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 UTILITY REFORM NETWORK ON RATE PROPOSALS

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Pursuant to the September 20, 2012 ruling of Assigned Commissioner Peevey and ALJ Sullivan, The Utility Reform Network (TURN) hereby submits these reply comments to the opening comments of various parties on rate reform proposals. TURN responds to the opening comments, of San Diego Gas & Electric (SDG&E), Pacific Gas & Electric (PG&E), Southern California Edison (SCE), the Environmental Defense Fund (EDF), and the Division of Ratepayer Advocates (DRA).

I. SDG&E'S RATE PROPOSAL WOULD HAVE EXTREME BILL IMPACTS

In opening comments, SDG&E asserts that its rate design proposal will "provide a smooth and long-term transition to optimal rates that minimizes bill impacts".[1] This assertion has been difficult to verify since SDG&E refused to provide any illustrative rates in its original proposal. After being scolded by the ALJ and Energy Division, SDG&E reluctantly provided four rate design permutations for distribution and commodity rates in a supplemental July 1st filing. Due to deficiencies in its July 1st supplemental filing, SDG&E was directed by the Commission to submit another supplemental filing modeling the bill impacts of a complete retail rate (fixed and commodity charges).

SDG&E's second supplemental filing (submitted July 17th) proposed "illustrative" rates that included fixed charges (either a Basic Service fee of $38.42/month or a Demand Differentiated Basic Service Fee between $15-65.17/month) and a choice between TOU or flat commodity rates.[2] Without any explanation, SDG&E made significant revisions to its proposed TOU rate between the July 1st and the July 17th filing. The following table shows the unexplained changes:

[1] SDG&E opening comments, page 1.

[2] SDG&E did not propose a flat commodity rate in its July 1st filing. In its July 17th filing, SDG&E added a flat rate option of 13.7 cents/kwh without explanation.

	July 1 filing	July 17 filing
Summer		
on-peak	24.6	28.2
mid-peak	6.6	10.3
off-peak	5.0	8.7
Winter		
on-peak	6.4	11.4
mid-peak	5.5	10.4
off-peak	4.2	9.2

In both the July 1st and July 17th supplemental filings, SDG&E refused to model the impact of transitioning from current rates to an "optimal" rate design and instead chose to divide the bill impacts into five separate steps. This exercise was an obvious attempt to prevent the Commission (or any party) from ascertaining the actual bill impacts of the proposed rates relative to current rates.

TURN served SDG&E with a data request within hours of receiving the July 1st filing seeking a comparison of current rates with SDG&E's proposed "step 5" retail rates.[3] SDG&E provided this analysis to TURN on July 22nd – almost two months after every other party was required to provide proposed rates and bill impacts analysis (and only four days before the deadline for submission of reply comments). For the benefit of the Commission and other parties, TURN attaches SDG&E's entire data response to this pleading.[4]

SDG&E sought to hide the true impact of its illustrative rate proposal because the cumulative bill impacts of the five separate "steps" are startling. The following chart shows the percentage of non-CARE residential customers receiving monthly bill increases of greater than 0%, 20%, 40% and 60% under the combination of SDG&E's

[3] TURN Data Request #3 was served at 5:44pm on July 1st.
[4] See Attachment A (SDG&E response to TURN Data Request #3).

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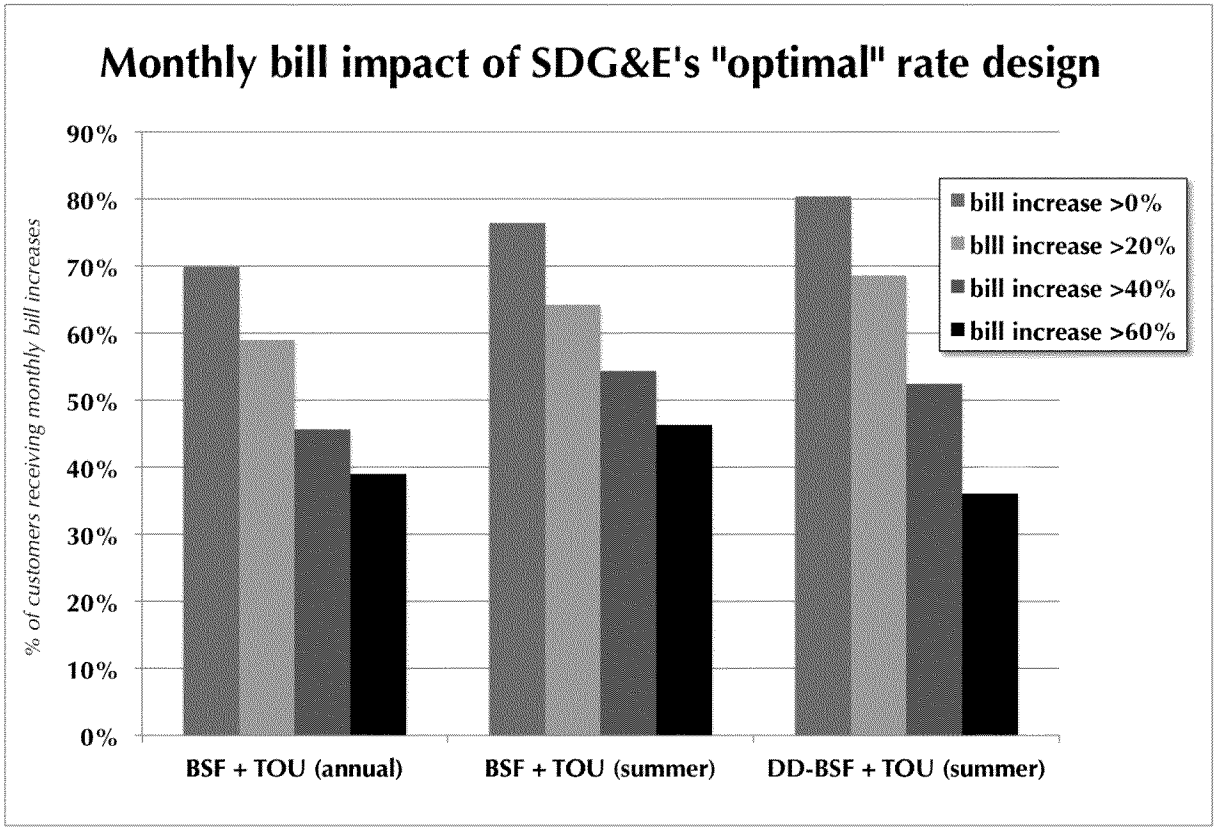
proposed Basic Service Fee (BSF) or Demand Differentiated Basic Service Fee (DD-BSF) and the Time of Use (TOU) commodity rate.



