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)

REPLY COMMENTS OF THE DIVISION OF RATEPAYER ADVOCATES ON PARTIES' RESIDENTIAL RATE DESIGN PROPOSALS

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I. INTRODUCTION

Pursuant to the Administrative Law Judge's June 24, 2013 Ruling, the Division of Ratepayer Advocates ("DRA") hereby submits its Reply Comments on the parties' residential rate design proposals. The focus of these comments is very similar to that of DRA's Opening Comments. We address the contentious issues of whether fixed charges should be part of rate design going forward as well as whether time-of-use ("TOU") rates should be introduced to customers on a default or optional basis. We also address the debate about how to deal with the effects of this transition on low-income ratepayers, and what the CARE discount should be going forward. Finally, we discuss the extent to which statutory changes will be required to accommodate this transition. DRA continues to support its proposed Introductory TOU rate, which adds TOU surcharges and credits to the existing rate structure, as the best way to move forward.

II. DISCUSSION

A. Fixed Costs and Fixed Charges

The three utilities predictably do not agree with DRA's views on fixed costs and fixed charges. SCE and SDG&E have the most to say on this issue. SCE discusses the issue in the context of rate efficiency.[1] Both SCE and SDG&E present examples in competitive industries where they say fixed charges are employed.[2] Finally, PG&E discusses the issue from the perspective of bill stability.[3]

1. Rate Efficiency

On the subject of rate efficiency, SCE states that:

> In terms of the economic efficiency of a proposal when compared to cost, each party has its own view of what constitutes a cost-based rate. Thus, the Commission's evaluation can be facilitated by comparing each rate design proposal using a common methodology and rate design model in order to make apples to apples comparisons. This enables an assessment of the efficiency of a rate design proposal and what effect it would have on intra-class subsidies compared to the current rate structure. [4]

It is true that "every party has its own view of what constitutes a cost-based rate," and this is true of SCE as well. The issues and methodologies relating to marginal cost determination have always been very contentious in the general rate cases ("GRCs"). Given the diversity of views concerning cost causation, it will be difficult for the Commission to develop a "common methodology" to assess rate design efficiency, and it should not rely on SCE's "rate efficiency" metrics contained in SCE's Tables II-2, II-3, and III-6[5].

SCE presents its view of its cost of service, relative to customer size, in Figure II-1 of its opening comments. It uses this cost curve to assess the relative rate efficiencies of the tiered and TOU rate designs proposed by various parties in Tables II-3 and III-6 respectively. In Figure 1 below, DRA presents its own cost curve superimposed on a

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[1] SCE July 12, 2013 RROIR Opening Comments (SCE OC), p. 5.

[2] SCE OC, pp. 34 – 35.

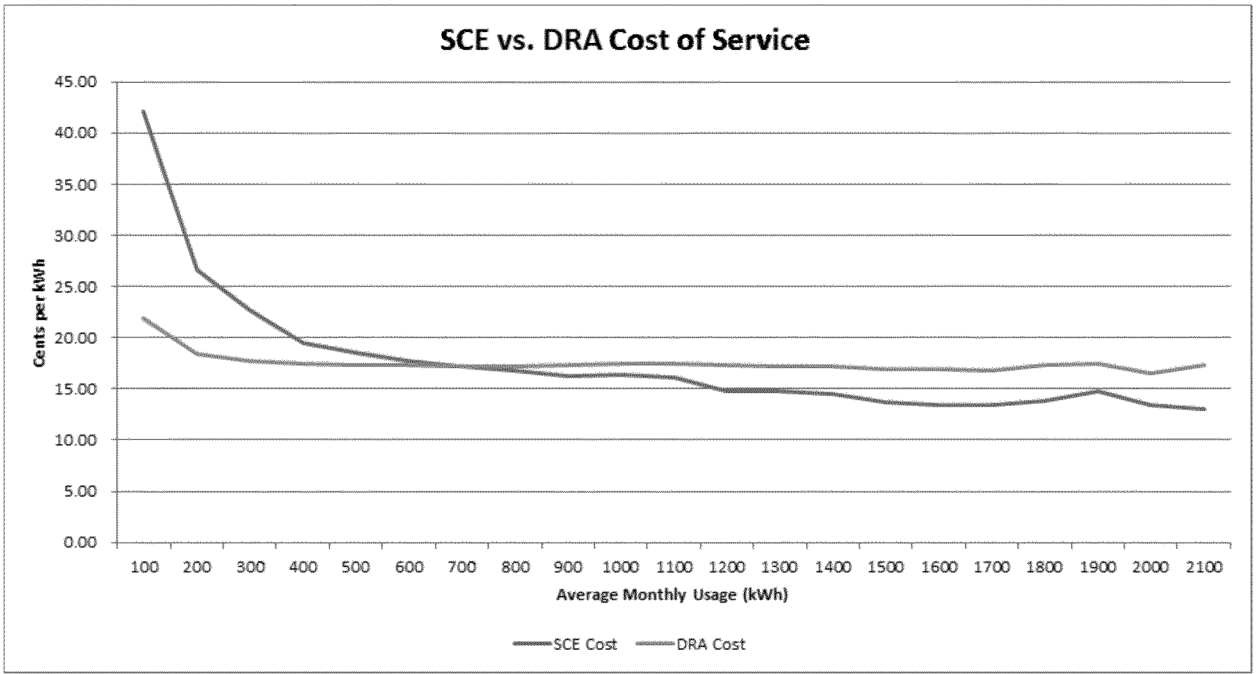
[3] PG&E July 12, 2013 RROIR Opening Comments (PG&E OC), p. 4.

[4] SCE OC, p. 5.

[5] SCE OC, p. 10, p. 12, and p. 25.

graph that shows SCE's cost curve for comparison. The rate efficiency of DRA's end-state TOU rate, shown in SCE's Table III-6, is 24%, which represents a 24% deviation from cost.[6] However, using DRA's cost curve below, this rate efficiency metric for DRA's end-state TOU rate drops to a 16% deviation from cost.

Figure 1 – DRA's and SCE's View of SCE's Cost of Service



[6] It appears that SCE's calculation of the 24% metric is based on a rate design that has a 20% CARE discount and zero fixed charge. DRA actually assumed a 30% CARE discount and $1 fixed charge. If those corrections are made, the metric increases to 26%.

