BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U39M)	Application 16-06-013 (Filed June 30, 2016)

ALTERNATIVE PROPOSAL OF THE OFFICE OF RATEPAYER ADVOCATES, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, AND THE UTILITY REFORM NETWORK FOR DETERMINATION OF FIXED COSTS

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In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission (the "Commission"), and the September 22, 2016 e-mail ruling of Administrative Law Judge ("ALJ") Jeanne M. McKinney ("ALJ Ruling"), the Office of Ratepayer Advocates, the Solar Energy Industries Association and The Utility Reform Network (collectively the "Joint Parties") submit this fixed cost report addressing categories of fixed costs to be considered in developing a future fixed charge and related topics, as well as materials intended for use at the workshop on November 2, 2016.

I. INTRODUCTION

The Joint Parties have come together to present a common methodology for determining the fixed costs to potentially include in the calculation of a fixed charge. We believe that this approach is consistent with Commission policy, as expressed in its previous examinations of the just and reasonableness of imposing fixed charges on residential consumers, and is consonant with the legislature's intent in AB 327 in affording the Commission greater authority to explore the imposition of fixed charges. Moreover, in crafting this proposal, the Joint Parties were aware that any adopted methodology for determining which utility costs are fixed, and which of such costs should be included in a fixed charge, should reflect the Commission's Rate Design Principles. The Joint Parties look forward to the workshop scheduled for November 2, 2016 where we can present our proposal to all parties.

In brief, the Joint Parties propose that the portion of the utilities' fixed costs that could be included in a fixed customer charge should be limited to those ongoing marginal customer costs that do not vary with customer usage. These are limited to (1) customer service costs and (2) operations and maintenance ("O&M") costs for the final-line transformer, service line, and meter ("TSM") equipment.

The Joint Parties emphasize that we are presenting a fixed charge proposal only because the focus of the workshop is on determining fixed cost categories that could be included in a fixed charge. The Joint Parties' preference is to retain the current minimum bill structure, and we propose a simple, practical $10 minimum bill consistent with the approach adopted by the Commission in D.15-07-001. This level of a minimum bill exceeds a reasonable calculation of marginal customer costs under either the new customer only (NCO) or rental methods.

In authorizing the Commission to consider whether to adopt a fixed charge, the Legislature included a requirement that any approved charge "reasonably reflect an appropriate portion of the different costs of serving small and large customers."[1] The Joint Parties do not offer a specific proposal for adjusting the fixed costs to reflect this difference at this time. Once the Commission establishes a methodology for calculating customer-related fixed costs, the requirement to differentiate between large and small customers should be addressed for purposes of developing any specific customer charges.

[1] Cal. Pub. Util. Code §739.9(e)(1).

II. CATEGORIES OF FIXED COSTS ELIGIBLE FOR FIXED CHARGE RECOVERY

In determining which categories of costs should be eligible for recovery in a fixed charge, it is imperative that the Commission recognize that the concepts of "fixed costs" and "fixed charges" are separate and distinct. A <u>fixed charge</u> is a type of utility rate that does not vary with customer usage and <u>fixed costs</u> are costs that do not vary with customer usage, where usage is defined fairly broadly as discussed below. Our review of the three investor owned utilities' ("IOU") proposals reveals that they have inappropriately conflated the two concepts.

AB 327 defines *fixed charges* as the following:

> "Fixed charge" means 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.[2]

The IOUs have mistakenly cited AB 327 as "identif[ying] *costs* eligible for recovery through a residential fixed charge."[3] In fact, the statute does not define the term "fixed costs."[4] The purpose of this proceeding is to identify any fixed costs that might be recovered through a fixed charge in the future.

In discussing fixed costs in Decision 15-07-001, the Commission defined them as those costs that do not change as a result of individual customer usage.[5] The question then becomes "usage of what"? The term "usage" is not confined to energy usage (i.e., kWh) and necessarily includes capacity usage in the form of peak demand (kW). Capacity costs vary as a result of individual customer demand on system or circuit capacity. An electric customer can use (and

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[2] Cal. Pub. Util. Code § 739.9.
[3] *See, e.g.*, San Diego Gas & Electric Company Fixed Cost Report; p. 9, Pacific Gas & Electric Company Fixed Cost Report, p. F-5.
[4] The only reference to "fixed costs" appears in Public Utilities Code Section 739.9(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.")
[5] D. 15-07-001, p. 190.

pay for) system or circuit capacity (kW) even if it does not consume any energy (kWh), for example, when a self-generation customer takes standby service. Thus, demand-related costs should not be categorized as fixed or customer-related costs, nor should such costs be recovered through a fixed charge such as a fixed monthly customer charge.

The IOUs propose that fixed costs should not only include customer-related costs but should also encompass any generation- and distribution-related capacity costs that exceed marginal costs as well as the full costs of public purpose programs ("PPP"). The methodology by which the IOUs propose to calculate these fixed costs is to subtract their marginal costs from their revenue requirements -- the entire remainder, according to the IOUs, is fixed costs. SDG&E goes even further, and characterizes all capacity-related costs, including marginal generation, transmission, and distribution capacity costs, as "fixed."[6]

Fundamentally, the IOUs' definition of fixed costs does not make sense. These costs should not be considered "fixed" if they are expected to change (or even be eliminated) based solely on the delta between total costs and the evolving calculation of marginal costs. Under this approach, increases to marginal costs in the future would necessarily reduce the calculation of "fixed" costs. The Joint Parties believe that these remaining costs are more appropriately defined as out-of- market costs -- i.e., the costs that remain when marginal cost revenues are insufficient to recover the IOUs' overall revenue requirements. With respect to generation, these out-of-market costs are the product of low gas costs, the acquisition of state-mandated renewables, and the lack of demand or need for additional capacity. This out-of-market component could be reduced or eliminated in the future, for example, if gas costs increase or if there is a strong upswing in the demand for and usage of electricity. Plainly, these are not fixed costs.

[6] San Diego Gas & Electric Company Fixed Cost Report, at Table 3.

Similarly, the IOUs' labeling of the PPP revenue requirement as a fixed cost belies fundamental economics and cost causation principles. The cost driver for these programs is not customer usage but rather state policies that support social equity goals (such as low-income assistance) and encourage reductions in demand as a substitute for building more generation (such as energy efficiency programs). The Commission has long found that the PPP costs of compliance with these state mandated programs should be collected through usage-based rates and allocated via broad measures of customer usage such as equal cents per kWh, and not collected regressively as part of a fixed customer charge.

Moreover, in examining the appropriate methodology for determining the fixed costs that could be included in a fixed charge, the Commission should look at its past examination of the issue as well as the indications of legislative intent. In this regard, the Commission, in discussing whether it was just and reasonable to include a fixed charge as a component of residential rates, stated that "[a] well-designed fixed *charge representing a portion of the fixed customer-related cost*s to serve the individual residential customer could be reasonable."[7] The Commission went on to state:

> Although we believe that a fixed charge may be appropriate for residential rates in the future, particularly as the electricity market evolves to accommodate increasing opportunities for customers to manage their own electricity needs, *fixed costs should be calculated in a manner that truly reflects customer-specific costs and minimizes regressive impacts of this cost collection method.*[8]

There is no basis for the Commission to find that the sweeping approach proposed by the IOUs is consistent with the Commission's stated intent of identifying "customer-specific costs" that "minimize[] regressive impacts" on customer bills. The Commission's focus on customer-specific costs is consistent with the statutory limitation of $10 per month ($5 per month for

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[7] D. 15-07-001 at Conclusion of Law (COL) 16 (emphasis added).
[8] *Id.,* p. 191 (emphasis added).

CARE customers) on fixed charges. This limitation demonstrates the Legislature's intent to ensure that "fixed costs" are narrowly defined and does not support the IOUs' efforts to claim that these "fixed costs" include large amounts of demand-related generation, transmission, and distribution capacity costs as well as public purpose program costs.

III. THE IOUS' PROPOSED FIXED COST METHODOLOGY DOES NOT COMPLY WITH A NUMBER OF THE COMMISSION'S RATE DESIGN PRINCIPLES.

The Rate Design Principles used in Phase 1 of R.12-06-13 and recognized by the Commission in Decision 15-07-001 must govern the adopted methodology for determining the fixed costs that could be included in a fixed charge. The methodology advanced by the IOUs appears inconsistent with several of these rate design principles:

- **<u>Principle 2</u>: Rates should be based on marginal costs.** A long-standing principle of the Commission's marginal cost ratemaking has been to use an Equal Percentage of Marginal Cost ("EPMC") multiplier to scale marginal cost revenues up or down to match the embedded cost revenue requirement. This process allocates the difference between marginal and embedded cost revenues in proportion to <u>all</u> marginal cost drivers. In contrast, if the IOUs' proposal to consider all above-marginal-cost revenues to be "fixed costs" is adopted, and if those revenues are allocated and collected through a fixed customer charge, they would be allocated based on only one cost driver -- the number of customers -- which would further distort and attenuate the marginal cost price signal.

- **<u>Principle 3:</u> Rates should be based on cost-causation principles.** The IOUs propose to recover through a fixed charge certain allegedly fixed costs (i.e., a portion of generation and distribution capacity costs, or, in SDG&E's case, all of such costs) that actually will vary with changes in peak demand (i.e. with changes in customer usage of system and circuit capacity). Recovering such variable costs through a fixed charge does not comport with cost causation.

Moreover, while the Joint Parties recognize that the purpose of this proceeding is to adopt a methodology for determining fixed costs and not a fixed charge, the Commission should be cognizant of the fact that the adoption of the methodology advanced by the IOUs would provide the underpinnings for the consideration of fixed charges which range from approximately $30.00 to $80.00 per customer/month. Such a fixed charge would violate several more of the Commission's Rate Design Principles.

- **Principle 4: Rates should encourage conservation and energy efficiency.**

Rates that recover through a fixed charge the entire difference between revenues at marginal cost and the authorized revenue requirement, as proposed by the IOUs, do not accomplish this goal of encouraging conservation and energy efficiency. The ultimate result of the implementation of the IOUs' approach is a very large fixed charge which, for many customers, would be the vast majority of their bill. The customer, no matter how much they conserve, will not be able to avoid that charge, and the resulting usage-based rates could be so low as to significantly reduce the value of conservation, efficiency and load shifting. Maintaining a strong conservation price signal through volumetric rates is particularly important given the state's ambitious new greenhouse gas reduction goals adopted in SB 350 and the need to ensure that rate design does not work at cross-purposes with existing energy efficiency programs and incentives.

