (SCE)

Considering SCE's proposed rate change as a whole, we believe that a decrease in baseline allowance to 50% is not warranted. Currently, SCE's baseline is under the middle range for baseline allowances. The primary objective of reducing the baseline allowance is to take another step toward bringing upper tier and lower tier rates closer together. We therefore deny SCE's request to reduce SCE's baseline allowance, and direct that the allowances be increased to 55%, the midpoint of the statutory range, in SCE's current GRC Phase 2.

As discussed above, we direct SCE to explore seasonal tiered rates.

11.2.3.6. Adjustments to CARE and FERA programs (SCE)

As discussed in Section 7 we direct SCE to maintain the current average discount for both CARE and FERA, and expect to gradually increase the CARE discount to 35%. We are also approving a minimum bill for CARE customers. In addition, we direct SCE to modify FERA as discussed above when it implements the reduced number of tiers.

Table showing SCE's Tier Flattening Glidepath for CARE rates (*no fixed charge*); with minimum bill under Scenario 3d[519]

	2014	2015
0 – 100% of BQ[520]	$0.088	$0.11225
100 -130% of BQ	$0.11	$0.16071
130 – 200% of BQ	$0.20	$0.16071
Over 200% of BQ	$0.20	$0.22959

11.2.4. SDG&E

Under SDG&E's current tier structure, the differential between Tier 1 and 2, and the differential between Tier 3 and 4, are very narrow. SDG&E describes it as "essentially an existing two tiered structure with a 50% differential."[521] For this reason, SDG&E's proposal for flattening its four-tiered rate structure is different from that of PG&E and SCE. SDG&E proposes to consolidate Tiers 1 and 2 into a new Tier 1, and consolidate Tiers 3 and 4 into a new Tier 2 in 2015. In addition, beginning in 2015, and continuing until 2018, SDG&E would reduce the differential between the consolidated Tier 1 and the new Tier 2 from approximately 50% to 20%.

SDG&E Proposed Tier Flattening Glidepath

Usage per Tier		Tier 1: up to 130% of BQ Tier 2: above 130% of BQ			
Differential	2.4 cents (Tier 1 and Tier 2) 15-17 cents (Tiers 1&2 and Tiers 3&4) 2 cents (Tiers 3 and 4)	~50%	40%	30%	20%

For non-CARE customers, 2018 illustrative rates <u>with fixed charge</u> would be $0.194 (Tier 1) and $0.342 (Tier 2 (all usage over 100% of baseline)). For non-

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519 Note that SCE did not model rates for 2016-2018 for Scenario 3d.

520 BQ = Baseline Quantity.

521 Exh. SDG&E 101 at CY-15.

CARE customers, 2018 illustrative rates without fixed charge but with a minimum bill would be $0.208 (Tier 1) and $0.345 (Tier 2 (all usage over 100% of baseline)).[522]

Table comparing SDG&E's proposed 2015 Non-CARE Rates: fixed charge vs. minimum bill[523]

Summer 2015 Rate Change with a Fixed Charge and with composite tier differential	February 2015	EOY 2015	Summer 2015 Rate Change without a Fixed Charge and with a Minimum Bill	February 2015	EOY 2015
Fixed Charge	$0	$5	Minimum Bill	$0	$10
0 – 100% of BQ	$0.172	$0.194	0 – 100% of BQ[524]	$0.172	$0.208
100 -130% of BQ	$0.202	$0.194	100 -130% of BQ	$0.202	$0.208
130 – 200% of BQ	$0.401	$0.342	130 – 200% of BQ	$0.401	$0.345
Over 200% of BQ	$0.421	$0.342	Over 200% of BQ	$0.421	$0.345

SDG&E proposes a monthly service fee that would begin in 2015 at $5.00 for non-CARE customers and $2.50 for CARE customers, and during the Roadmap Period would increase to the maximum permitted by statute.

As noted throughout this decision, the bill impacts of consolidating and narrowing tiers will be significant throughout the transition period. During this time, customers should be able to focus on understanding and responding to the change in tiered rates. As discussed earlier, we reject additional fixed charges for the foreseeable future. As a result, customers will be able to focus on changes to the tiered rates without the added complication of new or increased fixed charges. As with the other IOUs, we find that a minimum bill set at $10 for non-

522 SDG&E Supplemental Filing, April 1, 2015, Attachment C at 15.

523 *Id*. (Scenario 1a; Scenario 3a).

524 BQ = Baseline Quantity.

CARE customers and $5 for CARE customers should be implemented with the 2015 rate change.

Table: SDG&E Adopted Minimum Bill (per month)

	SDG&E non-CARE	SDG&E CARE
2015	$10.00	$5.00
2016	$10.00	$5.00
2017	$10.00	$5.00
2018	Annual CPI adjustment or GRC Phase 2 outcome	Annual CPI adjustment or GRC Phase 2 outcome

11.2.4.1. Consolidation of Tiers (SDG&E)

Under SDG&E's proposal, because the tiers that are being combined are already close together, the bill impacts for lower tier customers will be slightly less than the increase seen in SCE and PG&E tier consolidation proposals. However, when 2014 rate increases are included in the analysis, the Tier 1 bill impact is more dramatic. In July 2014, Tier 1 rates were 15.4 cents per kWh. After the change proposed by SDG&E for 2015, the Tier 1 rate will be 20.8 cents. This is a substantial increase of 20.93% in just over one year. At the same time, the Tier 4 rate will decrease by 14.18% over the same year. UCAN contends that adding two additional years to the glide path (and applying any fixed charge to Tier 1 only), would improve customer acceptance of the rate changes.

Table showing SDG&E's IllustrativeTier Flattening Glidepath for Non-CARE summer rates (*no fixed charge*), $10 minimum bill.

Scenario 3d – Minimum Bill of $10 – Non-CARE rates[525]										
	Jan-14	Feb-15		Dec-15		2016		2017		2018
	Rate	Rate	% Change YOY	Rate	% Change YOY	Rate	% Change YOY	Rate	% Change YOY	Rate
0 – 100% of BQ	$0.150	$0.172	14.67%	$0.195	13.37%	$0.194	-0.51%	$0.193	-0.52%	$0.193
100 - 130% of BQ	$0.173	$0.202	16.76%	$0.274	35.64%	$0.273	-0.36%	$0.272	-0.37%	$0.271
130 – 200% of BQ	$0.358	$0.401	12.01%	$0.274	-31.67%	$0.273	-0.36%	$0.272	-0.37%	$0.271
Over 200% of BQ	$0.378	$0.402	6.35%	$0.391	-2.74%	$0.390	-0.26%	$0.389	-0.26%	$0.387

ORA is also concerned about this substantial Tier 1 increase. ORA proposes that Tiers 3 and 4 be combined in 2015, but that SDG&E wait until at least 2016 to combine Tiers 1 and 2. Also, similar to its proposal for PG&E, ORA proposes that the cumulative change in rates applicable to baseline usage (Tier 1) should be capped at the RAR plus 5% compared to August of the prior year.[526] ORA contends that without such a cap, increases on Tier 1 rates would be unacceptably high. ORA cites the Phase 1 settlement as an example of where a cap on rate increases has been used before.

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525 *Id*, Scenario 3d

526 ORA OB at 19.

After reviewing the tier consolidation glidepath proposed by SDG&E for a tiered rate with a minimum bill, we have determined that a better approach would be to combine Tiers 2 and 3 gradually over time instead. Towards this end, we find that the glidepath shall continue until the later of (i) January 1, 2018 or (ii) the year a 33% tier differential is achieved. In addition, the glidepath should be no steeper than necessary to reach the tier differentials adopted here. We therefore direct SDG&E to update its rate for the following glidepath. The Tier 1 advice letter containing the updated tariff sheets for summer 2015 should also include the forecast rates for the new glidepath.

Approved Glidepath for Tier Consolidation (SDG&E)

	Current	2015	2016	2017	2018
Number of Tiers	4 tiers	4 tiers	4 tiers	3 tiers	3 tiers
Usage covered	Tier 1: 0-100% of BQ Tier 2: 101-130% of BQ Tier 3: 131-200%of BQ Tier 4: 200% + of BQ	Tier 1: 0-100% of BQ Tier 2: 101-130% of BQ Tier 3: 131-200%of BQ Tier 4: 200% + of BQ	Tier 1: 0-100% of BQ Tier 2: 101-130% of BQ Tier 3: 131-200%of BQ Tier 4: 200% + of BQ	Tier 1: 0-100% of BQ Tier 2: 101-200% of BQ Tier 3: 200% + of BQ	Tier 1: up to 100% of BQ Tier 2: 101%-200% of BQ Tier 3: 200%+ of BQ
Suggested Tier Differential		1:1.24:2.07:2.28	1:1.3:1.72:2.10	1:1.35:1.94	1:1.33:1.76

11.2.4.2. Revenue Requirement Increases

SDG&E proposes (i) to apply any reduction in revenue requirements (including from the monthly service fees) to the upper tier; (ii) Adjust any incremental revenue requirement to the lower tier at two times the percentage increase in the residential class average rate; and iii) to direct adjustment to the differential if the target is not met.

Based on the changes we are making to SDG&E's proposed rate design, and the principles of rate reform, we find that the revenue requirement treatment adopted above for PG&E should also apply to SDG&E:

- Revenue Requirement Increases: allow tiers to move on an equal percent basis, except that Tier 1 increases are capped at RAR plus 3% relative to May 1 rates for the first two years, and at RAR plus 5% thereafter

- Revenue Requirement Decreases: any revenue requirement decreases be treated the same across all tiers.

- The glidepath should be no steeper than necessary to reach 1:1.33:1.76 in 2018. The glidepath shall continue until the later of (i) January 1, 2018 or (ii) the year the tier ratio specified here is achieved.

11.2.4.3. Energy Burden Analysis

In their April 10 Supplemental Response, SDG&E calculated the estimated electric energy burden for both CARE and non-CARE customers by monthly usage cohort in their four different climate groups: Inland, Coastal, Mountain and Desert. We examined both the number and percentage of customers who are projected to see electric energy burdens of 5% or more by the end of 2018 under SDG&E's illustrative glidepath to a 1:1.4:2 tier differential by 2018 with a minimum bill of $10.[527] By the end of 2018, 17,656, or 1.99% of SDG&E's non-CARE residential customers, might have an electric energy burden of 5% or more. By the end of 2018, 832, or less than 1% of SDG&E's CARE residential customers, would have an electricity energy burden of 5% or more. We find that these estimates of electricity burden are reasonable and consistent with affordability requirements.

[527] SDG&E Supplemental Filing, April 1, 2015, Attachment C at 18, Scenario 3d.

11.2.4.4. Adjustments to CARE and FERA programs (SDG&E)

As discussed in Section 7 we approve a glidepath for the 35% CARE average discount by 2020. We are also approving a minimum bill for CARE customers. SDG&E only provided illustrative rates for the minimum bill scenario with a glidepath ending in 2017. We direct SDG&E to extend the glidepath until 2020, and not to combine Tiers 1 and 2 in 2015. SDG&E should also adjust its FERA discount consistent with our discussion in Section 7, above.

11.2.4.5. SDG&E Seasonal Rate

As discussed above, we find that SDG&E's proposal for seasonal rates in all tiers should be considered in a future proceeding.

11.2.4.6. SDG&E Baseline Reduction Rejected

The details of SDG&E's proposed baseline allowance reduction, including a five-year glidepath for all-electric customers, are set forth in Exhibit SDG&E 105, CF -1 through CF-6 and Attachment A. Because we reject SDG&E's consolidation of Tiers 1 and 2, the baseline allowances should remain unchanged for now. SDG&E shall propose new baseline allowances at the 55% level in its GRC Phase 2.

11.3. TOU Opt-In Rates for Residential Customers (PG&E, SCE, SDG&E)

As discussed above, the utilities already have optional TOU rates for residential customers. A summary of existing TOU rates is provided in the table below.

Utility	Opt-In TOU Tariff	Status/Approvals
PG&E	E-TOU	Approved in this decision with modifications. Peak periods being set in A.14-11-014
PG&E	E-6	Closure to new customers approved in this decision.

Utility	Opt-In TOU Tariff	Status/Approvals
		Legacy Tariff for existing customers with at least a 5-year transition to new TOU rate required; transition glidepath to be addressed in A.14-11-014.
PG&E	E-7	Closed to new customers. Legacy Tariff for existing customers with at least a 5-year transition to new TOU rate required; transition glidepath to be addressed in A.14-11-014.
PG&E	E-8	E-8 has been closed to new customers for 20 years. This decision approves eliminating E-8 and transferring existing customers to E-1.
SDG&E	Cost based TOU	This decision directs SDG&E to create a TOU opt-in rate that does not include DDMSF, and with other modifications consistent with this decision.
SDG&E	DR-SES EV-TOU EPEV-X; EPEV-Y; EPEV-Z	TOU period changes being considered in A.14-01-027.
SDG&E	DR-TOU	Closed as of January 2015 pursuant to D.12-12-004.
SDG&E	TOU-DR EECC-TOU-DR-P	Available January 1, 2015 pursuant to D.12-12-004
SCE	TOU D (Option A and Option B)	Approved in D.14-12-048.
SCE	CPP PTR SDP	Existing overlay tariffs.

11.4. TOU Pilots

In Section 5 we discussed the proposed TOU pilots for PG&E and SDG&E. We approved the development of these pilots, with specific parameters on the timeline set forth in the Next Steps section. In addition, we directed SCE to develop a similar TOU pilot.