In its curve, DRA used a fixed customer cost that is about one-third the size of SCE's.[7] This curve is comparable to the one presented in DRA's Opening Comments (in Figure 1) for PG&E. Accordingly, DRA includes only metering and billing costs as elements that can be unambiguously regarded as being the same regardless of customer size.

While DRA used metering and billing costs, whether the entire metering cost should be included in the fixed charge is open to question. NRDC raises an excellent point in this regard:

> As we have noted, there are many benefits from the installation of smart meters – benefits that bear on peak demand and energy savings – and a significant portion of these costs should be treated as usage-related costs, not customer-related costs. (NRDC Opening Comments, p. 4)

Indeed, the smart meters are more expensive than the legacy electromechanical meters that they replaced. The additional expense was justified on the basis of providing demand response benefits and can be seen as a substitute for investments in generation resources.

SCE disputes this contention stating, "NRDC misunderstands that the bulk of the business case for smart meters was the reduction of meter reading costs which is a fixed cost, independent of the amount of customer usage" (SCE Opening Comments, p. 35).

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[7] SCE's fixed cost were based on the rental method marginal costs of $12.10 per customer month as presented in Table RA-3 of the settlement agreement that was adopted in SCE's last general rate case in D.13-03-031. However, the value actually adopted for revenue allocation in that settlement was $9.64 per customer month, based on a 50-50 blend of the New Customer Only ("NCO") and rental values. DRA used the same 50-50 NCO/rental marginal customer cost methodology that was used in the settlement, with the exception of the exclusion of final line transformer and service drop costs. In DRA's view, these two types of equipment vary with the customer's size and therefore should be excluded from one-size-fits-all fixed charges. DRA's marginal customer cost, excluding final line transformer and service drop cost, is $4.34.

Thus, contrary to SCE's assertion, on page 13 of its Opening Comments, TURN was indeed correct in stating that SCE based its cost analysis on its "own position" in its recent GRC Phase 2 case. While SCE's rental method value of $12.10 (SCE's position) was reflected in a supporting table attached to the settlement, the actual settled marginal customer cost value was $9.64 reflecting an average of the NCO method, favored by DRA and TURN, and the rental method, favored by SCE.

However, SCE disregards the fact that 38% of its smart meter benefits are expected to come from demand response.[8] Accordingly, it would be appropriate to exclude 38% of the meter costs from the marginal customer costs used to develop a customer charge.[9]

Reliance on utility "efficiency metrics" is especially problematic given that rate efficiency is not the only consideration. Another factor is the ability of the rate design to promote energy efficiency, which higher volumetric rates and a lower fixed charge will accomplish. As D.11-05-047, on page 24, states: "the customer charge also would conflict with price signals that encourage conservation and utilization of alternative resources such as solar."[10]

2. What Competitive Markets Do

SCE and SDG&E have much to say about pricing in competitive industries. SCE states:

> DRA concludes that 'A fixed monthly charge is not sustainable in a competitive environment.' This argument is irrelevant and is flawed. While competition for generation services exists, the electric distribution system is not a competitive market. In the description above, customers cannot be expected to receive meaningful distribution service choice unless they choose simply not to consume and disconnect from the grid. Once one correctly understands that the 'per-unit-purchased' is the connection to the electrical grid, the virtues of a fixed charge become clear.[11]

DRA is not sure why SCE would say that "the electric distribution system is not a competitive market." This point is irrelevant because one of the main reasons why the

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[8] See A.07-07-026, Exhibit SCE-1, Table IV-2, p.26. The percentage of smart meter costs attributable to demand response varies by utility.

[9] DRA is not certain about whether the marginal customer costs used to develop SCE's and DRA's cost curves in Figure 1 assume a legacy meter or smart meter. Given the time of filing of SCE A.11-06-007, the deployment of AMI was not yet complete, and therefore the marginal costs adopted in D.13-03-031 may reflect legacy meter costs.

[10] Quoted by TURN in Footnote #60.

[11] SCE OC, pp. 34 – 35.

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Commission employs marginal cost pricing is to emulate the efficiencies of a competitive market. Indeed, the Commission reaffirmed this policy, which has been and continues to be the cornerstone of Commission ratemaking policy since the late 1970s, in SCE's 1995 GRC:

> We also reaffirm our policy of basing marginal costs for ratesetting purposes on short-term pricing signals. This approach is consistent with the ratesetting principles we have established in prior electric rate cases. It comports with economic theory as well as observed operations of competitive markets.[12]

SCE goes on to make a fixed charge sound more like a volumetric charge by saying that the "'per-unit purchased' is the connection to the electrical grid." Admittedly, there are markets where "the unit," on which the price is based, is analogous to a utility connection. This is true of the housing rental market, which is the analogy underlying the "rental" method for calculating marginal customer costs. However, the Commission has not, since 1992, adopted the rental method in any proceeding that has been litigated.[13] For houses and apartments, a fixed monthly rent is charged because monthly occupation is the most convenient unit on which to base the price. Any other pricing scheme would be more complicated. With utilities, the simplest pricing scheme is to base the price on the kilowatt-hours sold.

While it is possible to base pricing on different kinds of units representing various unbundled costs, many industries do not do so because it would result in more complex pricing. In fact, in footnote #80,[14] SCE gives an example of costs that are bundled

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[12] See D.96-04-050, p.2. Note that, in practice, the Commission has used a combination of short-run and long-run marginal costs in ratemaking.

[13] See Decisions 92-12-057, 95-12-053, 96-04-050, 97-03-017, and 97-04-082, which apply to both gas and electric utilities and include PG&E, SCE, and SDG&E.

[14] Footnote #80 states: "The trenching and backfill are usually incurred by the developer and the property deeded over to SCE. The developer must include recovery of these costs in the price of the homes. That is in fact the ultimate fixed charge, a one-time payment for the life of the house. Such pricing is quite common in competitive markets and is efficient."

together in the price of a new home. Nevertheless, both SCE and SDG&E are able to articulate exceptions to this rule. SCE states:

> There are many examples of pricing in unregulated markets where fixed charges, two-part prices, etc., are employed. Competition would indicate that such pricing is efficient, but like all other industries, all costs are variable in the long run. Amusement parks, health clubs, bars with cover charges, the Costco Stores with membership fees, etc., all use combinations of fixed and variable charges.[15]

While this is true, in virtually every one of these cases, competitive alternatives exist where there are different pricing structures that do not employ fixed charges. This variety of pricing options in a competitive market was explained by the Regulatory Assistance Project study, which DRA previously quoted:

> Competitive markets provide goods and services in all sorts of ways, with almost infinite variety of product offerings and pricing structures: consumers are given meaningful choices and are thus able to avoid costs either by not consuming or by finding substitutes.[16]

As DRA stated before, pricing that employs fixed charges is generally only sustainable in industries that are not competitive. Nevertheless, to refute this, SDG&E states that people pay for their houses through a combination of fixed and variable charges. The fixed charge is the mortgage or rent and the variable costs are for "the food, utilities and other things they consume as they utilize that capacity" (SDG&E Opening Comments, p. 10). What SDG&E ignores is that these payments are being made to separate suppliers that therefore must be unbundled. In the case of the utility, such unbundling is unnecessary because the utility is a single supplier.