As shown above, the combination of a $38.42/month basic service fee plus TOU commodity rates with ratios of 3.24/1 (peak/off-peak) in the summer and 1.24/1 (peak/off-peak) in the winter produces higher bills (compared to current rates) for 70% of non-CARE customers. On an annual basis, 59% of customers would receive bill increases in excess of 20% and 39% of customers would receive monthly bill increases of more than 60%. While 30% of customers would see bill reductions, more than half the total reductions would be provided to approximately 5% of the highest usage residential customers.

Bill impacts during the summer months would be more extreme. Under either the Basic Service Fee (BSF) or Demand Differentiated Basic Service Fee (DD-BSF),

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between 76-80% of customers would see higher summertime bills than under current rates. Between 52-54% of customers would experience summer bills that are at least 40% higher than current rates and between 36-46% would receive bills that are at least 60% higher. While 20-24% of customers would experience summertime bill decreases, up to 60% of the total reductions would go to approximately 5% of the highest usage residential customers.

It is important to note that SDG&E did not estimate the impact of these rate designs by baseline zone. Although TURN asked for such an analysis, SDG&E refused to provide this information.[5] Based on analysis performed by DRA, the bill impacts on customers in hot, inland climate zones are almost certain to be much more severe during the summer months. Because SDG&E provides a system-wide average, the Commission should assume that customers in the hotter, inland areas would experience more significant summer bill impacts than those shown in this data. It is very difficult to reconcile these bill impacts with SDG&E's public pleas that rate reform is needed in order to lower bills for customers in hotter parts of its service territory.

Although TURN is the only party who sought this bill impact information, DRA did hypothesize (based on the July 1 filing) that "the bill impacts for each step were significant enough to conclude that the cumulative bill impacts for their final proposed end state rate would be totally unacceptable."[6] In fact, the bill impacts of SDG&E's end-state rates would be dramatic and severe. Contrary to the claim that such reforms would provide relief to the bulk of SDG&E's customers, the "optimal" rate design would produce punishing rate increases to the vast majority and enrich a very small number of extreme users who are most likely to have the highest incomes.

[5] SDG&E response to TURN data request 3, Question 3.
[6] DRA opening comments, page 3.

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The Commission should reject SDG&E's illustrative design as less than "optimal" based on the extreme bill impacts. Moreover, the Commission should admonish SDG&E for such aggressive attempts to 'hide the ball' and prevent any meaningful analysis of its own preferred rate design. Given its role as a utility provider with substantial expertise and resources, SDG&E should be held to a high standard and required to participate responsibly in major proceedings such as this one.

II. PG&E ESTIMATES ARE SKEWED BY ASSUMED CHANGES IN AVERAGE CARE AND NON-CARE RATES

PG&E uses its opening comments to assert that moving to a flatter two-tier rate (from current rates) will yield reductions in overall usage. Specifically, PG&E applied various price elasticities to demand in each usage tier and compared usage under current non-CARE and CARE rate tiers with a scenario in which customers face a two-tier rate and CARE customers receive a 20% discount.[7] This exercise led to the conclusion that overall customer usage declined as much as 3.2%.

A major methodological flaw in this approach is the assumption regarding CARE rates. Currently, PG&E's average effective CARE discount is approximately 45%. By modeling usage under a 20% CARE discount scenario, PG&E assumes a massive increase in average rates for CARE customers. It would be surprising if CARE customer usage did not decrease given the substantial rise in average rates. Since PG&E does not provide any breakout of its scenarios to show the separate impacts on non-CARE and CARE customers, it is impossible to determine whether the change in usage is driven primarily (or exclusively) by CARE customers. Moreover, it is reasonable to assume that CARE and non-CARE customers have different price elasticities. CARE usage should be assumed to be far more sensitive to increases in

[7] PG&E opening comments, page 9.

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price. PG&E did not appear to make such an assumption and fails to disentangle the separate impacts of tier flattening and raising average CARE rates.

III. TOU RATES ARE MORE LIKELY TO PROMOTE LOAD SHIFTING AND PEAK-WEIGHTED CONSERVATION THAN TRUE ENERGY EFFICIENCY

TURN is concerned that advocates of TOU rates appear to be narrowly focused on using rates to reduce customer demand during summer peak periods. The prevailing assumption amongst TOU advocates is that reductions in demand and usage outside of summer peak hours have minimal value. Based on this worldview, some parties have proposed TOU rates that could severely erode the value of energy efficiency and conservation measures that provide baseload or off-peak weighted reductions.

EDF cites PG&E in claiming that existing tiered rates "shield lower energy users from increasing their appliance efficiencies, significantly muting any potential conservation benefit from the rates. While appliances that are always on, such as refrigerators and freezers, are susceptible to overall bill levels under virtually any rate structure, other residential electricity uses – such as clothes drying, cooking, and washing – could be shifted to lower cost periods under time variant rates, thereby creating peak load reduction benefits."[8]

This perspective ignores the fact that a relatively small percentage of customers are "shielded" from any meaningful marginal price signal. TURN previously demonstrated that 68-85% of non-CARE PG&E residential customers (depending on climate zone) had some usage in excess of 130% of baseline during 2009.[9] The portion of customers facing higher marginal prices will increase if baseline quantities are reduced (from 55% to 50% of average consumption) and if TURN's three-tier rate proposal (which provides higher

[8] EDF opening comments, pages 11-12.
[9] TURN rate proposal, page 31, Figure 10.

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marginal prices for usage above 100% of baseline) is adopted. The relatively small number of users who remain entirely in Tier 1 after these changes should not be driving the entire conservation and efficiency debate.

Instead, the Commission should recognize that customers facing higher marginal prices associated with Tier 2 and 3 usage will be incentivized to make investments in more efficient "always on" appliances and high efficiency lighting (such as LEDs) used more heavily in off-peak hours. By contrast, the adoption of TOU with steep differentials would disproportionately reward reductions during peak periods and disfavor baseload reductions. At best, customers with an appliance that is "always on" would offset the average retail rate under TOU. Under a tiered rate, customers would receive a credit based on the highest marginal rate they pay in each billing cycle.

