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Witnesses: Mohit Chhabra, Sylvie Ashford

OPENING TESTIMONY OF MOHIT CHHABRA AND SYLVIE ASHFORD, SPONSORED BY THE NATURAL RESOURCES DEFENSE COUNCIL AND THE UTILITY REFORM NETWORK ADDRESSING OPTIONS FOR AN INCOME-GRADUATED FIXED CHARGE

Natural Resources Defense Council
111 Sutter St., 21st Floor
San Francisco, CA 94104
(415) 875-6100

The Utility Reform Network
785 Market Street, 14th floor
San Francisco, CA 94103
(415) 929-8876

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I. INTRODUCTION (SA & MC)

NRDC is a non-profit membership organization with more than 95,000 California members who have an interest in receiving affordable energy services while reducing the environmental impact of California's energy consumption and achieving California's environmental goals cost-effectively and equitably. The Utility Reform Network (TURN) is a non-profit ratepayer advocacy organization representing the interests of the residential customers served by California utilities. This testimony is jointly sponsored by Sylvie Ashford (SA) and Mohit Chhabra (MC) of the Natural Resources Defense Council (NRDC) on behalf of both NRDC and TURN.

Assembly Bill 205 (2022) provides a unique opportunity to implement a progressive fixed charge that can help align residential rate design with the state goals of prioritizing affordability, equity, and beneficial electrification. This testimony recommends a pragmatic and implementable fixed charge amount that is well below what economic theory would justify. Income graduation of this fixed charge will result in progressive outcomes while limiting adverse impacts to any residential subgroup. The underlying rationales and economic bases for our proposal are discussed in the ensuing sections. Further background is provided via a white paper by Synapse Energy Economics in Appendix C.

The NRDC-TURN fixed charge proposal can be summarized as follows:

- An average customer fixed charge of approximately $36 for all investor-owned utilities (IOU) customers on default rates.
- Fixed charges progressively recovered from customers via three income tiers. This includes the following default rate fixed charges:
  - Low tier: CARE & FERA customers pay a fixed charge of $5 per month.
  - Middle tier: non-CARE and non-FERA customers with annual household income up to $150,000 pay approximately $40 per month.
  - High tier: non-CARE and non-FERA customers with annual household income greater than $150,000 pay approximately $62 per month.
- Volumetric charges on default rates commensurately decrease by approximately 25% for non-CARE customers and 20% for CARE customers.
- Separate, optional electrification rates include a fixed charge $10 higher than default

rates for all tiers described above.

A. Three Separate Problems: Utility Revenue Requirement, Social Policy Costs, and Rate Design

California residential electricity rates are among the highest in the country. Although California's temperate coastal weather, energy efficiency leadership, and low-income rate discount programs have kept some customers' residential bills in check, rising rates threaten affordability, equity, and electrification goals. Because residential electric rates are so much higher than the costs to both the utility and society at large of incremental electricity consumption, they create problematic incentives and large affordability challenges. While California's decarbonization goals require aggressive electrification of buildings and transportation, rapidly rising electric rates discourage electrification investments and exacerbate the affordability crisis for lower and middle-income Californians.

This proceeding's charter is to explore options for reforming residential rate design through the incorporation of income-based fixed charges, dynamic pricing, and other methods of using rates to promote demand flexibility. Although reforming rate design is part of the strategy for addressing affordability and encouraging electrification, no set of outcomes in this proceeding will solve the core problem of excessive revenue requirements collected through rates. Rates can provide the right marginal signals to customers but preserving the affordability of customer bills requires a primary focus on revenue requirements and making sure all connected customers fairly pay for the fixed costs of the grid and policy-related obligations. The Commission should continue to be vigilant about total revenue requirement authorizations by making sure utilities engage in efficient and necessary spending and funding societal policy goals and societal wildfire risk mitigation through sources other than utility revenue requirements.

This testimony describes why the current residential electric rate design leads to uneconomic, inequitable, and un-environmental outcomes; we propose a new rate structure that partly overcomes each of these issues and provide recommendations for the Commission to continue to improve residential rate design.

B. The Context for NRDC and TURN Support for Fixed Charges

California's equitable decarbonization ambitions require electricity prices to better reflect marginal costs of generation from an increasingly renewable grid to provide appropriate signals for beneficial electrification and efficiency. Equitable outcomes require that customer electric bills be affordable and as progressive as possible.

Historically, TURN and NRDC have opposed residential fixed charges due to concerns over regressive economic impacts and adverse impacts on efficiency, which is at the top of the CPUC's "loading order" of resources.[1] Several things have changed. (1) An income-based fixed charge allows for progressive implementation and mitigates disadvantages for low-income customers; (2) the California generation mix is increasingly composed of renewable resources, with surplus generation occurring primarily during the middle of the day, and the emissions intensity of the portfolio will continue to improve as California moves towards the target of 100% zero carbon resources by 2045 as required by law[2]; (3) significant increases in average rates over the past decade mean that usage-based rates, even with new fixed charges, are still sufficient to promote conservation and efficiency; (4) there is a relatively new imperative for beneficial electrification (buildings and transportation), which was not present in the past, to achieve carbon neutrality by 2045 per California law.[3]

The hypothesis underlying this policy proposal is broadly applicable. However, this policy proposal is germane solely to the specific circumstances currently present in California: extremely high electric rates; aggressive decarbonization goals; specific legislative direction to implement a progressive fixed charge; and an increasingly clean electricity generation mix.

C. Summary of the Joint Proposal

Residential rate design in California needs to balance the policy aims of economic efficiency, reducing greenhouse gases and local pollution, equitable outcomes, predictability,

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[1] CPUC Energy Action Plan II: "The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications." Available at: https://docs.cpuc.ca.gov/PUBLISHED/REPORT/51604.htm

[2] *See* Senate Bill 100: https://www.energy.ca.gov/sb100

[3] *See* Assembly Bill 1279, The California Climate Crisis Act: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB1279

customer acceptance/understanding, and stability.

Economic efficiency requires pricing informed by short run social marginal costs (SRSMC), as explained in Section II. Rates informed by SRSMC also provide the right environmental signal as they encourage customers to use more electricity when clean resources are at the margin, or conserve when polluting and expensive resources are at the margin. Equitable electric rate structures provide understandable and constructive price signals that enable easy customer response and are as progressive as possible.

An income graduated fixed charge is one tool the Commission can use to help achieve these objectives. While higher fixed charge levels result in lower and less distortionary volumetric rates, income graduating fixed charges will result in progressive electricity bills, and an appropriately time varying rate structure (that reflects the variation in SRSMC) will continue signaling conservation and load shifting during peak periods.

As a starting point, the Commission should raise fixed charges and provide sufficient income graduation to: (1) meaningfully reduce the gap between current inefficient and inequitable average cost based volumetric rates and SRSMC, and (2) realize significant improvements in the regressivity of electric bills. Continued use of optional electrification rates, which have a higher fixed charge than default rates and greater on- and off- peak differential, will also encourage beneficial electrification.

Table 1 and Table 2 present a representative snapshot of the NRDC-TURN proposal.

Table 1 Proposed Income Graduated Fixed Charges for Tiered and Electrification Rates; Fixed Charges for Other Rates are Similar.

Fixed Charge Amounts						
	PG&E		SCE		SDG&E	
	E-1	E-ELEC	D	TOU-D-PRIME	DR	TOU-ELEC
CARE & FERA	$ 5	$ 15	$ 5	$ 15	$ 5	$ 15
< $150,000	$ 41	$ 50	$ 41	$ 51	$ 41	$ 51
$150,000+	$ 62	$ 75	$ 62	$ 76	$ 62	$ 76
Average per customer	$ 36	$ 47	$ 36	$ 47	$ 36	$ 47

Table 2 Existing and New Proposed Volumetric Rates for Tiered Rate Schedules; The Change is Indicative of the Magnitude of Decrease in Volumetric Rates Across All Rate Schedules.

Volumetric Charges						
	PG&E (E-1)		SCE (D)		SDG&E (DR)	
	Existing Rate	New Rate	Existing Rate	New Rate	Existing Rate	New Rate
CARE	$ 0.24	$ 0.19	$ 0.26	$ 0.21	$ 0.38	$ 0.31
Non-CARE	$ 0.39	$ 0.30	$ 0.40	$ 0.31	$ 0.59	$ 0.47
Baseline Credits						
	PG&E (E-1)		SCE (D)		SDG&E (DR)	
	Existing Rate	New Rate	Existing Rate	New Rate	Existing Rate	New Rate
CARE	$0.05	$ 0.04	$ 0.06	$0.05	$ 0.08	$ 0.06
Non-CARE	$0.07	$ 0.06	$ 0.08	$0.07	$ 0.12	$ 0.10
High Usage Charge						
	PG&E (E-1)		SCE (D)		SDG&E (DR)	
	Existing Rate	New Rate	Existing Rate	New Rate	Existing Rate	New Rate
CARE	$ -	$ -	$ 0.06	$0.05	$ -	$ -
Non-CARE	$ -	$ -	$ 0.09	$0.08	$ -	$ -

As we illustrate throughout our testimony, there are significant economic and policy justifications for an evolving fixed charge that incorporates income graduation and can achieve economic, environmental, and equitable outcomes. The NRDC-TURN joint proposal is the right starting point for this reform. Further changes in the future should carefully consider distributional impacts of such changes on customers of various income levels and located in different climates.

D. Organization of the Testimony

- Section II explains basic economic concepts of rate design and illustrates the environmental, economic, and equity issues with today's residential rates. Then we describe attributes of an economically efficient and progressive rate structure, explain the implementation issues with such a rate structure, and describe attributes of a pragmatic and implementable rate design.
- Section III describes the Joint Proposal and identifies the determinants of the fixed charge for default and electrification rates, proposed income graduation schema, expected impacts on customer bills, and improved signals for beneficial electrification.

- Section IV explains how the income graduated fixed charge proposal can be implemented and evaluated post-implementation.
- Appendix A: Witness Qualifications.
- Appendix B: Index of ALJ guiding questions mapped to testimony.
- Appendix C: Synapse whitepaper on economic theory, policy tradeoffs, and practical considerations for fixed charge reform.
- Appendix D: Printed results requested by the ALJ. The first set includes the applicable fixed charges for default tiered and TOU rates, with heat maps for two rate types per utility. The second set includes applicable fixed charges for electrification rates, with heat maps for one such rate per utility.
- Appendix E: Explanation of changes to testimony (errata)

II. OVERARCHING THEORY OF RATE REFORM: ECONOMIC JUSTIFICATION AND POLICY CONSIDERATIONS (MC)

A. Short Run Marginal, Long Run Marginal, and Average Costs

Short run marginal costs (SRMC) are the utility's private marginal costs of increasing output in the short run when at least one input is fixed. In the electricity sector, in the short run, both generation capacity and grid capacity are fixed. SRMC is equal to the costs of producing and delivering a marginal unit of electricity; or the sum of the wholesale locational marginal price, (which includes the competitive clearing price of electricity generation plus high voltage transmission losses), and the costs of distribution system losses.