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[15] SCE OC, pp. 38 – 39

[16] *Charging For Distribution Utility Services: Issues In Rate Design*, December 2000, The Regulatory Assistance Project (Frederick Weston), quoted in Appendix A of DRA's May 29th proposal.

SCE goes on to articulate that there is a genuine cost associated with the fixed connection which the utilities seek to recover in a fixed charge. It states:

> It is reasonable to bill customers directly via fixed charges for customer-related costs. When SCE charges the customer only $0.91 per month, which is SCE's current customer charge, the implication is that the customer's occupation of the property does not result in any meaningful costs to SCE. … The current residential rate structure signals to residential customers that precluding other customers from accessing SCE's system does not harm them. But, that is not true. If enough residential customers were to vacate their property, releasing those positions on the grid for other customers' use, SCE could defer or avoid the extension of its system to serve a new development.[17]

What SCE neglects to state here is that this cost is one that was incurred in the ***past***. It is not an ongoing ***marginal*** cost. Thus it has no place in marginal cost based pricing.

SCE's notion that future customers are precluded from accessing SCE's system by existing customers occupying homes that are hooked up to SCE system ignores the fact that these facilities are uniquely dedicated to individual customers. Certainly existing connections do not impose an opportunity cost on green field development, which is the main source of new customer growth in Southern California. Individual hookups are not common facilities that are shared by multiple customers. Thus a customer vacating a home does not create room for net growth in the number of customers.

3. Rate Stability

Finally, PG&E argues in favor of fixed costs because they promote stability in utility bills:

> The parties who criticize the use of a fixed charge to recover fixed costs ignore a significant customer benefit of a fixed charge – a fixed charge moderates the volatility of many customers' monthly bills

[17] SCE OC, pp. 37 – 38

> due to extreme weather events, such as the extreme heat waves that California periodically experiences during summer months.[18]

Fixed charges are not the only way to achieve bill stability. Any customer who is concerned with bill volatility can sign up for a balanced payment plan. Moreover, some of the bill instability is caused by the current highly inverted tiered rate design, which leads to higher bill volatility in the warmer inland areas. DRA and most parties are in favor of reducing the level of tier inversion in future rate designs.

DRA suspects the large emphasis placed by utilities on fixed charges is as much motivated by the desire to stabilize their own revenue streams as it is by a desire to stabilize customer bills. In this regard, TURN observes that there are other ways to stabilize the utilities' revenue streams:

> Decoupling is one way to provide revenue stability for the utility, without introducing rate design elements such as high fixed monthly charges, in the form of a Straight Fixed/Variable rate design, that remove the appropriate price signals to consumers."[19] [20]

DRA agrees with TURN that rate design is not as good a mechanism to stabilize utility revenues as other regulatory mechanisms that already exist.

4. SDG&E's Proposal would Result in Insurmountable Bill Impacts

Apart from these conceptual issues, the implementation of large fixed charges can have significant bill impacts, especially on low-use customers. This is especially true of SDG&E's proposals. In fact, SDG&E's proposed basic service fees are so large that it would be difficult to implement them along with a default time-varying rate design. DRA thus assumes that SDG&E would prefer to offer its time-varying rates on a

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[18] PG&E OC, p. 4

[19] TURN Opening Comments, p. 33, citing Regulatory Assistance Project, "Revenue Regulation and Decoupling," June 2011, p. 26.

[20] Also see Edison Electric Institute, "Innovative Regulation: A Survey of Remedies for Regulatory Lag," April 2011, p. 17-24.

voluntary basis because doing so in combination with large fixed charges effectively is precluded by the size of the bill impacts – unless an extremely long transition period is contemplated. But sacrificing the widespread deployment of time-varying rates in order to implement large fixed charges may not be the policy direction in which the Commission wishes to go. There is a clear question of priorities before the Commission.

On July 15, 2013, SDG&E submitted more supplemental information about its rate proposals pursuant to direction from the Energy Division ("ED").[21] In this supplemental filing, SDG&E sought to satisfy the ED request by providing the following:

- Distribution Recovery through a basic service fee with a:
  - Commodity Flat Rate, or a
  - Commodity TOU Rate
- Distribution Recovery through demand-differentiated basic service fee with a:
  - Commodity Flat Rate, or a
  - Commodity TOU Rate

This supplemental filing followed the approach used in SDG&E's July 1st submittal that showed the changes to the delivery and commodity rates in separate bill impact analyses and in five separate steps. There is no analysis of the cumulative bill impacts of all these changes.

Therefore, DRA chose one of SDG&E's scenarios and used SDG&E's bill calculator model to calculate the cumulative bill impacts. We chose the scenario where distribution costs are recovered from a uniform basic service fee of $38 and with a flat

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[21] SDG&E's filing noted that on July 8, Gabriel Petlin of the Commission's Energy Division requested that SDG&E supplement its Response as follows: "The July 1 filing of SDG&E does not comply with the June 19th ALJ ruling. We understand that illustrative rates do not necessarily represent your actual proposed rate design, but are one possible example of a quantitative rate that illustrates how your proposed rate design narrative proposal could be implemented. We ask that you provide illustrative bundled rate designs and illustrative bill impacts for both (1) a transitional and (2) an end-state rate design based on the instructions found in Attachment B of the March 19 ruling. Without this it is difficult to fully evaluate your proposal. Please provide this as a supplemental filing by July 15 and please label your attachments very clearly. The format of SCE's filing on illustrative rates is an acceptable example of how to complete this filing." SDG&E July 15, 2013 supplemental filing, p. 1.