Many of the measures suggested by TOU advocates are primarily related to load shifting and may have little, if any, impact on total energy consumption. For example, a customer who uses a washing machine at 11pm instead of 4pm may satisfy the load shifting objective while still consuming the same number of kilowatt-hours. Furthermore, customers who understand that off-peak usage is billed at very low rates may be encouraged to increase their off-peak usage or forgo the purchase of more efficient appliances in favor of simply moving existing usage into off-peak periods. This virtual abandonment of off-peak or baseload efficiency and conservation measures has not been addressed by any of the TOU advocates.

The Commission should tread cautiously. If customers are told that they are only to mind their usage during peak, summer hours, there could be a substantial disincentive to embrace a variety of measures that promote round-the-clock conservation and efficiency. And some customers may be tempted to leave the lights on at night given the low prices they are being charged.

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IV. SUMMER BILL IMPACTS OF TOU

Few parties address the potential for significant summer bill impacts associated with highly differentiated TOU rates. As explained in TURN's opening comments, a switch to the TOU rates proposed by several parties would result in practically all customers in hot climate zones receiving higher monthly bills during the summer season than under current rates.[10] If the Commission wants to use rate reform to assist these customers with the burden of high summer bills, default TOU rates are not the answer.

While acknowledging that some of these impacts could be severe, DRA suggests that the solution lies in education, energy efficiency and balanced payment plans.[11] While TURN agrees that education is valuable (and should be used to better explain the current tiered rate structure), there may be limited steps that many customers in hot areas can take during summer months to materially reduce their peak usage. To the extent that these customers are already facing strong marginal price signals associated with upper tier usage under the current rate structure, the economic signal is already strong and promotes conservation. It is not obvious that these customers can adapt to very high on-peak summer rates without major investments in new equipment and building improvements. Customers with higher incomes have a much greater ability to access capital to make these investments. Customers with lower incomes are more likely to either pay higher monthly bills or experience extreme personal hardship by forgoing air conditioning during severe weather events.

It is ironic that DRA would propose a balanced payment plan as a possible solution to high summer bills. Such an approach would eliminate any direct nexus between monthly bills and monthly usage. Under a balanced payment plan, most customers

[10] TURN opening comments, pages 2-4.
[11] DRA opening comments, page 5.

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would be relatively unaware of the extent to which their summer on-peak usage drives higher overall bills. Given this fact, it is difficult to imagine that customers on both TOU rates and balanced payment plans are likely to respond to time-based pricing signals that are concentrated in summer on-peak periods. If the goal of TOU is to promote usage and demand reductions during summer on-peak periods, DRA's solution would appear to run directly counter to this objective.

V. SCE'S ARGUMENTS AGAINST A THREE TIER RATE STRUCTURE INCLUDE AN INCOMPLETE RETELLING OF HISTORY

SCE claims that the proposals from SCE and PG&E more appropriately comply with the guidance of §739(d)(1) that inverted tier rates provide an "appropriate gradual differential between the rates for the respective blocks of usage." SCE criticizes TURN for offering "no basis for its determination that three tiers are necessary or why its proposed tiered rate ratios should be adopted."[12]

TURN explained at length why our three-tiered rate proposal best preserves the benefits of tiered rates for promoting conservation and rewarding low-usage customers, while at the same time ameliorating the potential negative bill volatility and cost allocation impacts of existing tier differentials. Indeed, SCE's extensive discussion of tier differentials in its original proposal highlighted the fact that the Legislature has historically supported inverted tier rates but addressed tier differentials only due to **seasonal bill volatility problems** created by high tier differentials. [13] TURN's proposal is designed explicitly to address this problem. By contrast, parties who propose elimination of tiers and the imposition of time-of-use rates have completely ignored the more severe bill volatility problems caused by TOU rates.

[12] SCE Opening Comments, p. 8.
[13] SCE Proposal, p. 23-25. Indeed, SCE presented the history of present SB 987, which enacted § 739(d)(1), in a section entitled "Protection from Bill Volatility."

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As explained in SCE's comments and in SCE's rate design proposal, Legislative action to amend tier differentials of utility rates was originally motivated by high winter bills associated with tiered natural gas rates and the extreme cold snap in 1987-1988.[14] The resulting winter bill spikes led to the passage of SB 987, which enacted the language presently in § 739(d)(1).[15] SCE quotes from a February 1988 letter from Commission President Hulett to the Legislature that explains that extreme bill volatility resulted from tier differentials that had risen to as high as 2.7:1 for gas.[16] The tier differential in 1988 for PG&E was 2.1:1 for gas rates and 1.74:1 for electric rates.[17]

In response to SB 987 the Commission reduced electric tier differentials between the then two-tiered rates to between 1.15:1 and 1.27:1.[18] SCE now claims that its proposal for a tier differential of 1.2:1 is more reasonable because it is "closer to the historical rate differentials that existed when the AB 1890 rate freeze was implemented in 1997."[19] As both TURN and the utilities discussed in prior pleadings, SCE and PG&E electric customers experienced significant bill volatility in 2006 and 2009 due to electric demand fluctuations caused by hot summer weather. The tier differentials between the highest and lowest tiers at those times were 2.4:1 for SCE[20] and 3.0:1 for PG&E.[21]

There is no basis for concluding that a 1.2:1 tier differential is more consistent with §739(d)(1) than a tier differential of 1.3:1 or 1.5:1. TURN's proposed three-tier rate structure has differentials of 1.3:1 (tier 2:tier 1) and 1.6:1 (tier 3:tier 1). What is apparent from a brief review of the history is that the Legislature wanted the CPUC

[14] SCE Proposal, p. 23.
[15] SCE proposal, p. 24. TURN has not independently researched the Legislative history of SB 987.
[16] SCE Rate Design Proposal, p. 24.
[17] See, D.93-06-087, 50 CPUC 2d 1, 31.
[18] See, for example, D.96-04-050, 65 CPUC 2d 362, 431.
[19] SCE Opening Comments, p. 8.
[20] SCE Rate Design Proposal, p. 25.
[21] Based on August 2006 non-CARE rates of $0.346 (Tier 5) and $0.114 (Tier 1).