Short run social marginal cost (SRSMC) is the full marginal cost to society of increasing output in the short run when at least one input is fixed. The SRSMC is equal to the SRMC plus the costs of associated environmental externalities, namely the social costs of greenhouse gases and air pollution associated with producing an extra unit of electricity. In an increasingly renewable grid like California, SRSMC will be low during off-peak periods when renewables are increasingly on the margin, it could become extremely high during on-peak periods due to generation constraints, transmission constraints, and environmental externalities associated with fossil generation.

The economic ideal is to set prices at SRSMC.[4] Borenstein explains that "the idea that economic efficiency is maximized when price reflects full short-run social marginal costs (SRSMC) is a bedrock principle of microeconomics, because it is straightforward to show that any departure from social marginal costs is likely to reduce the economic value that the industry can create. Producing a good requires inputs — labor, fuel, machinery, land, etc. — and those inputs have alternative uses. The price of an input is generally a good indicator of its value in its next best use, so economics suggests that the inputs should only be brought together to produce this good if the value of this good to whoever consumes it exceeds the value of all the inputs necessary to make it. Setting price equal to short-run social marginal cost creates the incentive to consume an incremental unit of the good if and only if one values it more than the value that the inputs would create in their next best use."[5,6]

Long run marginal costs (LRMC) are the marginal costs of increasing one unit of output when all inputs can be varied. Accordingly, long run is the length of time through which all inputs can be varied. Long run social marginal cost (LRSMC) also account for the costs of any environmental externalities incurred in addition to LRMC. Avoided costs in the CPUC's Avoided Cost Calculator (ACC) are an intuitive adaptation of the LRMC concept. In summary, with simplifications, the CPUC's ACC is based on the total costs of meeting forecasted increases in future electricity demand by a unit in all hours of the year by adjusting all components of the electricity system (generation, capacity, transmission, and distribution); the marginal costs for generation capacity, transmission, and distribution are allocated to hours and locations based on a probability of when and where the grid will constrained for capacity in the future. The generation marginal costs for each hour are based on forecasts of wholesale market energy prices.

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[4] See, for example, A.E. Kahn, The Economics of Regulation (Vol. I), at 75. "The economic ideal is to set all public utility rates at short run marginal costs (with appropriate adjustments for the problems of second-best); and these must cover all sacrifices, present or future and external as well as internal to the company, for which is production at the margin causally responsible.

[5] Severin Borenstein, *The Economics of Fixed Cost Recovery by Utilities* (2016), at 2.

[6] For example, if the total societal cost to produce an extra unit of a good is $10 and it is priced at $10 then customers who value it at $10 and above will purchase it. An efficient outcome. If it is incorrectly priced at $20, then only those customers who value that good at more than $20 will purchase it. All the customers who value that good between $10 and $20 will forego consumption and there will be deadweight loss. On the other hand, if the good is incorrectly priced too low then it will induce overuse, which will lead to misallocation of resources and additional environmental externalities.

The ACC with minor modifications, henceforth called ACC_M,[7] could provide guidance for setting average volumetric rates if policymakers choose to include some longer run marginal costs (as explained above) and/ or collect some future fixed costs via volumetric rates to recover future marginal capacity and grid expansion costs based on customer consumption patterns today. However, the downside of including these additional longer run marginal costs from the ACC_M is loss of economic value in the short run when ACC_M is higher than SRSMC. On the other hand, LRSMC based values won't reflect the full SRSMC during times when demand exceeds supply which could lead to overbuilding, excess capacity, and a more expansive and expensive grid than necessary.

Although SRSMC is the economic ideal for setting the electricity price, or the volumetric rate, there are practical and policy reasons to deviate from SRSMC.

First, SRSMC may be too volatile as it changes with time, at least every fifteen minutes per the wholesale market, and by location. The effort required to comprehensively implement this price signal may not be the worth the additional benefit generated. Second, accurately implementing the SRSMC will require technological infrastructure that may not exist uniformly and may be very expensive to implement. Third, all residential customers may not be well equipped to efficiently respond to these constant changes in price. Fourth, rates need to be customer friendly and predictable so that residential customers understand their rates and its implications on their monthly bill. Finally, policy makers may want to include additional ACC_M longer term marginal costs to both influence customer behavior to potentially defer avoidable capital expenditures, and/or collect future fixed costs, which would also help smooth out sudden SRSMC price surges.

California's default residential rates are based on neither SRSMC nor any application of LRSMC. They are based on a variation of average costs; wherein (almost all) the residential revenue requirement is divided by forecasted consumption to determine average volumetric rates

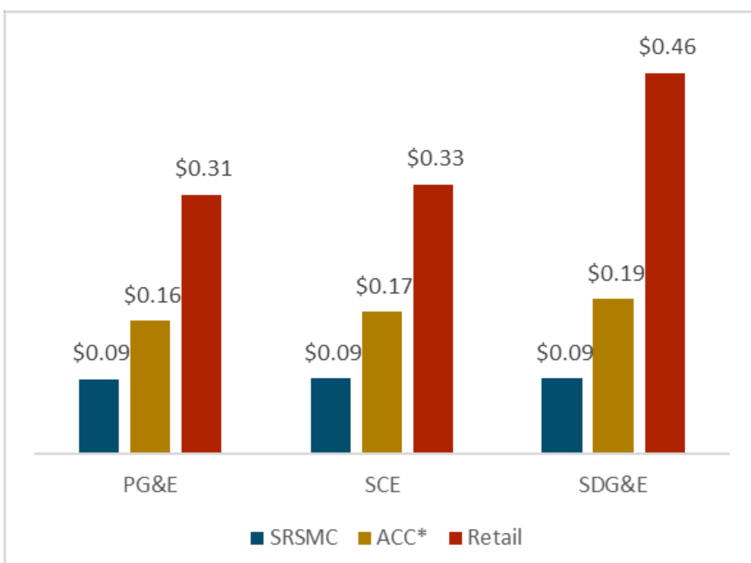
[7] To apply the ACC, the GHG Adder should be replaced by social damage costs of carbon and air pollution. Commission's adopted ACC includes the cost of specific GHG reduction goals, or a shadow price of GHG reduction, without any new or additional distributed energy resources. This shadow price, called the GHG Adder, helps accounts for the fact that in the absence of DER, utilities will contract with more supply side resources to meet GHG reduction goals. Social marginal costs should represent the total cost to society if an extra unit of electricity is consumed including environmental externalities which in this case are the social cost of carbon and air pollution.

per kWh. These average costs are then adjusted to reflect some of the time varying costs of delivering electricity in Phase 2 General Rate Case proceedings, which are often resolved via settlements. Currently, a very small portion of the residential revenue requirement is collected via fixed charges by those few customers that are on electrification rates who pay around $15 per month. Electrification specific rates have a higher on and off-peak differential and a modest fixed customer charge. These electrification rates are not currently based on SRSMC or any application of LRSMC.

B. Current Average Cost Based Volumetric Rates Have Economically Inefficient, Inequitable, and Environmentally Deleterious Outcomes

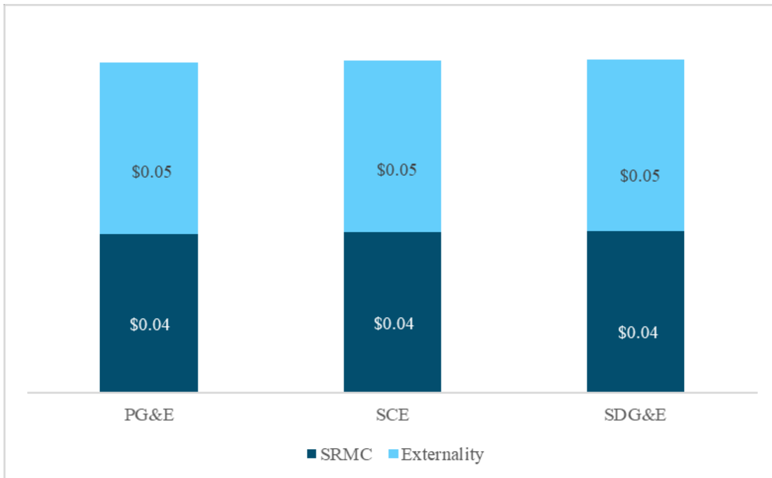
An estimate of SRSMC can be derived from the CPUC's ACC. The ACC includes forecasted wholesale prices, distribution losses, and marginal emissions. The CPUC's recent report on the Societal Cost Test (SCT Report) includes an estimate of social damages – due to GHG's and air pollution – from marginal emissions.[8] Combined, these two resources have all the information to develop an estimate of the SRSMC. Figure 1 shows how much default TOU rates differ from the SRSMC and ACCM; Figure 2 breaks out SRSMC into SRMC and externalities.

Figure 1 Comparison of SRSMC and ACCM with TOU Rates (PG&E = E-TOU-C. SCE = TOU D 4-9, SDG&E = TOU-DR1)[9]



[8] Energy Division Staff and E3 Consulting, *Societal Cost Test Impact Evaluation*, CPUC, January 2022.
[9] Calculation details in Appendix C, Section 5.2.

Figure 2 Decomposing SRSMC into SRMC and Externalities

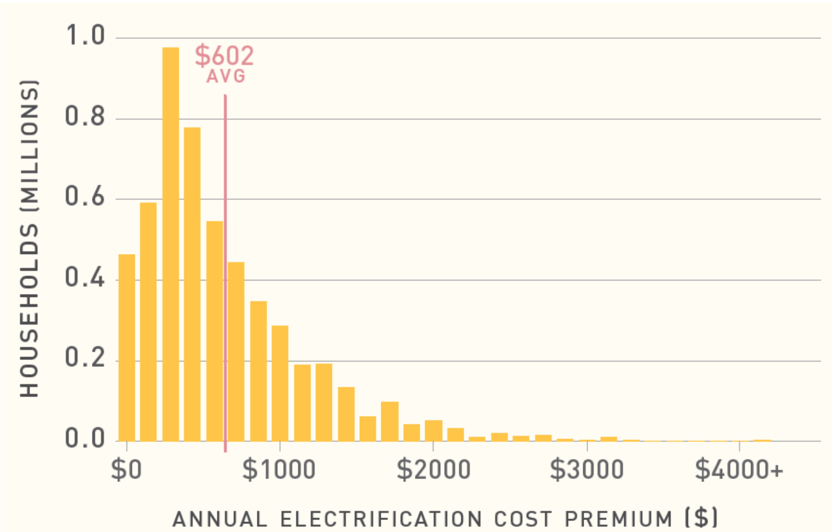


As seen in the figure, the retail price of electricity is much higher than both the SRSMC and the ACCM (which, in this example, is equal to the SRSMC plus longer run capacity adjustment costs as determined by the ACC). Aside from the economic surplus lost due to mispriced electricity, wherein customers are overcharged for consumption and consume less than they otherwise would, this mispricing causes serious environmental and equity issues.