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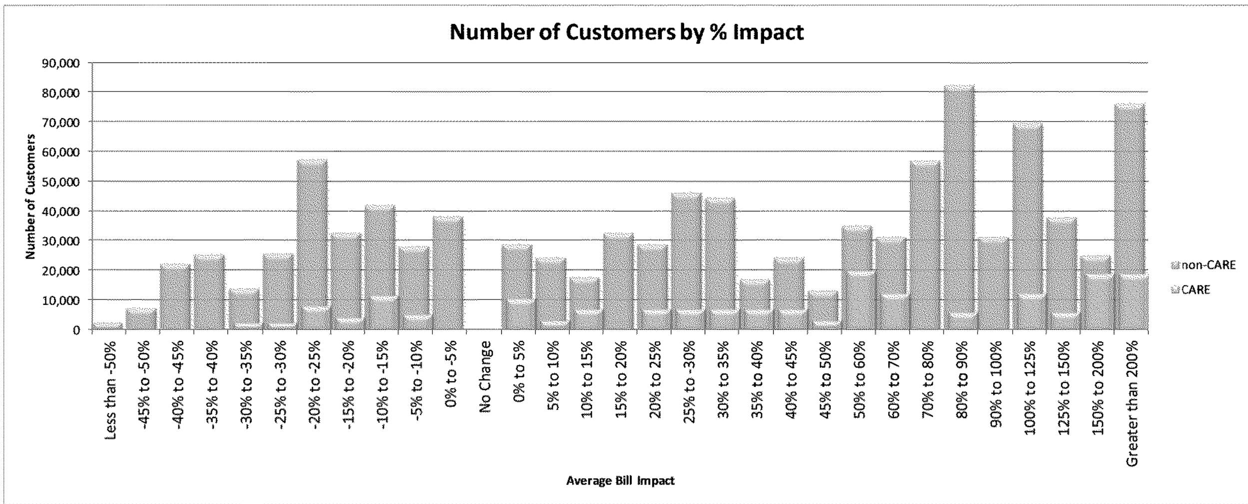
commodity rate. In this analysis, almost 20% of the customers would see bill increases of more than 100%, as shown below. Adding on the effects of a time-varying commodity rate would make the results even worse.

Figure 2 – Cumulative Bill Impacts of SDG&E Proposal



B. TOU Rate

1. Default TOU

DRA advocates cost-based default TOU rates for most customers, regardless of size,[22] after default transitional rates have been implemented. In contrast, NRDC advocates default TOU rates for "large" customers only, stating:

> "[O]ur proposed "dividing line" of 7 kW of consumption largely translates into a division between single-family customers being placed on the TOU rate, and multi-family customers being placed on the non-TOU rate, but very frugal small-use single- family, and larger, air-conditioned apartments, would be classified appropriately. We remain receptive to whether this 7 kW non-coincident peak demand criteria is the best definition between the two subclasses of residential usage. We believe it would place virtually all photovoltaic, electric vehicle, and air conditioning customers on the

[22] Medical baseline and third party notification customers are exceptions.

> TOU rate, and these are the customers with the most ability to shape their net demand on the utility in response to a TOU rate."[23]

DRA advocates default TOU pricing for both small and large customers because TOU rates have many benefits, which include avoiding future utility investments and mitigating bill increases. Therefore, DRA does not support NRDC's proposal, which would greatly reduce the benefits obtainable from TOU rates.

While DRA prefers a uniform timeframe for transitioning to default TOU pricing, DRA could support, as a second-best alternative, NRDC's proposed separation of large and small customers on a temporary basis. That is, if default TOU pricing were to start soon for large customers, to be followed by default TOU pricing for small customers within two years, any delay in rolling out default TOU rates to small customers could be minimized. However, if implementation of default TOU pricing were to be postponed for several years, then DRA would recommend that it apply to most customers at the same time. In the latter event, the IOUs would have adequate lead time to conduct comprehensive outreach and education for all customers.

DRA prefers that most customers ultimately be placed on default TOU rates because doing so is likely to lead to more customers being exposed to time-varying pricing than if such rates were offered as on an opt-in basis. A recent DOE study, analyzing customers' enrollment patterns in time-based rate programs, confirmed that a much higher recruitment rate for the default (opt-out) than the opt-in approach:

> More customers enroll in time-based rate programs with opt-out offers than with opt-in offers. When customers were solicited to join a study using **opt-out** recruitment approaches, the programs had an average recruitment rate of 84% (i.e., those solicited did not reject the offer and were placed into a program). On the other hand, when customers solicited using **opt-in** recruitment method (i.e., the

[23] NRDC July 12, 2013, RROIR Opening Comments (NRDC OC), pp. 14-16.

customers were informed of the study and asked to join) only 11% accepted the offer.[24]

With adequate customer education, the Commission could proceed directly to an opt-out TOU program.

2. TOU Rate Benefit

Nearly all the parties recommended some form of TOU rates, either as a default or optional rate. In its Appendix D to its May 29, 2013 Rate Design Proposal, DRA provided illustrative estimates of the following TOU benefits:

- Peak demand reduction (MW)
- Peak period electric usage reduction (MWH)
- Natural gas power plant fuel consumption reduction (MMBtu)
- Greenhouse Gas emissions reduction (tons CO2 equivalent)

Further, DRA provided an illustrative dollar value of societal benefits of $169 million annually. This estimate conservatively assumed that TOU rates would shift load but provide no reduction in total electric energy usage.[25] Of that benefit amount, 84% is related to avoided generation capacity costs[26] and 13% is related to avoided natural gas power plant fuel costs.[27] The remaining 3% comes from avoided GHG emissions.[28] No party took issue with DRA's illustrative capacity and fuel cost savings, but TURN and NRDC disputed DRA's findings of environmental benefits.

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[24] "Analysis of Customers' Enrollment Pattern in Time-based Rate Programs – Initial Results from the SGIG Consumer Behavior Studies", Published by DOE in July 2013.

[25] There would, however, be conservation of natural gas power plant fuel under such a scenario.

[26] Based on a marginal generation capacity cost of $85 per kW-year, adjusted by a factor of 70% to reflect the fact that TOU rates are elevated only during the summer peak hours. This adjustment uses the loss of load probability ("A-factor") methodology proposed by SCE in A.07-07-026 to reflect limited hours of operation of demand-side resources.

[27] Based on $5 per million Btu.

[28] Based on $20 per ton of CO_2 equivalent.