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to establish "appropriate" tier differentials that would be gradual enough **to avoid undue impacts caused by seasonal demand volatility**, whether for electricity in the summer or gas in the winter. Moreover, the facts on the record suggest that unreasonable bill volatilities are associated with tier differentials well above the 2.0:1 level.

TURN's proposal was designed, in part, to reduce seasonal bill volatility for customers. TURN's tier differentials are 1.3:1 and 1.6:1. However, the actual impacts on bill volatilities reflect both the tier differentials and the consumption quantities included in each tier. TURN supports analyzing the seasonal and monthly bill volatility impacts of our proposal in comparison to the proposals of other parties. However, we were unable to perform this analysis using the utility bill calculators since the models lack this functionality.

Nevertheless, TURN was able to provide some data on seasonal and geographic bill volatilities through data requests to the utilities and to the DRA. Those responses showed that the bill volatility impacts of some of the proposed TOU rate structures are **at least as high** as the bill volatility impacts of existing tiered rates.[22] And TOU rate proposals would significantly increase average summer bills for many customers as compared to present rates.

The legislature has historically responded to customer backlash associated with extreme seasonal bill volatility. TURN strongly encourages the Commission and the IOUs to more carefully analyze the bill volatility impacts of different rate designs before embarking on any major policy changes. Given the work already performed to develop the bill calculator models, TURN recommends that the Commission instruct the utilities to perform the additional coding necessary to aggregate the model outputs in order to analyze bill impacts by season and by Climate Zone. Such a

[22] TURN Opening Comments, p. 18-26.

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refinement of the models is entirely feasible, as illustrated by the outputs provided by DRA.

VI. FORECASTED COST SAVINGS FROM TOU RATES MAY BE DRAMATICALLY OVERSTATED

EDF asserts that any bill increases experienced under a TOU structure could be entirely offset by reductions in overall revenue requirements resulting from cost savings tied to customer behavior. Specifically, EDF states that "it is quite feasible to achieve a Pareto efficient outcome - where no customers are made worse off by the change in rate structure - under time variant rate structures."[23] This effect would supposedly be the result of system revenue requirement reductions occurring in General Rate Cases. EDF also suggests that some portion of these savings could be "partially shared with the IOUs to incentivize them to effectively work toward broad adoption of TOU rates by residential customers".[24]

EDF's model for estimating TOU savings relies on the simplified assumption that changes in residential customer demand and usage can be multiplied by marginal capacity, generation and distribution costs to determine revenue requirement reductions.[25] This approach does not accurately estimate the expected savings associated with changes in customer demand and consumption. Reliance on this methodology would grossly inflate the benefits of TOU rates and, combined with proposals to "share" these estimated benefits with utilities, could result in net

[23] EDF opening comments, page 8.
[24] EDF opening comments, page 9.
[25] EDF rate proposal, page A-4. ("The revenue sub-model estimates the change in total costs, comprised of capacity, generation and distribution costs, as well as change in utility marginal benefits for PG&E E-1, SCE Domestic and SDG&E DR rate groups when some portion of the group is moved to a TOU rate. To determine the change, the model first computes each cost component for the residential class before TOU are introduced and after some proportion of the residential class has moved to TOU. Generation energy costs are determined by multiplying the marginal generation energy costs ($/KWh) for the summer period by summer usage. Generation capacity costs are the product of marginal generation capacity costs and peak load, and, similarly, distribution costs are estimated by multiplying the marginal distribution costs by peak load")

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increases in system costs.

The simplified assumptions used by EDF to calculate total ratepayer savings are deeply flawed. There is no support for the assumption that all, or even most, marginal distribution costs can be offset by peak demand reductions. There is also no basis for concluding that embedded distribution costs will decline due to peak load reductions, an assumption that is implicit in the EDF analysis.

Moreover, portions of the distribution cost are not marginal to peak demand and can only be avoided by new construction (i.e., primary distribution line extensions). Some marginal distribution costs are tied to peak circuit loads that may not be coincident with TOU summer peak periods. For example, some of PG&E and SDG&E's distribution circuits are winter peaking and may realize no net savings from reductions in peak summer loads. More importantly, marginal distribution costs are location-specific and can be close to zero in some areas. The type of analysis conducted by EDF does not account for any of these factors. The Commission should have serious doubts about the validity of these estimates.

With respect to generation capacity marginal costs, there may be limited savings if the system contains significant surplus relative to currently forecasted demand. As the Commission is well aware, generation needs for the foreseeable future are related to localized need and possibly flexible capacity (much of which is already operating on the system). If there is excess system capacity, TOU-driven peak load reductions may result, at best, in a slight reduction in the procurement of Resource Adequacy by the utilities. Since these market prices are typically far below the marginal cost of newly constructed generating capacity, the savings could be a fraction of the costs estimated by EDF.

The use of TOU rates is unlikely to substitute for measures to integrate intermittent renewable resources since the reductions will be tied to system peak conditions

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rather than being responsive to the variability of intermittent generation. Retail load modifications that can assist with integration include smart appliances under direct utility or third-party aggregator control. Some of these measures may have more value during the off-peak hours that are ignored by EDF.

It is also possible that TOU-driven demand reductions may reduce the "needle peak" but cause the reserve margin to rise because there would be more hours close to the system peak. Under a Loss of Load Probability analysis, this could result in more hours when the system runs the risk of being unable to serve available demand. This result could severely undermine the expected savings from TOU-motivated peak load shifting.

The Commission should not, under any circumstances, rely upon the EDF methodology to provide estimates of savings that could be "shared" with utilities. Because the estimates could be an order of magnitude too high, any "sharing" of inflated estimates could eliminate any actual savings that flow through to ratepayers.

VII. THE ENVIRONMENTAL BENEFITS OF TOU RATES HAVE NOT BEEN DEMONSTRATED

Advocates of default TOU rates argue that the switch to time variant pricing is beneficial because reductions in peak demand are more likely to result in reduced air emissions from fossil fuel power plants. EDF claims that TOU rates will lead to "reductions in polluting air emissions" and favorable changes in "generation mix emissions intensity".[26] DRA asserts that TOU produces these benefits because "off-peak generation has smaller environmental impacts than peak-hour generation" and further states that "even if usage merely is shifted from peak hours to off-peak hours,

[26] EDF opening comments, pages 4, 15.