- **Principle 5: Rates should encourage reduction in peak demand.** For the same reason that the IOU proposal will not encourage conservation of energy, it also will not incentivize customers to reduce their peak demands. By categorizing a large amount of demand-related costs as fixed costs, the IOUs are suggesting that these costs should be recovered through fixed monthly charges or demand charges. However, fixed customer charges or demand charges are not cost-based ways to collect capacity costs from small customers. Capacity-related costs can be recovered through either tiered rates or time-sensitive volumetric rates. Either approach represents a more accurate and efficient means to recover demand-related costs from small customers than monthly fixed charges or demand charges. Energy usage is correlated with demand, particularly when energy usage is measured on a time-sensitive basis. *See* Appendix B illustrating that residential demand charges are not cost based.

- **Principle 9: Rates should encourage economically efficient decision making.**

Economically efficient decision-making should include, to the extent possible, recognition of the external costs of our dependency on fossil fuels and of the broad economic benefits of a transition to cleaner sources of energy. Economically efficient decision making would be frustrated through rates that do not properly encourage customers to take actions to reduce demand, lower usage, and shift consumption to more optimal time periods.

IV. JOINT PARTIES' PROPOSAL

The Joint Parties prefer continuation of the current minimum bill provision. Because the workshop is focused on the determination of fixed cost categories that could be included in a fixed charge, we also present an illustrative customer charge proposal. Our customer charge proposal is described in Section A below and our minimum bill proposal is in Section B.[9]

The Joint Parties prefer a minimum bill provision for three reasons:

1. Significant debate over the portion of distribution costs that are customer versus demand-related supports a more cautious approach to the recovery of these costs,

[9] As noted above, the fact that the Joint Parties provide an illustrative customer charge proposal does not mean that each of the organizations will support a fixed residential customer charge regardless of the methodology used to calculate the amount.

2. Hookup costs are only marginal in the year when the hookup initially is installed, and thus are sunk costs for all existing customers.

3. Unavoidable customer charges or membership fees are very rare in unregulated industries where there is a robust level of competition.

Our first reason for preferring a minimum bill relates to the ongoing debate over the portion of distribution costs properly classified as customer-related versus demand-related. This debate previously resulted in the Commission adopting a compromise, where the final-line transformer, service line, and meter ("TSM") are classified as "customer-related," and all other distribution system equipment is regarded as demand-related.[10] The obvious problem with this compromise is twofold. First, elements of the cost of transformers are demand-related, and to some extent, the same is true of service lines. In the 1980s, the Commission investigated ways of teasing out these separate cost drivers using statistical and engineering methods. But none of these approaches yielded conclusive results. For this reason, the TSM approach to classifying distribution costs was adopted. Second, while TSM equipment is uniquely dedicated to medium and large commercial and industrial customers, the same does not hold true for the residential and small commercial customers. The TSM definition is a better fit for most of the non-residential classes than it is for residential. Thus, caution should be exercised in instituting customer charges in the residential class, even though they exist in other customer classes.

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[10] D.86-08-083. In PG&E's Energy Cost Adjustment Clause proceeding, the Commission adopted for the first time The Public Staff Division's recommended "Directly Assignable Cost" ("DAC") method. Under the DAC method, any equipment uniquely assignable to customers is designated as "customer-related" and everything else "demand-related." That equipment that is directly assignable was deemed to be the final line transformer, service line, and meter (or "TSM"). Two years later, the possibility of separating the demand-related from customer-related equipment upstream from the final line transformer was explored in SDG&E's GRC. D.88-12-050 in that proceeding found that doing so was too difficult and thus it retained the DAC approach. It stated, on p. 19, that, "while there is not a clear line of distinction between demand and customer related equipment, we believe the TSM method provides us with the best approximation."

Our second reason for favoring a minimum bill provision is that the TSM hookup costs are only marginal in the year in which this equipment is installed. After that, they become sunk fixed costs, also known as "embedded" costs. Rate Design Principle 2 states that rates shall be based on marginal costs, not fixed costs. Fixed costs and marginal costs are not the same thing. Recovery of fixed costs is better accomplished through a minimum bill provision. That way, the rates themselves can reflect marginal costs without being contaminated with fixed costs. The only manner in which fixed embedded costs are allowed to influence rates, under marginal cost ratemaking, is through the EPMC scalar. Whether the scalar should be part of a customer charge is discussed below.

Our third reason for preferring a minimum bill over a fixed customer charge is that fixed charges and membership fees are very rare in truly competitive industries. Competitive industries often are not able and are not obligated to recover fixed costs through fixed charges. They commonly do so through a markup on the wholesale price, which is somewhat analogous to the EPMC multiplier. In Phase 1 of the RROIR, the IOUs argued that their use of a fixed charge is similar to Costco's membership fee and the various kinds of fixed charges employed by health clubs, cable television, the internet, and telephones. The IOUs, however, overlooked the point that neither the retail nor the communications industries offer fixed charges as the only option available to customers. Most offer choices. Indeed, a characteristic of robust competition is that it produces multiple choices in how to pay for goods and services.

Emulating a competitive market is a goal of marginal cost ratemaking. As stated in D.96-04-050, "Since 1981 … This commission has relied on marginal cost principles in order to simulate, to the extent possible, the pricing structure and resulting efficient resource allocation of a competitive market."

A. Fixed Customer Charge Proposal

The Joint Parties' customer charge proposal includes all ongoing costs and excludes capital costs that are made once, and thereafter, are sunk. Ongoing costs would be the cost of customer services and billing, plus the cost of operations and maintenance ("O&M") of equipment. Excluded would be the capital costs of the TSM hookup.

The cost of capital equipment is excluded because that cost is a sunk cost for all existing customers, who comprise about 98% of the customers who would be paying this charge. We also exclude the cost of hookups for new customers that year, even though they are included in the New Customer Only ("NCO") method, because they are marginal costs only in the year those hookups are made. It is important that the cost of new hookups is being imposed on the utility by a very small number of developers and contractors. Making the entire body of existing ratepayers pay for this in the form of a customer charge sends a meaningless price signal to those who are paying it. This suboptimal ratemaking practice is a result of the current practice of line extension allowances, which creates a large cross subsidy between existing and new customers. It would be more economically efficient if these costs were paid for by developers and built into the cost of homes. The Joint Parties are fine with continuing the inclusion of marginal customer costs in revenue allocation, since the entire body of residential customers includes both new and existing customers. But including these costs in rate design merely aggravates the suboptimal ratemaking practice of line extension allowances.

The Joint Parties believe that the NCO method is superior to the rental method since it replicates a ratemaking practice that actually occurs. Clearly, as hookups are added, the utility incurs costs at the margin. But we must be clear about who is imposing these costs even though they are collected from all customers. Under the NCO method, these costs are collected in proportion to the annual growth rates of individual classes, a factor over which no existing customer has control. Thus, including these costs in a customer charge would add further confusion to whatever price signal is built into that charge. The most recently litigated decisions have adopted the NCO method.[11] The Joint Parties strongly support the continuation of this approach.

Though we exclude the TSM capital costs, it would be reasonable to include the O&M costs on that equipment. These costs are ongoing whereas the TSM hookup itself occurred at a single point in the past. However, we do recognize that the O&M could have been excluded because the commitment to provide this O&M was made when the hookup was installed, and that commitment was in the past. The treatment of replacement TSM equipment capital in marginal costs has been debated in past proceedings. ORA has typically excluded replacement costs because they are excluded from marginal distribution demand costs. PG&E, in its compliance filings showing the NCO approach, has excluded it and SCE has included it. For the purposes of a customer charge, we excluded these costs.

There is a debate as to whether the EPMC scalar should be included as part of the customer charge. This is an area where some latitude exists because not all rate elements are scaled by the same proportion in performing rate design. Critical peak pricing rates often are not scaled, and small commercial customer charges often reflect little or no scaling because of the wide range of customer sizes to which the charge applies.

At a minimum the Joint Parties believe that the scalar should be excluded for one very practical reason. Given that the Phase 1 RROIR decision adopted composite tier differentials, scaling the marginal costs upwards will merely be offset by higher tier differentials. Thus, scaling will accomplish very little on a net basis for the many customers consuming just above or

[11] PG&E GRCs D.92-12-057 and D.97-03-017; SCE GRC D.96-04-050;1999 SoCal Gas/SDG&E BCAP D.00-04-060.

just below the baseline level. However, another reason for excluding the scalar is because customers cannot meaningfully respond to a fixed charge. The only way they can avoid it is by disconnecting from the utility system, which is not practical today in the absence of cost effective storage systems. It would be more meaningful to apply the scalar to rate elements to which customers can respond. Applying a larger scalar to energy rates will promote conservation and energy efficiency. Finally, as indicated before, unregulated markets with robust competition do not make fixed charges mandatory, but offer choices. To make the fixed charge essentially mandatory, by incorporating it into all rate schedules or by including it in the default rate, and then to scale the resulting number to make it more than twice the size, merely makes a suboptimal rate design even worse.

Illustrative numbers for our proposal are shown in Table 1. For simplicity, all of our illustrative numbers start with the IOUs' presentation in this proceeding. The actual numbers would be determined through litigation or settlement in future proceedings. We make several changes to the raw IOU numbers.

1. First, we subtract account setup costs from PG&E's Revenue Cycle Service costs because they are associated with new customers only. The data did not exist to do so for SCE or SDG&E. But we recommend excluding these costs for the other two utilities in future proceedings.

2. Second we subtract 37 cents per month from SCE's illustrative figures to exclude costs of uncollectible accounts because Commission precedent dating back to the 1980s excludes uncollectibles from marginal customer costs.[12] The other two IOUs do not include these costs.

3. Third, customer O&M costs collected in revenues paid by specific customers (service establishment, field collection, reconnection, returned checks, advanced meter opt-outs)

[12] In the last litigated phase 2 for SCE, the Commission reaffirmed that uncollectibles should be excluded from marginal customer costs (D. 96-04-050, pp. 70-71). In that decision, the Commission stated that exclusion of uncollectibles "is consistent with our practice in many recent cases both gas and electric. *See, e.g.*, D. 93-06-088 50 CPUC 2d 118, p. 135. The 1989 PG&E GRC also excluded uncollectibles. *See* D. 89-12-057, 34 CPUC 2d 199 at 320 corrected three errors identified by TURN, one was inclusion of uncollectibles, as shown in A. 88-12-005, Ex. 235 (TURN testimony), p. 24.

are double-counted if included in customer charges. To reflect this, we subtracted 18 cents per month from the SDG&E illustrative figures for revenues identified in UCAN's testimony[13] and accepted by SDG&E in rebuttal testimony. Depending on the specifics of the utilities' calculations that we have not examined, similar reductions may need to be made for PG&E and SCE.