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TURN's critique of DRA's TOU benefits analysis begins on a reasonable note but soon ventures into questionable assumptions:

> As aptly described by the Sierra Club, the calculation of marginal carbon intensities for on versus off-peak generation is extremely complicated. While there is data suggesting a positive impact in California, this impact depends greatly on the nature of off-peak generation, and the relative impacts likely change daily and seasonally, and may well change dramatically over time.

DRA agrees with this passage, but disagrees with the implication of the following reference to the possibility of increased coal consumption:

> In other parts of the Western Electric Coordinating Council, off-peak generation from baseload coal is actually more polluting. The biggest unknown factor is how much load is shifted to part-peak versus off-peak, and the amount of system power imports from the Southwest that might replace on-peak generation. At least one study conducted for the CEC suggests that any pure "peak" load reduction mechanism could actually increase net CO_2 emissions in the Western grid by increasing imports of dirtier system power from the southwest.

TURN clearly implies that TOU rates in California could somehow increase coal generation in the Western Electric Coordinating Council area, thereby negating any environmental benefit.

TURN's logic is defective on several levels. First, TURN uses the phrase "baseload coal." If coal is base loaded, then its production cannot be ramped up to meet increased off-peak demand in California. Second, recent PG&E "effective marginal heat rate" calculations imply that natural gas units, and not coal production, are on the margin during the off-peak hours. Third, implementation of cap and trade will make coal increasingly uncompetitive with natural gas-fueled and renewable-fueled generation.

Regarding the second point above, PG&E has presented heat rate data in its 2014 GRC. These data show an off-peak average heat rate of 5,900 Btu per kWh compared to a summer peak average of 9,100 Btu/kWh.[29] This implies that, during off-peak hours, there are relatively efficient natural gas units (e.g., with heat rates between 6,000 and 7,500 Btu/kWh) that are idle due to low demand. If off-peak demands were to increase in California due to load shifting, surely the more efficient of these idle units would be called upon before any "dirtier system power from the southwest". In fact, the amount of capacity that can be base loaded could be expected to increase under TOU rates, thereby reducing inefficiencies associated with unit "start-ups" and "shut-downs."

In a similar vein, NRDC relies on a single, uncorroborated, 13-year old study to make a similar point about coal.[30] No party has provided any recent and credible evidence that transitioning California's customers to TOU rates would increase the consumption of coal in the Western U.S. Absent such evidence, the Commission should place no weight on these assertions of TURN and NRDC.

3. Cost-Based Rates

TURN makes an error with respect to the cost basis of TOU rates, stating:

> The argument that TOU rates more correctly reflect marginal costs than tiered rates is not entirely self-evident. While it is true that marginal prices on the wholesale markets are higher during a limited number of hours of peak demand, the relationship is nowhere near as dramatic as during the 2000-2001 time period, when 100% of energy was purchased on the Power Exchange spot market.

[29] PG&E's 2014 GRC Ph. 2 (A.13-04-012) marginal energy cost workpapers contain hourly "effective marginal heat rate" data by month and by CAISO peak and off-peak period based on four years of CAISO locational marginal price data. DRA computed the average summer peak period heat rate based, on the CAISO peak period data for May-October (from noon to 6:00 PM), as 9,100 Btu/kWh. The off-peak average heat rate, of 5,900 Btu/kWh, was computed similarly. The calculation used the CAISO peak hour data for those hours that occur within the 16-hour CAISO peak period and the off-peak period data only for those hours that fall outside the CAISO 16 hour peak period.

[30] The 2000 "study" cited by NRDC was based on a dispatch simulation using a model called "Aurora". The peak hour was listed as 10:00-11:00 in July & August. This study has little if any relevance to CA: (1) it's old, the WECC generation fleet has changed a lot in 13 years; (2) it does not use a peak hour definition that is relevant to CA; and (3) it does not model the impact of shifting load in CA on the deployment of WECC generation.

As DRA noted in its July 12, 2013 Opening Comments, TURN did not sufficiently distinguish between dynamic pricing and TOU pricing. With dynamic pricing, retail prices are intended to follow the unpredictable fluctuations of wholesale real-time energy markets.[31] With TOU pricing, retail prices follow the regular and predictable hourly variations in marginal costs averaged over groupings of similar hours. Similarly, TURN fails to distinguish between hourly wholesale prices and marginal generation costs. The latter are, at least in part, designed to reflect longer-term cost causation.[32]

Thus, TURN continues:

> Presently, the on/off peak price differentials are significantly muted due to resource adequacy requirements. This is precisely the point made by DRA in its Motion to Reopen the Record in A.09-02-022, filed on October 31, 2011. (TURN Opening Comments, pp. 51-52)

Whether TURN's statement continues to be true or not, it is largely irrelevant to TOU rates. No party has alleged that the ***marginal cost*** differences between on-peak and off-peak hours are "muted." In fact, there currently is at least a three-to-one variation in generation energy and capacity costs between the on-peak and off-peak periods. It is these marginal cost differences that TOU rates are designed to track, not the fluctuations in the hourly spot markets for electric energy.

4. DRA Has Provided Mitigation Measures to Address Significant High Bills or Hot Summer Bill Scenarios.

TURN pointed out that residents of hot climate zones in the Central Valley have high summer electric demand due to air conditioner use. Thus, the introduction of time-

[31] This is true, at least, for RTP. CPP prices are artificial, and do not necessarily correspond either to wholesale real-time energy market prices or marginal costs.

[32] Hourly wholesale energy market prices rarely reflect the full value of capacity costs, and therefore often diverge greatly from the generation energy and capacity marginal costs that are the basis for TOU rates.

varying rates with higher on-peak prices will result in much higher summer bill impacts for these residents.[33]

As noted in DRA's May 29th proposal and July 12th Opening Comments, DRA has provided comprehensive mitigation measures to minimize such impact:

- Customers will start with a transitional rate. The Introductory TOU rate will begin with a very mild TOU surcharge of 4 cents/kWh during summer peak hours. The on and off-peak rate differential will gradually increase over time to limit bill impacts.[34]

- Customers will have the choice of opting out to tiered rates. In actual fact, customers who live in hot climate zones and must use air conditioning in the summer season are likely to be the same customers who would reach the higher tier rates. Therefore, they are likely to see substantial bill increases during summer seasons with either tiered or TOU rates. However, if they prefer tiered rates, they can opt out to tiered rates.[35]

- Customers can elect to have a SNAP credit or balanced payment scheme to spread out their high summer bills over a few installments and have stable monthly payments over the year.[36]

- IOUs would target outreach and education to customers who have significant bill increases with the goal of connecting them with energy efficiency ("EE") or other customer programs to help reduce their energy usage over time.[37]

- IOUs would provide financial incentives for high-usage low-income customers, as well as offering programmable communicating thermostats ("PCTs") or other EE devices.