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and no electricity is saved on a net basis, there is a significant economic and environmental benefit to society."[27]

The claims made by EDF and DRA rest on the assumption that switching load from peak to off-peak periods results in environmental benefits that can be quantified by the difference in average heat rates between gas-fired units in California under high and low load conditions. These parties also believe that reductions in carbon dioxide associated with reduced on-peak generation represent incremental environmental benefits. Finally, EDF appears to conclude that TOU-driven load reductions will lead to power plant retirements because some portion of lower-efficiency peaking plants would no longer be needed.

A. The most recent analysis of the Western electric system suggests that baseload and off-peak load reductions would yield larger emissions reductions than reductions in on-peak usage

In opening comments, TURN referenced a recent report produced under the Public Interest Energy Research Program (PIER) administered by the California Energy Commission. The report, authored by a team at Synapse Energy Economics, examined the displaced energy production in the Western Electric Coordinating Council (WECC) associated with peak, off-peak and baseload demand reductions and renewable supply additions in California.[28] The study relied upon extensive production simulation modeling of the entire WECC to determine the impact of actions taken in California on electricity production and air emissions (NOx, SO2 and

[27] DRA opening comments, page 29-30.
[28] Emissions Reductions from Renewable Energy and Energy Efficiency in California Air Quality Management Districts, Public Interest Energy Research Program Final Project Report, prepared by Synapse Energy Economics for the California Energy Commission, November 2011. (Hereafter *Synapse study*).

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CO2) throughout the WECC.[29] The results of this study contradict the commonly held assumptions of TOU advocates.

Contrary to the assumptions of EDF and DRA, the Synapse report finds that although changes in peak and off-peak loads have an impact on emissions within California, there are much greater emissions impacts associated with displaced energy outside of California and within the WECC. Because the displaced energy outside of California has far higher emissions rates (due to the prevalence of coal), measures that led to a reduction in unit dispatch outside the state appear to have far more significant emissions impacts.

The study found the greatest displacement of out-of-state coal generation tied to the addition of in-state wind facilities that have more production in off-peak hours and seasons. When modeling the impact of wind in SDG&E's service territory, "the greatest coal displacement occurs during the spring and early winter, so called 'shoulder' seasons where regional demand is relatively low and hydroelectric availability is greatest. According to the model results, coal generation in the Intermountain is primarily displaced during the shoulder seasons."[30] The authors explain that "in periods of low demand, coal is displaced on a regular basis, while during the highest consumption months, natural gas is displaced almost exclusively."[31]

The Synapse study also analyzed peak load reductions of 10% in hours when system loads were in the 90th percentile or above.[32] The authors found that peak load reductions did lessen the dispatch of in-state gas-fired generation but also produced smaller west-wide emissions reductions benefits than baseload energy efficiency or

[29] The Synapse study modeled unit dispatch and was not based on commercial arrangements between California utilities and WECC generating units.
[30] Synapse study, page 51.
[31] *Ibid.*
[32] Synapse study, page 27.

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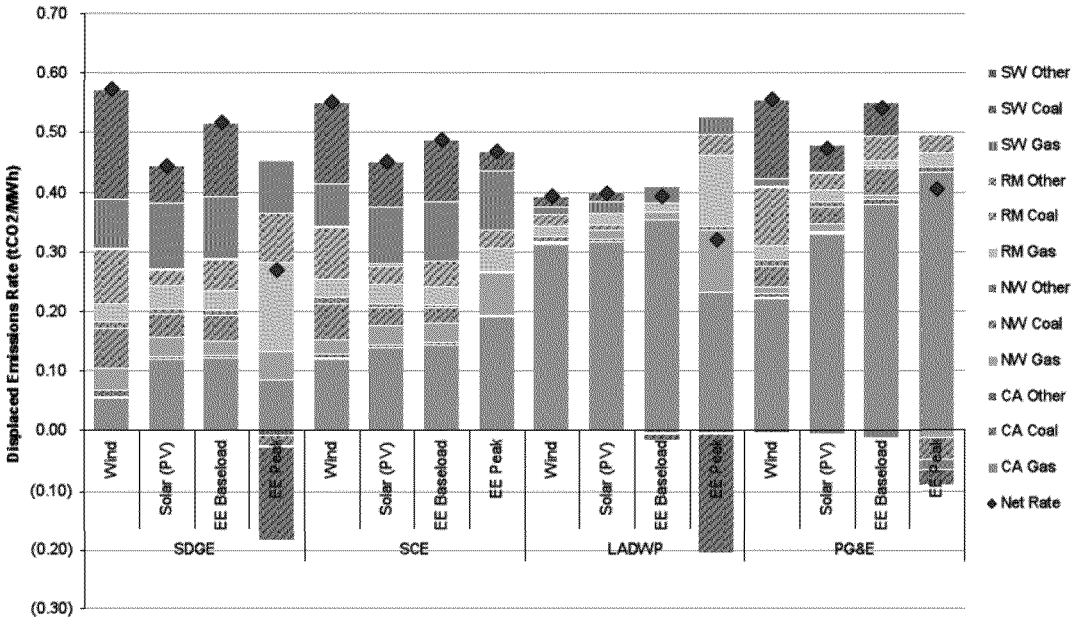
off-peak wind generation. This result suggests that prioritizing peak-load shifting will yield smaller emissions reductions than an emphasis on baseload, or off-peak, conservation and efficiency. The following figure shows the results of the analysis for on-peak, off-peak and baseload measures in each of four utility service territories:[33]

Figure 3: Displaced CO_2 Emissions (tons of CO_2 / MWh of Energy Efficiency/Renewable Energy) by Western Electricity Coordinating Council Region and Fuel Type in 2016, Relative to the Base Case



As shown in this figure, on-peak reductions (listed as "EE peak") typically yielded the smallest displaced CO2 emissions of any of the measures studied. As can be seen in the color-coded bars, this result is based on the fact that on-peak summer reductions displace far more gas-fired generation than baseload or off-peak measures. By contrast, the addition of new wind facilities (which provide less output in peak hours and more output during off-peak periods such as the spring and winter) yielded the largest CO2 displacement due to the fact that this production reduced the dispatch of coal-fired units outside California. Similarly, baseload

[33] Synapse study, page 5.

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energy efficiency displaced more CO2 than peak-load reductions based on more significant offsets to the dispatch of coal-fired plants in the southwest, rocky mountains and northwest.