11.5. Cost Tracking: Memorandum Accounts

Each IOU is directed to file a Tier 1 Advice Letter to create a memorandum account to track the costs of (i) TOU pilots, (ii) TOU studies, including hiring of a consultant to assist in developing study parameters, (iii) MEO costs associated with the rate changes approved in this decision, and (iv) other reasonable expenditures as required to implement this decision. These memo accounts would be subject to review in the utility's next GRC, with the burden on the utility to show that the expenditure were incremental, verifiable and reasonable.

12. Next Steps

12.1. Phase 3

This decision has identified three areas to be addressed in Phase 3: (1) interpretation of the Section 745 conditions that must be met for default TOU, (2) requirements for supporting information and documentation for the Residential RDW applications, and (3) CARE restructuring under AB 327.

A PHC will be scheduled for summer 2015.

12.2. TOU Design and study Working Group

We direct the parties to meet and confer regarding implementing a working group to propose and evaluate the study of residential TOU rates and the design of new TOU pilots obtain targeted information. We expressly authorize the working group to select a consultant, to be hired by the IOUs, to advise on and document the study parameters and pilot designs. Parties should be prepared to report on progress at the Phase 3 PHC. We expect the process of pilot design to be completed in 2015, and submitted for approval by each utility through a Tier 3 advice letter.

12.3. Progress on Residential Rate Reform (PRRR) Reports/Workshops

The purpose of the PRRR is to provide the Commission and interested parties with regular updates on the IOUs' progress on understanding TOU rate impacts. Each PRRR includes a written report and a workshop presenting the written report and answer questions. The PRRR workshop will be scheduled twice per year, with reports due quarterly (November 1, February 1, May 1, and August 1). The PRRR workshops will be held in November and May. Primary topics covered in the PRRR will include: outreach strategies, metrics, pilot design and results, opt-in TOU results, budget, and updates on other proceedings that will impact residential TOU rate design. The list of topics will be refined at the first PRRR. The first PRRR report will be due November 1. The IOUs should be prepared to present a progress summary at the first PRRR.

The first PRRR workshop will be held in summer 2015 to address creation of a working group or groups, hiring of a consultant to assist in TOU pilot design and TOU study parameters.

12.4. Annual Residential Electricity Rate Summit (RERS)

The RERS will provide an opportunity for the Commission and the public to stay updated on the IOUs progress toward reforming residential rates and preparing their Residential RDW applications. Importantly, it will include a forum at which the IOUs will give a high level overview and respond to questions. Workshops geared toward participants in the proceeding, including the September PRRR, can be held on the same day. By coordinating the timing of these workshops, it will be more efficient for parties to attend.

The RERS Forum will put residential rates in in a broader, forward-looking context. The RERS Forum will address residential rates and programs across all relevant proceedings at the Commission and other agencies that impact the design of residential rates and residential customers' opportunities to respond to rates. The presentation must include the status and success of outreach programs to educate customers about their rates. We expect that the RERS Forum will be attended by parties, Commission staff, and the public.

At the RERS Forum, each utility will have ten minutes to give a five-slide presentation, demonstrate currently available online bill comparison tool, and respond to questions from Commission staff. The five slides for the 2015 RERS Forum are:

i. Summary of Summer 2015 rate impacts
ii. outreach materials and metrics
iii. coordination with other proceedings at CPUC and other agencies that impact residential rates
iv. status of meeting Residential RDW application requirements

The first RERS will be in November 2015.

12.5. Residential Rate Design Window

Each IOU must file a Residential RDW application no later than January 1, 2018. The Residential RDW application must include (1) default TOU proposal, (2) fixed charge proposal, and (3) tiered opt-in rate, and (4) at the discretion of the IOU, other optional residential rates. The Residential RDW application must include testimony to support the proposed rate change. Phase 3 will address specific information and supporting documentation that should be included in the Residential RDW application. We anticipate that these applications will be consolidated to facilitate participation by other parties.

At a minimum, the Residential RDW application must include the following information and supporting documentation:

(i) Default TOU:

1. Results of required bill impact studies, including income/usage, GHG reduction, cost savings.
2. Section 745(d) requirements
3. TOU rate design to maximize customer acceptance.
4. Load response studies.

5. Alternative TOU tariff such as multiple TOU periods, matinee pricing, and seasonally differentiated TOU periods that are designed for advance customers.

(ii) if a fixed charge is included it should be supported by:

1. a residential fixed cost allocation approved for this purpose in the utility's last GRC Phase 2.

12.6. Schedule

Deadline	Event
30 days after decision	AL 1 with tariff changes: 2015 summer rate changes Proposed glidepath and bill impacts for tier consolidation after 2015
Quarterly (February 1, May 1, August 1, November 1)	IOUs file quarterly PRRR and host workshop to report on TOU pilot design, opt-in tariff studies, and status of Residential RDW application materials.
Summer 2015	First PRRR workshop to discuss next steps, including creating working groups and hiring of consultant
Semi-annually, May, November	PRRR workshop held each April and November to present PRRR reports and provide opportunity for questions and for parties to meet collaboratively.
Ongoing	Working group to design pilots, design studies of TOU, and to comment on plans for Residential RDW application required materials.
Summer, 2015	Phase 3 PHC and possible workshop to informally discuss scope and schedule for Phase 3. Presentations/proposals on CARE restructuring.
November 1, 2015	Residential Rate Summit: - Presentation and Q&A on identified aspects of residential rates - Related technical workshops
January 1, 2016	Submit Tier 3 AL for approval of TOU pilots
May 31, 2016	Progress on Residential Rate Reform (PRRR) Workshop

Deadline	Event
Spring 2016	TOU Pilots approved
Summer 2016	TOU Pilots start
November 30, 2016	Residential Rate Summit: - Presentation and Q&A on identified aspects of residential rates Related technical workshops
May 31, 2017	Progress on Residential Rate Reform (PRRR) Workshop
November 30, 2017	Residential Rate Summit: - Presentation and Q&A on identified aspects of residential rates Related technical workshops
January 1, 2018	Residential RDW application for default TOU Start of default TOU pilot
May 31, 2018	Progress on Residential Rate Reform (PRRR) Workshop
November 30, 2018	Residential Rate Summit: - Presentation and Q&A on identified aspects of residential rates Related technical workshops
2019	Residential RDW application rates become effective as approved
May 31, 2019	Progress on Residential Rate Reform (PRRR) Workshop
November 30, 2019	Residential Rate Summit: - Presentation and Q&A on identified aspects of residential rates - Related technical workshops, including initial results of default TOU pilot
2019	Residential RDW application rates become effective as approved.

13. Safety Consideration

A significant concern raised throughout this proceeding primarily by CforAT, but also by TURN and ORA is the need to ensure customer access to sufficient amounts of electricity to maintain public safety and health. Access to affordable energy is increasingly important in light of the rate design proposals contemplated in this proceeding. While our objective in this proceeding has been to ensure that rates are both equitable and cost-based, we must simultaneously consider whether our rates and policies ensure affordable access to electricity for all IOU customers.

As a starting point, we note that utilities are required to offer "such adequate, efficient, just and reasonable service…as [is] necessary to promote the safety, health, comfort and convenience of its patrons, employees and the public…"[528] While Section 451 does not speak directly to the level of service or affordability that is reasonable, many other statutory requirements and Commission policies provide guidance. In particular, as discussed at length above, Section 739 requires the Commission to designate a baseline quantity of electricity necessary to supply a significant portion of the reasonable energy needs of the average residential customer at rates below average cost. In setting those quantities, the Commission takes into account the difference in energy needs between all-electric residences and those residences with both gas and electric service as well as differences in energy use by climate zone and season. By statute, the baseline quantity must be set at 50 to 60% of the average residential consumption within each climate zone.[529] The statute also requires that the Commission provide baseline rates that apply to the first or lowest block of an increasing block rate structure. Pursuant to Section 739(c)1, the Commission is also required to provide higher energy allocations for residential customers with special medical needs or who are dependent on life-support equipment.

[528] Pub. Util. Code § 451, in pertinent part.

[529] Section 739(a) 1.

In addition to ensuring an adequate quantity of energy, the state and the Commission have developed specific programs to help low income customers with energy bills. Specifically, the Commission's CARE and FERA programs exist to provide rate assistance to low-income electric customers and households that meet certain annual income levels. Pursuant to Section 382(b), the Commission is required to ensure that low-income customers are not jeopardized by or overburdened by monthly energy expenditures. The Commission currently complies with the requirement through a combination of low-income rate assistance as well as low-income energy efficiency programs. The Commission also has in place certain policies that seek to minimize the termination of utility services for nonpayment and require third-party notification and/or in person visits for certain customer disconnections.[530]

We discuss the impact of the rate design proposals on CARE and FERA and medical baseline programs and customers at length in this decision and determine that the outcome results in a rate design that is cost-based, substantially fair to all customers, and does not jeopardize customers' access to a sufficient amount of energy.

[530] Section 779.1, et seq.

14. Comments on Proposed Decision

The proposed decision of the ALJs 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 ____________, and reply comments were filed on ______________ by __________________.

15. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Jeanne M. McKinney and Julie M. Halligan are the assigned ALJs in this proceeding.

Findings of Fact

1. Residential rates for the three IOUs are based on an inclining block price structure, wherein monthly usage is broken into tiers by volume with usage in the lower tiers paying a lower rate than usage in the higher tiers.
2. One purpose of the inclining block rate structure is to encourage residential customers to reduce aggregate electricity consumption.
3. Since 2001, lower usage tier rates were frozen until recently, resulting in most increases in revenue requirements being allocated to residential customers with usage in the upper tiers.
4. In 2014, for all three IOUs, the rates charged for electricity usage in Tier 4 were more than double the rates charged for electricity usage in Tier 1.
5. The steep differentials between usage tiers have resulted in significant bill volatility for upper tier customers, particularly those living in hot climates.
6. SCE currently has a fixed charge of less than $1 for residential customers. SDG&E and PG&E currently do not charge residential customers a fixed monthly fee but charge a minimum bill instead.

7. The Hiner study demonstrates that customers do not currently have a clear understanding of the structure of their electricity rates.

8. Conservation can take the form of behavioral changes or investments in energy efficiency.

9. Rooftop solar is not a form of conservation, but it is a renewable source of energy and a form of demand side energy management.

10. A customer's electricity price elasticity is based on the customer's ability to reduce or shift use.

11. If the customer is not aware of differences in the electricity price at different hours, the price will not incent the customer to shift usage.

12. Customers with low usage are likely to have less discretionary use than high usage customers.

13. The evidence presented in this proceeding suggests that larger customers have somewhat greater price elasticity than smaller customers.

14. Even if residential customers do not understand how the inclining block price increases with increased usage, they can be expected to react to changes in their total bill from month to month, which are driven by the marginal price.

15. The Marginal Price methodology used by Dr. Faruqui could be improved by eliminating the income elasticity variable.

16. There is no evidence that customers who respond the marginal price do so in a way that takes into account the income elasticity variable ("expenditure" variable).

17. Payback periods for energy efficiency investments and investments in rooftop solar by customers who consume in the upper tiers will be reduced if the price of upper tier energy decreases.

18. The payback period for investments in energy efficiency and solar will be reduced for customers in the upper tiers as upper tier rates are reduced, yet these are the customers most likely to undertake such investments.

19. Customers cannot reduce the monthly service fee (fixed charge) by conserving energy or by any other action other than discontinuing service entirely.

20. The marginal price methodology for determining price elasticity better reflects customers' response to changes in their energy bills from month to month as consumption varies.

21. If the tiered rate structure is flattened, high usage customers with meaningful consumption in the upper tiers can be expected to respond by increasing use. Only those customers whose usage rarely if ever exceeds the baseline quantity can be expected to reduce usage if the tier structure is flattened.

22. It is very likely that the rate design proposals of the IOUs will lead to decreased conservation and reduced investments in energy efficiency.

23. The impacts of the rate design changes on conservation could be significant, and may require increased expenditures on efficiency incentives (paid by ratepayers) if the upper tiers are reduced significantly.

24. Measuring usage-to-income correlations at the city-wide level does not provide a complete picture of the relationship between usage and income, but does provide some useful information for designing rates.

25. Low-income and moderate-income ratepayers are not universally low users of energy, but usage does tend to increase with income.

26. If utilities are not required to use a composite tier differential, rates will be essentially flat.

27. The record in this proceeding is insufficient to conclude that load shifts from TOU rates will have an impact on GHG emissions.

28. It will be valuable to future TOU rate design to further study whether TOU load shift has a significant impact on GHG.

29. If peak use is reduced, the need to build power plants to serve customers for short periods of time may also be reduced.

30. The cost of new power plants is part of the revenue requirement and this cost would be reduced if fewer new power plants are needed.

31. Currently, California has sufficient available energy resources to cover peak periods, but this could change in coming years as plants are retired and the population grows.

32. The need for investing in power plants could also increase if more flexible power is needed to support the growing amount of intermittent renewable energy.

33. If the need to build power plants is reduced by shifts in time of use, then increases in the cost of electricity may be mitigated.

34. The average peak period load reduction for default TOU participants in SMUD's study was 5.8%. Opt-in customers provided a larger average reduction of 11.9%, but, because SMUD was only able to recruit 17.5% of the targeted customers on to the opt-in TOU rate, the absolute load reduction provided by default TOU would be nearly three times greater than opt-in TOU due to the much larger number of participants.