4. Finally, we note that the SDG&E O&M number is much higher than that of PG&E and SCE, and future proceedings should investigate whether this difference is justified.

	PG&E	SCE	SDG&E
Ongoing Customer Services	$2.80	$2.16	$2.18
Equipment O&M	$0.44	$0.11	$2.52
TOTAL	$3.24	$2.27	$4.70

The actual utility tables from which these numbers are taken, along with a description of the sources of data, appear in Appendix A. Note that the Joint Parties do not support many of the numbers in the utility tables, even while using customer O&M costs from the tables.

B. Minimum Bill Proposal

The Joint Parties believe that the current $10 minimum bill applied to delivery services is reasonable. The figure is small enough that it will largely assure collection of a minimum amount of distribution system revenues from vacant dwellings and rental units between tenants,

[13] A. 15-04-012, Prepared Testimony of Garrick Jones and William Perea Marcus on behalf of UCAN (July 5, 2016), p. 22. The revenues did not include advanced meter opt-out revenues.

customers with net energy metering, and other unusual conditions such as extended vacations. Most customers would not be affected.[14]

The table below analyzes minimum bills based on the number of kWh of delivery service that the minimum bill purchases and examines the reasonableness of this metric based on several measures of customer costs. The metrics that we used to evaluate this minimum bill proposal were the NCO and RECC customer costs developed by TURN and UCAN in recent cases, as well as modified NCO and RECC data based on excluding the cost of transformers and 30% of AMI meter costs cost.

In developing modified NCO and RECC calculations for evaluation, transformers are excluded because there is extreme variability in the number of customers per transformer, from over 25 in many apartment buildings, to 5 to 10 customers in subdivisions, to one or a few customers in rural areas or large custom home developments.[15] This variability means that averaging transformer costs will tend to require smaller users and those in apartments to subsidize larger users and those in single-family homes. We exclude 30% of meter costs, because smart meters were originally projected to have an operational benefit-cost ratio of 60% to 70% based on reducing meter reading and other customer-related distribution system costs such as field orders. In other words, access can be provided by ordinary meters at 60-70% of the cost of smart meters. Smart meters are installed instead because they can provide system benefits unrelated to metering and customer costs such as the ability to provide for widespread time-of-use rates and critical peak pricing, allow the measurement of other demand response programs, and they provide upstream benefits on the distribution network such as outage detection. The remaining 30-40% of AMI costs are thus related to policy, to improving service

[14] Significant increases to minimum bills above the $10 level would end up raising costs to customers in the smallest apartments.
[15] There is also variability in service drop costs, but that variability is not as large as for transformer costs.

and reducing distribution O&M costs, and to substituting preferred resources in the loading order for generation. They are not customer access costs.

As shown below, the minimum delivery service bill of $10 collects the costs of slightly over 100 kWh of delivery service at baseline rates for the three utilities. It is higher than NCO and RECC costs modified to exclude transformers and 30% of meters as well as full NCO customer costs. while being slightly below the full RECC amount.

	minimum bill	delivery rate per kWh	kWh of delivery	Customer Variable	Modified NCO	Modified RECC	Total NCO	Total RECC
SDG&E	$ 10.00	$ 0.07928	126	$ 4.62	$ 5.49	$ 7.28	$ 6.86	$ 12.09
SCE	$ 10.00	$ 0.08843	102	$ 2.16	$ 3.83	$ 7.08	$ 4.85	$ 10.40
PG&E	$ 10.00	$ 0.08669	115					
SDG&E delivery rate is arithmetic average of summer and winter rates.								
SCE kWh of delivery reflects $1 customer charge.								
PG&E rates effective October 1, 2016.								
	http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_SCHEDS_E-1.pdf							
SCE Rates effective September 21, 2016. minimum bill includes $1 customer charge.								
	https://www.sce.com/NR/sc3/tm2/pdf/ce12-12.pdf							
Uses Edison's capital costs, TURN RECC and PVRR, which excludes Administrative and General								
Costs included by Edison except for insurance and uses current cost of capital.								
Removes uncollectible accounts expenses from O&M.								
SDG&E Rates effective July 15 2016.								
	http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_DR.pdf							
Uses SDG&E's rebuttal case for RECC and NCO, except for UCAN's transformer capital cost								
and UCAN's 1.5% replacement rate for NCO equipment. Uses UCAN's O&M calculations.								

Respectfully submitted this 26th day of October, 2016, at San Francisco, California.

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Appendix A

Sources of Illustrative Numbers*

- **PG&E**
  - Customer Services: From Table F-2, RCS cost of $3.52 less New Account Setup cost of $0.72.
  - O&M: From PG&E's MCAC workpapers in this GRC. O&M adders are multiplied by plant costs. Meter O&M costs are excluded because they already are included in RCS.
- **SCE**
  - Customer Services: From SCE Fixed Cost Report, Appendix B (10/6/16). We used the adopted "Customer Service and Billing" cost.
  - O&M: *Ibid*., O&M from 1/9/15 errata. (Note, we used the errata because O&M is not broken out in the adopted numbers.)
- **SDG&E**
  - Customer Services: From SDG&E's Fixed Cost Report, p. 17 (10/6/16). We used "Total Customer Accounts/Services Costs." O&M: *Ibid*. We used the "O&M Cost" applied to the TSM.

* The Joint Parties used data from the following tables for constructing illustrative marginal customer cost values, and the Joint Parties do not endorse or agree with the IOU's marginal customer cost calculations.

Source of PG&E Data

TABLE F-2
PG&E ESTIMATED RESIDENTIAL MARGINAL CUSTOMER COSTS

[A] Marginal Customer Costs	[B] Costs ($/cust-yr)	[C] Costs ($/cust-mo)	[D] Costs ($ million/yr)
Revenue Cycle Services (RCS) Costs			
Account Set-Up	$8.59	$0.72	$41
Meter Reading	$4.77	$0.40	$23
Billing and Payment	$14.97	$1.25	$71
Credit and Collections	$2.11	$0.18	$10
Metering Services	$11.84	$0.99	$56
RCS Total	$42.28	$3.52	$201
New Connection Costs	$117.67	$9.81	$559
Total Marginal Customer Costs	$159.95	$13.33	$760

Source of SCE Data

SCE 2015 GRC		
Marginal Customer Costs	SCE Proposed Errata 1-9-2015	Settlement Agreement *
Final Line Transformer (FLT)	$3.61	
Service Drop	$4.10	
Meter and Panel	$1.83	
Customer Service	$2.49	
O&M	$0.11	
Collections	$0.23	
Total $/Customer Month**	$12.37	$7.97

Notes:
* 2015 GRC Phase 2 Marginal Cost and Revenue Allocation Settlement Agreement: TURN's 50:50 NCO; RECC Monthly RECC Customer

** The $12.37 ($/cust-mo - 2015$) in the table above represents the *weighted average of all sub categories* in the Residential class
The customer service costs (Monthly A+B+C in table below) for each group is as follows (2015$);
- Domestic TOU ($/cust-yr) = $32.55 ($2.71 * 12)
- Domestic Master Metered ($/cust-yr) = $163.62 ($13.64 * 12)
- Single / Multi Family ($/cust-yr) = $32.28 ($2.69 * 12)

The Proposed and Adopted table below details only the Single Family costs

Proposed Residential Distribution Marginal Costs (Single Family)

[A]	[C]	[C1]	[D]
Marginal Customer Costs	Costs ($/cust-mo) 2015$	Costs ($/cust-yr) 2015$	Costs ($ million/yr)
Billing and Customer Service Marginal Costs For 2012			
Meter Services (A)	$0.09	$1.08	$5
Meter Reading (B)	$0.42	$5.04	$22
Customer Service and Billing			$0
Perform Credit Checks and Manage Deposits			
Billing Exceptions	$0.34	$4.08	$18
Interval Data Management	$0.00	$0.00	$0
Send Monthly Bill	$0.40	$4.80	$21
Process Customer Payment	$0.13	$1.56	$7
Customer Inquires (trouble,billing, turn on/off, payment, misc)	$0.63	$7.56	$33
Field Services	$0.06	$0.72	$3
Collections	$0.25	$3.00	$13
Uncollectibles	$0.37	$4.44	$19
MAFs			
Sub total (C)	$2.18	$26.16	$114
Monthly (A+B+C)	$2.69	$32.28	$140
Final Line Transformers, Service Drop, Meter and related O&M (D)	$10.64	$127.68	$555
Single Family Monthly (A+B+C+D)	$13.33	$159.96	$695

Customer-months 52,139,961
Customers 4,344,997

Check: $645
Weighted average of the residential class (single, multi, TOU & master-meter) => $644

Adopted Residential Distribution Marginal Costs***

[A]	[B]	[C]	[D]
Marginal Customer Costs	Costs ($/cust-yr)	Costs ($/cust-mo)	Costs ($ million/yr)
Billing and Customer Service Marginal Costs For 2012			
Meter Services (A)			
Meter Reading (B)			
Customer Service and Billing			
Perform Credit Checks and Manage Deposits			
Billing Exceptions			
Interval Data Management			
Send Monthly Bill			
Process Customer Payment			
Customer Inquires (trouble,billing, turn on/off, payment, misc)			
Field Services			
Collections			
Uncollectibles			
MAFs			
Sub total (C)			
Monthly (A+B+C)	$30.36	$2.53	$132
Final Line Transformers, Service Drop, Meter and related O&M (D)	$65.28	$5.44	$284
Monthly (A+B+C+D)	$95.64	$7.97	$416