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[33] TURN July 12 Opening Comments, p. 3.

[34] DRA RROIR May 29, 2013 Proposals, p. 17, Table 2

[35] Id, pp. 34-35, Tables 4 & 5, customer choices.

[36] DRA RROIR July 12, Opening Comments, p. 5.

[37] DRA RROIR May 29, 2013 Proposals, p. 44

- Vulnerable customers would be kept on tiered-rate options.[38]

It is also worth noting that a recent DOE study states that many utilities commented on the importance of effective training for installation personnel and contractors who meet with customers in their homes to install devices such as in-home devices ("IHDs") and PCTs. They state:

> The installers were frequently asked questions about the time varying rate programs, and being able to answer them accurately and represent the programs effectively were said to be a key part of making the installation experience positive and customer-friendly.[39]

DRA also urges the IOUs leverage on the above lessons learned when IOUs design their outreach and education to implement TOU rates.

C. Transitional Rates

SCE and TURN both argue that DRA's introductory TOU rate is too complicated because it combines tiers and TOU periods. SCE states:

> Based on SCE's experience, tiered, TOU rate structures such as those proposed by DRA or NRDC are simply too complex to be successfully adopted by residential customers. Although DRA's proposed end-state state rate structures are relatively simple, DRA's "simplified introductory TOU rate" has nine rates (3 tiers times 3 TOU periods) in the summer season and six rates (3 tiers times 2 TOU periods) in the winter season. (SCE, Reply Comments, p. 28)

TURN states:

> "[A]fter examining DRA's proposal, which provides for some tiering with a TOU rate, we suggest that a non-tiered TOU rate option may better provide customers (and vendors) with the ability to model the economics of energy efficiency or demand response investments. We appreciate DRA's point that even a tiered TOU

[38] DRA RROIR May 29, 2013 Proposals, p. 13

[39] "Analysis of Customers' Enrollment Pattern in Time-based Rate Programs – Initial Results from the SGIG Consumer Behavior Studies", Published by DOE in July 2013. Executive Summary, p. V.

> rate could be made understandable to a customer; however, we remain concerned that even if the rate is understandable, it may still be too complicated to allow for easy evaluation of the payback period for any particular investment in more efficient appliances or lighting."

SCE's argument ignores that the purpose of structuring the introductory TOU rate as a transitional rate.[40] It also is simpler than most existing California IOU TOU rates, such as PG&E's E-6 tariff.[41] DRA also emphasizes that its Introductory TOU rate is presented as a transitional "stepping stone" to a simpler TOU rate with a baseline credit, which is its proposed end-state default residential rate. Further, DRA was the only party to present a feasible, detailed plan for transitioning from today's four-tier, non-TOU rates to a simple TOU rate design with a baseline credit. DRA believes that its end-state rate proposal is the simplest possible proposal that meets the Commission's ten rate design objectives set forth in this Proceeding, and we appreciate that SCE acknowledges the relative simplicity of this rate. While DRA's Introductory TOU rate is more complex than its end-state TOU rate, DRA has established that the additional complexity is needed to enable a transition to the simpler TOU rate design, consistent with bill impacts that are acceptable to customers.

As for TURN's argument that customers would not be able to compute a pay-back period for a combination tiered-TOU rate, what really complicates this calculation is the tiered rate design. Even with a simple tiered rate design such as TURN's May 29th proposal, the customer must determine in which tier their marginal usage falls. This can

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[40] DRA's Introductory TOU rate contains an overlay consisting of a peak surcharge and off-peak credit. As such, it is presented as five rates (three tiers plus a surcharge and credit), not nine rates in the summer and six in the winter, as SCE contends. PG&E offers its Smart Rate as an overlay that can be placed on top of any rate schedule.

[41] Certain SCE rate schedules, such as SCE's Schedule TOU-D-T-CPP, as adopted in D.13-03-031, are even more complex than either PG&E's E-6 or DRA's proposed Introductory TOU. SCE's Schedule TOU-D-T-CPP is structured similarly as an overlay, but SCE's rate contains not only tiers and TOU periods, but a CPP surcharge plus two levels of a PTR credit (with and without technology).

vary from month to month. The TOU surcharge and credit are comparatively easier to deal with in a payback period calculation. For end uses that operate in all time periods (e.g., refrigerators), the surcharges and credit can be ignored since they are designed to be revenue neutral with respect to each other for the average customer. For those that predominantly are used on-peak (e.g., air conditioners) or off-peak (lighting), only the surcharge or credit would be applied respectively.

D. CARE and Baseline

1. CARE Issues Raised by SCE

On page 52 of SCE's Opening Comments, SCE discusses Public Utilities ("PU") Code §382 (b) in conjunction with its proposal to decrease the CARE discount from the current effective level of 31% to 32% (for SCE) to 20%. SCE states that its proposal would comply with this statute but that the determination of meeting basic needs should be left to the Commission in future rate setting proceedings. PU Code §382 (b) states:

> In order to meet legitimate needs of electric and gas customers who are unable to pay their electric and gas bills and who satisfy eligibility criteria for assistance, recognizing that electricity is a basic necessity, and that all residents of the state should be able to afford essential electricity and gas supplies, the commission shall ensure that low-income ratepayers are not jeopardized or overburdened by monthly energy expenditures. Energy expenditure may be reduced through the establishment of different rates for low-income ratepayers, different levels of rate assistance, and energy efficiency programs.

DRA proposes that the CARE discount for SCE and SDG&E should be 30%, which is close to the current level for these two IOUs. DRA also will examine the CARE discount issue in future rate setting proceedings as well as in CARE proceedings and in disconnection proceedings. DRA remains concerned about the level of CARE disconnections throughout California, and is concerned that lowering the CARE discount to 20% would result in even more service disconnections for CARE customers. In an era where CARE customers already are having trouble paying their electric bills, DRA fails to see how SCE's proposal complies with PU Code §382 (b).

On page 53 of SCE's Opening Comments, SCE discusses DRA's recommendations regarding the level of appropriate CARE discounts. SCE states:

> …DRA proposes end-state CARE rates that would deliver a discount of 35% for PG&E customers and essentially hold the average elective CARE discount to 30% for SCE and SDG&E electric customers. There is no basis or rationale for such an arbitrary outcome.