35. The Commission has long supported time variant rates for large customers.

36. Energy costs vary by time of day.

37. Ratepayers have already invested billions of dollars in advanced metering infrastructure.

38. The investment in advanced AMI was justified by specific forecast cost savings, and supported by assumptions that AMI would be the basis for programs to assist residential customers to shift their use of energy.

39. To date, the utilities do not have significant enrollment in TOU rates, and therefore the some of the benefits of AMI technology are not optimized.

40. TOU rates can reflect the predictable changes in energy costs during the day.

41. If there is a fixed charge or minimum bill, calculating the tier differential between Tiers 1 and 2, without taking into account the fixed charge/minimum bill, can result in rates where the per kWh price customers pay while in Tier 1 is higher than the price paid in Tier 2.

42. Revenue requirement changes after 2015 are not known.

43. A 2.1% increase in revenue requirement per year does not appropriately reflect the impact on rates of years with significantly higher revenue requirement increases.

44. The evidence in this proceeding shows a meaningful correlation between income and usage.

45. Tiered rates do not incent usage shifts that reduce peak load or promote grid reliability needs, such as the need for flexible ramping resources. Likewise, time varying rates do not necessarily incent increased investment in energy efficiency.

46. A rate design that encourages both energy efficiency and load shifting is desirable and achievable.

47. Tiered rates provide a financial incentive for customers using more than the baseline quantity to invest in energy efficiency improvements and rooftop solar.

48. Low income customers seeking to reduce energy usage may not have the financial or other resources to invest in energy efficiency or rooftop solar.

49. Tiered rates promote energy efficiency and conservation, but a meaningful differential between tiers is necessary to maintain the conservation signal.

50. Programs such as CARE and FERA are designed to keep energy affordable for lower income customers.

51. A tiered rate structure can result in more volatile month-over-month electricity bills, but that volatility is what provides the conservation/efficiency price signal.

52. Determining the appropriate degree of tier inversion to maintain the conservation price signal while avoiding excessive bill volatility requires an exercise of judgment that can be informed by the history of past rate designs.

53. Rates that were too steeply tiered have caused excessive bill volatility during summer months, especially in hot, inland areas that rely on air conditioning.

54. Immediately prior to the 2001 energy crisis there were two tiers, but at times before that the rate design included three tiers.

55. Currently each IOU has four tiers.

56. A 33% tier differential is meaningful.

57. Low income customers with low usage will be harmed by a flattened tier structure.

58. There is a positive correlation between household electricity consumption and income.

59. A three-tier rate with 1:1.33:1.77 differentials meets statutory requirements and is consistent with state policy goals.

60. To minimize the rate shock, the transition from the current 4-tiered rates to three tiers that are more evenly spread must be gradual.

61. A longer transition period would allow more time for the tiers to be combined and narrowed.

62. The timing of tier consolidation has a significant impact on whether the transition to fewer tiers is consistent from year to year.

63. Customers prefer gradual rate structure changes.

64. The transition period to an end-state of three tiers at 1:1.33:1.77 should extend to 2018.

65. Tiers should not be combined all at once if the difference between the tiers would result in an unacceptable rate increase for usage in the lower tier.

66. Changes to the default rate structure must be considered holistically.

67. The baseline quantity is intended to represent a portion of the reasonable energy needs of the average residential customer by climate zone.

68. By definition, the average customer uses more electricity than the baseline quantity.

69. When lower tier rates were frozen, changes to the baseline percentage was the only means of decreasing rate impacts on higher tier customers.

70. The baseline quantity must be between 50 and 60% of average residential Consumption, and setting it at a target of 55% is reasonable.

71. Currently, Tier 1 is designed to be equal to 100% of the baseline quantity. Tier 1 is sometimes called the "baseline tier."

72. Any change in baseline quantity should take into account other rate changes proposed.

73. SDG&E's tier consolidation proposal would result in 130% of baseline usage, instead of 100%, being in Tier 1 (the baseline tier), which is undesirable and inconsistent with longstanding practice..

74. For SDG&E the baseline quantity should not be reduced.

75. Other changes to baseline quantities should be addressed outside of this proceeding.

76. Energy prices differ by season.

77. SCE and PG&E do not currently have seasonally-differentiated rates for residential customers.

78. Residential customers prefer simple rate designs and differentiating rates by season will result in a more complex rate design.

79. SDG&E seasonally differentiates its higher tier rates.

80. There is no good reason to seasonally differentiate lower tier rates at this time.

81. TOU rates align with the rate design principles to the extent that they reflect the time variation of marginal energy and capacity costs. However, TOU rates without a baseline credit could have adverse effects on customers in hot climate zones.

82. For TOU rates to be effective, customers must understand their electricity rate structure.

83. Medical baseline customers, customers requesting third-party notification pursuant to Section 779.1(c), and customers who cannot be disconnected without an in-person visit are exempt from being defaulted to a TOU rate.

84. The evidentiary record in this proceeding did not address whether there are other customer groups that should be exempt from default TOU.

85. In Section 745(c) the terms "senior citizens," "hot climate zones," and "economically vulnerable customers" are not defined.

86. Residential customers need a variety of rate options that include a combination of TOU and tiered rates in order to encourage both energy efficiency and load shifting.

87. TOU rates frequently have a mild price differential between on and off peak periods.

88. A mild price differential results in a less volatile rate.

89. A default TOU rate with a mild differential (TOU Lite) will be more acceptable to most customers than a sharply differentiated TOU rate.

90. Some residential customers may prefer a sharply differentiated rate.

91. A sharply differentiated rate will allow some customers to save more money by shifting their use.

92. Not all customers are able to shift their energy use to different time periods.

93. The beneficial effects of baseline rates can be maintained in a TOU rate structure by overlaying a baseline credit and an excess consumption surcharge.

94. Because the baseline quantity is different for each Climate Zone, a baseline credit is a way to account for a customer's energy needs by geographic location.

95. If TOU rates do not include a baseline credit and excess consumption surcharge, low usage customers may have an incentive to stay on tiered rates and high usage customers may have an incentive to move to TOU without shifting their usage.

96. One year of bill protection is required for default TOU.

97. Section 745 requires a shadow bill and a bill comparison tool.

98. A bill comparison tool is the best way for customers to understand how they would be impacted by different rate structures.

99. A bill comparison tool must reflect the individual customer's usage under different rate structures.

100. Reducing peak loads and integrating renewables are two areas in which TOU rates could be used to encourage changes in use to promote the efficiency and reliability of the grid.

101. A default TOU rate that is poorly designed could exacerbate grid reliability concerns and increase the need for certain types of generation.

102. The time periods during which shifts in load are needed will change over time.

103. Residential customers prefer stability in their rates.

104. Residential customers are likely to find default TOU periods that change frequently unacceptable.

105. Section 746(c)(3) of the Public Utilities Code encourages the Commission to approve TOU periods "that are appropriate for at least the following five years."

106. IOUs should generally set TOU periods in GRCs. The currently ongoing rate design window proceedings for PG&E and SDG&E are an exception.

107. TOU periods should be based on grid needs and customer acceptance.

108. There are many ways in which special opt-in rates could incent customer behavior that improves grid reliability.

109. The IOUs should consider a menu of TOU rates for residential customers, but all of them should include a baseline credit and excess consumption surcharge to prevent rate arbitrage, except for rates designed for switching to electricity from other more carbon-intensive fuels (e.g., EV rates), and in a limited number of pilots.

110. The IOUs should encourage each customer to switch to an optional rate that best serves the customer's usage pattern.

111. Customers who opt-in to TOU rates are more likely to reduce or shift their load than customers who are defaulted.

112. There are many programs available that promote energy efficiency. The cost of these programs is likely to increase in order to achieve the same amount of efficiency gains if tiers are flattened.

113. TOU rates will help customers align their investments with the IOUs' avoided costs.

114. The NEM tariff was "grandfathered" by D.14-12-048, but because the NEM tariff is an "overlay" rate, NEM customers will be impacted by rate changes in this proceeding.

115. Modifications to the NEM tariff are under consideration in a different proceeding.

116. NEM customers taking service under existing TOU rates may have expected that their rate structure would not change.

117. The times of day during which additional generation, or reductions in usage, are needed have changed over the last ten years.

118. TOU tariffs with outdated TOU periods should be closed to new customers.

119. Customers on TOU tariffs should be permitted to remain on them for at least five years (unless otherwise agreed to by the customer at time of enrollment).

120. Customers on PG&E's E-6, EL-6, E-7, and EL-7 rate schedules and SDG&E's TOU tariff should be permitted at least a five year transition to new TOU rates.

121. A baseline credit and excess consumption surcharge may reduce the risk of revenue shortfalls from TOU customers.

122. A TOU rate should be designed to be revenue neutral to the residential customer class.

123. At this time there is not sufficient information to accurately predict usage under default TOU and therefore a revenue shortfall is possible

124. If the TOU rate is not properly defined there is a risk of undercollection from customers on the TOU tariffs.

125. All residential customers should contribute to any revenue shortfall occurring during the transition period.

126. Opt-in TOU tariffs and TOU pilots are a source for information on TOU rates, customer acceptance, load reductions and other factors that should be considered in the design of default TOU.

127. Parties have suggested numerous aspects of TOU rates to study.

128. The majority of the suggested studies can be achieved without a default TOU pilot.

129. An opt-in TOU pilot cannot correct for self-selection bias.

130. The requirements of Section 745(d) can be met using existing data.

131. Opt-in pilots should be designed in 2015 to start in 2016.

132. The IOUs must begin the process of designing a default TOU rate promptly.

133. IOU progress toward default TOU should be carefully monitored over the next six years.

134. A collaborative process will assist the IOUs in developing an acceptable default TOU structure and menu of optional rates.

135. Because the focus in the next few years is on understanding how residential customers respond to TOU, SDG&E should not deploy DDMSF pilots at this time.

136. An opt-in TOU tariff or pilot will provide more useful data for default TOU rate design if it includes a baseline credit and excess consumption surcharge.

137. Under a volumetric rate structure, customers with extreme low usage, such as vacation home owners and NEM customers, may not contribute to the recovery of customer-related costs.

138. A minimum bill that recovers variable customer-related costs would result in more equitable rates for vacation homeowners and NEM customers.

139. A fixed charge would decrease volumetric rates.

140. A decrease in the volumetric rate is likely to reduce conservation and the payback period for investments in energy efficiency and solar.

141. Through letters to the Public Advisor's Office and at public participation hearings, customers have indicated that a fixed charge is not popular.

142. A fixed charge cannot be avoided by a customer's reducing usage or becoming more energy efficient.

143. The GRC Phase 2 allocates cost among different classes of customers to reflect cost causation.

144. Recent GRCs have usually settled the allocation of costs between classes and are therefore not useful as a basis for setting a new rate structure that was not contemplated during the GRC settlement.

145. A minimum bill to reflect variable customer-related costs will result in a more equitable rate design.

146. A fixed charge does not incent any desirable customer behavior.

147. A minimum bill would ensure that vacation homeowners and NEM customers make some contribution to the cost of the system.

148. A minimum bill will not result in a perceptible impact for customers other than owners of vacant properties and NEM customers who generate the majority of their electricity.

149. PG&E has not sufficiently justified the need to retain the ZMB.

150. PG&E's proposed Zero Minimum Bill provision may be inconsistent with Rule 18 of the Code of Conduct concerning CCAs.

151. A fixed charge designed to recover a portion of fixed costs is not consistent with marginal cost ratemaking.

152. The CARE discount was originally set at approximately 15% off otherwise applicable non-CARE rates.

153. Currently, the effective discount rates for CARE have increased to 43.2% (PG&E), 31% (SCE), and 38% (SDG&E).

154. AB 327 allows the CARE discount to be restructured provided that it results in an average effective discount between 30 – 35%.

155. Because FERA is based on the current four-tier rate structure, FERA will need to restructured when the four tiers are consolidated into three.

156. Currently, FERA customers receive a discount on usage in Tier 3.

157. The approximate current discounts received by FERA customers range from 10% to 12.5% when measured over total usage.

158. A 20% discount on all Tier 2 usage would result in a reasonable rate for FERA customers once Tiers 2 and 3 are combined.

159. Changes to the medical baseline program discount should be minimized in this proceeding.

160. ARB administers the AB 32 Cap-and-Trade program pursuant to which the state grants a direct allocation of GHG allowances to electric utilities on behalf of customers for the dual purposes of protecting customers and of advancing AB 32 objectives. The revenue from the sale of GHG allowances is returned to residential customers through a variety of means, including an off-bill volumetric return applied to upper tier usage and the California Climate Credit which is made on a per household basis to residential customers.

161. The Climate Credit currently appears as a credit on each residential customer's bill twice per year.

162. The IOUs' GHG compliance obligations result in an increase in the cost of electricity, and these increased costs are currently reflected in the rates of all customers other than residential customers.

163. Because the lower tiers were frozen, the Commission determined it was not fair for upper tier residential customers to bear all of the GHG compliance costs.

164. The lower tiers are no longer frozen so that the upper tiers no longer have to bear all of the GHG compliance costs incurred to supply residential customers with electricity.