As the California grid gets cleaner due to increasing penetration of renewable generation, SRSMC and ACC_M values will decrease in most hours except those with significant generation capacity and transmission & distribution capacity constraints. This means that Californians should be able to avail themselves of low-cost and clean electricity in all hours without scarcity – where supply is low relative to demand – and when clean resources are on the margin. If retail pricing for these hours matched SRSMC or ACC_M values, customers would be more motivated to electrify their building and transportation needs. Yet even as social marginal costs decrease, existing residential electricity prices are escalating rapidly and increasingly provide inaccurate price signals in virtually all hours. The inefficiencies illustrated in the figures above will only get worse over time unless the Commission adopts the Joint Proposal and begins reforms to residential electric rate design.

Figure 3 shows an estimate of the premium Californians are paying for electrified space heating due to this inefficient electric pricing. This analysis, conducted by the Energy Institute at Haas, uses slightly different rate and SRSMC values than presented in this testimony; the overarching finding, that operating costs of space heating via beneficial electrification are a lot more than they should be, stands.

Figure 3 Current Inefficient Rates Make Electrification a Hard Proposition for Californians[10]



This figure shows a histogram of the annual increase in space heating costs due to electricity prices being above SMC. Each data point is one single-family detached dwelling in the RASS. The annual burden estimates the additional operating costs at 2019 retail prices compared to operating cost if retail prices were set at SMC.

The second major issue with existing average cost volumetric rates is their regressive impacts. The fact that lower income customers pay a much higher portion of their expendable income on electricity than higher income customers in California isn't a surprise. What is shocking, however, is that compared to other essential household expenditures, spending on electricity is by far the most regressive. Figures from a recent Next 10 report, based on research conducted by the Haas Energy Institute, illustrate the inequitable impacts of the current electricity rate structure. This analysis is based on 2017-18 data; because electric rates have significantly increased since then, the trends in these charts are even more troublesome today. The income graduated fixed charges in the NRDC-TURN proposal will improve this regressivity.

[10] Borenstein, Fowlie, and Sallee. 2022. *Paying for Electricity in California: How Residential Rate Design Impacts Equity and Electrification*, 20. Next 10 and the Energy Institute. Available at: https://www.next10.org/sites/default/files/2022-09/Next10-paying-for-electricity-final-comp.pdf
The values presented here are estimates of meeting heating demand, derived from the Residential Appliance Saturation Survey, with 2019 Energy Star standard efficiency electric heating appliance.

Figure 4 Electricity Expenditure is more Regressive than Other Household Expenditures[11]

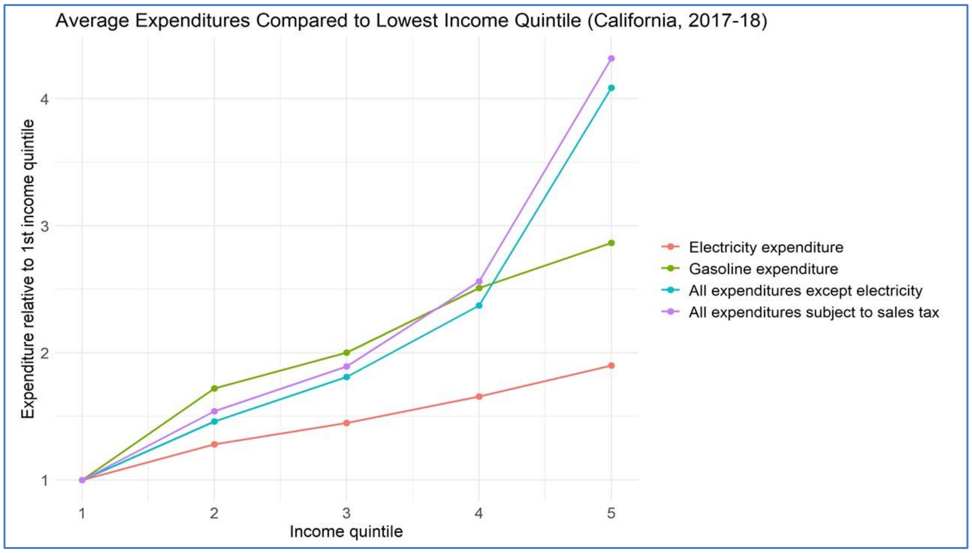
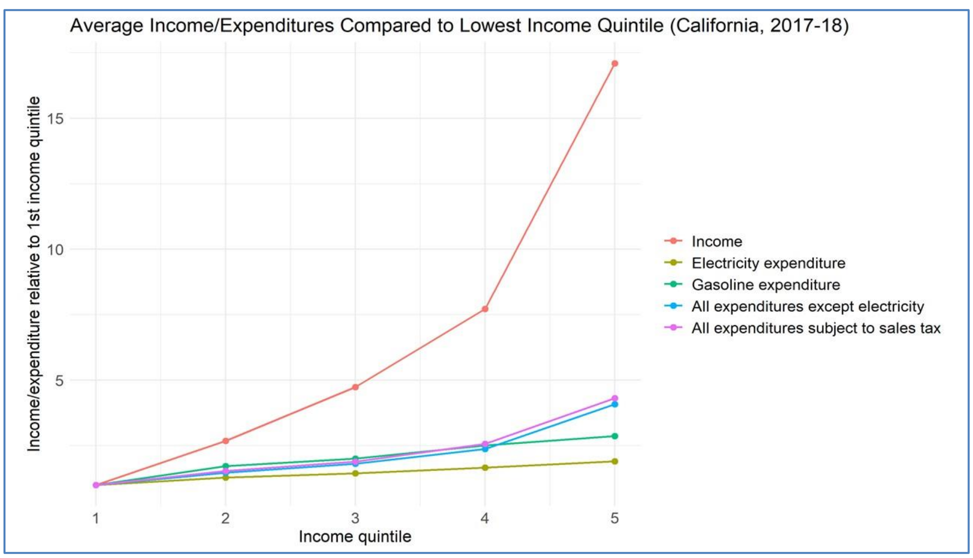


Figure 5 Electricity Expenditure Does Not Track Income; Lower Income Households Spent a Lot More on Electricity Relative to Their Income[11]



The first part of the optimal economically efficient solution is to set prices, or volumetric rates, equal to SRSMC. Because setting prices at SRSMC maximizes societal value and efficiency, it provides a reference point for evaluating the economic efficiency of new proposed rate design's consumption charges.

[11] Borenstein. 2020. "Reinventing Fixed Charges." Energy Institute at Haas. Available at: https://energyathaas.wordpress.com/2020/11/16/reinventing-fixed-charges/

However, this presents a challenge for revenue recovery. As illustrated above, utility average costs are much higher than SRSMC or even ACC_M; the gap between average costs and utility's private marginal costs (SRMC) is even greater. Specifically, utilities and community choice aggregators will not recover most fixed costs if volumetric rates are set at either SRSMC or at ACCM. A different revenue collection mechanism in addition to one based on usage is required to collect these residual fixed costs. Innovative methods of recovery, such as income graduated fixed charges, can accomplish this- collection of full revenue requirement while making electric bills more progressive.

C. Residual fixed cost Recovery Via Income Graduated Fixed Charges and The Case Against Demand Charges

If volumetric rates are set at true SRSMC then each customer would pay for the full marginal costs their usage imposes on the electricity system and society. Customers who use more electricity during times of generation capacity and grid constraints would pay the most per kilowatt-hour, while others who use electricity when there is excess clean supply would pay the least. When electricity is priced based on economic efficiency, all residual costs, or revenue requirement remaining over and above usage-based cost recovery, are fixed and unaffected by the volume or timing of electricity consumption.

The primary consideration for allocating residual fixed costs to a utility's customer base is one of fairness. Who should pay how much and why? There are multiple dimensions to fairness and multiple approaches to answering this question. One purely economic approach would allocate fixed costs to all customers based on the consumer surplus each customer derives from electricity use (from the grid). Those who use the most electricity and value electricity the highest would then pay most. This determination, however, requires an understanding of each customer's intrinsic valuation of electricity use, or each customer's own personal demand function. Moreover, this method of allocating fixed costs does not differentiate between customers who value electricity highly as a matter of necessity (e.g., a seven-person household that requires a high base level of electricity use) and wealthy customers who want to (and can) spend more on electricity to fulfil their desires. Said another way, two customers can have the same demand functions for electricity for distinct reasons, and these distinctions may justify different fixed charge amounts for each based on fairness considerations.

Another way to allocate fixed costs is based on each customer's ability to pay. Because universal access to electricity is a basic right, fulfilling this right requires maintaining a collective good, the grid, to serve all customers at all income levels. This approach supports paying these fixed costs, which are independent of future usage, progressively or based on each household's ability to contribute. Households would pay toward fixed cost recovery based on their individual income or wealth. Assembly Bill 205's (AB205) requirement to income graduate fixed charges supports the implementation of such an approach.

Combining these two approaches would mean that customers who are the richest and use the most electricity should pay a greater share of fixed costs. This ideal solution is nearly impossible to implement. However, a progressive graduation of the fixed charge is feasible (as demonstrated by this proposal) and takes a step in this idealized direction. In particular, there is a significant correlation between income and energy use as wealthier customers tend to consume more electricity within each climate zone as TURN has previously demonstrated.[12] This ideal approach would, on average, recover more fixed costs from wealthier customers with higher energy use.

Practically, as rates evolve from their current state to SRSMC, utilities will continue to recover a portion of fixed costs via volumetric rates.[13] Larger electricity users will continue to pay more towards fixed cost recovery than lower electricity users; and there is no need for an additional usage or demand-based mechanism to allocate fixed costs among residential customers.

The Problem with Demand Charges

Because pricing electricity based on economic efficiency, where variable charges are equal to SRSMC, will recover whatever marginal costs each customer imposes on the grid, any demand charge to ensure cost causation-based recovery of fixed costs is unnecessary. In addition

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[12] TURN analysis of PG&E data finds that when normalized by climate zone, there is a correlation between wealthier customers and higher energy use. TURN conducted this analysis on customers on tiered rates and found that the average rate for wealthier customers is higher. This implies that higher customers were also consuming more and were thus on higher $/kWh tiers. *See*, TURN. July 26, 2013. "Reply Comments of The Utility Reform Network on Rate Proposals," 21-24. CPUC Rulemaking 12-06-013.

[13] The fairness of fixed cost recovery through volumetric rates is also contingent on how fixed costs are spread over different hours in current time of use rate structures.

to being superfluous when electricity is priced at SRSMC, residential demand charges have arbitrary impacts on customers, are misaligned with state policy goals, provide perverse incentives, and cause confusion.

Non coincident peak demand charges (NCP) are usually based on a customer's highest 15 minutes of usage, independent of the SRSMC or LRSMC at that time. Two customers with the exact same profile and identical consumption quantities could have different NCP based on their highest fifteen-minute period of electric consumption. Customers who intentionally use more electricity and have a high NCP during periods of surplus will end up paying extra for being good actors. As customers electrify, their NCP will increase so demand charges would cause these customers to unnecessarily overpay even if they time their incremental electric usage to coincide with periods of low grid costs. This disincentivizes electrification policy goals.[14]

Coincident demand charges beg the question: coincident with what? Coincident with local distribution congestion or coincident with systemwide capacity shortfall? Or a mixture of both? Applying a uniform definition of coincident demand charges will again have arbitrary impacts across a utility's customer base in addition to some of the same problems that an NCP causes.