Customer-months 52,139,961
Customers 4,344,997

Check: $417

Source of SDG&E Data

TABLE 4
SDG&E ESTIMATED RESIDENTIAL MARGINAL CUSTOMER COSTS

[A] Marginal Customer Costs	[B] Costs ($/cust-yr)	[C] EPMC-adjusted Costs ($/cust-yr)*	[C] Costs ($/cust-mo)	[D] EPMC-adjusted Costs ($/cust-mo)*
Customer Accounts/Services Costs				
Customer Services Field	$3.70	$6.06	$0.31	$0.50
Advanced Metering	$1.75	$2.86	$0.15	$0.24
Billing	$1.80	$2.95	$0.15	$0.25
Credit & Collections	$1.32	$2.17	$0.11	$0.18
Remittance Processing	$2.47	$4.05	$0.21	$0.34
Branch Offices	$1.03	$1.69	$0.09	$0.14
Customer Contact Center Operations	$4.69	$7.68	$0.39	$0.64
Customer Contact Center Support	$1.18	$1.94	$0.10	$0.16
Residential Customer Services	$3.97	$6.51	$0.33	$0.54
Communication, Research & Web	$4.94	$8.10	$0.41	$0.68
Customer Programs & Projects	$0.66	$1.09	$0.06	$0.09
Other Office	$0.37	$0.60	$0.03	$0.05
Shared	$0.40	$0.65	$0.03	$0.05
Total Customer Accounts/Services Costs	**$28.29**	**$46.36**	**$2.36**	**$3.86**
New Connection Costs				
Annualized Transformer, Service & Meter Costs	$93.56	$153.35	$7.80	$12.78
O&M Costs	$30.24	$49.56	$2.52	$4.13
Total New Connection Costs	**$123.80**	**$202.91**	**$10.32**	**$16.91**
Total Marginal Customer Costs	**$152.09**	**$249.27**	**$12.67**	**$20.77**

APPENDIX B

Marginal Cost, Revenue Allocation and Rate Design Policy Issues for San Diego Gas and Electric Company

Prepared testimony of
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on behalf of
Utility Consumers Action Network

California Public Utilities Commission
Application 15-04-012

July 5, 2016

VI. Rate Design Policy – Demand Charges

One key aspect of rate design policy is that SDG&E believes that demand costs should be collected in demand charges. SDG&E witness Ms. Fang says the following about generation and distribution capacity costs.

> Distribution Demand Costs – SDG&E incurs these costs independent of energy usage. These costs are incurred on the basis of local capacity needs to meet the combined maximum demand of customers served off of a given circuit. These costs are best recovered on non-coincident demand ("NCD"), distribution demand costs should be recovered in a NCD charge ($/NCD – kW).
>
> Generation Capacity Costs – SDG&E does not incur these costs on the basis of energy usage, but rather on the basis of meeting net peak capacity needs of the system; therefore, system capacity costs should be recovered in a demand charge consistent with the time period in which those costs occur, which is demand at the time of net system peak when SDG&E may require additional capacity ($/peak-kW).[34]

We respond to this testimony to demonstrate that the residential demand charges are not cost-based and therefore should not be pursued.

A. Problems with Demand Charges Other than their Cost Basis

Demand charges were invented in the 1890s because all that a meter could measure was the customer's non-coincident peak demand and folks in the industry, without today's computer technology that enables better analysis, simply thought that customer peaks had something to do with system-wide phenomena.

Demand charges have been made obsolete in large part by time-of-use energy rates. But utilities support them because they create revenue stability at the expense of efficient energy use. High-load factor industrial customers support them, because they gain an advantage relative to lower load factor commercial customers in the same rate classes. And there is an almost ideological belief, presented as fact by many utilities, that a cost related to system demand in some way should be charged to customers based on the customer's demand even though the nexus between customer demand and system demand is not clear at all, particularly for the residential class. Thus, demand

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[34] Prepared Testimony of Cynthia Fang, pp. 14-15.

charges have persisted despite technological obsolescence. But they should not be expanded to residential customers.

Using a smart meter to deliver a residential demand charge instead of a time of use rate is like using a sophisticated video camera to take grainy snapshots.

Customers also mistrust demand charges. A recent focus group study in Ontario, Canada, where time of use (TOU) rates have been in place for several years and customers are thus fairly sophisticated, suggests that residential customers do not understand demand charges and believe that such charges are demanding perfection in their conservation efforts. The Ontario Energy Board conducted an analysis with residential focus groups that raised concerns about maximum monthly usage charges (another term for demand charges) in addition to TOU rates that Ontario customers understand:

> The concept of maximum use during peak times is difficult for people to understand and raised concern among a few. There is no template for measuring maximum use that people are used to in the way they understand TOU. It was not obvious how this would be calculated.
>
> Without precise details of this there was concern expressed by some that small lapses in their conservation efforts will mean they will have to pay a high price for that (even if they conserve diligently on the vast majority of days during peak times). So there will be questions of fairness if they have conserved on the vast majority of days during peak demand times and essentially helped to reduce peak consumption.[35]

There are a number of reasons why residential demand charges are a bad idea.

1. They blunt incentives to conserve – even during peak periods - once a maximum demand is hit. Here is a personal example. Because it was 108 degrees in the Central Valley and I had a houseguest, I ran both air conditioners in my house and clearly hit a maximum demand in the last week of June that I haven't seen in a couple of years. With a demand charge, I would have far less incentive to conserve energy – even on other hot days that stress the system which might be a little cooler or without the houseguest – because I would

[35] The Gandalf Group, Ontario Energy Board Distribution Charge Focus Groups: Final Report, October 9, 2013, p. 9.

already be tens of dollars of fixed charges in the hole and my savings from reducing energy use would be limited.

2. They require customers to keep track of random events which have no intrinsic value to anyone. Customers do not want to be rate computers, but to reduce their demand charge they need to have the following scenario in mind **every winter morning**: "My coffee-maker is running, and it's chilly so my furnace fan is running. That means I shouldn't turn on the toaster and the hair dryer at the same time at 7 am or I could get a higher demand charge. I need to wait 15 minutes to use that toaster." This kind of price signal is totally disconnected from either causation of or avoidance of utility costs. It is also a waste of the very limited amount of brainpower that most people want to spend on their electric rates. So customers will eventually screw up, pay up, and give up.
3. They give customers who are connected to gas incentives to get rid of electric stoves and ovens and electric dryers. Before bringing in a residential demand charge, an electric utility should have the obligation to inform customers them that an electric stove is one of the worst things to own if there's a demand charge – either non-coincident or peak period only, because the oven plus the air conditioner will trigger the charge. If SDG&E were in competition with an independent gas utility, which it is not, it would be handing the gas utility a great marketing plan to poach load from the electric utility because gas would be far more cost-effective by avoiding demand charges.
4. Residential demand charges have bizarre impacts on cost-effectiveness of energy efficiency to customers – which are not necessarily the same as cost-effectiveness to the utility or society. Getting a more efficient air conditioner (or even a smaller one of the same efficiency) can avoid a demand charge, but weatherizing one's house so an existing air conditioner runs less frequently but produces the same number of kilowatts when it turns on, will not reduce the customer's bills nearly as much, even if it has similar effects on system peak demand.
5. Specifically, residential non-coincident demand charges such as those proposed by SDG&E for distribution can work at cross-purposes with time-of-use energy rates. A customer does everything she can to not use peak period energy, and when the peak period is over turns on energy-consuming equipment. Bingo! High demand charge to penalize her for following the TOU price signals. And more customer confusion.

6. If a utility wants to reduce feeder loads and defer construction, a time of use rate component at times when most feeders are peaking will do a better job than a demand charge. If it wants to build as many feeders as possible to expand rate base without demand reductions getting in the way, a demand charge is the best way to build them and get customers to pay for them.

But having briefly made these points, which I will expand upon in far more detail at a later time if SDG&E actually proposes something instead of just talking about policy, I now analyze the major objection to residential demand charges. They are not cost-based.

Demand charges systematically overcharge small users. The summation of the analysis below is that residential customers using less than 300 kWh use 15% less demand per unit of energy than the system average but would pay 27% more demand charges that the system average. Residential customers using over 1000 kWh use approximately the same amount of demand per unit of energy as the system average but would pay 32% less demand charges per unit of energy than the system average. The large customers are subsidized by the small customers. Demand charges (or other fixed charges for costs that vary with usage) are Robin Hood in reverse.

The Commission should reject residential demand charges out of hand for creating intra-class subsidies of big users, before even thinking about dealing with the rest of the problems caused by their implementation that I discussed above.

B. Some Key Concepts in Analyzing Demand Charges

Critical concepts in analyzing demand charges are load diversity and coincidence.

Load diversity reflects the fact that the utility does not expect to experience the maximum NCP load of each individual customer at the same time, on parts of the system that do not serve a single customer (i.e., all parts of the system other than service lines to an individual customer and specific transformers that serve one single customer). As a result, the utility does not need to build most of its system to meet the sum of each customer's NCP. The system becomes more diverse (i.e., the load that the system must carry becomes a smaller fraction of the sum load of the individual customers) as more customers are aggregated. SDG&E's engineering manuals suggest that load diversity even for sizing transformers is 70% for single-family customers with air conditioning, 60% for multi-family customers with air conditioning, and 50% for customers without air conditioning.[36] Thus, at the level of the transformer, 30-50% of the individual customer's non-coincident peak load is diversified away in SDG&E's own engineering analysis, which is likely to be conservative to prevent overloads.

Coincidence is related to the concept of load diversity, which can be examined at the level of the individual customer, the entire rate class, or subsets of the class.

The analysis involves a comparison of the customer's own maximum demand with estimated generation or distribution demands available for those same customers. While recognizing that generation demand is allocated over a large number of hours, this analysis used the four coincident peak hours in the months of July-October (4CP) because those data sets were readily available from SDG&E's load data. We analyzed distribution demand on a system-wide basis using SDG&E's load research sample based on the Class Peak demand, given that feeders and substations serving residential customers peak later in the day than the system peak and closer to the residential class' own peak. We also conducted a review of the extent to which the customer's NCP, when combined with energy in the relevant time period, explains the customer's Class peak or 4CP demand.

The coincidence factor is thus the generation or distribution demand divided by the customer's NCP demand. The NCP demand can be calculated as the maximum demand in the year, or alternatively as the average maximum demand on a monthly basis (how a demand charge in equal dollars in every month would be calculated). The customer NCP demands will always be larger than the more diversified demands at 4CP or Class Peak. So the coincidence factor is always less than one. The lower the coincidence factor, the worse the sum of customer NCPs (and thus a demand charge) will be in actually matching up with the demand-related costs that the utility is proposing to collect through NCP demand.