The report contains the following summary conclusions based on this extensive modeling effort:[34]

> **Dispersed emissions benefits:** The Western grid is highly interconnected, and therefore changes in load, generation, or resource availability in California affect generators throughout the entire Western Electricity Coordinating Council system. As a result, criteria emissions benefits from the energy efficiency/renewable energy programs implemented in California are highly dispersed. Further, programs implemented in different parts of California appear to have varying impacts across the Western Electricity Coordinating Council and within California. It is concluded that a comprehensive modeling approach is required to estimate the emissions reduction potential of energy efficiency/renewable energy in a highly interconnected and highly diverse region such as Western Electricity Coordinating Council.
>
> **Large benefit out-of-state:** This research finds that while California does not necessarily realize significant criteria emissions benefit from energy efficiency/renewable energy programs in State, other regions of the West see significant emissions reductions from demand reductions in California, posing important questions about interstate energy and emissions planning. This out-of-state energy displacement, and particularly the displacement of coal in the Intermountain West, does not conform to conventional concepts about the nature and cost of energy resources in the Western Electricity Coordinating Council region. However, the results consistently show reductions in out-of-state coal, which have higher emissions than California generators, and hence deliver a significant benefit to other Western Electricity Coordinating Council regions.
>
> **Greenhouse gas benefits:** A notable benefit identified in this analysis is that energy efficiency/renewable energy programs have a large displacement outside of the state, often displacing coal-fired resources in the Rocky Mountain and Southwest regions of Western Electricity Coordinating Council. Because of this coal displacement, the greenhouse gas benefit of the energy efficiency/renewable energy programs is higher than would be seen were the displacement within California only. In many of the programs, displacing a

[34] Synapse study, pages 5-6.

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combination of California natural gas and out-of-state coal (such as in the SDG&E wind scenario) results in a 50 percent increase in GHG emissions benefit (0.6 tons of carbon dioxide [tCO2]/MWh) relative to displacing in-state natural gas only (such as in the LADWP baseload energy efficiency scenario, 0.4 tCO2/MWh).

TURN submits that this analysis should be taken seriously by the Commission and advocates of TOU rate designs. If the conclusions reached by Synapse are correct, policymakers need to reconsider the assumption that summer peak load reductions produce superior environmental benefits. State policies designed to move load to off-peak periods and seasons could end up yielding higher emissions throughout the WECC and defeating many of the environmental objectives behind rate reform.

B. Due to the cap on greenhouse gas emissions in California, reductions by some emitters may lead to increased emissions by other sources

Because California electric generation is now covered under the AB 32 cap-and-trade program administered by the California Air Resources Board (CARB), any measures intended to yield direct in-state reductions in CO2 emissions may not provide incremental. Under a cap-and-trade system, the overall cap governs total emissions and reductions at one in-state peaking plant may simply free up allowances to cover increased emissions at another covered facility. The net effect of emissions reductions is to lower the price of CO2 allowances which could, in turn, encourage increased emissions by other sources. This is exactly how the cap is supposed to function.

There is no basis for concluding that residential TOU rates would lead to net GHG emissions that are permanently below the AB 32 cap. TURN therefore questions whether any of the purported in-state CO2 benefits of peak-load reductions are actually incremental. By contrast, few Western states have binding greenhouse gas emissions limits. Any actions taken in California that reduce the dispatch of coal-fired power plants in other Western states would yield truly incremental reductions.

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Because there are no caps or allowances in these states, the reduction in CO2 emissions by a particular unit does not free up, or reduce the pricing of, allowances. Therefore, policies that promote both in-state and out-of-state emissions reductions may prove more valuable than those that are focused exclusively on reducing the use of peakers in California.

C. Due to localized capacity needs and the way system needs are modeled, systemwide peak load reductions may have little impact on retirements

DRA takes issue with TURN's contention that TOU rates may not offset new generation construction because incremental system additions are being driven by local reliability concerns rather than meeting peak system loads. Specifically, DRA asserts that TURNs argument may not be valid "in the light of SONGS and OTC."[35] This reference is puzzling because there it is widely understood that any replacements for SONGS and retiring Once Through Cooling (OTC) plants must address local reliability rather than system peak needs. In the Long-term Procurement Plan (LTPP) docket (R.12-03-014), the Commission recently noted that ongoing studies related to the SONGS shutdown are focused on local area needs in the Los Angeles Basin local area and San Diego sub-area.[36]

New long-term procurement is likely to be driven almost exclusively by local needs and the desire to have more flexible resources able to adjust to variable production from intermittent renewable resources. It is not obvious that reductions in peak system demand that may be produced by TOU rates would address either of these concerns. Moreover, TURN previously explained that the result of shaving peak system demand could have little or no impact on overall resource adequacy needs or

[35] DRA opening comments, page 30.
[36] See Revised Scoping Ruling and Memo of the Assigned Commissioner and Administrative Law Judge, R.12-03-014, May 21, 2013, page 4.

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planning reserve margins due to the manner in which loss of load probability studies are conducted (see Section VI).

The Commission must recognize that the relationship between systemwide peak load reductions and the need for new generation is complicated. Any simplistic mathematical estimate of displaced capacity will not hold up to scrutiny. Future generation construction is likely to be driven by many factors. Although peak loads may be one driver, it is not clear that they are the primary one.

VIII. RESPONSE TO PG&E'S CLAIMS REGARDING USAGE AND INCOME

PG&E devotes significant space in opening comments to attacking TURN's use of data showing that, under the current structure, the highest average non-CARE rates are charged in extremely wealthy communities and the lowest average non-CARE rates are charged in low-income communities. PG&E offers two basic critiques of TURN's approach. First, PG&E argues that extending TURN's analysis to all 216 cities in its service territory shows that although "high-income cities do generally show higher average rates..for the vast majority of cities, the 187 where the median income is less than $100,000 per year, average rates show no discernable pattern as income declines".[37] Second, PG&E asserts that it is inappropriate to use city level data to establish any correlations.

TURN reviewed the city level data that PG&E relied upon to reach its conclusions regarding correlations between average rates and median household income.[38] The fundamental error made by PG&E was to include all cities within its service territory in a single analysis rather than performing separate analyses by climate area. Relying on PG&E's own model data, TURN analyzed the relationship between average rates

[37] PG&E opening comments, page 17.
[38] TURN Data Request #6 to PG&E (served July 12th).