Finally, demand charges are notoriously hard to explain to customers. Customers have an intuitive sense of how their electric usage corresponds to their total electric bill, but keeping track of their highest fifteen minutes of consumption over a month or a year may prove to be untenable and cause confusion.[15] Demand charges also cause perverse and unfair incentives for wealthier and savvier customers who have the resources to minimize their peak demand through a mix of smart appliances, programmable storage, and or paid expert/ consultant advice. Demand charges could effectively shift costs towards customers with less ability to avail themselves of such services including renters (who tend to have lower than average incomes) and many

[14] CPUC Staff explain how "counterproductive demand charges inhibit load-shift and require reform." *See CPUC. 2022. Advanced Strategies for Demand Flexibility Management and Customer DER Compensation*. Energy Division White Paper and Staff Proposal, 32-36. Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/demand-response-workshops/advanced-der---demand-flexibility-management/ed-white-paper---advanced-strategies-for-demand-flexibility-management.pdf
[15] Is it really practical to ask customers to not run their dishwasher while they charge their EV, particularly if this occurs during off-peak hours?

middle-income families.

Compliance with Public Utilities Code Section 739.9(d)

Public Utilities Code §739.9(d) requires that fixed charges reasonably reflect the costs of serving small and large customers, not unreasonably impair incentives for conservation, efficiency, beneficial electrification, and GHG reductions, and not overburden low-income customers.[16] Income graduating fixed charges addresses the requirement to not overburden low-income customers. To the extent wealthy customers are also larger customers, larger customers will on average pay higher fixed charges; and to the extent larger customers consume more electricity, they will pay more toward fixed cost recovery so long as a significant fraction of fixed costs are recovered via volumetric rates (as explained above.) Fixed charges aligned with our Joint Proposal will incentivize beneficial electrification while continuing to prioritize efficiency.

Finally, utilities should account for any difference in marginal customer access costs between single family and multi-family dwellings by modifying our proposed fixed charge levels. The Commission should direct the utilities to improve their collection of customer data to include identifiers as to whether a residential account reflects a single or multi-family unit. Once there is better confidence in the accuracy and completeness of this information, the Commission can direct utilities to evaluate the establishment of separate single-family and multi-family fixed charges in appropriate rate design proceedings (such as a Phase 2 General Rate Case).

D. Real World Barriers to An Economically Efficient and Ideally Progressive Rate Design Require Pragmatic Solutions

As explained in Section II.A, there are pragmatic economic and policy reasons for deviating from SRSMC, such as the need to develop a predictable and understandable default rate. Geographic and hourly variations should be averaged to address customer understanding

[16] §739.9(d) The commission may adopt new, or expand existing, fixed charges for the purpose of collecting a reasonable portion of the fixed costs of providing electrical service to residential customers. The commission shall ensure that any approved charges do all of the following:
(1) Reasonably reflect an appropriate portion of the different costs of serving small and large customers.
(2) Not unreasonably impair incentives for conservation, energy efficiency, and beneficial electrification and greenhouse gas emissions reduction.
(3) Are set at levels that do not overburden low-income customers.

without overly compromising price signals for both capacity constrained hours (which correlates to times when polluting resources are on the margin) and off-peak hours when social marginal costs for consumption are very low. Moreover, if volumetric rates (on-average) equal SRSMC, very high fixed customer charges, between $75 and $90 per month, would be required to recover residual fixed costs.

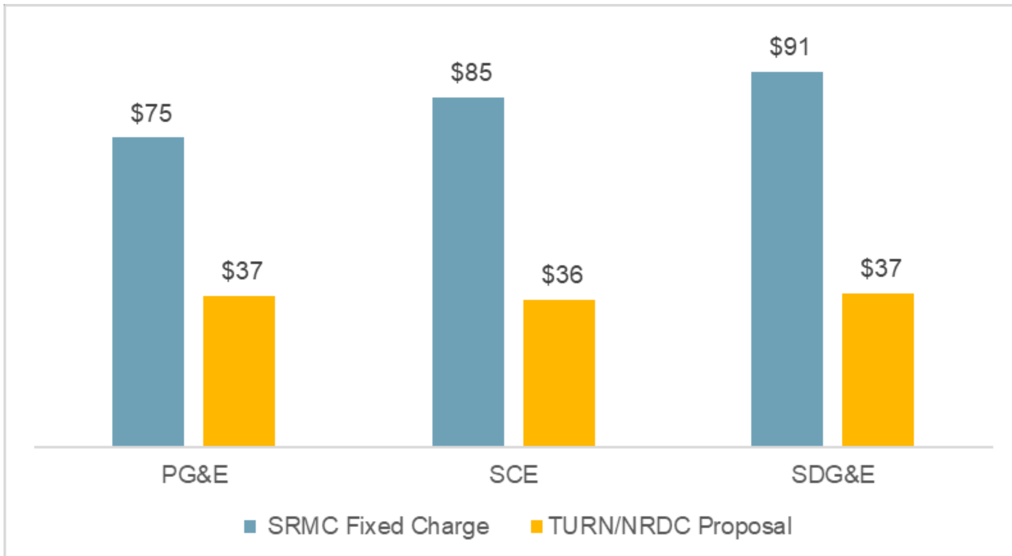
A rate design that meaningfully reduces the gap between SRSMC and current rates is a reasonable starting place. Collecting residual fixed costs via progressive income graduated fixed charges is a novel approach which requires new organizational and informational structure development. Moreover, utility billing systems need to accommodate this scale of change, e.g., the way that transmission, distribution and policy-driven costs are collected will need to evolve, and major changes would be required to accurately bill both bundled and departing load customers.

Finally, funding for social policy goals and shared public safety obligations like wildfire mitigations that go beyond compliance with utility regulatory requirements, or are driven by larger public safety objectives, should be collected via the state budget or another external funding source rather than the electricity revenue requirement. It is far more progressive to collect funding from taxpayers than ratepayers given California's progressive state income tax. This shift would also improve electricity pricing signals by removing these costs from the pricing of electric consumption. Until new mechanisms are developed to collect these social policy and public safety related costs via taxpayer funding, these will remain in utility revenue requirements and should ultimately be recovered via fixed charges.

E. The Joint Proposal Balances Economic Efficiency, Environmental Goals, and Prioritizes Equitable Outcomes

We propose starting with an average fixed charge that is less than halfway between current fixed charges and the amount required to recover revenues when volumetric rates equal SRSMC. Our proposal leverages existing programmatic structures to develop a three-tier household income graduation starting point. We propose continuing opt-in electrification rates with a slightly higher fixed charge than default rates. Off peak rates for customers on these electrification rates are closer to SRSMC and thus encourage beneficial electrification; high on-peak charges in these electrification rates will provide the right signal for efficiency and demand response.

Figure 6 TURN/ NRDC Proposed Average Fixed Charge Versus Fixed Charge Needed to Get Volumetric Rates to Equal SRSMC



The Commission should implement this no-regrets first step. A no-regrets fixed charge would result in volumetric electric rates that remain high. These rates will continue to incentivize distributed generation, energy efficiency, and demand response even though not all this encouragement will be economically efficient.

As existing rates still significantly deviate from the SRSMC, the Commission should continue to adjust the fixed charge, existing time of use period definitions and volumetric charges over time to make rate design more efficient. To address policy objectives, the Commission should continue updating this rate structure to ensure that income graduated fixed charges are collected more progressively over time, and that rates continue to balance Commission priorities for cost-effective energy efficiency and demand response, beneficial electrification, and cost-effective distributed generation.

In taking this stepwise approach, the Commission should continue to analyze distributional impacts of rate reform. Specifically, there should be an ongoing evaluation as to which customers gained and lost the most from these changes. For example, income graduated fixed charges' impacts will vary geographically; high income coastal customers will likely see the greatest percentage increases in their bills, low-income inland customers will likely realize the most savings. Future rate updates should continue to prioritize keeping default rates understandable, predictable, and manage customer expectations.

III. DETAILS OF THE JOINT PROPOSED RATE STRUCTURE (SA & MC)

A. Determinants of Average Levels of Fixed Charge

The rationale for sorting cost categories between fixed and variable is straightforward. All cost categories that aren't part of the strict economic definition of marginal SRSMC are candidates for fixed charges; cost categories that aren't part of LRSMC adaptation to the electric sector, or ACC_M, are definite candidates.

To develop our fixed charge recommendation, we start with including all feasible cost categories and then add a portion of non-marginal distribution costs for each utility until achieving our desired fixed charge amount. We solved for an average fixed charge that results in approximately $40 for the middle income graduated tier and $5 for CARE customers. This approach yields an average fixed charge across all three utilities of approximately $37. This recommended level considers the bill impacts for coastal customers who tend to have lower usage than inland customers. We found moderate bill impacts for coastal customers at this (and even higher) levels. We also wish to introduce fixed charges in a more gradual fashion than required for volumetric rates to reach SRSMC to ensure customer acceptance of these rate changes. changes. We recommend fixed charges for all residential rate options.

Table 3 presents all cost categories for each utility and the portions of each category we propose for inclusion in the fixed charge. Highlighted categories are those categories that meet the strict definition of SRSMC or are included in ACC_M; all other categories are thus candidates for inclusion in a fixed charge.

Table 3. Average Determinants of Default and Electrification Rate Average Customer Fixed Charge

Cost Category	Cost Component	Percent to Include in Customer Charge		
		PG&E	SCE	SDG&E
Generation	PCIA	100%	100%	100%
Generation	Marginal Energy Cost	0%	0%	0%
Generation	Marginal Generation Capacity Cost	0%	0%	0%
Generation	Non-Marginal Generation	0%	0%	0%
Distribution	Marginal Customer/ Customer Access	100%	100%	100%
Distribution	Marginal Distribution Capacity Cost - Primary	0%		
Distribution	Marginal Distribution Capacity Cost - New Business	100%		
Distribution	Marginal Distribution Capacity Cost - Secondary	0%		
Distribution	Marginal - Grid		0%	
Distribution	Marginal - Peak		0%	
Distribution	Marginal Demand - Non-Coincident Peak			0%
Distribution	Marginal Demand - Coincident Peak			0%
Distribution	Non-Marginal Distribution	20%	45%	7%
Transmission	All Transmission Categories	0%	0%	0%
Line Items	Public Purpose Programs - SGIP	100%	100%	100%
Line Items	Wildfire Fund Charge	0%	0%	0%
Line Items	Wildfire Hardening Charge	100%	100%	
Line Items	Recovery Bond Charge	0%	0%	
Line Items	Recovery Bond Credit	0%	0%	
Line Items	Public Purpose Programs - Not CARE Exempt	100%	100%	100%
Line Items	Nuclear Decommissioning	100%	100%	100%
Line Items	New System Generation Charge	100%	100%	100%
Line Items	Competition Transition Charge	0%		0%
Line Items	Energy Cost Recovery Account	0%		
Line Items	Total Rate Adjustment Component - Baseline adjustment component			0%
Line Items	Residential CARE Contribution	100%	100%	100%
Average Default Fixed Charge Per Customer Per Month		$36	$36	$36
Modifications for Electrification Rates				
Distribution	Non-Marginal Distribution	55%	76%	43%
Average Electrification Fixed Charge Per Customer Per Month		$47	$47	$47