DRA extensively examined bill impacts of rate design proposals. Based on this analysis, and because of the differing circumstances for these IOUs, DRA recommends different levels of CARE discounts for the different IOUs. PG&E currently has an effective CARE discount of roughly 48%, while SCE and SDG&E currently have effective CARE discounts of 31% to 32%. DRA recommends a target 35% CARE discount for PG&E to move PG&E closer to the other two utilities. Moving PG&E's even to a 35% CARE discount will entail substantial CARE bill increases. Because of the size of the bill increases, DRA recommends that the reduction in the CARE discount be implemented gradually. During the course of this transition, CARE customers will be subject to other bill increases stemming from other proposed changes in residential rates.

DRA recommends a target CARE discount of 30% for SDG&E and SCE. This level of discount is closer to the current level of the CARE discount for these two IOUs. Thus this transition will result in smaller bill increases than those for PG&E. DRA's proposed CARE discounts take into account the current CARE discounts for PG&E, SCE, and SDG&E, and the fact that the effective CARE discounts for these IOUs are currently so far apart.

The Environment Defense Fund ("EDF") makes a number of recommendations regarding the CARE program in its Opening Comments. On pages 5 to 6, it states:

> EDF supports maintaining and even increasing the CARE discount. EDF suggests that in the first phase of a transition, CARE customers be given the opportunity to see TOU rates on an opt-in basis. Once into the transition, EDF recommends moving to opt-out TOU rates for CARE customers if certain agreed-upon metrics are met. As well, EDF recommends that CARE customers receive a "basket of

goods and services", such as set-it-forget-it thermostats, with dual goals of education and enablement that helps households reduce their energy bills through energy conservation and load shifting.

Several of these ideas deserve further consideration. The idea for a two-phase transition to default TOU rates for CARE customers, with additional metrics that must be met, is a creative proposal that could help these customers' transition process to default TOU. EDF's idea for a basket of goods and services for CARE customers also should be examined more thoroughly. DRA could support this proposal if three conditions are met:

- Such goods and services would be incremental to the CARE rates discounts that DRA is proposing,
- Consensus could be reached on which goods and services to offer to CARE customers, and
- The total expenditures on these goods and services are reasonable.

2. Tier Differentials

Page 8 of SCE's Opening Comments discusses its proposed tier differentials and states:

> SCE's proposed tier differentials do not include fixed charges in the Tier 1 usage level, i.e. these are not nonbaseline to baseline "composite" tier differentials. PUC Code 739.7, which requires an "appropriate inverted rate structure", has been interpreted by the Commission to include any fixed or minimum charge revenues with the baseline volumetric rate to determine whether the tier structure is inverted. This approach was used to protect low-usage customers from substantial bill impacts when the legislature directed the Commission to significantly reduce the tier differentials. It should not be applied to the current residential rate reform process because it could defeat the purpose of reductions to the volumetric rate differentials, assuming a meaningful fixed charge is ultimately reflected in residential customer rates.

DRA disagrees with SCE and proposes to maintain the Commission's approved "composite baseline approach" when examining tier differentials between tier 1 and tier 2 rates. Using this approach, customer charges are considered part of the baseline rates

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(tier 1 rates) for the purpose of calculating tier differentials. The Commission has looked at the issue of appropriate tier differentials since the 1980s and consistently has ruled that the composite baseline is the best approach to guarantee baseline protections for low usage customers.

The essence of the baseline statute is that the tier 1 rate be ***lower*** than the tier 2 rate. This is because the intent of the statute is to provide a discount on baseline usage. But, if a sufficiently large fixed charge is levied in addition to the tier 1 rate, then the effective ***average*** rate that the customer would pay for baseline usage could exceed the tier 2 rate. This would violate the intent of PU Code § 739.7. This is the reason for the composite baseline approach. If fixed charges are allowed for residential customers in the future, it will be important to maintain the composite baseline approach and limit any new fixed charges, so that the average baseline rate remains below the tier 2 rate.

To elaborate, PU Code §739(b) states that "The Commission shall designate a baseline quantity of gas and electric which is necessary to supply a significant portion of the reasonable energy needs of the average residential customer." This is because the goal of the baseline program is to provide affordable gas and electric prices for a significant portion of reasonable energy needs. Maintaining the availability of electricity to the greatest number of California residents remains an important policy. Such a policy is similar to the policy of universal service in the telecommunications industry. It is important that the Commission continue to promote access to a commodity which is essential to basic comfort and safety. Viewed in these terms, the Commission's practice of including the customer charge in a calculation of composite baseline rates makes sense. By using a composite baseline approach, the Commission could help maintain the current high level of access to electricity usage.

The Commission's longstanding support for the composite tier one approach is discussed in numerous Decisions. For instance, in D.87-12-039, the implementation decision of the restructuring of the gas industry, the Commission stated:

> …the issues raised during this proceeding concern the imposition of new customer charges, the increase of present customer charges,

> and the question of whether to include customer charges in the calculation of baseline rates. The issue of whether customer charges must be included in the calculation of the baseline rate is so well settled in favor of inclusion that it requires no further discussion. Our current policy will continue.[42]

In D.89-01-055, an Order modifying but denying rehearing of D.88-10-062, which examined the Realignment of Residential Rates, Including Baseline Rates, of California Energy Utilities, continued this approach:

> We share TURN's view that SB 987 and §739(c) of the Public Utility Code require that residential rates be inverted. We also reaffirm our view that revenues from any customer charge must, as a matter of law, be included in the baseline rate for the purposes of §739(c) When this is done under the rate structure we have adopted for CP National's South Lake Tahoe District, the inverted rate structure disappears and becomes one of declining blocks, in contravention of the statue.
>
> In order to correct this situation, we will adopt TURN's proposed modifications to the South Lake Tahoe rates. This means that the baseline commodity rate will become 46.4 cents, and the Tier II rate will become 57.612 cents. The "total baseline rate", including the $5.50 per month customer charge, will be 55.055 cents. This will preserve the inverted rate structure. (D.89-01-055, mimeo, p. 1)
>
> While SB 987 grants this Commission significant additional flexibility in establishing residential rates, the total baseline rate, including any customer charge revenue, must still be less that the non-baseline rate.
>
> Because they result in a declining block rate structure when the customer charge revenue is added to the baseline commodity rate, the rates proposed by CP National for its South Lake Tahoe District are unlawful."(D.89-01-055, mimeo, p. 2, emphasis added)

In SCE's 1996 GRC Phase II proceeding, the Commission found it appropriate to use a composite tier one approach where a residential customer charge exists:

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[42] D.87-12-039, 26 CPUC 2d 270.