165. If the volumetric credit is discontinued, GHG costs will be reflected in the rates of residential customers.

166. If the volumetric credit is discontinued, the amount of the semi-annual per household climate credit will increase.

167. Marketing, education and outreach for rate design changes must be robust and cost-effective.

168. In 2014, each utility provided marketing and outreach to the customers most impacted by summer 2014 rate changes.

169. The outreach model used for summer 2014 rate changes is adequate for 2015 summer rate changes.

170. After summer 2015 rate changes, the IOUs should develop a more specific and robust MEO campaign for the rate changes and pilots.

171. Without metrics that evaluate customer understanding over time it is not possible to determine if MEO is effective.

172. A robust bill comparison tool is an important part of customer education on rate options.

173. The April 2015 supplemental filing pertaining to post-2015 rate changes is useful for illustrative purposes but should not be relied on s an accurate prediction of actual rates.

174. A bill comparison tool that uses generic customer information instead of a customer's own interval data is of limited use in helping customers understand their rate options.

175. An educational outreach campaign focused on low-cost and no-cost energy efficiency options will help lower tier customers in respond to higher rates.

176. By tracking expenditures on outreach specific to the requirements of this proceeding separately, it will be easier to evaluate the costs incurred for these programs.

177. One measure of affordability is the ratio of electricity charges to customer income (electricity burden). The Commission has not adopted a specific benchmark or metric for identifying what ratio constitutes a "high" electricity burden.

178. This proceeding does not address IOU revenue requirements.

179. Decision 14-06-029, adopted in Phase 2 of this proceeding, approved interim rate change proposals for summer 2014.

Conclusions of Law

1. The legal obligation of the Commission is to establish just and reasonable rates to enable the utility to provide service that is adequate, safe and reliable for the convenience of the public.

2. The changes in rates and charges authorized by this decision are just and reasonable.

3. Pub. Util. Code Section 382(b) requires the Commission to make a finding that customers are not jeopardized or overburdened by monthly energy expenditures.

4. Pursuant to Section 745(c), the Commission may not require or authorize default TOU pricing prior to January 1, 2018.

5. Consistent with our statutory obligation to ensure that rates are affordable, it is reasonable to adopt a baseline quantity for all optional TOU rate schedules except those designed to attract switching away from fossil fuels to electricity.

6. A baseline tier is not statutorily required for default TOU rates, but inclusion of a baseline credit and excess consumption surcharge will prevent rate arbitrage and revenue shortfalls.

7. Based on record evidence, it is reasonable to conclude that customers respond to their marginal tier price.

8. We find that a residential rate structure with three tiers and a meaningful tier differential should apply to residential customers.

9. The utilities should be required to follow specific procedures, as set forth in this decision, to ensure that the glidepath to a three-tier rate structure is gradual.

10. A composite tier differential is required by law and past Commission decisions.

11. The adopted tier differentials with a composite tier and glidepath to a differential of 1:1.33:1.77 complies with the Section 739(d)(1) requirement that the Commission "establish an appropriate gradual differential between rates for the respective blocks of usage."

12. Baseline quantities should not be changed at this time, but in the next GRC each IOU should adjust its allowance to 55%.

13. A minimum bill representing a portion of the variable customer-related costs to serve the individual residential customer is reasonable.

14. Adopting a fixed charge would be contrary to the public interest and our statutory duty to ensure reasonable rates.

15. A fixed charge should not be implemented.

16. Adopting a minimum bill instead of a fixed charge is reasonable.

17. As part of their next General Rate Case Phase 2, each utility may submit testimony addressing the appropriate level of variable customer-related costs.

18. The adopted minimum bill amount should be applied to all residential rate schedules.

19. Revenues from the adopted minimum bill should be applied to reduce the volumetric rate for Tier 1.

20. The statutory limits in Section 739.9 regarding fixed charge amounts do not necessarily apply to minimum bill amounts.

21. It is reasonable to adopt minimum bill amounts consistent with the statutory limits for fixed charges

22. The CARE discount reduction glidepaths proposed by SDG&E and PG&E should be extended to 2020.

23. SDG&E's proposed line item discount method for calculating a CARE discount of 35% is consistent with Section 739(1)(c) and should be approved.

24. A FERA discount consisting of a 20% reduction in Tier 2 rates to reflect tier flattening is reasonable and should be adopted for PG&E, SDG&E and SCE once Tiers 2 and 3 have been combined.

25. The utilities' methodologies for calculating medical baseline should not be changed at this time.

26. The volumetric GHG rate offset for upper tier residential customers should be eliminated starting January 1, 2016. Beginning in 2016, GHG costs should be reflected in residential customer's electricity rates.

27. The IOUs' 2016 ERRA Forecast filings should reflect that the residential volumetric GHG rate offset will be eliminated in 2016.

28. The IOUs' proposed customer outreach plans for 2015 rate changes are reasonable and should be approved.

29. A bill comparison tool that provides individual customers with bill comparison information tailored to their individual usage is an essential piece of the long-term customer outreach program for residential rate design.

30. The IOUs should be required to develop bill comparison tools that provide individual customers with bill comparison information tailored to their individual usage.

31. An outreach and education program to promote low-cost and no-cost energy efficiency options for current Tier 1 and Tier 2 customers will improve the ability of these customers to conserve energy under new rates.

32. The long-term MEO program for residential rate design should include workshops and/or working groups, as well as regular updates to the Commission.

33. The utilities should be authorized to create memorandum accounts to track expenses for rate design outreach.

34. A three-tier rate structure, with a composite first tier, and a tier convergence glide path between 2015 and 2018 no steeper than is necessary to reach a tier differential of 1:1.33:1.77 in 2018 is reasonable and should be approved.

35. PG&E's proposed reduction of the SmartRate discount, concurrent with the combination of Tiers 2 and 3 is reasonable and consistent with the law and the RDP.

36. Each IOU should be directed to file a Tier 1 Advice Letter to create a memorandum account to track the costs of (i) TOU pilots, (ii) TOU studies, including hiring of a consultant to assist in developing study parameters, (iii) MEO costs associated with the rate changes approved in this decision, and (iv) other reasonable expenditures as required to implement this decision.

37. PG&E's request to close Schedules E-6 and EL-6 to new customers should be granted.

38. PG&E's request to eliminate Schedules E-8 and EL-8 should be approved.

39. PG&E should be authorized to offer the optional E-TOU rate schedule proposed, with the exceptions that we require a baseline credit and excess consumption surcharge, and a minimum bill in lieu of a fixed customer charge.

40. In order to provide for a gradual transition to new TOU periods and rate schedules, customers on PG&E's E-6, EL-6, E-7 and EL-7 rate schedules should be allowed to remain on those tariffs for a transition period that extends for at least five years after the respective tariff is closed to new customers.

41. PG&E's proposal to include a Zero Minimum Bill provision on all residential rate schedules should be denied.

42. We should adopt a baseline credit and/or excess consumption surcharge on default and optional TOU optional rates, except for those designed to switch the use of fossil fuels to electricity (e.g., EV rates), or in some (but not all) pilots.

43. SDG&E's proposed DDMSF for optional TOU rate schedules should not be adopted at this time.

44. Any revenue shortfall resulting from optional TOU rate schedules should be recovered from all residential customers.

45. The ten-party timeline for default TOU is not reasonable.

46. The proposed 2015 rates of PG&E, SCE, and SDG&E, as modified by this Decision, are reasonable and compliant with law and the RDP.

47. The proposed roadmap for the transition period for each of the IOUs, as set forth in this decision, is reasonable and compliant with law and the RDP.

48. The proposed 2015 rates and roadmap for the transition period, as set forth in this decision for each of the IOUs, should be adopted.

49. The IOUs should endeavor to develop more accurate energy burden and electricity burden ratios in the future.

50. An annual summit on residential rates is reasonable and will help customers, the public, the utilities, the Commission, and stakeholders better understand residential rate reform.

51. The proposed rate designs, combined with existing programs for low-income and vulnerable customers, will ensure an affordable quantity of energy is available for customer health and safety.

52. The IOUs should continue to examine ways to ensure that customer health and safety are not impaired by electricity costs.

53. A third phase of this proceeding should be opened to consider (1) interpretation of the Section 745 conditions that must be met for default TOU,

(2) requirements for supporting information and documentation for the Residential RDW applications, and (3) CARE restructuring under AB 327.

54. The new rate design proposals for PG&E, SCE, and SDG&E set forth in this decision should be adopted.

55. This order should become effective on the date issued.

O R D E R

IT IS ORDERED that:

1. The 2015 rate changes for Pacific Gas and Electric Company are approved as set forth in Section 11 of this decision.

2. The 2015 rate changes for Southern California Edison Company are approved as set forth in Section 11 of this decision.

3. The 2015 rate changes for San Diego Gas & Electric Company are approved as set forth in Section 11 of this decision.

4. Within 30 days of the date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 1 Advice letter setting forth the new residential rates adopted for 2015 with a requested effective date that is as soon as feasible. The advice letter shall include revised tariff sheets to implement the 2015 rate designs adopted in this order, subject to the conditions set forth in this decision, including the minimum bill, tier structure, and adjustments to California Alternative Rates for Energy discount. The advice letter shall include documentation sufficient to permit the Commission's Energy Division to determine if the advice letter is in compliance with this decision. The tariff sheets shall become effective on the requested effective date pending disposition

by the Commission's Energy Division and the advice letter shall prominently designate that it is "effective pending disposition."

5. The 2016 through 2018 rate design changes set forth above, including the minimum bill, tier rate structure, and modifications to California Alternative Rates for Energy, are approved subject to the conditions set forth in this decision.

6. Rate changes authorized by this decision and made after summer 2015 must be coordinated with other residential rate change filings.

7. Pacific Gas and Electric Company is directed to file a residential rate design window (RDW) application no later than January 1, 2018 proposing a default time-of-use rate for residential customers. The RDW application must be consistent with this decision and include information and documentation reasonably sufficient to support the proposed rate.

8. San Diego Gas & Electric Company is directed to file a residential rate design window (RDW) application no later than January 1, 2018 proposing a default time-of-use rate for residential customers. The RDW application must be consistent with this decision and include information and documentation reasonably sufficient to support the proposed rate.

9. Southern California Electric Company is directed to file a residential rate design window (RDW) application no later than January 1, 2018 proposing a default TOU rate for residential customers. The RDW application must be consistent with this decision and include information and documentation reasonably sufficient to support the proposed rate.

10. Within 30 days of the date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must each file a Tier 1 Advice letter establishing a new memorandum account to track costs associated with time-of-use rate design, and pilot and

study design, including marketing, education and outreach specific to time-of-use rates and other rates required by this decision.

11. Within 30 days of the date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must initiate the process of forming a working group to address the issues regarding time-of-use rate design and study as detailed in this decision, and as modified or revised during Phase 3 of this proceeding.

12. Within 30 days of the date of this decision, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) must collectively provide Energy Division staff with proposed dates for the November 2015 Residential Electricity Rates Summit. Each of PG&E, SCE, and SDG&E is required to prepare and present materials at the Residential Electricity Rates Summit as directed by Energy Division staff, the assigned Administrative Law Judge, or the assigned Commissioner, as applicable.

13. Within 30 days of the date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must collectively organize and host a workshop to formalize the procedure for quarterly progress reports and future semi-annual Progress on Residential Rate Reform workshops.

14. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Gas Company, and Southern California Edison Company shall mutually agree and select one utility to hire a qualified consultant to assist with the design and implementation of time-of-use pilots and studies. The utilities must obtain concurrence on the selection from other members of any

working group formed as part of this proceeding to develop the pilot and study design.

15. The residential volumetric greenhouse gas rate offset must be discontinued starting January 1, 2016. The revenue return allocated to the residential class will consist solely of the semi-annual California Climate Credit.

16. The assigned Commissioner and assigned Administrative Law Judge are authorized to take all procedural steps promote the objectives in this decision and to provide clarification and direction as required to assure the effective, fair and efficient implementation of this decision in this proceeding.

17. All outstanding motions and requests in this proceeding that are not specifically addressed in this decision are denied.

18. A prehearing conference for Phase 3 will be scheduled as soon as practicable after the adoption of this decision.

19. Rulemaking 12-06-013 shall remain open.

This order is effective today.

Dated ____________________________, at San Francisco, California.