The questions required to analyze the cost basis of demand charges are (1) whether the customer NCP has a systematic bias (i.e., smaller or lower load factor customers have a lower coincidence with generation or distribution demand than larger or higher load factor customers), (2) whether there are large amounts of variation in the coincidence among customers of the same size (so that

[36] UCAN DR 2-39, Residential Demand Estimating, Table 3, fourth page.

the coincidence is so variable that it cannot be used to establish a demand charge without harming large numbers of customers by charging them rates that are not cost-based), and (3) whether the generation and distribution demand costs can be better predicted by energy use in a relevant time period than by maximum customer NCP demand in the same time period. To the extent that energy use is a better predictor of Class Peak or 4CP than maximum NCP demand, a demand charge is a less accurate and more crude method of setting rates than an energy charge, which may include time-of-use components. The third question is answered by use of regression equations, which I discuss further below.

C. Using Load Research Data to Analyze Coincidence and Determine Whether Residential Demand Charges Are Cost-Based for SDG&E.

SDG&E's load research data for the Rate DR class was analyzed by breaking the residential class into groupings by average monthly usage and by comparing average usage to various measures of demand (the average 4CP (July-October) as a shorthand way to analyze generation demand, the class peak demand (for distribution demand), and the customer's own NCP measured in two ways – the maximum demand at any time in the year and the average of the 12 maximum demands in each month – which would be the basis for a demand charge). Coincidence of the NCP demand with Class Peak and 4CP and differences in load factor[37] by size of customers were computed.[38] The four figures below present data from SDG&E's load study for the residential class as a whole. Attachment 6 contains the aggregated data used to construct them.

[37] The load factor is the average load divided by the peak load being measured.

[38] From SDG&E's response to UCAN DRs 2-2 and 2-3. To conduct the analysis, I excluded customers with less than 50kWh in one month and customers whose minimum monthly consumption was less than 15% of the maximum monthly consumption to try to screen out customers with partial year data, and other customers whose load patterns changed dramatically in the middle of the year. This removed some solar customers but also screened out customers with bad data. I also excluded customers with missing demand data, even though energy data existed for them. Finally, five cases were removed where the maximum demand during the year was less than the average demand during the year, which is a physical impossibility and must result from some kind of data error.

Figure 1: Energy and Demand by Size of SDG&E Residential Customer

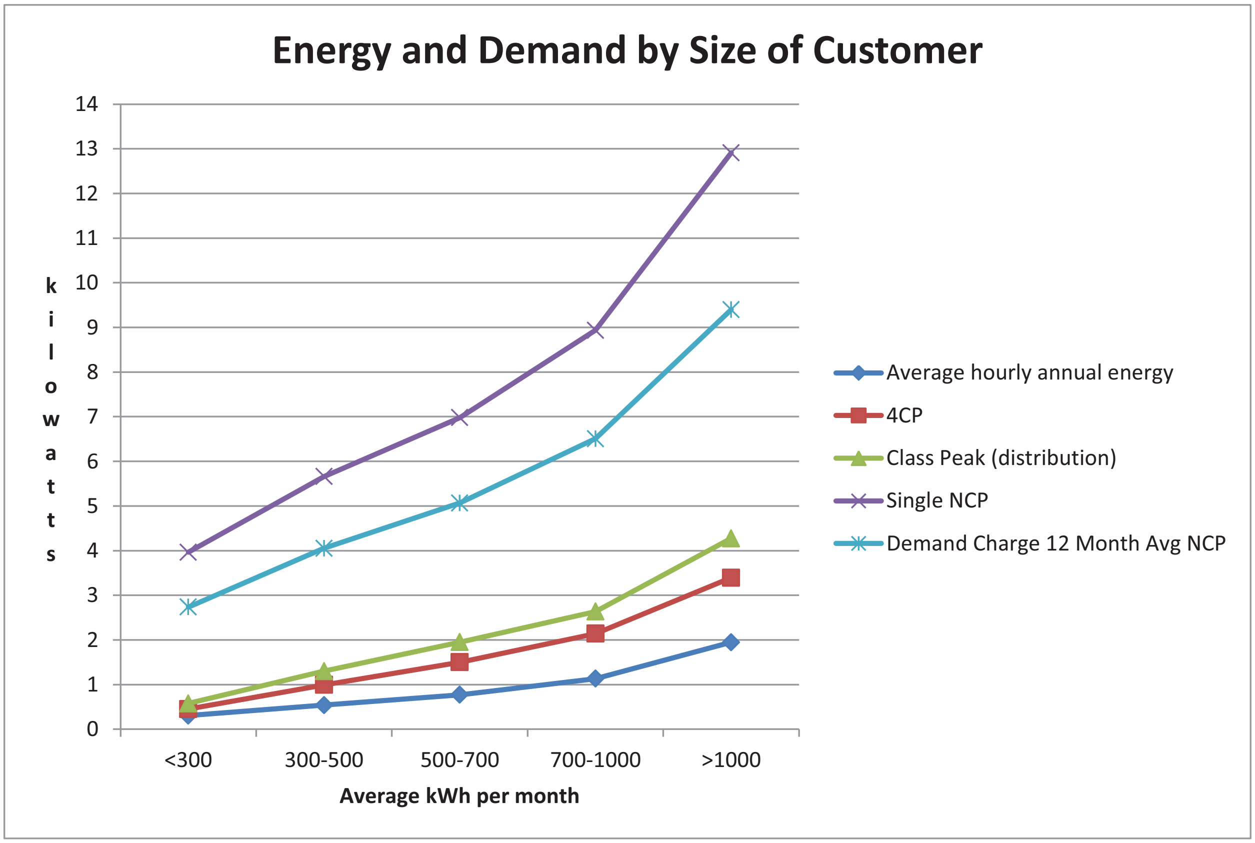

Figure 1shows the loads for residential customers of different size groups. SDG&E's strata were used to weight the specific customers in each group. It shows that from the smallest to the largest customers, energy use rises by 6.4 times, 4CP system peak rises 7.5 times, the MDD rises 7.4 times, but the NCP rises only 3.2 times based on the maximum throughout the year and 3.4 times based on the 12-month average on which demand charges are based.

Figure 2: Load Factors by Size of Residential Customer

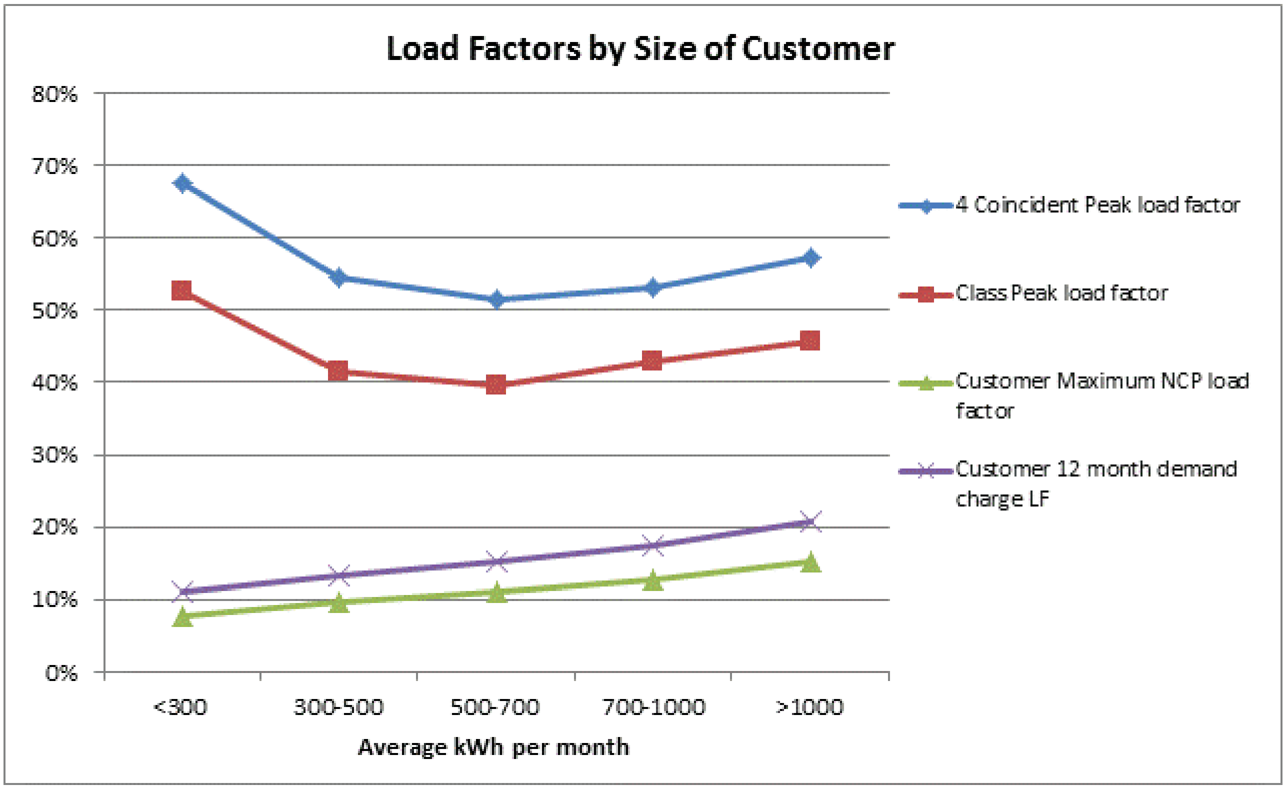

Figure 2 shows that the system load factors (4CP and Class Peak) are highest for the smallest customers and otherwise relatively constant across size ranges, except that the very largest customers have slightly better load factors than the mid-range. If the system load factors of smaller customers are the same as for larger customers, then the demand-related cost of service for those customers is approximately equal per kWh to larger customers. In the case of SDG&E, smaller customers have slightly better load factors than larger customers which would mean that their costs of generation, transmission, and distribution capacity per kWh of energy are actually lower than for larger customers. In any event, it is the <u>system</u> load factors that are important in determining the costs of serving customers.

The NCP load factor goes up as usage increases. But the NCP load factor—although the basis for a demand charge—is irrelevant to how the system as a whole is planned and operated. Therefore, assigning higher costs to customers with lower NCP load factors – which is what a demand charge does – is not cost-based if the underlying system load factors are similar or if small customers have better system load factors.