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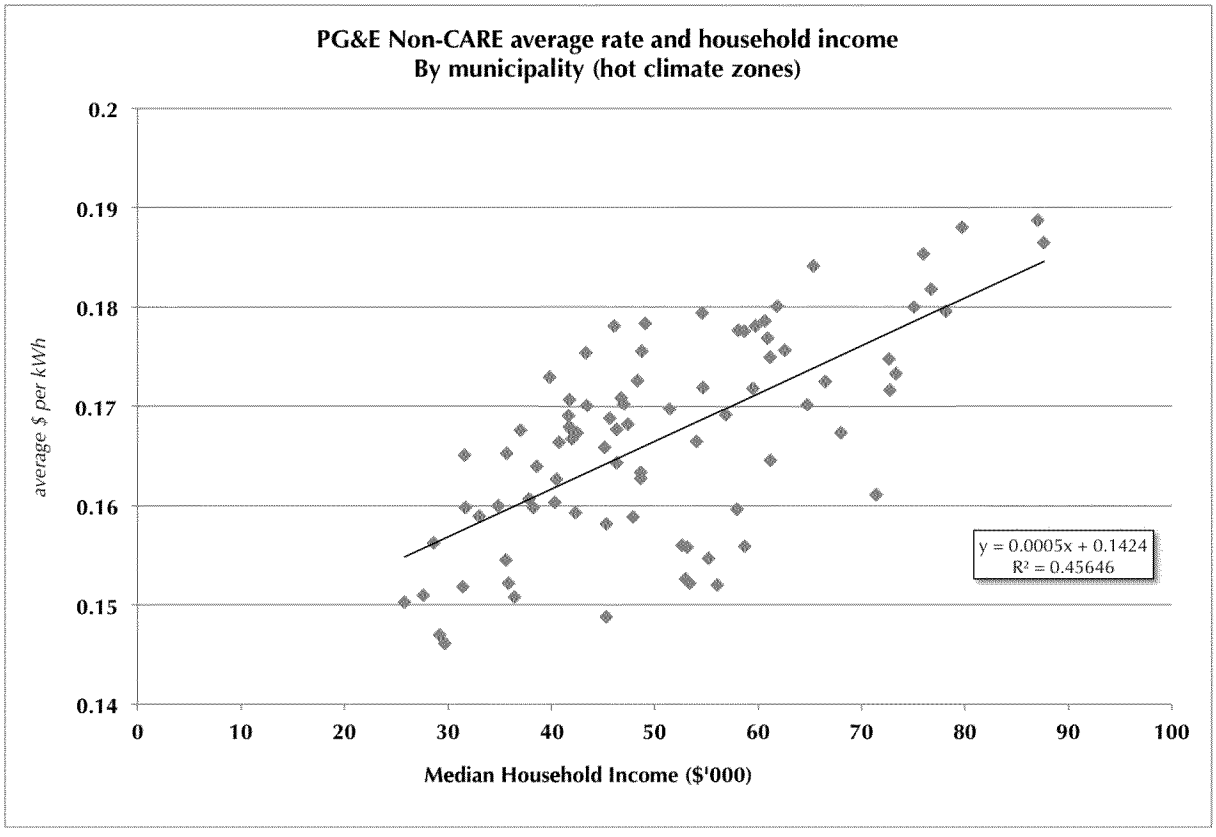
and household income by climate area.[39] The results are quite different from those shown in PG&E's opening comments. The following charts show the trends by climate area.



[39] TURN divided PG&E cities into three groupings – hot (zones R, S, W, Y), Mid (zone X) and Cool (zone T). Cities with less than 800 total customers or less than 500 non-CARE customers were excluded from the analysis.

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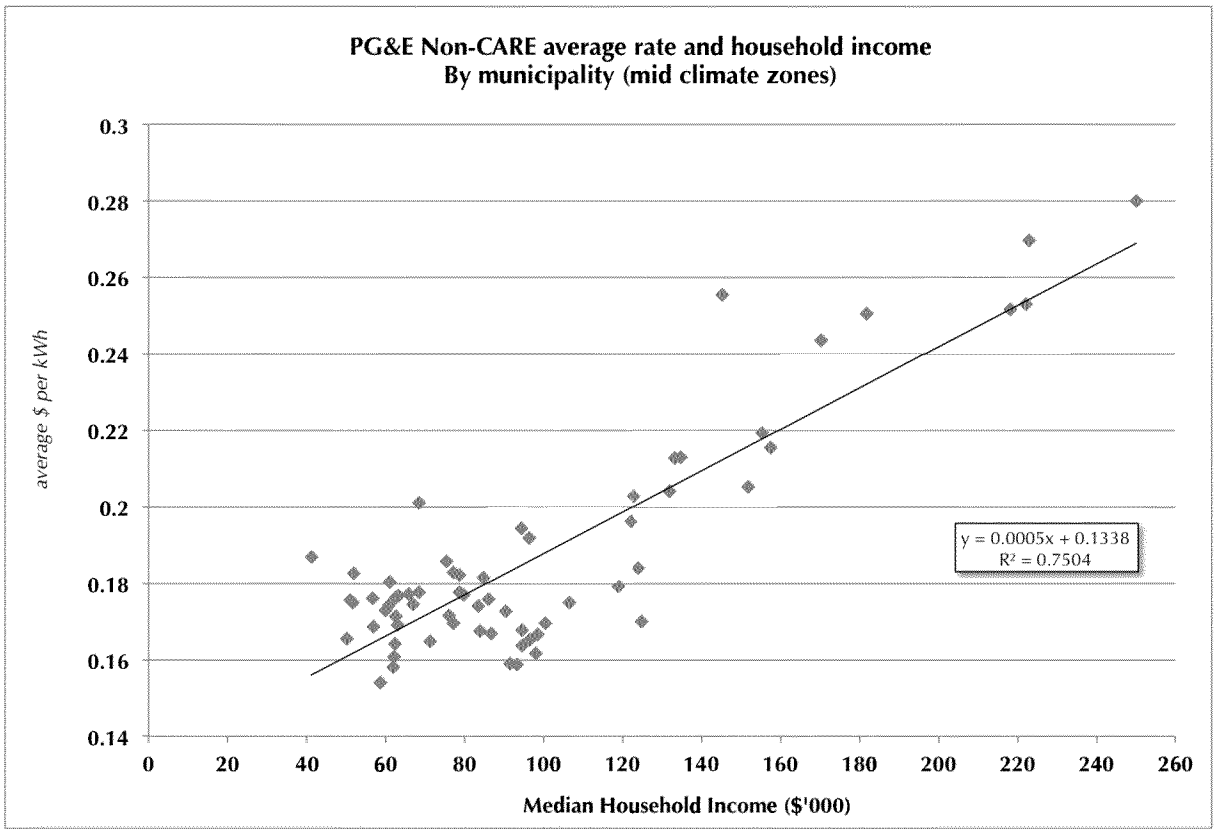