> We also note that the composite approach is consistent with our policy of applying the CARE discount to customer charges. As we stated in D.89-09-044: "In the case of utilities which assess a monthly residential customer charge, the discount will apply to the customer charge as well. This is because the customer charge collects revenues that would otherwise be collected through the tier 1 rate. (32 CPUC 2d 406,410)[43]
>
> The Decision went on to say:
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> In PG&E's test year 1993 GRC, we adopted PG&E's proposal to use a simple tier differential in conjunction with its current minimum charge because we agreed that it was easier to implement than the composite approach. However, we stated that there may be technical problems with that approach when it is applied with a customer charge. Moreover, we noted that the issue of including a customer charge in a composite tier 1 rate was not well developed in that case. In contrast, this issue was fully explored on the record in this proceeding."[44]
>
> It concluded:
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> In view of the above, we will adopt a 1.15:1 composite tier ratio for both summer and winter seasons at this time.[45]

Thus, in D.96-04-050, the Commission found it appropriate to use the composite tier one approach for a utility with a residential customer charge.

In D.00-04-060, SoCalGas' 2000 Biennial Cost Allocation Proceeding, the Commission again found it appropriate to use the composite tier one approach for a utility with a customer charge. This decision provides a good summary of this issue:

> Section 739(c) (Public Utilities Code) requires the Commission to establish "baseline rates" which apply to the lowest block of an increasing block rate structure. The statute is premised on the principle that "electricity and gas are necessities, for which a low

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[43] D.96-04-050, 65 CPUC 2d, 428.

[44] D.96-04-050, 65 CPUC 2d, 428.

[45] D.96-04-050, 65 CPUC 2d, 432.

> affordable rate is desirable." (739 (c) (2).) Section 739.7 similarly requires an "appropriate inverted rate structure". These code sections have been consistently interpreted to include the customer charge in determining whether the rate structure is, in fact, inverted. Under this "composite tier differential" approach, customer charges are considered part of the Tier 1, or baseline, rate for the purpose of calculating tier differentials. (D.87-12-039, 26 CPUC2d 213, 270; D.89-01-055; D.97-04-082, pp. 117-118)[46]

It went on to say:

> We reject SoCalGas' proposal. As we said in the last SoCalGas BCAP, "Therefore, we should retain the existing tier differential calculated on a composite basis. The composite tier differential is more meaningful than the simple differential because it gives the price for access and purchase of a quantity of gas that covers basic needs. (D.97-04-082, p. 118)[47]

Thus, the Commission has consistently ruled that a utility with a customer charge should use a composite baseline approach in evaluating the appropriate tier differentials between tier 1 and tier 2 rates, and to achieve an appropriate inverted residential tier structure that is required by § 739.7. SCE's proposal to abandon the composite baseline approach when examining appropriate tier differentials should be rejected. Continuing to include any fixed charge revenues in the composite baseline calculation makes sense as the composite baseline approach helps to ensure access and affordable rates for basic uses of electricity. SCE's approach could result in especially harsh bill impacts if its proposals for a fixed charge and a two-tiered rate design were adopted.

E. Legislative Changes

A majority of the parties' Opening Comments did not elaborate on the legislative changes they suggested in their rate design proposals. PG&E pointed out that a broad spectrum of stakeholders "share with PG&E and the other utilities the consensus opinion

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[46] D.00-04-060, p.105.

[47] D.00-04-060, p.107.

that legislative reforms are needed to return to the Commission the ability to address the fairness and reasonableness of residential electricity rates."[48]

PG&E goes on to specifically discuss DRA's proposed legislative changes and states, DRA "endorses the need for legislative reform to allow the current rate design structure to be modified."[49] PG&E mischaracterized DRA's legislative changes proposal as endorsing their overly broad statutory reform proposal. DRA does support modifications to the PU Code Sections 739.1(b)(2), 739.9(a), and 745(d), but desires to maintain adequate important customer protections. Whereas, PG&E recommends broad changes and deletions of the entire PU Code sections, including Sections 739(d), 739.1, and 739.9. These vary significantly from DRA's recommended specific modifications, which were described in detail in DRA's Opening Comments.[50]

The Alliance for Solar Choice ("TASC") proposes an optimal rate structure that is similar to DRA's suggested end state rate. TASC acknowledges that P.U. Code §739.9(a) interferes with their proposed rate structure because it limits annual increases to baseline quantities and usage up to 130% of baseline. DRA's rate design proposal recommends modifying P.U. Code §739.9(a) to allow for limited rate increases to the baseline rate and to 101% to 130% of baseline usage, in order to combine Tier 2 and Tier 3. TASC recommends "limiting the applicability of Section 739.9(a) to increases up to baseline usage rather than 130% of baseline usage where a rate design also incorporates a TOU component."[51] DRA supports a majority of TASC's proposal for modifications to P.U. Code §739.9(a) because it gives the necessary flexibility for the changes to rate design but makes that flexibility contingent on the incorporation of a combined TOU/Tiered structure. DRA suggests slightly modifying TASC's proposal to allow for

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[48] PG&E OC, p. 6.

[49] PG&E OC, p. 6.

[50] DRA OC, p. 51-55.

[51] TASC Opening Comments, p. 17.

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greater rate increases to the baseline rate than currently are allowed by statute, while still maintaining important baseline protections.

III. CONCLUSION

Redesigning rates to reflect the marginal cost of service will be complicated both by bill impacts as well as by parties' differing views on what the true cost of service is. Parties agree that costs vary by season and by time of day, but they differ on whether fixed connection costs are marginal costs that should be recovered in a fixed charge.

DRA has attempted to present a balanced proposal that would introduce time-varying rates with a transitional Introductory TOU rate. It has provided mitigation measures, such as snap credits and opt-out provisions, to ease the transition and to address bill impacts. DRA opposes fixed monthly charges, but because this is such a complex issue, it is best left for the GRCs.

It will take many years to transition customers to fully cost-based default TOU rates. But that transition should begin as soon as possible, ideally in each utility's next GRC.

Respectfully submitted,

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