ATTACHMENT A

Acronym List

ATTACHMENT A

ACRONYM LIST

AB	Assembly Bill
ACR	Assigned Commissioner Ruling
ALJ	Administrative Law Judge
AMI	Advanced metering infrastructure
ARB	Air Resources Board
BQ	Baseline Quantity
CAISO	California Independent System Operators
CALSEIA	California Solar Energy Industries Association
CARE	California Alternate Rates for Energy
CCA	Community Choice Aggregation
CEC	California Energy Commission
CforAT	Center for Accessible Technology
CPI	Consumer Price Index
CSE	Center for Sustainable Energy
CSI	California Solar Initiative
DDMSF	Demand Differential Monthly Service Fee
DG	Distributed Generation
DR	Demand Response
DWR	Department of Water Resources
EDF	Environmental Defense Fund
EE	Energy Efficiency
EH	Evidentiary Hearing
EPA	Environmental Protection Agency
EPMC	Equal Percentage of Marginal Cost
ERRA	Energy Resource Recovery Account
ESA	Energy Savings Assistance
EV	Electric Vehicle
FERA	Family Electric Rate Assistance
GHG	Greenhouse Gas
GRC	General Rate Case
IEPR	Integrated Energy Policy Report
IOUs	Investor Owned Utility
IREC	Interstate Renewable Energy Council
kWh	Kilowatt hour
LINA	Low Income Needs Assessment
LTPP	Long-Term Procurement dockets
MCE	Marin Clean Energy
MEO	Marketing, education, and outreach

MWh	Megawatt hour
NEM	Net Energy Metering
NRDC	Natural Resources Defense Council
OEB	Ontario Energy Board
OIR	Order Instituting Rulemaking
ORA	Office of Ratepayer Advocates
PCIA	Power Charge Indifference Adjustment
PHC	Prehearing conference
PPA	Power purchase agreement
PPH	Public Participation Hearing
PRRR	Progress on Residential Rate Reform
RAR	Residential Average Rate
RASS	Residential Appliance Saturation Study
RDP	Rate Design Proposals
RDW	Rate Design Windows
RERS	Residential Electric Rate Summit
SB	Senate Bill
SDCAN	San Diego Consumers' Action Network
SEIA	Solar Energy Industry Association
SGIP	Self-Generation Incentive Program
SMUD	Sacramento Municipal Utility District
SPO	SmartPricing Option
SRP	Salt River Project
TASC	The Alliance for Solar Choice
TOU	Time of Use
TURN	The Utility Reform Network
UCAN	Utility Consumers' Action Network
WECC	Western Electricity Coordinating Council
ZMB	Zero Minimum Bill

(End of Attachment A)

ATTACHMENT B

2015 Expected Revenue Requirement Changes

ATTACHMENT B

2015 Expected Revenue Requirement Changes

PG&E 2015 Residential Rate Changes [1]

	Date	Description	Residential Class Average Rate (cents/kWh)**
1.	January 1, 2015	Annual Electric True-Up Filing, to consolidate previously-approved CPUC and FERC revenue requirement changes (including PG&E's 2014 ERRA Forecast approved in D.14-12-053), and also including the recovery of balances in balancing accounts previously approved for amortization in 2015. (Resolution E-4693, approving Advice 4484-E and Advice 4484-E-A	18.9
2.	March 1, 2015	Consolidated rate changes including (a) FERC-approved decrease to TACBAA rate; (b) FERC-approved increase to TO rates; (c) amortizing year-end 2014 balances in rates approved in Resolution E-4693; and (d) deferring implementation of Schedules AG-R and AG-V (Advice Letter 4596-E).	19.1

** Excludes Climate Credit.

[1] PG&E Supplemental Filing April 14, 2015, at 2.

SCE 2015 Residential Rate Changes[2]

	Date	Description	Residential Class Average Rate (cents/kWh)**
1.	January 1, 2015	Implementation of authorized residential rate changes (Advice Letter 3155-E)	17.04
2.	March 2, 2015	Implementation of GHG allowance revenue to EITE customers (Advice Letter 3178-E)	17.13
3.	June 1, 2015 (Earliest Anticipated)	Anticipated implementation of revenue requirement changes pursuant to 2015 ERRA Forecast (A.14-06-011)	18.66
4.	Q3 2015 (Anticipated)	Anticipated implementation of revenue requirement changes pursuant to 2015 GRC Phase 1 (A.13-11-003) and access to SCE's Nuclear Decommissioning Trust (D.14-11-040, Advice Letter 3193-E).	18.56

** Excludes Climate Credit.

[2] SCE Supplemental Filing April 14, 2015, at 3.

SDG&E 2015 Residential Rate Changes[3]

	Date	Description	Residential Class Average Rate (cents/kWh)**
1.	January 1, 2015***	The rates reflect the implementation of the SDG&E's Consolidated Advice Letter Filing, AL-2685-E, which implements the electric rate adjustments authorized by the CPUC and filed at the FERC through advice letters or decisions effective January 1, 2015.	23.2
2.	February 1, 2015***	Implementation of Advice Letter 2695-E for rates effective February 1, 2015: In compliance with Ordering Paragraph ("OP") 2 of the California Public Utilities Commission ("Commission") Decision ("D.") 15-01-004 approved on January 15, 2015, SDG&E is filing this advice letter to adopt its 1) 2015 Energy Resource Recovery Account ("ERRA") revenue requirement; 2) Ongoing Competition Transition Charge ("CTC") revenue requirement; 3) Local Generation ("LG") revenue requirement, and 4) 2015 vintaged Power Charge Indifference Adjustment ("PCIA") rates.	23.1
3.	GHG****	Implementation of SDG&E's 2015 Greenhouse Gas Revenue and Reconciliation Application (2015 GHG) (A.14-04-018). The rates presented reflect the anticipated impacts of SDG&E's revised updated application as filed which assumed an implementation date of April 1, 2015 without amortization resulting in an incremental increase in revenue requirement of $28 million. On March 26, 2015, CPUC approved SDG&E's 2015 GHG that includes a reduced amortization period from implementation to year-end. As a result, SDG&E anticipates a May 1 implementation, which would mean an 8-month amortization period. Therefore the actual rates reflecting SDG&E's implementation of its 2015 GHG will differ from the rates reflected in these scenarios.	23.4
4.	GHG + ERRA****	Potential ERRA Trigger filing. Currently SDG&E's ERRA Balancing Account is excess of the trigger threshold amount of $82 million. Preliminary estimates of the year-end balance are $90 million. This assumes that SDG&E does not receive funds from the Nuclear Decommissioning Trust Fund that would be used to offset the existing balances in this account as permitted under the SONGS Settlement Agreement approved by the Commission in D.14-11-040. In the event that SDG&E receives the funds from the Nuclear Decommissioning Trust Fund, based on preliminary estimates SDG&E anticipates the balance in the ERRA Balancing Account would then be reduced to below the trigger threshold at which time there would be no need to request recovery of the outstanding balance.	23.8

** Excludes Climate Credit.

[3] SDG&E Supplemental Filing April 14, 2015, Appendix C.

*** Represents SDGE's Rate Changes since May 1, 2014 through current rates effective February 1, 2015.
**** Projected Residential Average Rates that reflect the assumptions presented in SDG&E's April 1 response.

(End of Attachment B)

ATTACHMENT C

SERVICE LIST

************** SERVICE LIST *************
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************* **PARTIES** *************

Jamie Mauldin
ADAMS BROADWELL JOSEPH & CARDOZO, PC
601 GATEWAY BLVD., STE. 1000
SOUTH SAN FRANCISCO CA 94080
(650) 589-1660
jmauldin@adamsbroadwell.com
For: Coalition of California Utility Employees (CCUE)

Nora Sheriff, Attorney
ALCANTAR & KAHL
EMAIL ONLY CA 00000
(415) 721-4143
nes@a-klaw.com
For: California Large Energy Consumers Assoc./Energy Producers Users Coalition

---

Len Canty, Chairman
BLACK ECONOMIC COUNCIL
484 LAKE PARK AVE., SUITE 338
OAKLAND CA 94610
(510) 452-1337
For: Black Economic Council

Scott Blaising
BRAUN BLAISING MCLAUGHLIN P.C.
EMAIL ONLY CA 00000
(916) 682-9702
blaising@braunlegal.com
For: Local Energy Aggregation Network

Margie Gardner
CAL. ENERGY EFFICIENCY INDUSTRY COUNCIL
EMAIL ONLY CA 00000
(916) 390-6413
policy@efficiencycouncil.org
For: California Energy Efficiency Industry Council

Karen Norene Mills, Assoc. Counsel - Legal Svcs. Div.
CALIFORNIA FARM BUREAU FEDERATION
2300 RIVER PLAZA DRIVE
SACRAMENTO CA 95833
(916) 561-5655
kmills@cfbf.com
For: California Farm Bureau Federation

Jordan Pinjuv
Counsel
CALIFORNIA ISO
250 OUTCROPPING WAY
FOLSOM CA 95630
(916) 351-4429
jpinjuv@caiso.com
For: California Independent System Operator Corporation (CAISO)

Brad Heavner
CALIFORNIA SOLAR ENERGY INDUSTRIES ASSN.
EMAIL ONLY CA 00000
(415) 328-2683
brad@calseia.org
For: California Solar Energy Industries Association (CALSEIA)

Melissa W. Kasnitz
CENTER FOR ACCESSIBLE TECHNOLOGY
3075 ADELINE STREET, SUITE 220
BERKELEY CA 94703
(510) 841-3224 X2019
service@cforat.org
For: Center for Accessible Technology

Sachu Constantine
CENTER FOR SUSTAINABLE ENERGY
EMAIL ONLY CA 00000
(858) 244-1177
sachu.constantine@energycenter.org
For: Center For Sustainable Energy

Cathy Zhang, Executive Director
CHINESE AM. INSTITUTE FOR EMPOWERMENT
15 SOUTHGATE AVE., STE. 200
DALY CITY CA 94015
(650) 952-0522
cathy.zhang@soundofhope.org
For: Chinese American Institute for Empowerment (jt. party)

Eric Eisenhammer
COALITION OF ENERGY USERS
4010 FOOTHILLS BLVD., STE 103 NO. 115
ROSEVILLE CA 95747
(916) 833-9276
Eric@CoalitionofEnergyUsers.org
For: Coalition of Energy Users

************** SERVICE LIST *************
Last Updated on 21-APR-2015 by: AMT
R1206013 LIST

Donald P. Hilla
CONSUMER FEDERATION OF CALIFORNIA
EMAIL ONLY
EMAIL ONLY CA 00000
dhilla@consumercal.org
For: Consumer Federation of California

Vidhya Prabhakaran
DAVIS WRIGHT & TREMAINE LLP
505 MONTGOMERY STREET, SUITE 800
SAN FRANCISCO CA 94111
(415) 276-6568
VidhyaPrabhakaran@dwt.com
For: California Pacific Electric Company, LLC

Brad Bordine
DISTRIBUTED ENERGY CONSUMER ADVOCATES
516 WHITEWOOD DRIVE
SAN RAFAEL CA 94903
(213) 784-2507
b.bordine@d-e-c-a.org
For: Distributed Energy Consumer Advocates

Bob Dodds
933 ELOISE AVENUE
SOUTH LAKE TAHOE CA 96150
(530) 541-5780
Bob.Dodds@liberty-energy.com
For: California Pacific Electric Company, LLC

Daniel W. Douglass
Attorney
DOUGLASS & LIDDELL
21700 OXNARD ST., STE. 1030
WOODLAND HILLS CA 91367
(818) 961-3001
douglass@energyattorney.com
For: Western Power Trading Forum/Alliance for Retail Energy Markets/Direct Accesss Custoner Coalition

---

Donald C. Liddell
DOUGLASS & LIDDELL
2928 2ND AVENUE
SAN DIEGO CA 92103
(619) 993-9096
liddell@energyattorney.com
For: California Energy Storage Alliance (CESA)

Mark E. Whitlock, Jr., Exe. Dir.
ECUMENICAL CTR. FOR BLACK CHURCH STUDIES
46 MAXWELL ST
IRVINE CA 92618
(949) 955-0014
MarkW@CORChurch.org
For: Ecumenical Center for Black Church Studies (jt. party)

Chris Cone, Policy Manager
EFFICIENCY FIRST CALIFORNIA
1000 BROADWAY, STE. 435
OAKLAND CA 94607
(510) 899-9773
chris@efficiencyfirstca.org
For: Efficiency First California

Chase Kappel
ELLISON SCHNEIDER & HARRIS, LLP
2600 CAPITOL AVE., SUITE 400
SACRAMENTO CA 95816
(916) 447-2166
cbk@eslawfirm.com
For: Vote Solar

Jamie Fine, Sr. Economist
ENVIRONMENTAL DEFENSE FUND
123 MISSION ST., 28TH FLOOR
SAN FRANCISCO CA 94105
(415) 293-6060
jfine@edf.org
For: Environmental Defense Fund

Nguyen Quan, Mgr - Regulatory Affairs
GOLDEN STATE WATER CO. - ELECTRIC OP.
630 EAST FOOTHILL BOULEVARD
SAN DIMAS CA 91773
(909) 394-3600 X664
nguyen.quan@gswater.com
For: Golden State Water Company

Brian Cragg, Attorney
GOODIN, MACBRIDE, SQUERI, DAY & LAMPREY
505 SANSOME STREET, SUITE 900
SAN FRANCISCO CA 94111
(415) 392-7900
BCragg@GoodinMacbride.com
For: Independent Energy Producers Association

************** SERVICE LIST *************
Last Updated on 21-APR-2015 by: AMT
R1206013 LIST

Jeanne Armstrong
Attorney At Law
GOODIN, MACBRIDE, SQUERI, DAY & LAMPREY
505 SANSOME STREET, SUITE 900
SAN FRANCISCO CA 94111
(415) 392-7900
jarmstrong@goodinmacbride.com
For: Solar Energy Industries Association

Gregory Heiden
Legal Division
505 Van Ness Avenue, RM. 5039
San Francisco CA 94102 3298
(415) 355-5539
gxh@cpuc.ca.gov
For: ORA

Jason B. Keyes, Counsel
KEYES FOX & WEIDMAN LLP
436 14TH STREET, STE. 1305
OAKLAND CA 94612
(510) 314-8203
jkeyes@kfwlaw.com
For: Interstate Renewable Energy Council, Inc.

David Wooley, Of Counsel
KEYES FOX & WEIDMAN, LLP
436 14TH STREET, STE. 1305
OAKLAND CA 94612
(510) 314-8207
dwooley@kfwlaw.com
For: SolarCity Corporation

Tim Lindl, Counsel
KEYES FOX & WIEDMAN LLP
436 14TH STREET, STE. 1305
OAKLAND CA 94612
(510) 314-8385
TLindl@kfwlaw.com
For: The Alliance for Solar Choice

Kevin T. Fox
KEYES FOX & WIEDMAN, LLP
436 14TH STREET, SUITE 1305
OAKLAND CA 94612
(510) 314-8201
kfox@kfwlaw.com
For: Sunrun, Inc.