Figure 3: Coincidence by Size of Residential Customer

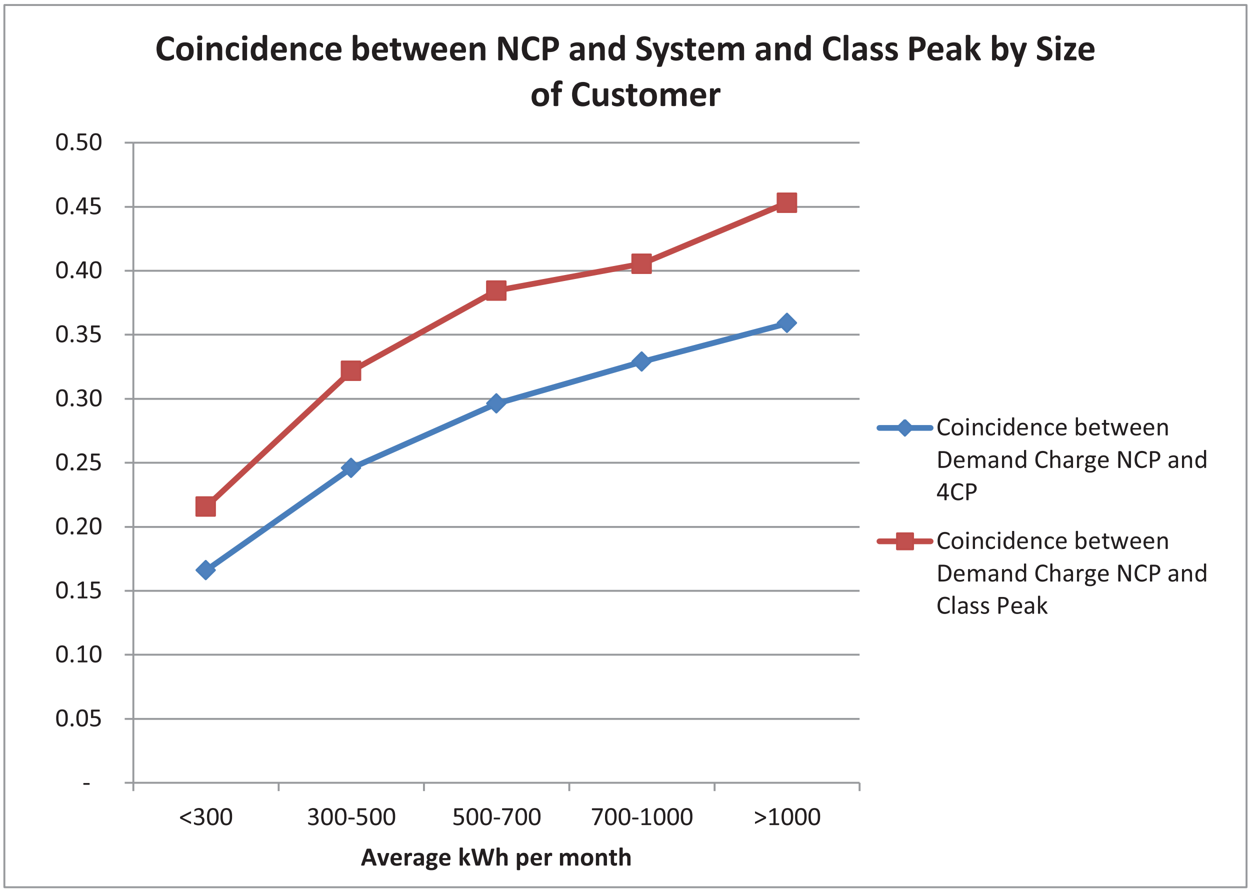

Figure 3puts it all together and looks at the coincidence between NCP and system peaks. It indicates that demand charges are highly problematic. The coincidence factors are not figures like 80% (as observed for large commercial and industrial customers with load factors above 40% in the load research studies provided to UCAN in response to DR 2-1 and other studies that I have reviewed) but are no higher than 50%. Thus, there is considerably more variation in customer NCP demand for residential customers than for non-residential customers. Moreover, coincidence is much lower for small residential customers than for large ones. Thus, using a maximum demand charge to collect demand costs will systematically overcharge small customers and undercharge larger customers on the SDG&E system.

Figure 4: Demand Costs and Charges, Relative to Class Average by Size of Residential Customer

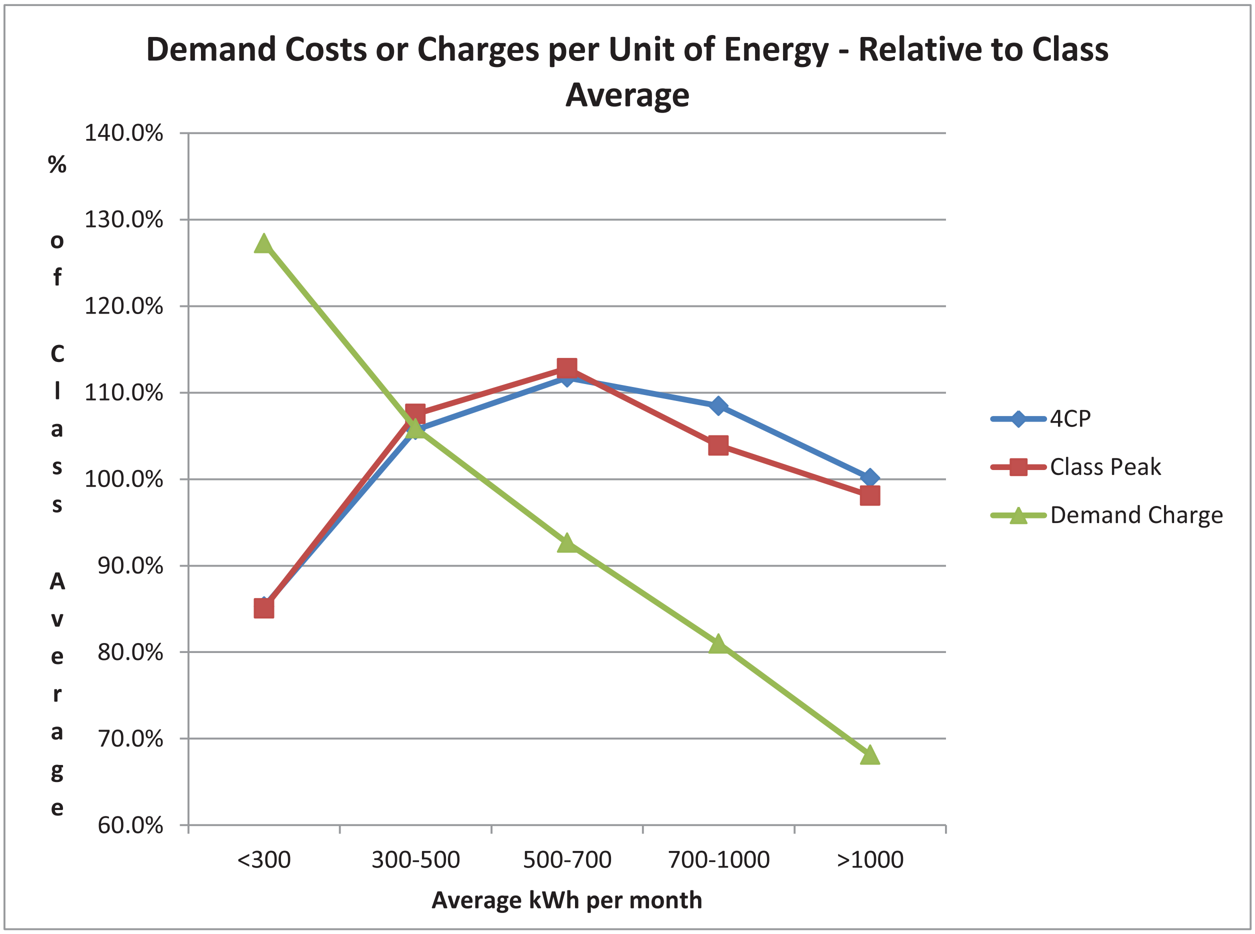

Figure 4 summarizes everything that is wrong with residential demand charges from a cost of service point of view. A residential customer using less than 300 kWh imposes approximately 15% less than the system average demand <u>costs</u> (measured by 4CP or class peak) per unit of energy but would pay 27% more demand <u>charges</u> per unit of energy than the system average. Similarly, the average customer using more than 1000 kWh has about a system average level of demand per unit of energy (101% of 4CP and 98% of class peak), while paying a demand charge that is 32% less than the system average. Thus demand charges on the SDG&E system would subsidize large customers at the expense of small ones.

D. Individual Residential Customers vs. Mobile Home Parks: An Example of Coincidence and Diversity

Finally, we can examine why individual residential customers' demand charges do not adequately reflect coincidence and diversity by comparing rate DR to rate DT (master metered mobile home parks). The chart below makes that comparison from SDG&E's 2013 load research data.

Table 16: Comparison of 2013 load characteristics of Individual Residential Customers and Master-Metered Mobile Home Parks

	Rate DR	Rate DT
Average number of customers	1,238,263	437
Annual Energy	7,142,254,160	155,111,564
Average hourly use	815,326	17,707
4CP	1,523,275	34,905
Class Peak	1,896,040	48,278
Demand Charge (12 NCP)	5,452,000	37,318
load factor		
4CP	54%	51%
Class Peak	43%	37%
Demand Charge (12 NCP)	15%	47%
coincidence of demand charge with		
4CP	0.28	0.94
Class Peak	0.35	1.29

The kW of noncoincident demand collected in demand charge (average of customer's NCP across the entire year) for a Rate DR customer is 3.6 times the 4CP demand and 2.9 times the class peak demand. For a Rate DT customer, the demand collected through a demand charge is 1.1 times the 4CP demand and is actually less than 0.8 times the class peak demand – a very different level of coincidence and diversity. The reason is that the demand measured at the mobile home park is a diversified demand of its residents, not the sum of each individual resident (as it would be with Rate DR).[39] Therefore, the coincidence of a demand charge paid by a mobile home park is much

[39] The 2013 load research data shows an average of 437 DT customers. We can estimate the average mobile home park served with electricity has somewhere between 50-70 spaces based on usage per park and usage per Rate DR residential customer. We unfortunately cannot provide a more precise estimate because SDG&E never in its workpapers included the number of spaces subject to the space discount in its billing determinants – unlike both of the other electric utilities in the state and unlike its own gas department's TCAP filing (where 239 GT customers served 27,189 spaces or 114 spaces per customer). We realized that this routine information was missing too late to

higher than for each individual residential customer, because the load is diversified across a large number of customers for each Rate DT meter. The load subject to the demand charge for the residential class as a whole would be 4.4 kW per customer. For master-metered mobile home parks, it is only 1.2 to 1.7 kW per customer (based on 50-70 customers per park). This illustrates the very large amount of diversity between one residential customer and a large number served through a single meter.