Additional context for these categorizations:

- Non-Marginal Generation: These are sunk costs and candidates for inclusion in a fixed charge. However, the Staff provided E3 tool doesn't allow this category to be included in a fixed charge.
- Power Cost Indifference Adjustment (PCIA): These are sunk costs of legacy generation resources including utility-owned generation and power purchase contracts. The PCIA revenue requirement is a function of the difference between the annual costs of these resources and their annual market value. Although the PCIA is currently collected on the basis of usage and vintage of departing customers, they can also be collected via a fixed charge. Once the annual PCIA revenue requirement is forecasted for each customer vintage, it is divided by total forecasted retail sales to determine per kWh PCIA contribution. Instead, the annual PCIA revenue requirement could be collected as a vintaged monthly fixed charge amount from all customers. Currently, the PCIA is collected on a vintaged basis which means that the IOUs have sufficient information to determine which customers should be assigned different levels of cost responsibility. We have not attempted to calculate the different fixed charge levels associated with each customer vintage due to the limitations of the E3 model.
- Marginal Distribution Capacity Cost – New Business (PG&E): This, per the E3 tool, is the cost of acquiring new customers and is thus not marginal to consumption.
- Transmission: Almost all transmission costs are fixed (especially in the short run). However, transmission costs are currently collected through volumetric rates that are subject to approval by the Federal Energy Regulatory Commission (FERC). There is no reason why the utilities couldn't recover transmission costs from retail customers via a fixed charge so long as this approach does not affect the manner in which transmission access costs are assessed on wholesale market participants. Due to the requirement that FERC approve any change in the method of retail rate collection, we assume no change in the use of volumetric rates to recover transmission costs at this time.
- Wildfire Fund Charge: The statutory requirement to collect this based on usage supports no change to the status quo.
- New System Generation Charge: These are sunk costs of mostly local capacity procured

by the IOUs to meet reliability needs and collected to all customers via the Cost Allocation Mechanism (CAM).

- Residential CARE Contribution: The low-income discount reflects the costs of a social policy goal and therefore shouldn't be collected via volumetric rates.

Consistently and accurately determining what cost categories to include in a fixed charge, to what extent, and why, requires more granular categorization of costs and uniformity on how costs are reported by all IOUs. For example, utility spending on societally oriented wildfire mitigation is a fixed cost and a candidate for non-ratepayer funding from sources like the tax base. However, the E3 model does not separately identify transmission and distribution spending based on wildfire mitigation. This limitation frustrates our ability to determine what percentage of the named cost categories should be separated out for collection via fixed charges and/ or from non-ratepayer funds. Because utilities use different cost categorization schema, it is near impossible to have a consistent determination of all the costs appropriately characterized as fixed across all three IOUs.

In a future phase of this proceeding, or in future Phase 2 General Rate Cases, the Commission should direct each utility to provide more accurate and consistent data on sub-categories of costs that could be categorized as fixed. This information can inform future adjustments to any fixed charges adopted in this proceeding.

B. Income Based Graduation of Fixed Charges

We propose three income tiers as a starting point to fulfill the statutory requirements of AB 205 and realize significant progressive impacts on customer bills. The lowest income tier should capture customers currently enrolled in the CARE and FERA programs, with household income up to 200 and 250 percent of the Federal Poverty Level (FPL). This will provide consistent support for protected low-income households, based on a well-established metric of household earnings relative to size.[17]

The highest income tier should capture customers with household incomes over $150,000. To achieve progressive fixed charge outcomes while keeping the upper income tier's

[17] Many income-qualified programs in California base eligibility using the FPL, such as CARE, FERA, ESA, Covered California, Lifeline, LIHEAP, Medi-Cal, and California Low-Cost Auto Insurance.

fixed charge reasonable, the upper income tier needs to have enough customers. The highest income band in the E3 tool, $200,000 and above, has too few customers to raise significant revenue from a higher fixed charge; $150,000 and above captures many more customers. $150,000 also exceeds 400 percent of the FPL ($120,000),[18] the average California household income ($119,149)[19] and median California household income for a family of four in most California counties.[20] The middle-income tier would then capture non-CARE, non-FERA customers with annual household income above 250 percent of the FPL, and below $150,000.

Additional tiers should be considered as the implementation and income verification process improves (further discussed in Section IV) to recover fixed costs as progressively as possible. With more room for future precision, rationale for tier cutoffs could also be further developed based on household size, median income relative to geographic regions, or other approaches.

For default and tiered rate schedules, customers in the CARE and FERA program should pay a $5 monthly fixed charge. We propose a 1:1.5 ratio of fixed charges for middle- and high-income customers. This approach represents a feasible degree of differentiation between non-low-income tiers that balances the desire for low-income customer savings with a goal of keeping the highest tier fixed charge reasonable.

Even under our proposed fixed charge, volumetric rates would remain much higher than SRSMC and remain unreflective of low costs during off-peak hours. Moreover, to our knowledge, temporal variations in current time of use (TOU) rates don't fully reflect the variations in SRSMC. Until the Commission updates TOU rates to make them more reflective of SRSMC, we propose retaining opt-in electrification rates with a slightly higher fixed charge. A combination of higher fixed charge and a more time differentiated volumetric rate structure means that off peak volumetric charges in electrification rates are closer to SRSMC than in default rates. To this end, we propose that electrification rates have a $10 higher fixed charge than default and tiered rates.

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[18] "Federal poverty level (FPL)." Healthcare.gov, accessed April 2023. https://www.healthcare.gov/glossary/federal-poverty-level-fpl/

[19] American Community Survey 2021 5-year estimates

[20] Excluding Santa Clara, San Mateo, San Francisco, and Marin counties. See county median income: https://www.hcd.ca.gov/docs/grants-and-funding/inc2k22.pdf

The proposed fixed charge for each income tier, also reflected in the E3 model printouts (Appendix D), are summarized in Table 4 for tiered rates. Although these differ slightly for other rate types, the values in Table 4 are representative. Complete results are presented in the Appendix.

Table 4. Proposed Income Graduated Fixed Charges for a Sample of Rates

Fixed Charge Amounts						
	PG&E		SCE		SDG&E	
	E-1	E-ELEC	D	TOU-D-PRIME	DR	TOU-ELEC
CARE & FERA	$ 5	$ 15	$ 5	$ 15	$ 5	$ 15
< $150,000	$ 41	$ 50	$ 41	$ 51	$ 41	$ 51
$150,000+	$ 62	$ 75	$ 62	$ 76	$ 62	$ 76
Average per customer	$ 36	$ 47	$ 36	$ 47	$ 36	$ 47

Although our income graduation proposal recommends that both CARE and FERA customers have a fixed charge of $5, the E3 tool does not allow a separately specified FERA fixed charge. As a result, FERA customers are grouped in with the middle and high tiers in our modelling. This means that the income graduated fixed charge for non-CARE/FERA customers will be slightly higher than our estimate for the middle and high tier customers. Because of the low number of customers currently enrolled in FERA, our estimates of income graduated fixed charges wouldn't materially change from the values included in the table above.

C. CARE Discount Methodology

To comply with AB205 and maximize benefit to lower income customers, we propose applying the statutory CARE discount (30-35%) to the total revenues collected from non-CARE customers net of any other rate discounts or exemptions provided to CARE customers including the CARE fixed charge discount.[21] The specific requirements of AB 205 with respect to the calculation of the CARE discount have not yet been determined by the Commission although reply briefs on the legal issues were submitted in February. It is not clear whether the E3 tool calculates and applies the CARE discount in a manner that conforms with the position taken by TURN/NRDC in briefs.

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21 This approach is described in the TURN/NRDC opening and reply briefs submitted earlier in this proceeding addressing the requirements of AB 205. See TURN/NRDC reply brief, pages 10-11.

To model our basic proposal, we set the Customer Charge Option to "User-defined CARE charges," and then set these CARE customer charges to $5 per month for default and tiered rates and $15 for opt-in electrification rates in the Rate Design Dashboard tab. We further set the lever "average CARE funding to support customer charge" at $0 to ensure that no CARE program funding is used to support a discount in the customer charge. Finally, we set 100% of the residential CARE contribution to be included in the fixed charge for all IOUs via the Cost Allocation tab.

D. Impact on Volumetric Charges to Achieve Revenue Neutrality

Volumetric rates commensurately decrease due to proposed average fixed charges per customer. Average proposed volumetric rates are presented in Table 5. For brevity, here we only present a weighted average volumetric rate, by referencing the non-TOU rate for each utility. The magnitude of the differences between existing and new are indicative of the reduction in TOU rates in each period. Detailed results for all rates are presented in Appendix D.

Table 5. Average Volumetric Charges for Each IOU's Default Rate

Volumetric Charges						
	PG&E (E-1)		**SCE (D)**		**SDG&E (DR)**	
	Existing Rate	New Rate	Existing Rate	New Rate	Existing Rate	New Rate
CARE	$ 0.24	$ 0.19	$ 0.26	$ 0.21	$ 0.38	$ 0.31
Non-CARE	$ 0.39	$ 0.30	$ 0.40	$ 0.31	$ 0.59	$ 0.47
Baseline Credits						
	PG&E (E-1)		**SCE (D)**		**SDG&E (DR)**	
	Existing Rate	New Rate	Existing Rate	New Rate	Existing Rate	New Rate
CARE	$0.05	$ 0.04	$ 0.06	$0.05	$ 0.08	$ 0.06
Non-CARE	$0.07	$ 0.06	$ 0.08	$0.07	$ 0.12	$ 0.10
High Usage Charge						
	PG&E (E-1)		**SCE (D)**		**SDG&E (DR)**	
	Existing Rate	New Rate	Existing Rate	New Rate	Existing Rate	New Rate
CARE	$ -	$ -	$ 0.06	$0.05	$ -	$ -
Non-CARE	$ -	$ -	$ 0.09	$0.08	$ -	$ -

To illustrate the change in electrification rates, we present one electrification rate per utility in the figures below. All electrification rate details are also presented in Appendix D. All electrification rates results presented in this testimony refer to the specific rate schedules in Table

6: PG&E E-ELEC, SCE TOU-D-PRIME, SDG&E TOU-ELEC.