Chairman / President
LAT. BUS. CHAMBER OF GREATER L.A.
634 S. SPRING STREET, STE 600
LOS ANGELES CA 90014
(213) 347-0008
info@lalcc.org
For: Latino Business Chamber of Greater Los Angeles

Andy Katz
LAW OFFICES OF ANDY KATZ
2150 ALLSTON WAY , STE. 400
BERKELEY CA 94704
(510) 848-5001
andykatz@sonic.net
For: Sierra Club

Elizabeth Kelly
Legal Director
MARIN CLEAN ENERGY
EMAIL ONLY CA 00000
(415) 464-6022
Ekelly@mceCleanEnergy.org
For: Marin Energy Energy

Sara Steck Myers
Attorney At Law
122 28TH AVENUE
SAN FRANCISCO CA 94121
(415) 387-1904
ssmyers@att.net
For: Center for Energy Efficiency and Renewable Technology

Faith Bautista, President / Ceo
NATIONAL ASIAN AMERICAN COALITION
15 SOUTHGATE AVE, STE. 200
DALY CITY CA 94015
(650) 953-0522
Faith.MabuhayAlliance@gmail.com
For: National Asian American Coalition

Sheryl Carter
NATURAL RESOURCES DEFENSE COUNCIL
111 SUTTTER ST., 20TH FLR.
SAN FRANCISCO CA 94104-4540
(415) 875-6117
scarter@nrdc.org
For: Natural Resources Defense Council

************ SERVICE LIST ***********
Last Updated on 21-APR-2015 by: AMT
R1206013 LIST

Christopher J. Warner
PACIFIC GAS AND ELECTRIC COMPANY
LAW DEPT.
77 BEALE STREET, MC B30A, RM 3145
SAN FRANCISCO CA 94105
(415) 973-6695
CJW5@pge.com
For: Pacific Gas and Electric Company

Sarah Wallace
Senior Attorney
PACIFICORP
825 NE MULTNOMAH, STE. 1800
PORTLAND OR 97232
(503) 813-5865
sarah.wallace@pacificorp.com
For: PacifiCorp

Michael Shames
SAN DIEGO CONSUMERS' ACTION NETWORK
6975 CAMINO AMERO
SAN DIEGO CA 92111
(619) 393-2224
michael@SanDiegoCAN.org
For: San Diego Consumers' Action Network

Thomas R. Brill, Sr Counsel & Director
SAN DIEGO GAS & ELECTRIC COMPANY
8330 CENTURTY PARK CT., CP32E
SAN DIEGO CA 92123-1530
(858) 654-1601
TBrill@SempraUtilities.com
For: San Diego Gas & Electric Company (SDG&E)

Tim Mcrae
SILICON VALLEY LEADERSHIP GROUP
2001 GATEWAY PLACE, STE. 101 E
SAN JOSE CA 95110
(408) 501-7864
TMcRae@svlg.org
For: Silicon Valley Leadership Group

Fadia Khoury
SOUTHERN CALIFORNIA EDISON COMPANY
EMAIL ONLY CA 00000
fadia.khoury@sce.com
For: Southern California Edison Company

Stephanie C. Chen
THE GREENLINING INSTITUTE
EMAIL ONLY
EMAIL ONLY CA 00000
(510) 898-0506
stephaniec@greenlining.org
For: The Greenlining Institute

Hayley Goodson
Staff Attorney
THE UTILITY REFORM NETWORK
785 MARKET ST., STE. 1400
SAN FRANCISCO CA 94103
(415) 929-8876
hayley@turn.org
For: TURN

Donald Kelly
Exe. Dir.
UTILITY CONSUMERS' ACTION NETWORK
3405 KENYON STREET, SUITE 401
SAN DIEGO CA 92110
(619) 610-9001
don@ucan.org
For: Utility Consumers' Action Network (UCAN)

********** **STATE EMPLOYEE** ***********

Amy C. Baker
Executive Division
RM. 5210
505 Van Ness Avenue
San Francisco CA 94102 3298
(415) 703-1691
ab1@cpuc.ca.gov

Nathan Barcic
Energy Division
505 Van Ness Avenue
San Francisco CA 94102 3298
(415) 703-2357
nb1@cpuc.ca.gov

Lynn Marshall
CALIFORNIA ENERGY COMMISSION
1516 9TH STREET, MS-20
SACRAMENTO CA 95814
(916) 654-4767
Lynn.Marshall@Energy.Ca.Gov

************** SERVICE LIST *************
Last Updated on 21-APR-2015 by: AMT
R1206013 LIST

Patrick Saxton
Advisor To Comm. Andrew Mcallister
CALIFORNIA ENERGY COMMISSION
1516 NINTH ST., MS-37
SACRAMENTO CA 95814
(916) 651-0489
patrick.saxton@energy.ca.gov

Matthew Tisdale
CALIFORNIA PUBLIC UTILITIES COMMISSION
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 703-5137
MWT@cpuc.ca.gov

Patrick Doherty
CALIFORNIA PUBLIC UTILITIES COMMISSION
EMAIL O NLY
EMAIL ONLY CA 00000
(415) 703-5032
pd1@cpuc.ca.gov

Shannon O'Rourke
CALIFORNIA PUBLIC UTILITIES COMMISSION
ENERGY
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 703-5574
shannon.o'rourke@cpuc.ca.gov

Tim Drew
CALIFORNIA PUBLIC UTILITIES COMMISSION
EMAIL ONLY
EMAIL ONLY CA 00000
tim.drew@cpuc.ca.gov

Tory Francisco
CALIFORNIA PUBLIC UTILITIES COMMISSION
ENERGY DIVISION - RESIDENTIAL PROGRAMS
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 703-2743
tnf@cpuc.ca.gov

Whitney Richardson
CALIFORNIA PUBLIC UTILITIES COMMISSION
ENERGY DIVISION - RETAIL RATES
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 703-2108
whitney.richardson@cpuc.ca.gov

Zaida C. Amaya
CALIFORNIA PUBLIC UTILITIES COMMISSION
ENERGY DIVISION - RESIDENTIAL PROGRAMS
EMAIL ONLY
EMAIL ONLY CA 00000
(916) 928-4702
zaida.amaya@cpuc.ca.gov

Noel Obiora
Attorney
CPUC
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 355-5539
noel.obiora@cpuc.ca.gov

Paul S. Phillips
CPUC
ENERGY DIV
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 703-1786
Paul.Phillips@cpuc.ca.gov

Scott Murtishaw
CPUC - EXEC DIV
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 703-5863
SGM@cpuc.ca.gov

Ravneet Kaur
Regulatory Analyst
CPUC - PUBLIC ADVISOR'S OFFICE
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 703-1972
Ravneet.Kaur@cpuc.ca.gov

Cherie Chan
Office of Ratepayer Advocates
505 Van Ness Avenue, RM. 4209
San Francisco CA 94102 3298
(415) 703-1779
cyc@cpuc.ca.gov

Elizabeth Curran
Energy Division
505 Van Ness Avenue, AREA 4-A
San Francisco CA 94102 3298
(415) 703-1101
ec7@cpuc.ca.gov

**************** SERVICE LIST ***************
Last Updated on 21-APR-2015 by: AMT
R1206013 LIST

Christopher Danforth
Office of Ratepayer Advocates
RM. 4209
505 Van Ness Avenue
San Francisco CA 94102 3298
(415) 703-1481
ctd@cpuc.ca.gov

Syreeta Gibbs
Energy Division
AREA 4-A
505 Van Ness Avenue
San Francisco CA 94102 3298
(415) 703-1622
syg@cpuc.ca.gov

Julie Halligan
Administrative Law Judge Division
RM. 5041
505 Van Ness Avenue
San Francisco CA 94102 3298
(415) 703-1587
jmh@cpuc.ca.gov

Valerie Kao
Safety and Enforcement Division
505 Van Ness Avenue
San Francisco CA 94102 3298
(415) 703-1341
vuk@cpuc.ca.gov

Dexter E. Khoury
Office of Ratepayer Advocates
RM. 4209
505 Van Ness Avenue
San Francisco CA 94102 3298
(415) 703-1200
bsl@cpuc.ca.gov

Michele Kito
Energy Division
505 Van Ness Avenue, AREA 4-A
San Francisco CA 94102 3298
(415) 703-2197
mk1@cpuc.ca.gov

Robert Levin
Energy Division
505 Van Ness Avenue, RM. 4102
San Francisco CA 94102 3298
(415) 703-1862
rl4@cpuc.ca.gov

Jeanne McKinney
Administrative Law Judge Division
RM. 5011
505 Van Ness Avenue
San Francisco CA 94102 3298
(415) 703-2550
jmo@cpuc.ca.gov

Rajan Mutialu
Office of Ratepayer Advocates
AREA 4-A
505 Van Ness Avenue
San Francisco CA 94102 3298
(415) 703-2039
rm3@cpuc.ca.gov

Gabriel Petlin
Energy Division
AREA 4-A
505 Van Ness Avenue
San Francisco CA 94102 3298
(415) 703-1677
gp1@cpuc.ca.gov

Sean A. Simon
Energy Division
AREA 4-A
505 Van Ness Avenue
San Francisco CA 94102 3298
(415) 703-3791
svn@cpuc.ca.gov

Devla Singh
Communications Division
505 Van Ness Avenue, AREA 3-F
San Francisco CA 94102 3298
(415) 703-5581
dsc@cpuc.ca.gov

Stephen St. Marie
Policy & Planning Division
505 Van Ness Avenue, RM. 5119
San Francisco CA 94102 3298
(415) 703-5173
sst@cpuc.ca.gov

Lee-Whei Tan
Office of Ratepayer Advocates
505 Van Ness Avenue, RM. 4102
San Francisco CA 94102 3298
(415) 703-2901
lwt@cpuc.ca.gov

************** SERVICE LIST *************
Last Updated on 21-APR-2015 by: AMT
R1206013 LIST

Ava N. Tran
Energy Division
AREA 4-A
505 Van Ness Avenue
San Francisco CA 94102 3298
(415) 703-2887
atr@cpuc.ca.gov

Karen Camille Watts-Zagha
Office of Ratepayer Advocates
RM. 4104
505 Van Ness Avenue
San Francisco CA 94102 3298
(415) 703-2881
kwz@cpuc.ca.gov

Dan Willis
Office of Ratepayer Advocates
RM. 4104
505 Van Ness Avenue
San Francisco CA 94102 3298
(415) 703-2384
dw1@cpuc.ca.gov

Marzia Zafar
Policy & Planning Division
505 Van Ness Avenue, RM. 5119
San Francisco CA 94102 3298
(415) 703-1997
zaf@cpuc.ca.gov

Zhen Zhang
Executive Division
505 Van Ness Avenue, RM. 5102
San Francisco CA 94102 3298
(415) 703-2624
zz1@cpuc.ca.gov

********* **INFORMATION ONLY** **********

Marc D. Joseph
ADAMS BROADWELL JOSEPH & CARDOZO
601 GATEWAY BLVD., SUITE 1000
SOUTH SAN FRANCISCO CA 94080
(650) 589-1660
mdjoseph@adamsbroadwell.com

Evelyn Kahl
Counsel
ALCANTAR & KAHL
EMAIL ONLY CA 00000
(415) 403-5542
ek@a-klaw.com

Karen Terranova
ALCANTAR & KAHL
EMAIL ONLY
EMAIL ONLY CA 00000-0000
(415) 403-5542
filings@a-klaw.com

Stephen M. Barrager
BAKER STREET PUBLISHING, LLC
2703 BRODERICK STREET
SAN FRANCISCO CA 94123
(650) 504-1578
steve@bakerstreetpublishing.com

Barbara Barkovich
BARKOVICH & YAP
EMAIL ONLY
EMAIL ONLY CA 00000
(707) 937-6203
barbara@barkovichandyap.com

Cathy Yap
BARKOVICH & YAP, INC.
EMAIL ONLY
EMAIL ONLY CA 00000
(510) 450-1270
Cathy@BarkovichAndYap.com

James Barsimantov
EMAIL ONLY
EMAIL ONLY CA 00000
jbarsimantov@ecoshift.com

Nicole Wright
BRAUN BLAISING MCLAUGHLIN & SMITH
915 L STREET, SUITE 1270
SACRAMENTO CA 95814
(916) 326-5812
nicole@braunlegal.com

Justin Wynne
Attorney
BRAUN BLAISING MCLAUGHLIN & SMITH, P.C.
915 L STREET, SUITE 1270
SACRAMENTO CA 95814
(916) 326-5812
wynne@braunlegal.com
For: California Municipal Utilities Association (CMUA)

************** SERVICE LIST *************
Last Updated on 21-APR-2015 by: AMT
R1206013 LIST

Eli Harland
CALIFORNIA ENERGY COMMISSION
ENERGY RESEARCH & DEVELOPMENT DIV.
EMAIL ONLY
EMAIL ONLY CA 00000
(916) 327-1463
Eli.Harland@energy.ca.gov

CALIFORNIA ENERGY MARKETS
425 DIVISADERO ST STE 303
SAN FRANCISCO CA 94117-2242
(415) 552-1764
cem@newsdata.com