E. Regression Analyses to Show that Demand is More Related to Energy than Customers' Own Non-Coincident Peaks.

Ms. Fang stated that distribution and generation costs are "independent of energy usage."[40] Well actually they may not be. Energy usage appears to be a better measure of the demands that cause generation and distribution plant to be built than the customers' own non-coincident peaks. We used regression analysis to show this point.

I conducted a regression analysis relating 4CP and Class Peak to customers' summer energy use (July-October) and to maximum NCP summer demand. A regression equation is a statistical method of fitting a dependent variable (in this case 4CP or Class Peak) to one or more other independent variables to determine the best fit and the coefficients associated with each variable that give the least amount of variation (measured by the least squared error). A regression equation is more detailed than a simple coincidence analysis, as it takes into account all of the individual data points representing individual observations. In this specific case, the dependent variable was the measure of system peak (4CP or Class Peak). The two independent variables used (separately or in combination) were the customer NCP in the four summer months and kWh usage in the four-month summer period. Attachment 7 shows the equations.

For residential customers, NCP demand is a worse variable for explaining CP demand than energy use. Energy use by itself explained 57% of the variation in average 4CP demand, while NCP demand by itself explained only 44%. In other words, if an analyst were to choose only one variable to explain 4CP loads (or Class peak loads), NCP demand is a worse variable to pick than summer energy use. Using both variables, 61% of the variation was explained, but most of the

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submit a data request that could be answered in time for this filing. We have requested this information and will update these calculations when we receive it.

[40] Testimony of SDG&E witness Cynthia Fang, p. CF-15

variation was explained by differences in energy use. While the NCP variable was statistically significant it only had a coefficient of 0.098 (i.e., after considering energy, only 9.8% of NCP was related to 4CP).

For Class MDD, the relationships were less strong but similar. NCP demand was still a weaker variable. Energy use by itself explained 37% of the variation in Class peak, while NCP demand explained only 33%. Again, NCP would be a worse choice for a single variable. Using both variables, 42% of the variation was explained, and NCP was statistically significant but again only had a coefficient of 0.17, showing slightly more explanatory power than the 4CP equation but still relatively weak.

This information also suggests that demand charges for generation and transmission and distribution should not be used for residential customers. The NCP variable has only a weak explanatory power when examining both 4CP and class peak. The biases and problems with difference in coincidence by size of customer discussed overcome any weak explanatory power that such a variable might have.

F. Conclusion

As a matter of policy, demand charges should not be pursued. They are not cost-based because there is a large variation in the coincidence of NCP demand for residential customers, which can be driven by random fluctuations, particularly when measured on a short interval, with coincident peak demand and the class coincident peak. In addition, small customers have a higher NCP demand (caused by randomly turning on equipment) as compared to their coincident peak demands or class peak. This means that using a demand charge to collect either generation or distribution costs will systematically overcharge the average of small residential customers. Demand charges are not cost based for residential customers because they cause small customers to subsidize larger ones. If the utility wants to try to reduce generation peaks or substation and feeder peaks in residential areas, time-of-use rates will support that outcome better than crude 1890s rate design.

VII. Overall Conclusion

As noted in the detailed analysis provided by UCAN above, in addition to not pursuing demand charges for the residential class, whether the Commission chooses to apply the rental method or the NCO method for customer related costs, the Commission should use the estimates provided by UCAN. Also, given the significant concerns with SDG&E's allocation data there should be a 1.5% cap on rate increases to prevent significant increases that may arise from all of the moving of goal posts for generation and distribution costs. Finally, the Commission should reject SDG&E's three-year path to equal percent of marginal cost.

Joint Fixed Cost Proposal

Presented by Jeanne Armstrong (SEIA), Chris Danforth (ORA), and Bill Marcus (TURN)

PG&E GRC (A.16-06-013)

Second Fixed Cost Workshop
November 2, 2016

Definition of Fixed Costs

- Fixed costs are not the same as fixed charges.
- Fixed costs are not defined in AB 327.
  - Section 739.9(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 established this process in D. 15-07-001 in order to determine what are "fixed costs."
- D. 15-07-001 defined fixed costs as "costs that do not change as a result of individual customer usage" (see p. 190).

Definition of Usage

- "Usage" is not just volumetric kWh usage.
  - Customers can use kW as well as kWh.
  - Utilities charge some non-residential customers for kW usage even if they use no kWh (e.g. standby rates).
  - Use of kW can be best collected through energy rates (including time-of-use components)
  - Demand charges are not a cost-based way to collect residential demand costs (see Appendix)
- Agreement that customer-related costs are the one category in which some costs do not vary with usage.
  - "No party in this proceeding denies that utilities have fixed costs, or the existence of customer-related fixed costs" (see D. 15-07-001, at p. 189).

The 10 Rate Design Principles

- Rate Design should be based on the 10 rate design principles listed on p. 84 of D.15-07-001.
  - D. 15-07-001, on p. 206, states that Commission will place significant weight on better aligning rates with cost causation, which is Principle #3.
    - Principle # 5 further states that rates should encourage reduction in peak demand.
    - Recovering costs that are caused by changes in peak demand through a fixed customer charge that does not vary with changes in demand violates both these principles.
  - Paying for demand-related costs through a fixed customer charge also violates Principle #9, which states that rates should encourage economically efficient decision making.
    - Recovering demand costs through energy charges at least comes closer to this principle since energy usage is correlated with demand, particularly TOU energy charges.

The 10 Rate Design Principles

- Principle #2 states that rates shall be based on marginal costs.
  - A long-standing principle of marginal cost ratemaking at the Commission has been to recover the difference between the revenue requirement and what revenues would be if rates were set at marginal cost through the EPMC process.
  - This process allocates this difference proportionally to all cost drivers rather than to just one, the change in the number of customers.
- Principle #4 states that rates shall encourage conservation and energy efficiency.
  - Rates that recover the entire difference between revenues at marginal cost and the authorized revenue requirement through a fixed charge does not accomplish this goal.
  - This is because the energy rates must be significantly reduced to balance the rate design to yield revenue neutral results.
  - The recent focus on GHG reduction from SB 350 increases the importance of reducing energy usage.

Focus on customer costs

- AB 327's $10 limit ($5 for CARE) on fixed charges
  - Applies to residential default rates, plus one optional TOU and one optional tiered rate.
  - Practically, this focuses the debate on customer costs.
- Are the utilities seriously interested in residential fixed charges of $66, $33, or $81 per month…
  - … given the state's investment in demand-side programs & policies (EE/ DR /DG)?
  - … given the bill impacts for small & low income customers?

Thoughts on specific cost categories

- G, T & D costs above marginal costs
  - Historical embedded costs above today's marginal costs.
  - "Out of Market Costs" in Generation are caused by low gas prices, acquisition of state-mandated renewables, and little need for capacity.
  - How can these costs be "fixed" if they will no longer be "fixed costs" if marginal costs increase?
  - These are costs that are driven by usage of kWh or kW.
  - In the long run, marginal costs equal embedded costs.

Policy Driven Costs Should Not Be Collected in Customer Charges

- Costs Included in
  - Public Purpose Programs (CARE, Energy Efficiency - EE, R&D, etc.)
  - Distribution (Demand Response – DR, SGIP, CSI, Excess Advanced Metering Costs, etc.) – part of the EPMC Scalar in Utility Proposals
- Cost Driver is State Policy.
  - These costs are neither Fixed nor Variable.
- Many Policy Driven Costs (EE, DR, SGIP, CSI, Excess Advanced Metering) are Generation Substitutes.

Policy Driven Costs, continued

- Cost of Compliance with State Policy Objectives Should be Collected Broadly, Not Regressively in Customer Charges.
- Generation Costs Should Not Be Part of Customer Charges; Neither Should Generation Substitutes.
  - Otherwise small customers would lose from following the loading order instead of building fossil resources.
- Excess Advanced Metering Costs
  - Least cost for Customer Access is about 60-70% of AMI.
  - Remaining AMI costs were incurred to allow for DR and Efficiency.

ORA/TURN/SEIA Preferred Rate Design

- We are providing a customer charge proposal because the initial focus of the workshop was on cost categories includable in a *customer charge*.
- Our preference is for a *minimum bill* provision for three reasons:
  - There has been much debate about what distribution costs are customer versus demand driven.
    - TSM, at best, is a compromise between parties.
    - This suggests a cautious approach to the recovery of those costs.
  - The hookup costs are marginal only when the hookup initially is installed, not years later.
    - Thus, to the extent that sunk fixed costs are to be recovered, it's best to recover them in a way that allows the rates themselves to reflect ***marginal*** costs, which a minimum bill provision accomplishes.
  - Unavoidable customer charges or membership fees are very rare in unregulated industries where there is a robust level of competition.
    - This is important because a goal of marginal cost rates is to emulate a competitive market:

      "Since 1981 … This commission has relied on marginal cost principles in order to simulate, to the extent possible, the pricing structure and resulting efficient resource allocation of a competitive market." (D.96-04-050)

Monthly Customer Charge

- ORA includes only the ongoing costs of (1) ***Customer services and billing,*** and (2) ***Equipment O&M***.
- Excluded are the capital costs of TSM (including for new customers) because:
  - The NCO method assumes those costs are sunk for all existing customers.
    - The NCO method assumes TSM costs are marginal only in the year when the hookup is installed and thus only counts those costs for ***new*** customers.
  - Yet almost all customers that pay rates are ***existing*** customers.
    - To have them pay for the hookup costs of other customers only aggravates the effects of the subsidy built into line extension allowances.
    - We are fine with continuing to include new hookup costs in revenue allocation because the residential class includes both new and existing customers.

Treatment of O&M and the EPMC Multiplier

- O&M costs on equipment could have been excluded since the commitment to pay those costs occurred when the hookups were first installed.
  - We include them because they are ongoing costs.
- The EPMC multiplier is not applied because:
  - Customers cannot meaningfully respond to a fixed customer charge, thus the scaler should be applied to rate elements to which they can respond.
  - Applying the scalar to the energy rates promotes conservation and energy efficiency.
  - Because of composite tier differentials, scaling up the customer charge will result in an increase in the tier differentials, effectively negating the effect of scaling on customers who consume near baseline levels.
  - Unregulated markets with robust competition only rarely rely on customer charges or membership fees to recover such costs.