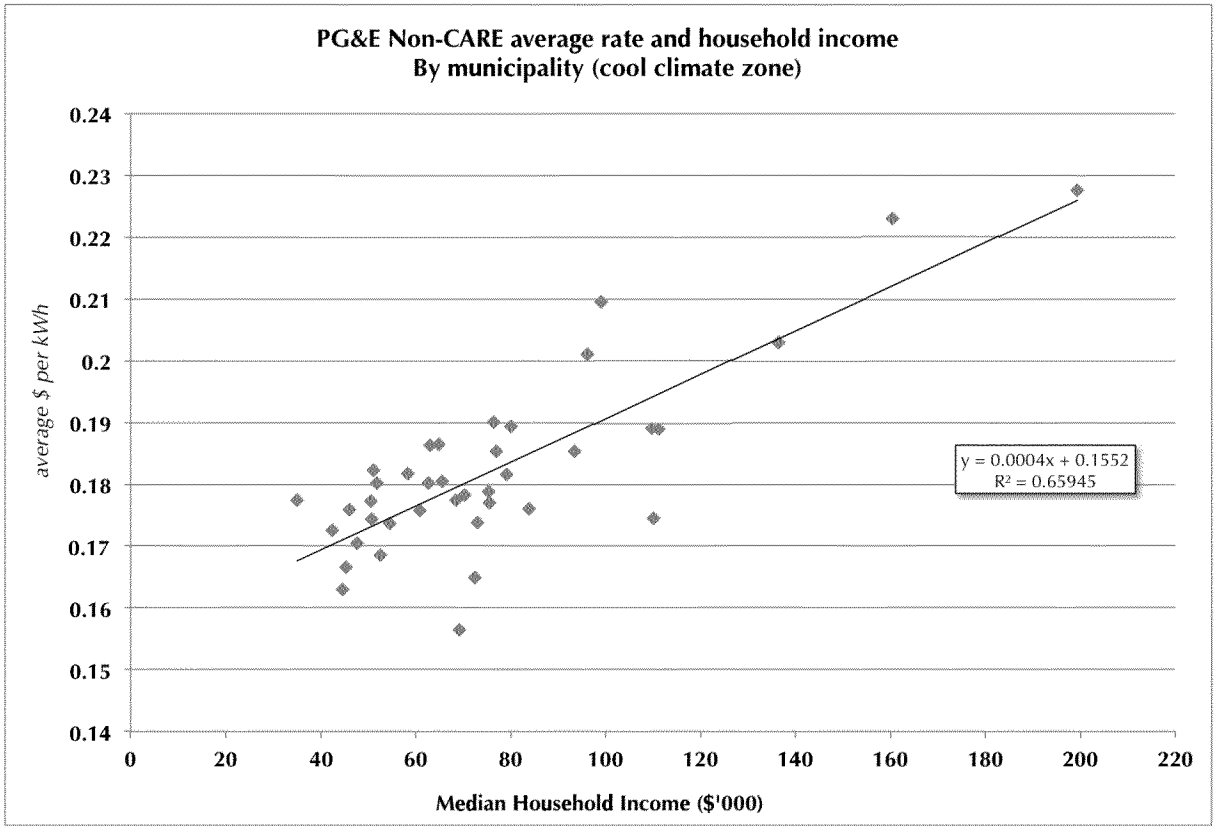

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TURN's reanalysis of PG&E's data shows the strongest correlations for cities with household incomes below $100,000 per year in the hot zone, significant correlations in the cool zone and weaker correlations in the mid zone. TURN suspects that the weaker mid zone correlations are due to the fact that Zone X has a greater diversity of climates that masks the relationship. When comparing cities where customers are exposed to very similar climates, the correlations are clear and robust.

PG&E further asserts that "it is simply not accurate to assume that all customers in a city are fairly represented by the *average* figure for that city."[40] PG&E then offers several hypothetical scenarios in which data for a particular city does not accurately show correlations relevant to individual households. TURN does not dispute that using city-level data introduces complications and is not a perfect proxy for household-level data. However, TURN submits that the correlations by climate zone are sufficiently obvious to demonstrate the basic principle that usage and income are correlated at all levels. This correlation does not apply to every customer and there will always be outliers.

TURN has provided analysis in many previous rate cases showing correlations between usage and income at the individual household level by climate zone.[41] Neither SCE nor PG&E took issue with those detailed analyses (which relied primarily on RASS data). The attempt to respond to TURN's repeated analyses only comes now that these utilities are trying to push for flatter tiers and large customer charges. The Commission should not allow itself to be lulled into a false sense that changes to the rate structure will equally benefit lower and higher income customers. It is clear that the benefits of tier flattening and fixed charges accrue disproportionately to customers with the highest incomes in each area of the service territory and disproportionately burden customers with the lowest incomes.

[40] PG&E opening comments, page 15.

[41] For example, see testimony of Bill Marcus on behalf of TURN in A.11-06-007 (SCE General Rate Case, Phase 2), A.10-03-014 (PG&E General Rate Case, Phase 2), and A. 11-10-002 (SDG&E General Rate Case, Phase 2).

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Respectfully submitted,

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Dated: July 26, 2013

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VERIFICATION

I, Matthew Freedman, am an attorney of record for THE UTILITY REFORM NETWORK in this proceeding and am authorized to make this verification on the organization's behalf. The statements in the foregoing document are true of my own knowledge, except for those matters which are stated on information and belief, and as to those matters, I believe them to be true.

I am making this verification on TURN's behalf because, as the lead attorney in the proceeding, I have unique personal knowledge of certain facts stated in the foregoing document.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on July 26, 2013, at San Francisco, California.

_____/S/_____

Matthew Freedman
Staff Attorney

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ATTACHMENT A

SDG&E RESPONSE TO TURN DATA REQUEST#3