Table 6. Proposed Changes to PG&E, SCE, and SDG&E Electrification Rates

Volumetric Charges - Electrification Rates				
	PG&E (E-ELEC)			
	CARE		Non-CARE	
	Existing Rate	New Rate	Existing Rate	New Rate
Summer - Peak	$ 0.32	$ 0.29	$ 0.52	$ 0.44
Summer - Part-Peak	$ 0.22	$ 0.18	$ 0.36	$ 0.28
Summer - Off-Peak	$ 0.18	$ 0.15	$ 0.30	$ 0.23
Winter - Peak	$ 0.17	$ 0.14	$ 0.29	$ 0.21
Winter - Part-Peak	$ 0.16	$ 0.12	$ 0.27	$ 0.19
Winter - Off-Peak	$ 0.15	$ 0.11	$ 0.25	$ 0.18

Volumetric Charges - Electrification Rates				
	SCE (TOU-D-PRIME)			
	CARE		Non-CARE	
	Existing Rate	New Rate	Existing Rate	New Rate
Summer - Peak	$ 0.41	$ 0.37	$ 0.62	$ 0.55
Summer - Part-Peak	$ 0.24	$ 0.19	$ 0.36	$ 0.29
Summer - Off-Peak	$ 0.15	$ 0.11	$ 0.24	$ 0.17
Winter - Peak	$ 0.37	$ 0.33	$ 0.56	$ 0.49
Winter - Part-Peak	$ 0.14	$ 0.10	$ 0.22	$ 0.15
Winter - Off-Peak	$ 0.14	$ 0.10	$ 0.22	$ 0.15

Volumetric Charges - Electrification Rates				
	SDG&E (TOU-ELEC)			
	CARE		Non-CARE	
	Existing Rate	New Rate	Existing Rate	New Rate
Summer - Peak	$ 0.49	$ 0.45	$ 0.77	$ 0.68
Summer - Part-Peak	$ 0.25	$ 0.20	$ 0.40	$ 0.31
Summer - Off-Peak	$ 0.22	$ 0.17	$ 0.35	$ 0.26
Winter - Peak	$ 0.34	$ 0.29	$ 0.53	$ 0.44
Winter - Part-Peak	$ 0.24	$ 0.19	$ 0.39	$ 0.30
Winter - Off-Peak	$ 0.21	$ 0.16	$ 0.34	$ 0.25

E. Average Bill Impacts for Low-Income and Non-Low-Income Ratepayers

The bill impacts of the proposed fixed charge are progressive. CARE customers see a lower average monthly bill across climate zones, middle-income customers receive minimal average bill impacts, and high-income customers generally see higher bills. We estimate that CARE customers in inland climate zones will see greatest monthly savings and upper income customers in coastal climate zones will see greatest bill increases. Table 7 presents the bill impacts for all three income tiers for the average customer type in each utility's coastal and inland climate zone. Table 8 presents the same data for non-NEM customers only.[22,23] These extreme climate zones should encapsulate the full variation in bill impacts. The results in these figures show how customer monthly bills would change all else kept equal, i.e., if customers made no change to the amount of electricity they consume or when they consume.

Table 7. Average Monthly Bill Impacts, All Customers - Default TOU Rates

	PG&E		SCE		SDG&E	
	Coastal (T)	**Inland (W)**	**Coastal (6)**	**Inland (15)**	**Coastal**	**Desert**
CARE	$ (10.12)	$ (21.48)	$ (10.49)	$ (26.39)	$ (13.69)	$ (41.23)
< $150,000	$ 13.24	$ (7.65)	$ 8.33	$ (16.27)	$ 3.52	$ 0.77
$150,000+	$ 34.29	$ 21.57	$ 29.40	$ 7.18	$ 25.92	$ 28.47

Table 8. Average Monthly Bill Impacts, Non-NEM Customers – Default TOU Rates

	PG&E		SCE		SDG&E	
	Coastal (T)	**Inland (W)**	**Coastal (6)**	**Inland (15)**	**Coastal**	**Desert**
CARE	$ (10.35)	$ (24.86)	$ (10.60)	$ (28.60)	$ (14.07)	$ (42.11)
< $150,000	$ 12.74	$ (14.59)	$ 7.86	$ (20.44)	$ 2.21	$ (3.58)
$150,000+	$ 33.45	$ 6.12	$ 28.49	$ 0.19	$ 22.85	$ 17.06

CARE customers are better off in all instances. The average CARE customer saves approximately $10 to $40 per month. Relatively wealthy coastal customers see the highest increase in bills since coastal customers tend to have lower consumption, so a higher fixed charge impacts them the most. As the income based fixed charge more equitably recovers fixed

[22] Data for both "All customers" tables come from the E3 tool 'Heat Map Results' tab, taking an average of customer bill impacts within each income tier in two baseline territories per IOU, representative of different climate zones (T and W for PG&E, 6 and 15 for SCE, and the coastal and desert zones for SDG&E). Default TOU rates refer to: PG&E E-TOU-C, SCE TOU-D-4-9, and SDG&E TOU-DR1. Optional electrification rates refer to: PG&E E-ELEC, SCE TOU-D-PRIME, and SDG&E TOU-ELEC.

[23] Data for both "non-NEM" tables come from the E3 tool 'Subclass Bill Comparison' tab, showing customer bill impacts within each income tier in two baseline territories per IOU.

costs of the grid, non-NEM customers end up relatively better off than the average customer in all categories. This also implies that, on average, non-CARE NEM customers will likely pay more in monthly bills than they currently do due to fairer fixed cost recovery. Table 9 and Table 10 present bill impacts for customers on electrification rates.

Table 9. Average Monthly Bill Impacts, All Customers - Optional Electrification Rates

	PG&E		SCE		SDG&E	
	Coastal (T)	**Inland (W)**	**Coastal (6)**	**Inland (15)**	**Coastal**	**Desert**
CARE	$ (7.70)	$ (17.37)	$ (9.23)	$ (24.39)	$ (12.32)	$ (34.84)
< $150,000	$ 10.38	$ (8.25)	$ 5.60	$ (18.22)	$ 0.54	$ (2.63)
$150,000+	$ 35.83	$ 24.10	$ 31.28	$ 9.70	$ 27.26	$ 28.60

Table 10. Average Monthly Bill Impacts, Non-NEM Customers – Optional Electrification Rates

	PG&E		SCE		SDG&E	
	Coastal (T)	**Inland (W)**	**Coastal (6)**	**Inland (15)**	**Coastal**	**Desert**
CARE	$ (7.90)	$ (20.11)	$ (9.34)	$ (26.46)	$ (12.65)	$ (35.68)
$150,000	$ 9.94	$ (14.11)	$ 5.16	$ (22.12)	$ (0.54)	$ (6.30)
$150,000+	$ 35.11	$ 11.06	$ 30.44	$ 3.16	$ 24.74	$ 18.98

The progressive impacts are clear. Under default TOU rates CARE customers would save up to $40 per month, while upper income customers are forecasted to pay at most $35 more per month. Collectively, these results show that the average low-income CARE customer will pay a lower average monthly bill without any change in usage as required by AB 205.

These findings significantly improve as customers from all income levels start to electrify.

F. Proposed Rate Design Improves the Economics of Electrification

Investment decisions are made on the margins, bill impacts are felt in the aggregate. Understanding the impacts of our proposed rate design on whether electrification is an economic proposition for customers requires an evaluation as to how much a customer saves on operating cost of electrified space heating and water heating equipment under existing rates and under our new rate proposal. Annual household energy expenditure before and after electrification is the right metric to understand the aggregate economic our proposed rates will have on customers that decide to electrify.

Table 11 presents the annual operating costs of space and water heating equipment for a mixed fuel customer under current rates, for that customer if they were to electrify under current rates, and for the same customer who were to electrify after our rate design proposal is adopted.[24] Operating costs only include the marginal costs of consumption from electrification equipment, e.g., appliance consumption times the volumetric rate. In each case, we assume that the customer chooses the optional electrification rate to maximize savings upon electrification. The E3 rates model did not present operating cost data; we had to extract these data for each case using total energy bill estimates for different scenarios. To illustrate the broadest range of impacts across income tiers, we modelled results for CARE customers and non-CARE customers in the high-income tier.

Table 11. Economics of Building Electrification Improve Relative to the Status Quo for All Customers Categories[25]

			Heating and Water Heating Annual Operating Expenses				
			Mixed Fuel	**Electric - Existing Rate**		**Electric - New Rate**	
			Gas Operating Expense	Electric Operating Expense	Difference from Mixed Fuel Bill	Electric Operating Expense	Difference from Mixed Fuel Bill
PG&E (E-ELEC)	Coastal	CARE	$520	$326	($195)	$254	($267)
		$150,000+	$650	$544	($107)	$396	($254)
	Inland	CARE	$611	$156	($455)	$107	($503)
		$150,000+	$763	$269	($495)	$169	($594)
SCE (TOU-D-PRIME)	Coastal	CARE	$391	$276	($115)	$213	($179)
		$150,000+	$489	$433	($57)	$320	($169)
	Inland	CARE	$648	$168	($479)	$115	($533)
		$150,000+	$809	$269	($540)	$174	($635)
SDG&E (TOU-ELEC)	Coastal	CARE	$599	$426	($173)	$342	($257)
		$150,000+	$749	$676	($72)	$526	($222)
	Inland	CARE	$616	$147	($469)	$107	($509)
		$150,000+	$770	$238	($532)	$167	($603)

On the margins, customers save in operating expenses when they electrify space and

[24] We created this table using the E3 tool's "electrification dashboard" for each customer type. In first column, we display the gas bill (operating expenses) from the mixed-fuel heating and water heating case. In the second, we isolate the change in electric bill (new operating expenses) if customers adopt electric space and water heating on current electrification rates. The difference, in column three, shows the overall change in operating expenses. Next, we isolate the change in electric bill (new operating expenses) if customers adopt electric space and water heating on the new electrification rates with the fixed charge, and lastly show how it differs from the mixed fuel bill.

water heating and take service under electrification rates today in almost all climate zones. We expect savings to be lower under default rates. Under the new electrification rates, however, customers save even more on water and space heating operating costs upon electrifying. Coastal high tier customers for each IOU generally more than double their savings under our new electrification rate proposal relative to the existing rate. Under SCE's current TOU-D-PRIME rate, for example, a coastal high tier customer could save $57 in annual operating costs by switching from gas to electric space and water heating. After incorporation of the income based fixed charge, and commensurately lower volumetric rates, those savings substantially increase by $112 to total $169. A coastal CARE customer on SDG&E's current TOU-ELEC rate would save $173 from electrifying space and water heating; on the new rate, that customer would pay $84 less than electrifying on the current rate, or $257 less than on gas.