CALIFORNIA PACIFIC ELECTRIC COMPANY, LLC
933 ELOISE AVENUE
SOUTH LAKE TAHOE CA 96150
(530) 546-1720
cpuc@libertyutilities.com

Matthew Barmack
Dir. - Market & Regulatory Analysis
CALPINE CORPORATION
4160 DUBLIN BLVD., SUITE 100
DUBLIN CA 94568
(925) 557-2267
BarmackM@calpine.com

Andrew Gay
CARLSON CAPITAL L.P.
712 FIFTH AVE., 25 TH FLOOR
NEW YORK NY 10019
(212) 994-8324
agay@carlsoncapital.com

Danielle Osborn Mills
Policy Director
CEERT
1100 11TH STREET, SUITE 311
SACRAMENTO CA 95814
(916) 320-7584
danielle@ceert.org

David Miller
CEERT
1100 ELEVENTH ST., SUITE 311
SACRAMENTO CA 95814
(916) 442-7785
david@ceert.org

Benjamin Airth
CENTER FOR SUSTAINABLE ENERGY
EMAIL ONLY
EAMIL ONLY CA 00000-0000
(858) 244-1194
benjamin.airth@energycenter.org

Jack Clark
CENTER FOR SUSTAINABLE ENERGY
EMAIL ONLY
EMAIL ONLY CA 00000
jack.clark@energycenter.org

Paul D. Hernandez
CENTER FOR SUSTAINABLE ENERGY
EMAIL ONLY
EMAIL ONLY CA 00000
(858) 244-1190
paul.hernandez@energycenter.org

Sephra A. Ninow, J.D.
Regulatory Affairs Mgr.
CENTER FOR SUSTAINABLE ENERGY
EMAIL ONLY
EMAIL ONLY CA 00000
(858) 244-1177
sephra.ninow@energycenter.org

Stephanie Wang
Sr. Policy Regulatory Attorney
CENTER FOR SUSTAINABLE ENERGY
426 17TH STREEET, SUITE 700
OAKLAND CA 94612
(415) 659-9958
stephanie.wang@energycenter.org

Terry Clapham
CENTER FOR SUSTAINABLE ENERGY
EMAIL ONLY
EMAIL ONLY CA 00000-0000
(858) 244-4872
terry.clapham@energycenter.org

Timothy Treadwell
CENTER FOR SUSTAINABLE ENERGY
EMAIL ONLY CA 00000
timothy.treadwell@energycenter.org

Hanna Grene
CENTER FOR SUSTAINBLE ENERGY
EMAIL ONLY CA 00000
hanna.grene@energycenter.org

Janette Olko
Electric Utility Division Manager
CITY OF MORENO VALLEY
14325 FREDERICK ST., STE. 9
MORENO VALLEY CA 92552
(951) 413-3502
jeannetteo@moval.org

Curt Barry
Senior Writer
CLEAN ENERGY REPORT
717 K STREET, SUITE 503
SACRAMENTO CA 95814
(916) 449-6171
cbarry@iwpnews.com

Francois Carlier
CODA STRATEGIES
EMAIL ONLY
EMAIL ONLY CA 00000
carlierfrancois@yahoo.fr

Nicole Johnson, Regulatory Attorney
CONSUMER FEDERATION OF CALIFORNIA
150 POST ST., STE. 442
SAN FRANCISCO CA 94108
(415) 597-5707
njohnson@consumercal.org

Patrick Jobin
CREDIT SUISSE SECURITIES (USA) LLC
ONE MADISON AVENUE
NEW YORK NY 10010
(212) 325-0843
patrick.jobin@credit-suisse.com

Tom Beach
CROSSBORDER ENERGY
2560 NINTH STREET, SUITE 213A
BERKELEY CA 94710
(510) 549-6922
tomb@crossborderenergy.com

DAVIS WRIGHT & TREMAINE LLP
EMAIL ONLY CA 00000
dwtcpucdockets@dwt.com

Ann Trowbridge, Attorney
DAY CARTER & MURPHY LLP
3620 AMERICAN RIVER DR., STE. 205
SACRAMENTO CA 95864
(916) 246-7303
ATrowbridge@DayCarterMurphy.com

Dan Delurey
DEMAND RESPONSE AND SMART GRID COALITION
1301 CONNECTICUT AVE., NW, STE. 350
WASHINGTON DC 20036
(202) 296-3636
dan.delurey@drsgcoalition.org
For: Demand Response and Smart Grid Coalition

Lauren Duke
DEUTSCHE BANK SECURITIES INC.
EMAIL ONLY
EMAIL ONLY NY 00000
(212) 250-8204
lauren.duke@db.com

Nat Treadway
DISTRIBUTED ENERGY FINANCIAL GROUP
EMAIL ONLY
EMAIL ONLY TX 00000
(713) 729-6244
ntreadway@defgllc.com

Cassandra Sweet
Reporter
DOW JONES NEWSWIRES
201 CALIFORNIA ST.
SAN FRANCISCO CA 94111
(415) 439-6468
cassandra.sweet@dowjones.com

Paul M. Pietsch
Research Coordinator
DRSG COALITION
1301 CONNECTICUT AVE., NW, STE. 350
WASHINGTON DC 20036
(202) 296-3636
paul.pietsch@drsgcoalition.org

Anadelia Chavarria
EDISON INTERNATIONAL
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770
(626) 302-1496
anadelia.chavarria@edisonintl.com

Belinda Dela Cruz
EDISON INTERNATIONAL
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770
(626) 302-3548
belinda.delacruz@edisonintl.com

************ SERVICE LIST ***********
Last Updated on 21-APR-2015 by: AMT
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Felicia Willliams
Senior Manager, Investor Relations
EDISON INTERNATIONAL
2244 WALNUT FROVE, GO1 ROOM 445
ROSEMEAD CA 91770
(626) 302-5493
felicia.williams@edisonintl.com

Spencer Edmiston
Corporate Financial Planning
EDISON INTERNATIONAL
2244 WALNUT GROVE AVENUE
ROSEMEAD CA 91770
(626) 302-2001
spencer.edmiston@edisonintl.com

Andrew Brown
ELLISON SCHNEIDER & HARRIS LLP
EMAIL ONLY
EMAIL ONLY CA 00000
(916) 447-2166
abb@eslawfirm.com

Ronald Liebert
Attorney At Law
ELLISON, SCHNEIDER & HARRIS
2600 CAPITOL AVENUE, SUITE 400
SACRAMENTO CA 95816
(916) 447-2166
RL@ESLAWFIRM.COM
For: California Manufacturers & Technology Assn

Lynn Haug
ELLISON, SCHNEIDER & HARRIS L.L.P.
2600 CAPITOL AVENUE, SUITE 400
SACRAMENTO CA 95816-5931
(916) 447-2166
lmh@eslawfirm.com

Mona Tierney-Lloyd, Sr. Dir., Western Regulatory Affairs
ENERNOC, INC.
PO BOX 378
CAYUCOS CA 93430
(805) 995-1618
mtierney-lloyd@enernoc.com

Jason Simon, Dir - Policy Strategy
ENPHASE ENERGY
1420 N. MCDOWELL BLVD.
PETALUMA CA 94954
(707) 763-4784 X7531
JSimon@EnphaseEnergy.com

Jennifer Weberski
Consultant On Behalf Of:
ENVIRONMENTAL DEFENSE FUND
49 TERRA BELLA DRIVE
WALNUT CREEK CA 94596
(703) 489-2924
jleesq@yahoo.com

Lauren Navarro
ENVIRONMENTAL DEFENSE FUND
1107 - 9TH ST., STE. 1070
SACRAMENTO CA 95814
(916) 492-7074
lnavarro@edf.org

Michael Panfil
ENVIRONMENTAL DEFENSE FUND
257 PARK AVENUE SOUTH, FLOOR 16
NEW YORK NY 10010
(212) 616-1217
mpanfil@edf.org

Steven Moss
ENVIRONMENTAL DEFENSE FUND
2325 THIRD STREET, STE. 344
SAN FRANCISCO CA 94114
1040@pacbell.net

Michael Perry
FREEMAN SULLIVAN & CO.
101 MONTGOMERY ST., 15TH FLOOR
SAN FRANCISCO CA 94104
(415) 777-0707
michaelperry@fscgroup.com

Michael Sullivan
FREEMAN SULLIVAN & CO.
101 MONTGOMERY ST., 15TH FLOOR
SAN FRANCISCO CA 94104
(415) 777-0707
MSullivan@Nexant.com

Sam Holmberg
FREEMAN SULLIVAN & CO.
101 MONTGGOMERY ST., 15TH FLOOR
SAN FRANCISCO CA 94104
(415) 777-0707
samholmberg@fscgroup.com

Brian Geiser
EMAIL ONLY
EMAIL ONLY CA 00000
bgeiser@lmi.net

************** SERVICE LIST *************
Last Updated on 21-APR-2015 by: AMT
R1206013 LIST

Robert Gnaizda
Of Counsel
15 SOUTHGATE AVE., STE. 200
DALY CITY CA 94015
(650) 953-0522
robertgnaizda@gmail.com

Steven Kelly
Policy Director
INDEPENDENT ENERGY PRODUCERS ASSCIATION
1215 K STREET, STE. 900
SACRAMENTO CA 95814
(916) 448-9499
steven@iepa.com

William B. Marcus
Consulting Economist
JBS ENERGY, INC.
311 D STREET, SUITE A
WEST SACRAMENTO CA 95605
(916) 372-0534
bill@jbsenergy.com

Joseph F. Wiedman
Attorney
KEYES FOX & WIEDMAN LLP
436 - 14TH STREET, SUITE 1305
OAKLAND CA 94612
(510) 314-8202
jwiedman@kfwlaw.com

Thadeus B. Culley
KEYES FOX & WIEDMAN LLP
EMAIL ONLY
EMAIL ONLY CA 00000
(510) 314-8205
tculley@kfwlaw.com

Erica M. Schroeder
KEYES FOX & WIEDMAN, LLP
436 14TH STREET, STE. 1305
OAKLAND CA 94612
(510) 314-8206
ESchroeder@kfwlaw.com

Barry Friedman
KEYES, FOX & WIEDMAN, LLP
9179 W. MARYLAND PL
LAKEWOOD CO 80232-5289
(720) 253-2998
bfriedman@kfwlaw.com

Rachel Gold
LARGE-SCALE SOLAR ASSOCIATION
2501 PORTOLA WAY
SACRAMENTO CA 95818
(510) 629-1024
Rachel@largescalesolar.org

Brian Orion
LAWYERS FOR CLEAN ENERGY
656A CLAYTON STREET
SAN FRANCISCO CA 94117
(858) 354-8222
borion@lawyersforcleanenergy.com

Roger Levy
LEVY ASSOCIATES
EMAIL ONLY
EMAIL ONLY CA 00000
(916) 487-0227
rogerl47@aol.com

David Marcus
EMAIL ONLY
EMAIL ONLY CA 00000-0000
dmarcus2@sbcglobal.net

Jeremy Waen
Regulatory Analyst
MARIN CLEAN ENERGY
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 464-6027
JWaen@mceCleanEnergy.org

Mce Regulatory
MARIN CLEAN ENERGY
EMAIL ONLY
EMAIL ONLY CA 00000
regulatory@mceCleanEnergy.org

Michael Callahan-Dudley, Regulatory Counsel
MARIN CLEAN ENERGY
781 LINCOLN AVE., STE. 320
SAN RAFAEL CA 94901
(415) 464-6045
MCallahan-Dudley@mceCleanEnergy.org

Shalini Swaroop
Regulatory Counsel
MARIN CLEAN ENERGY
EMAIL ONLY CA 00000
(415) 464-6040
sswaroop@mceCleanEnergy.org

************ SERVICE LIST ***********
Last Updated on 21-APR-2015 by: AMT
R1206013 LIST

John W. Leslie, Esq.
MCKENNA LONG & ALDRIDGE LLP
EMAIL ONLY
EMAIL ONLY CA 00000
(619) 699-2536
jleslie@McKennaLong.com

Geoff Mclennan
EMAIL ONLY
EMAIL ONLY CA 00000
gtmclennan@gmail.com

Daryl Michalik
3435 CESAR CHAVEZ ST., NO. 208
SAN FRANCISCO CA 94110
(415) 500-2835
darylmic@gmail.com

Gregory Reiss
MILLENNIUM MANAGEMENT LLC
666 FIFTH AVENUE, 8TH FLOOR
NEW YORK NY 10103
(212) 320-1036
Gregory.Reiss@mlp.com

James (Jim) Von Riesemann
MIZUHO SECURITIES USA, INC.
320 PARK AVENUE, 12TH FLOOR
NEW YORK NY 10022
(212) 205-7857
James.vonRiesemann@us.mizuho-sc.com

Jimi Netniss
MODESTO IRRIGATION DISTRICT
1231 11TH STREET
MODESTO CA 95354
(209) 526-7592
jimin@mid.org

Joy A. Warren, Regulatory Administrator
MODESTO IRRIGATION DISTRICT
1231 11TH STREET
MODESTO CA 95354
(209) 526-7389
joyw@mid.org

Linda Fischer
Legal Department
MODESTO IRRIGATION DISTRICT
1231 11TH STREET
MODESTO CA 95354
(209) 526-7388
lindaf@mid.org

MRW & ASSOCIATES, LLC
EMAIL ONLY
EMAIL ONLY CA 00000
(510) 834-1999
mrw@mrwassoc.com