“Customer” Costs that Should Not Be Included in Customer Charges Regardless of Methodology

- Uncollectible accounts expenses
  - Should be Excluded from Marginal Customer Costs based on 30 years of Precedent
  - Revenue-related, not a marginal cost of bill-paying customers
  - Costs now collected as an adder to all base and balancing account rates
- Costs collected from specific customers (charges for AMI opt-out, service establishment, collection, reconnection after non-payment, returned checks)
  - Would be double-collected if included in customer charge.

- The Joint Parties estimate these costs to be about $0.37/mo. for SCE and $0.18/mo. for SDG&E.

Illustrative Numbers

- For ease of understanding, all of our illustrative numbers start with the utilities’ presentations in this proceeding.
  - Actual numbers would be determined through litigation or settlement in future proceedings.
- We subtract account setup costs from PG&E’s RCS costs because they are associated with new customers.
  - The data did not exist to do so for SCE or SDG&E.
  - But we recommend excluding these costs for the other two utilities in future proceedings.
- The SDG&E O&M number is much higher than that of PG&E and SCE, and future proceedings should investigate whether this difference is justified.

Illustrative Numbers

	PG&E	SCE	SDG&E
Ongoing Customer Services	$2.80	$2.16	$2.18
Equipment O&M	$0.44	$0.11	$2.52
TOTAL	$3.24	$2.27	$4.70

Sources of Illustrative Numbers*

- **PG&E**
  - Customer Services: From Table F-2, RCS cost of $3.52 less New Account Setup cost of $0.72.
  - O&M: From PG&E's MCAC workpapers in this GRC. O&M adders are multiplied by plant costs. Meter O&M costs are excluded because they already are included in RCS.
- **SCE**
  - Customer Services: From SCE Fixed Cost Report, Appendix B (10/6/16). We used the adopted "Customer Service and Billing" cost.
  - O&M: *Ibid*., O&M from 1/9/15 errata. (Note, we used the errata because O&M is not broken out in the adopted numbers.)
- **SDG&E**
  - Customer Services: From SDG&E's Fixed Cost Report, p. 17 (10/6/16). We used "Total Customer Accounts/Services Costs."
  - O&M: *Ibid*. We used the "O&M Cost" applied to the TSM.

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* The Joint Parties do not endorse the numbers in these tables but only present them for illustration.

Source of PG&E Data

TABLE F-2
PG&E ESTIMATED RESIDENTIAL MARGINAL CUSTOMER COSTS

[A]	[B]	[C]	[D]
Marginal Customer Costs	**Costs ($/cust-yr)**	**Costs ($/cust-mo)**	**Costs ($ million/yr)**
Revenue Cycle Services (RCS) Costs			
Account Set-Up	$8.59	$0.72	$41
Meter Reading	$4.77	$0.40	$23
Billing and Payment	$14.97	$1.25	$71
Credit and Collections	$2.11	$0.18	$10
Metering Services	$11.84	$0.99	$56
RCS Total	$42.28	$3.52	$201
New Connection Costs	$117.67	$9.81	$559
Total Marginal Customer Costs	$159.95	$13.33	$760

Source of SCE Data

SCE 2015 GRC		
Marginal Customer Costs	SCE Proposed Errata 1-9-2015	Settlement Agreement *
Final Line Transformer (FLT)	$3.61	
Service Drop	$4.10	
Meter and Panel	$1.83	
Customer Service	$2.49	
O&M	$0.11	
Collections	$0.23	
Total $/Customer Month**	$12.37	$7.97

Notes:

* 2015 GRC Phase 2 Marginal Cost and Revenue Allocation Settlement Agreement: TURN's 50:50 NCO: RECC Monthly RECC Customer

** The $12.37 ($/cust-mo - 2015$) in the table above represents the *weighted average of all sub categories* in the Residential class
The customer service costs (Monthly A+B+C in table below) for each group is as follows (2015$);
- Domestic TOU ($/cust-yr) = $32.55 ($2.71 * 12)
- Domestic Master Metered ($/cust-yr) = $163.62 ($13.64 * 12)
- Single / Multi Family ($/cust-yr) = $32.28 ($2.69 * 12)

The Proposed and Adopted table below details only the Single Family costs

Proposed Residential Distribution Marginal Costs (Single Family)

[A] Marginal Customer Costs	[C] Costs ($/cust-mo) 2015$	[C1] Costs ($/cust-yr) 2015$	[D] Costs ($ million/yr)
Billing and Customer Service Marginal Costs For 2012			
Meter Services (A)	$0.09	$1.08	$5
Meter Reading (B)	$0.42	$5.04	$22
Customer Service and Billing			$0
Perform Credit Checks and Manage Deposits			
Billing Exceptions	$0.34	$4.08	$18
Interval Data Management	$0.00	$0.00	$0
Send Monthly Bill	$0.40	$4.80	$21
Process Customer Payment	$0.13	$1.56	$7
Customer Inquires (trouble,billing, turn on/off, payment, misc)	$0.63	$7.56	$33
Field Services	$0.06	$0.72	$3
Collections	$0.25	$3.00	$13
Uncollectibles	$0.37	$4.44	$19
MAEs			
Sub total ('C)	$2.18	$26.16	$114
Monthly (A+B+C)	$2.69	$32.28	$140
Final Line Transformers, Service Drop, Meter and related O&M (D)	$10.64	$127.68	$555
Single Family Monthly (A+B+C+D)	$13.33	$159.96	$695

Customer-months	52,139,961
Customers	4,344,997

Check: $645
Weighted average of the resdential class (single, multi, TOU & master-meter) => $644

Adopted Residential Distribution Marginal Costs***

[A] Marginal Customer Costs	[B] Costs ($/cust-yr)	[C] Costs ($/cust-mo)	[D] Costs ($ million/yr)
Billing and Customer Service Marginal Costs For 2012			
Meter Services (A)			
Meter Reading (B)			
Customer Service and Billing			
Perform Credit Checks and Manage Deposits			
Billing Exceptions			
Interval Data Management			
Send Monthly Bill			
Process Customer Payment			
Customer Inquires (trouble,billing, turn on/off, payment, misc)			
Field Services			
Collections			
Uncollectibles			
MAEs			
Sub total ('C)			
Monthly (A+B+C)	$30.36	$2.53	$132
Final Line Transformers, Service Drop, Meter and related O&M (D)	$65.28	$5.44	$284
Monthly (A+B+C+D)	$95.64	$7.97	$416

Customer-months	52,139,961
Customers	4,344,997

Check: $417

Source of SDG&E Data

TABLE 4
SDG&E ESTIMATED RESIDENTIAL MARGINAL CUSTOMER COSTS

[A]	[B]	[C]	[C]	[D]
Marginal Customer Costs	**Costs ($/cust-yr)**	**EPMC-adjusted Costs ($/cust-yr)***	**Costs ($/cust-mo)**	**EPMC-adjusted Costs ($/cust-mo)***
Customer Accounts/Services Costs				
Customer Services Field	$3.70	$6.06	$0.31	$0.50
Advanced Metering	$1.75	$2.86	$0.15	$0.24
Billing	$1.80	$2.95	$0.15	$0.25
Credit & Collections	$1.32	$2.17	$0.11	$0.18
Remittance Processing	$2.47	$4.05	$0.21	$0.34
Branch Offices	$1.03	$1.69	$0.09	$0.14
Customer Contact Center Operations	$4.69	$7.68	$0.39	$0.64
Customer Contact Center Support	$1.18	$1.94	$0.10	$0.16
Residential Customer Services	$3.97	$6.51	$0.33	$0.54
Communication, Research & Web	$4.94	$8.10	$0.41	$0.68
Customer Programs & Projects	$0.66	$1.09	$0.06	$0.09
Other Office	$0.37	$0.60	$0.03	$0.05
Shared	$0.40	$0.65	$0.03	$0.05
Total Customer Accounts/Services Costs	**$28.29**	**$46.36**	**$2.36**	**$3.86**
New Connection Costs				
Annualized Transformer, Service & Meter Costs	$93.56	$153.35	$7.80	$12.78
O&M Costs	$30.24	$49.56	$2.52	$4.13
Total New Connection Costs	**$123.80**	**$202.91**	**$10.32**	**$16.91**
Total Marginal Customer Costs	**$152.09**	**$249.27**	**$12.67**	**$20.77**

Minimum Bill

- Current $10 minimum bill for delivery service is reasonable.
- Customer pays all other rate components based on actual billed usage.
- Minimum bill is slightly over 100 kWh at current rates for all three utilities.
- Compare to NCO and RECC with and without modifications
  – Modification removes transformers, 30% of AMI meter cost per discussion above

Minimum Bill Continued

- Greater than modified NCO, NCO, modified RECC, less than total RECC.

	minimum bill	delivery rate per kWh	kWh of delivery	Customer Variable	Modified NCO	Modified RECC	Total NCO	Total RECC
SDG&E	$ 10.00	$ 0.07928	126	$ 4.62	$ 5.49	$ 7.28	$ 6.86	$ 12.09
SCE	$ 10.00	$ 0.08843	102	$ 2.16	$ 3.83	$ 7.08	$ 4.85	$ 10.40
PG&E	$ 10.00	$ 0.08669	115					
SDG&E delivery rate is arithmetic average of summer and winter rates.								
SCE kWh of delivery reflects $1 customer charge.								

- Did not calculate PG&E because we have not fully reviewed PG&E's Phase 2 filing for adjustments and we did not calculate RECC-based costs for PG&E in 2014 GRC Phase 2.

Minimum Bill Data for Edison

- Edison Marginal Costs Rate DR only (no master metered customers in average).
- TURN assumptions in last Phase 2:
  - Edison's capital costs
  - Edison's O&M costs removing uncollectibles.
  - RECC and PVRR from TURN testimony (no A&G, adopted rate of return as cost of capital) – used in settlement.
  - Replacement rate for NCO is 1.553% from TURN testimony.

Minimum Bill Data for SDG&E

- Current Phase 2
- SDG&E rebuttal position on capital costs except for UCAN adjustment to transformer cost.
- SDG&E rebuttal position on RECC and PVRR calculations (no differences with UCAN).
- UCAN position on replacements for NCO (1.5%)
- UCAN position on customer O&M expenses (reduce tree trimming of service drops and reduce field orders due to AMI).
- Offset 18 cents per month of customer costs with customer-specific revenues (SDG&E agreed in rebuttal)