The economics of transportation electrification similarly improve under our proposed rate design. These values are direct outputs from the E3 model and maintain all inputs and assumptions. The only difference in operating costs between customer groups in the model comes from the different volumetric rates paid by CARE and non-CARE customers, thus the high tier savings displayed should be the same for middle tier customers. It is worth noting that the E3 model assumes that gasoline costs $4/gallon and that the average ICE vehicle achieves a real-world efficiency of 35 miles per gallon. These assumptions may not reflect future fuel costs and over-estimate the efficiency of many existing passenger vehicles. Thus, savings from switching to electric vehicles are likely even higher than what is shown below in Table 12. [26]

Table 12. Economics of Transportation Electrification Improve Relative to the Status Quo for All Customers Categories

Transportation Annual Operating Expenses							
		ICE Fuel Costs	EV Fuel Costs (Existing Electrification Rate)	Savings, switch from ICE to EV (Existing Electrification Rate)	EV Fuel Costs (New Electrification Rate)	Savings, switch from ICE to EV (New Electrification Rate)
PG&E	CARE	$1,589	$730	$858	$568	$1,020
	$150,000+	$1,589	$1,220	$369	$887	$701
SCE	CARE	$1,589	$717	$872	$535	$1,053
	$150,000+	$1,589	$1,130	$459	$807	$781
SDG&E	CARE	$1,589	$1,057	$532	$837	$751
	$150,000+	$1,589	$1,683	($94)	$1,291	$297

A customer on their electrification journey will start off with a mixed fuel home and

[26] Data comes from the 'Electrification Dashboard' of the E3 model, including ICE fuel cost assumptions. Existing and new electrification rates used: PG&E E-ELEC, SCE TOU-D-PRIME, and SDG&E TOU-ELEC

gasoline car, likely on a default TOU rate. They will end their journey with a fully electrified home and car and take service on an updated electrification rate with income graduated fixed charges. Table 13[27] presents the annual household energy expenditure for a household with a car at the start (mixed fuel home, gasoline car, on existing TOU rates) and end of their electrification journey (all electric home, electric vehicle, on new electrification rates.) Home electrification measures here include space and water heating, as well as equipment for cooking and clothes drying. This full picture view of annual household energy expenditure also accounts for the addition of the fixed charge on customer bills. As a result, savings are slightly lower than on previous tables, which displayed only savings on operating costs (volumetric charge impacts).

Table 13. Annual Household Energy Expenditure Before and After Electrification and Rate Reform for Homes with Cars

			Annual Household Energy Expenditure (including vehicles)		**Savings**
			Mixed Fuel Bill and Fueling (Existing TOU Rate)	Electrified Bill and Fueling (New Elec. Rate)	
PG&E	Coastal	CARE	$ 3,070	$ 1,846	$ 1,224
		$150,000+	$ 3,775	$ 3,506	$ 270
	Inland	CARE	$ 4,601	$ 2,747	$ 1,854
		$150,000+	$ 6,228	$ 4,908	$ 1,321
SCE	Coastal	CARE	$ 3,055	$ 1,962	$ 1,093
		$150,000+	$ 3,702	$ 3,589	$ 113
	Inland	CARE	$ 4,952	$ 3,005	$ 1,947
		$150,000+	$ 6,550	$ 5,154	$ 1,396
SDG&E	Coastal	CARE	$ 3,645	$ 2,718	$ 927
		$150,000+	$ 4,587	$ 4,818	$ (231)
	Inland	CARE	$ 5,702	$ 3,972	$ 1,730
		$150,000+	$ 7,788	$ 6,741	$ 1,047

All customer categories, except for the high tier customers in coastal SDG&E territories, will be better off in aggregate. A combination of high SDG&E electric rates, the reasons for which are discussed in the introduction to this testimony, and income graduation of fixed charges cause this issue. While we haven't analyzed total customer impacts on electrification under existing rates, we expect them to be less beneficial across all customer types.

Table 14 presents the same results for the electrification journey of customers without

[27] Data comes from the 'Electrification Dashboard' of the E3 model, including ICE fuel cost assumptions. Existing TOU rates used: PG&E E-TOU-C, SCE TOU-D-4-9, and SDG&E TOU-DR1. New electrification rates used: PG&E E-ELEC, SCE TOU-D-PRIME, and SDG&E TOU-ELEC

cars.[28] Savings decrease relative to households with cars because the savings in operating expenses of an electric car on our proposed rates are significant and these households don't realize those savings. Total household energy expenditures decrease relative to the status quo in all but three categories. Upper income customers in coastal zones in all IOUs pay slightly more. This again is the product of high electric rates and income graduation of fixed charges. CARE and middle-tier customers, however, save in every presented case.

Table 14. Annual Household Energy Expenditure Before and After Electrification and Rate Reform for Homes without Cars.

			Annual Household Energy Expenditure (excluding vehicles)		Savings
			Mixed Fuel Bill (Existing TOU Rate)	Electrified Bill (New Elec. Rate)	
PG&E	Coastal	CARE	$ 1,481	$ 1,278	$ 203
		$150,000+	$ 2,187	$ 2,618	$ (431)
	Inland	CARE	$ 3,013	$ 2,179	$ 833
		$150,000+	$ 4,640	$ 4,020	$ 619
SCE	Coastal	CARE	$ 1,467	$ 1,427	$ 40
		$150,000+	$ 2,113	$ 2,782	$ (669)
	Inland	CARE	$ 3,364	$ 2,470	$ 894
		$150,000+	$ 4,961	$ 4,347	$ 614
SDG&E	Coastal	CARE	$ 2,056	$ 1,881	$ 175
		$150,000+	$ 2,998	$ 3,526	$ (528)
	Inland	CARE	$ 4,114	$ 3,134	$ 979
		$150,000+	$ 6,199	$ 5,450	$ 750

IV. IMPLEMENTATION AND INCOME VERIFICATION PROCESS (SA & MC)

Implementation of the fixed charge requires a process to assign customers to the appropriate income tiers. There are multiple viable approaches to household income qualification and enrollment for this purpose. Existing income-qualified programs in California rely on a variety of methods to identify eligible benefit recipients, including self-reporting, private income verification services, and income verification using government databases.[29] Different implementation options should be considered based on costs, complexity, and accuracy.

[28] Data comes from the 'Electrification Dashboard' of the E3 model. Existing TOU rates used: PG&E E-TOU-C, SCE TOU-D-4-9, and SDG&E TOU-DR1. New electrification rates used: PG&E E-ELEC, SCE TOU-D-PRIME, and SDG&E TOU-ELEC

[29] For example, low-income customers in California can currently enroll in the CARE, FERA, and Covered California programs through self-attestation. Programs such as CalWORKS and CalFRESH prompt applicants to submit proof of income and use the Equifax Work Number service for income eligibility verification. The California Earned Income Tax Credit is awarded after verification by the Franchise Tax Board upon tax return submission.

A. Priorities Guiding Equitable Implementation

Priorities guiding design of the fixed charge tier enrollment are: balancing accuracy and efficiency; establishing protections for low-income customers; and fostering accessibility, transparency, and privacy. The process should weigh accurate customer assignment against efficiency, in terms of cost and time to implement, to reduce the implementation costs borne by customers and achieve the objectives of the fixed charge in a timely manner. Where possible, the method should rely on customer enrollment in other income-qualified programs and otherwise leverage existing income verification pathways. It should also establish equity safeguards to ensure that low-income customers are not incorrectly defaulted into the wrong income tier. These safeguards include minimizing enrollment barriers, such as paperwork submissions and interviews, that frustrate customer participation in income-qualified programs.[30] For accessibility and transparency, there should be adequate time for customer outreach and appeals, so that customers are informed of the new rate changes and understand their tier assignment.

Implementation should address data privacy concerns associated with income reporting and verification. Confidentiality rules limit IOUs access and use of personal customer data.[31] Utilities have also been increasingly subject to cyber-attacks [32] and data breaches[33] in recent years, which may pose a challenge to customer acceptance of income verification through the IOUs themselves.

Given these concerns, the CPUC should designate a third-party organization to administer the income qualification process on behalf of the IOUs. This Third-Party Administrator (TPA) may be a non-profit organization or government agency with the capability

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[30] Research has demonstrated an inverse relationship between paperwork requirements and participation in income-qualified programs. See: Schweitzer, Justin. "How To Address the Administrative Burdens of Accessing the Safety Net." Center for American Progress. May 5, 2022. https://www.americanprogress.org/article/how-to-address-the-administrative-burdens-of-accessing-the-safety-net/

[31] *See* Decision 11-07-056 in CPUC Rulemaking 8-12-009, issued 7/29/2011 https://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/140369.pdf

[32] These include the October 2022 ransomware attack on Sargent & Lundy that accessed data belonging to multiple electric utilities. See: Lyngaas, Sean. "Hackers stole data from multiple electric utilities in recent ransomware attack." CNN. December 27, 2022. https://www.cnn.com/2022/12/27/politics/hackers-data-utilities-ransomware-sargent-lundy/index.html

[33] For example, FERC fined PG&E $2.7 million for exposing thousands of confidential records in 2016. See: Smith, Rebecca. "PG&E Identified as Utility That Lost Control of Confidential Information." Wall Street Journal. August 24, 2018. https://www.wsj.com/articles/pg-e-identified-as-utility-that-lost-control-of-confidential-information-1535145850

of performing the specifically delegated functions. The Administrator would have their performance, and budget, subject to regular Commission review and approval. Creating a single statewide administrator would also improve the accessibility and efficiency of the process. Establishing a single online user interface for customer enrollment and securing joint contracts for third-party services, for example, would avoid duplicative administrative costs of each IOU undertaking similar steps.

B. Implementation Proposal

In the near-term, we propose that the TPA use a combination of methods to verify household income, as summarized below. These methods include previous program eligibility, a third-party income verification service, and self-attestation. In the long-term, it will be valuable to develop a new verification platform with direct access to government databases (such as the California Franchise Tax Board) for more robust implementation. Given the diversity of feasible implementation approaches, we expect that the income-graduated fixed charges can be implemented quickly and are open to supporting other proposals, or a combination of multiple proposals, that would accomplish key objectives.

Near-term implementation pathway

A designated TPA runs the income verification process for the income-graduated fixed charge in five stages.

1- Customers currently enrolled in the CARE and FERA programs are assigned to the lowest tier of the fixed charge and all other customers preliminarily assigned to the highest tier.

2- The TPA uses an income estimation service to identify households likely to be eligible for the low- and middle-tier. Customers are informed of their assignment and non-CARE/FERA customers are prompted to opt-in for income verification to change tiers if they believe their assignment is incorrect, with targeted outreach based on estimates.

3- For those non-CARE/FERA customers that opt in to change tiers, the TPA uses an income verification service to assign customers to the middle and high tiers.

4- All customers are informed of their tier assignment and granted a period for appeals.

5- The TPA shares customer tier assignments with the IOUs, and the IOUs apply fixed charges and applicable rates to customers accordingly.

Post-implementation, the TPA works with contracted service providers to evaluate the implementation process and recommend improvements.

The TPA could oversee the income tier assignment process in five stages. First, customers currently enrolled in the CARE and FERA programs should be assigned to the lowest tier of the fixed charge and all other customers preliminarily assigned to the highest tier. This defaulting establishes an important protection for low-income customers. CARE and FERA customers have already taken steps to enroll in an IOU discount program, attesting that they meet the requirement of household income 200% under the federal poverty level (or 250% for FERA customers). Further, there is confidence that the CARE program captures a significant portion of eligible low-income households, given high participation rates across IOU territories: 95% at PG&E; 88% at SCE; 93% at SDG&E; and 95% at SoCalGas.[34] Participation rates in the FERA program are lower (13%, 10% and 20% respectively),[35] which suggest targeted outreach is needed to reach all low-income customers. There is no evidence of significant fraud rates under either program.