Aaron J. Lewis
Counsel
NATIONAL ASIAN AMERICAN COALITION
15 SOUTHGATE AVE., STE. 200
DALY CITY CA 94015
(650) 952-0522 X-235
alewis@naac.org

Maria Stamas
Legal Fellow, Energy Program
NATURAL RESOURCES DEFENSE COUNCIL
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 875-8240
mstamas@nrdc.org

Merrian Borgeson
Sr. Scientist, Energy Program
NATURAL RESOURCES DEFENSE COUNCIL
111 SUTTER ST., 20TH FL.
SAN FRANCISCO CA 94104
(415) 875-6100 X6174
mborgeson@nrdc.org

Nancy Brockway
NBROCKWAY & ASSOCIATES
10 ALLEN STREET
BOSTON MA 02131
(617) 645-4018
nbrockway@aol.com

Josh Bode
NEXANT
EMAIL ONLY CA 00000
jbode@nexant.com

Stephen George
NEXANT
EMAIL ONLY CA 00000
sgeorge@mexant.com

Kerry Hattevik, Reg. Dir.- West Governmental Affairs
NEXT ERA ENERGY RESOURCES LLC
829 ARLINGTON BLVD.
EL CERRITO CA 94530
(510) 898-1847
kerry.hattevik@nee.com

************** SERVICE LIST *************
Last Updated on 21-APR-2015 by: AMT
R1206013 LIST

Rekha Rao
NEXTILITY
2015 SHATTUCK AVE., 5TH FLOOR
BERKELEY CA 94704
(202) 719-5297 X-720
rrao@nextility.com

Abraham Silverman
Assist. Gen. Counsel - Regulatory
NRG ENERGY, INC.
211 CARNEGIE CENTER DRIVE
PRINCETON NJ 08540
(609) 524-4696
abraham.silverman@nrg.com
For: NRG Home

Brian Theaker
Director - Market Affairs
NRG ENERGY, INC.
3161 KEN DEREK LANE
PLACERVILLE CA 95667
(530) 295-3305
brian.theaker@nrg.com

Sean P. Beatty
Director - West Regulatory Affairs
NRG WEST
EMAIL ONLY
EMAIL ONLY CA 00000
(925) 427-3483
sean.beatty@nrg.com

Diane I. Fellman
Director, Regulatory & Gov'T Affairs
NRG WEST & SOLAR
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 601-2025
Diane.Fellman@nrg.com

Nick Pappas
OFFICE OF ASSEMBLYMAN NATHAN FLETCHER
EMAIL ONLY CA 00000
(916) 319-2959
Nick.Pappas@asm.ca.gov

Catherine Tarasova
PACIFIC GAS & ELECTRIC COMPANY
77 BEALE ST., RM. 1053, MC B10A
SAN FRANCISCO CA 94105
(415) 973-5461
yxt5@pge.com

Margot Everett
Senior Director
PACIFIC GAS & ELECTRIC COMPANY
77 BEALE ST., B10B
SAN FRANCISCO CA 94105
mec3@pge.com

Steve Haertle
PACIFIC GAS & ELECTRIC COMPANY
77 BEALE STREET, ROOM 967, MC B9A
SAN FRANCISCO CA 94120
(415) 222-5603
SRH1@pge.com

Amanda Pinkston
PACIFIC GAS AND ELECTRIC COMPANY
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 973-8629
a3pm@pge.com

Case Coordination
PACIFIC GAS AND ELECTRIC COMPANY
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 973-4744
RegRelCPUCCases@pge.com

Charles R. Middlekauff
PACIFIC GAS AND ELECTRIC COMPANY
LAW DEPT.
77 BEALE STREET, B30A / PO BOX 7442
SAN FRANCISCO CA 94105
(415) 973-6971
CRMd@pge.com

Gail L. Slocum
PACIFIC GAS AND ELECTRIC COMPANY
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 973-6583
glsg@pge.com

Renee C. Samson
Dir. - Regulatory Rate & Proceedings
PACIFIC GAS AND ELECTRIC COMPANY
77 BEALE ST., RM. 941, MC B9A
SAN FRANCISCO CA 94105
(415) 973-6164
r5sz@pge.com

************** SERVICE LIST *************
Last Updated on 21-APR-2015 by: AMT
R1206013 LIST

Cathie Allen
Regulatory Affairs Mgr.
PACIFICORP
825 NE MULTNOMAH ST., STE 2000
PORTLAND OR 97232
(503) 813-5934
cathie.allen@pacificorp.com

Joelle Steward
PACIFICORP
EMAIL ONLY
EMAIL ONLY OR 00000
(503) 813-5542
Joelle.Steward@PacifiCorp.com

Ben Griffiths
Research Assistant
RESOURCE INSIGHT
5 WATER STREET
ARLINGTON MA 02476
(781) 646-1505 X-203
bgriffiths@resourceinsight.com

Paul Chernick
RESOURCE INSIGHT
5 WATER ST.
ARLINGTON MA 02476
(781) 646-1505 X207
pchernick@resourceinsight.com

Susan Geller
Senior Research Associate
RESOURCE INSIGHT
5 WATER ST.
ARLINGTON MA 02476
(781) 646-1505
sgeller@resourceinsight.com

Sue Mara
Consultant
RTO ADVISORS, LLC
164 SPRINGDALE WAY
REDWOOD CITY CA 94062
(415) 902-4108
sue.mara@RTOadvisors.com

Charles R. Manzuk
Dir. - Rates & Revenue Requirements
SAN DIEGO GAS & ELECTRIC COMPANY
8330 CENTURY PARK CT, CP32D
SAN DIEGO CA 92123-1530
(858) 654-1782
CManzuk@SempraUtilities.com

Cynthia Fang
SAN DIEGO GAS & ELECTRIC COMPANY
8330 CENTURY PARK COURT, CP32E
SAN DIEGO CA 92123-1530
cfang@semprautilities.com

Dana Golan
SAN DIEGO GAS & ELECTRIC COMPANY
8306 CENTURY PARK CT., CP421
SAN DIEGO CA 92123-1530
DGolan@semprautilities.com

Jamie K. York
Regulatory Case Admin.
SAN DIEGO GAS & ELECTRIC COMPANY
8330 CENTURY PARK COURT, CP32D
SAN DIEGO CA 92123
(858) 654-1739
JYork@SempraUtilities.com

Parina Parikh
Regulatory Affairs
SAN DIEGO GAS & ELECTRIC COMPANY
8330 CENTURY PARK COURT, CP32
SAND IEGO CA 92123
(858) 636-5503
pparikh@semprautilities.com

William Fuller
Calif. Regulatory Affairs
SAN DIEGO GAS & ELECTRIC COMPANY
8330 CENTURY PARK COURT, 32CH
SAN DIEGO CA 92123-1548
(858) 654-1885
WFuller@SempraUtilities.com

Steve Rahon
Dir., Tariff & Regulatory Accts
SAN DIEGO GAS & ELECTRIC COMPANY (902)
8330 CENTURY PARK COURT, CP32C
SAN DIEGO CA 92123-1548
(858) 654-1773
SRahon@SempraUtilities.com

Shaibya Dalal
Regulatory Analyst
SAN FRANCISCO PUBLIC UTILITIES COMM.
525 GOLDEN GATE AVE., 7TH FLOOR
SAN FRANCISCO CA 94102
(415) 554-1516
sdalal@sfwater.org

************ SERVICE LIST ***********
Last Updated on 21-APR-2015 by: AMT
R1206013 LIST

Hugh Wynne
SANFORD C. BERNSTEIN & CO.
1345 AVENUE OF THE AMERICAS, 15TH FLR
NEW YORK NY 10105
(212) 823-2692
hugh.wynne@bernstein.com

Central Files
SDG&E/SOCALGAS
8330 CENTURY PARK COURT, CP31-E
SAN DIEGO CA 92123
(858) 654-1240
CentralFiles@SempraUtilities.com

Chris King
SIEMENS SMART GRID SOLUTIONS
4000 E. THIRD AVE., STE. 400
FOSTER CITY CA 94404
(650) 227-7770 X-187
chris_king@siemens.com

Alison Seel
Associate Attorney
SIERRA CLUB
85 SECOND STREET, 2ND FLOOR
SAN FRANCISCO CA 94105
(415) 977-5737
alison.seel@SierraClub.org

Matthew Vespa
Sr. Attorney
SIERRA CLUB
85 SECOND ST,, 2ND FL
SAN FRANCISCO CA 94105
(415) 977-5753
matt.vespa@SierraClub.org

Kevin Fallon
SIR CAPITAL MANAGEMENT
EMAIL ONLY
EMAIL ONLY NY 00000
(212) 993-7104
kfallon@sirfunds.com

Ruth Hupart
SOLAR ELECTRIC POWER ASSOCIATION
1220 19TH STREET, NW, STE. 800
WASHINGTON DC 20036
(202) 559-2032
rhupart@solarelectricpower.org

Sara Birmingham
SOLAR ENERGY INDUSTRIES ASSOCIATION
3300 NE 157TH PLACE
PORTLAND OR 97230
(415) 385-7240
sbirmingham@seia.org

Andy Schwartz
SOLARCITY
3055 CLEARVIEW WAY
SAN MATEO CA 94402
(650) 963-3879
aschwartz@solarcity.com

Daniel Chia, Dir.
SOLARCITY
3055 CLEARVIEW WAY
SAN MATEO CA 94402
(650) 332-0452
dchia@solarcity.com

Marc Kolb
SOLARCITY
444 DE HARO STREET, SUITE 100
SAN FRANCISCO CA 94107
(650) 477-7292
mkolb@solarcity.com

Mary Hoffman
SOLUTIONS FOR UTILITIES, INC.
EMAIL ONLY CA 00000
(760) 724-4420
maryhoffmanRE@gmail.com

Case Administration
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVENUE, PO BOX 800
ROSEMEAD CA 91770
(626) 302-6906
case.admin@sce.com

Russell Garwacki
SOUTHERN CALIFORNIA EDISON COMPANY
2244 WALNUT GROVE AVE.
ROSEMEAD CA 91770
russell.garwacki@sce.com

Melissa P. Martin
Senior Regulatory Counsel
STATESIDE ASSOCIATES
EMAIL ONLY VA 00000
(703) 525-7057 X-237
mpf@stateside.com

**************** SERVICE LIST ***************
Last Updated on 21-APR-2015 by: AMT
R1206013 LIST

Adam Gerza
SULLIVAN SOLAR POWER OF CALIFORNIA, INC.
169 11TH STREET
SAN FRANCISCO CA 94103
(310) 210-2392
adam@sullivansolarpower.com

Holly Gordon
Vp, Legislative & Regulatory Affair
SUNRUN INC.
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 684-9837
holly@SunrunHome.com

Walker Wright
SUNRUN INC.
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 684-9980
WWright@SunrunHome.com

Walker Wright
SUNRUN, INC.
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 580-6980
wwright@sunrunhome.com

Edward G. Cazalet
TEMIX, INC.
101 FIRST STREET
LOS ALTOS HILLS CA 94022
(650) 949-5274
ed@temix.com

Ahmad Faruqui
THE BRATTLE GROUP
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 217-1026
ahmad.faruqui@brattle.com

Carmelita L. Miller
Legal Counsel
THE GREENLINING INSTITUTE
1918 UNIVERSITY AVENUE
BERKELEY CA 94704
(510) 926-4017
carmelitam@greenlining.org

Marcel Hawiger
Staff Attorney
THE UTILITY REFORM NETWORK
785 MARKET ST., STE. 1400
SAN FRANCISCO CA 94103
(415) 929-8876 X311
marcel@turn.org

Matthew Freedman
THE UTILITY REFORM NETWORK
EMAIL ONLY
EMAIL ONLY CA 00000
(415) 929-8876 X304
matthew@turn.org

Matt Fallon
TIMEWAVE CAPITAL MANAGEMENT
EMAIL ONLY CT 00000
matt.fallon@timewavecapital.com

Morgan Lee
U-T SAN DIEGO
350 CAMINO DE LA REINA
SAN DIEGO CA 92108
(619) 293-1251
Morgan.Lee@UTSanDiego.com

David Croyle
UCAN
3405 KENYON STREET, STE. 401
SAN DIEGO CA 92110
sandiegodavid@gmail.com

Andrew G. Campbell, Exec.Dir.- Energy Institute At Haas
UNIVERSITY OF CALIFORNIA, BERKELEY
2547 CHANNING WAY
BERKELEY CA 94720-5180
(415) 515-4655
acampbell@haas.berkeley.edu

Rick Gilliam
VOTE SOLAR
1120 PEARL STREET
BOULDER CO 80302
(303) 550-3686
rick@votesolar.org

Susannah Churchill
Solar Policy Advocate
VOTE SOLAR
EMAIL ONLY CA 00000
(415) 817-5065
susannah@votesolar.org

Sheridan J. Pauker
WILSON SONSINI GOODRICH & ROSATI
EMAIL ONLY
EMAIL ON LY CA 00000
(415) 947-2136
spauker@wsgr.com

Kevin Woodruff
WOODRUFF EXPERT SERVICES
1127 - 11TH STREET, SUITE 514
SACRAMENTO CA 95814
(916) 442-4877
kdw@woodruff-expert-services.com

Stephen Ludwick
ZIMMER PARTNERS
EMAIL ONLY
EMAIL ONLY CA 00000
sludwick@zimmerpartners.com

(End of Attachment C)