After this preliminary assignment, the TPA may contract with a third-party income estimation service to identify potential low- and middle-income customers defaulted in the high tier. These services, such as Experian's Consumer View and Equifax's Income 360, use predictive modelling to estimate household income[36] given an address and, if available, one household member name.[37] Intended for marketing purposes, such estimates are not data records and do not require customer consent prior to purchase. The TPA can then contact all customers about the opt-in period and inform a subset of customers that they may be eligible to pay a lower fixed charge. This outreach could also be strengthened with targeted marketing based on

[34] *See* D. 21-06-015 in the matter of A.19-11-003 et al., issued June 7, 2021, pp. 18-20. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M387/K107/387107687.PDFPp
[35] Ibid, pp. 89-90.
[36] Typically incremented by thousands, up to $250,000 - $2,000,000 depending on the service.
[37] For more information on Experian's Consumer View product, see: https://www.experian.com/assets/dataselect/brochures/consumerview.pdf
On Equifax's Income 360, see: https://assets.equifax.com/marketing/US/assets/income360_ps.pdf

geography and other program eligibility.

Customers should be informed of their preliminary assignment for income verification to adjust their enrollment through a central portal, such as an online web interface and physical mailing address maintained by the TPA. When customers opt-in, they will confirm necessary household information which the TPA transmits to a contracted third-party income verification service. One such service is the Equifax Work Number, an income and employment verification service and database. Many state agencies already use the Work Number's employment and income verification system, including the CPUC.[38] The Work Number also provides verification for social service organizations administering low-income benefits programs in California, including Medicaid, the Supplemental Nutrition Assistance Program (SNAP), and Temporary Assistance for Needy Families (TANF).[39] The Work Number can provide real-time income verification, given customer consent via submission of address, household member names, and if applicable, social security numbers.[40] Customers should also be given the option to report their household income at this stage, relevant in the event of a dispute or absence from the verification database.[41] Once the verification service has assessed household income based on all reported household members, it can report back income tier assignment for the TPA to share with the IOUs.

It is important to note that income verification services, such as the Work Number, are regulated by the Fair Credit Reporting Act (FCRA). Credit agencies are limited to furnishing consumer reports for permissible purposes and restricted in terms of enabling adverse actions against customers.[42] In this use case, income verification would be conducted for the purposes of administering a public program, through a contract facilitated by the CPUC and appointed TPA. Verification would assess customer eligibility to pay a lower fixed charge than the present default highest charge. As a result of this process, customers would only be subject to favorable

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[38] "The Work Number Employment and Income Verification." California State Controller, accessed April 2023. https://www.sco.ca.gov/ppsd_se_worknumber.html

[39] "How Verifications Help Enable Faster Decisions for Vital Social Service Benefits." Equifax, accessed April 2023. https://www.equifax.com/newsroom/all-news/-/story/how-verifications-help-enable-faster-decisions-for-vital-social-service-benefits//

[40] "How It Works." The Work Number, accessed April 2023. https://theworknumber.com/how-it-works

[41] This is particularly relevant for undocumented and unemployed customers. If these customers are missing from the verification system, the TPA should defer to the customer's self-attestation and allow placement in the low tier.

[42] *See* Fair Credit Reporting Act § 603 (k), § 604(a)(3), and § 615 (a) https://www.ftc.gov/legal-library/browse/statutes/fair-credit-reporting-act

or neutral actions with respect to their financial interests: assignment into the low- or middle-income tiers, or no change from their assignment in the high tier.

After this verification step, customers should be informed of their updated tier assignment and granted an appeals period. This window should be adequate to enable middle and high-income assigned households to appeal their tier assignment. This appeal could be handled directly by the third-party verifier, as provided through the Work Number service, or by the TPA. To maximize equity and accessibility, the appeals process should allow a pathway for tier assignment based on self-attestation under penalty of perjury similar to the Covered California program.[43] This would ensure that low and middle-income customers are not overcharged in the event of missing or outdated records in the chosen verification system.

Following appeals, the TPA will share customer tier assignments with the IOUs, enabling the IOUs to charge customers appropriate rates and implement the income-graduated fixed charges. The assignments should be reviewed periodically to ensure that customers remain on the correct fixed charge tier. Customers should also be given the opportunity to request reverification through the central portal at any point, in the event of changes in household composition or income.

In the longer term, it may be viable to create a new income verification third-party platform to implement the income-based fixed charges. This system would directly access government data and improve upon the Income and Eligibility Verification System (IEVS) supporting the CalWORKS and CalFresh programs.[44] IEVS currently sources data from the Franchise Tax Board, Social Security Administration, and other databases to assess applicants' income, wealth, and low-income program enrollment and qualification. To identify as many customers accurately for the low-income tier as possible, it would be particularly relevant to reference customer enrollment in other income-qualified programs beyond CARE. This new system could facilitate the implementation of granular income tiers and a more progressive graduation of the fixed charge, to increasingly align with income tax collection over time. This

[43] "Proof of Income." Covered California, accessed April 2023. https://www.coveredca.com/documents-to-confirm-eligibility/income/

[44] For a description of IEVS, see: "Income Eligibility Verification System (IEVS)." Santa Clara County Social Services Agency, accessed April 2023. https://stgenssa.sccgov.org/debs/policy_handbook_CP/cpchap02.pdf

platform would, however, require new legislatively authorized pathways for data access and a process for mapping household members to addresses for a complete picture of household income, requiring significant financial investment. The costs, challenges and opportunities associated with this type of platform should be evaluated while an existing income verification method is administered in the short term.

C. Evaluating the Implementation Method

The TPA should work with the contracted verification service to evaluate the implementation process and recommend improvements. Equifax, for example, conducts audits on a set percentage of all Work Number verifications.[45] The TPA should also defer to the income verification processes and ongoing audits of the CARE/FERA programs for evaluation of the low-income tier placement. These audits require random or high-usage sample of customers to submit documentary proof of income for all household members.[46] In the event of non-response, following all reasonable attempts to contact the customer and repeat warnings, the customer is removed from the CARE program. The TPA should ensure that those customers are subsequently defaulted into the high-income tier and notified to opt-in to income verification for correct tier assignment. After these audit steps, the TPA should submit an assessment for the CPUC to evaluate the success of the implementation and adjust the design of the process in subsequent years.

Weaknesses of this combined methods approach include reliance on customer self-attestation in the CARE program, the requirement that non-CARE customers opt-in for income verification, and the limitations of third-party income estimation and verification services. Enrollment via self-attestation raises concern for free ridership, which could ultimately lead to inaccurate recovery of fixed costs relative to principles of fairness. The Commission should address the process for identifying and remedying improper CARE or FERA enrollments in

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[45] "Government Verification." The Work Number, accessed April 2023. https://theworknumber.com/solutions/industries/government-verification

[46] Details on the CARE verification process can be found on the websites of PG&E: https://www.pge.com/en_US/residential/save-energy-money/help-paying-your-bill/longer-term-assistance/care/post-enrollment-verification/care-program-main.page SCE: https://www.sce.com/residential/assistance/fera-care/High-Energy-Usage-FAQ SDGE: https://www.sdge.com/residential/pay-bill/get-payment-bill-assistance/assistance-programs

ongoing proceedings dedicated to low-income program oversight.

Requiring non-CARE and -FERA customers to opt-in for income verification, or otherwise pay the highest fixed charge, may lead to some low- and middle-income households incorrectly paying the highest fixed charge. Customers that do not receive or understand marketing notices, due to change in address, language barriers, or lacking internet access, may inadvertently miss the window for enrollment. This challenge may be addressed by maintaining an interim appeals and bill correction period after the fixed charges go into effect. In the first billing periods of the new rates, customers that fail to pay their electricity bills or express alarm at high and unexpected charges should be granted a pathway to adjust their tier enrollment.

Income estimation services are inherently limited by the data inputs to their predictive modeling. Since estimates are not data, using estimates to send targeted notices to customers about correcting their fixed charge enrollment will not reach all low- and middle-customers. Income verification services are also limited by the freshness and completeness of the information databases that they reference. While the Equifax Work Number provides verification for much of the workforce, a small percentage of customers may not be in the system. This challenge could be addressed by accepting household income self-attestation from residents that cannot be verified, supplemented by random audits.

D. Cost of the Implementation Method

Costs associated with this combination of methods for near-term implementation include: administrative costs of the TPA; developing and maintaining a central web portal; contracting an income estimation service; contracting an income verification service; multiple rounds of customer outreach; appeals; and auditing. Income estimates are inexpensive, potentially costing in the range of \$0.005-\$0.015[47] per household record depending on the service and contract volume. The costs of income verification services are significantly higher. For example, the Master Service Agreement (MSA) between the Equifax Work Number and State of California, valid until 2025, sets a rate per individual verification of \$10.30-\$15.08 based on a batch of

[47] Based on conversations with sales representatives that provided non-binding estimates; exact costs depend on negotiated terms.

3,000 transactions.[48] However, the terms of the MSA include a stipulation for price negotiation based on volume. Verifying household, rather than individual, income requires purchasing verification for a much larger number of records. It is also likely that only a subset of customers would seek income verification, given CARE/FERA and high-income customers would not be incentivized to opt-in to the verification process.

The costs associated with the creation of a new income verification system in the long-term are less clear and will depend upon the specific approaches endorsed by the Commission in this proceeding.

Conclusion

While this proposal lays out one potential combination of methods to verify customer income and assign customer tiers, we are open to other proposals. What is clear is that a reasonable income-graduated fixed charge is feasible to implement, and the statutory requirements of AB 205 can be satisfied in the near-term. Timely implementation is critical to address the energy affordability crisis and ensure residential electricity rates are not hindering our decarbonization goals, as described in Section II. The charges should be implemented with the understanding that accuracy will improve over time through customer appeals, audits, and modifications to the combination of methods approach.

E. Post-Implementation Assessment of Income-Graduated Fixed Charges

Post-implementation, the CPUC should assess the effectiveness of the income-graduated fixed charges based on whether the new residential rates increase equity, encourage beneficial electrification, and fairly recover electric system costs. As proposed in section II, the fixed charge should recover system costs in a progressive manner that reduces energy burden for low-income relative to higher-income households. Incorporation of the fixed charge should also lower volumetric charges, sending price signals to customers that better encourage electrification compared to existing residential rates. To ensure that fixed charge design and implementation achieves these objectives, the CPUC should periodically assess the impact of the fixed charges on households of different income levels and consumption bands across baseline territories.

[48] The MSA can be accessed via the Cal eProcure portal: https://caleprocure.ca.gov/pages/LPASearch/lpa-search.aspx

Relevant impacts may include but are not limited to: electricity bill impacts; affordability metrics, such as the affordability ratio established in the affordability rulemaking;[49] changes in rate enrollment; changes in energy use; and new electrification measures, such as investment in electric household appliances, electric vehicles, and whole-home electrification.

The CPUC should separately assess the effectiveness of the income qualification process to understand how implementation may affect these customer outcomes and alter the intended impacts of the fixed charge. Incorrect tier enrollment would hinder the effectiveness of the fixed charge design. Under-enrollment in the low and middle-income tiers would hinder the progressiveness of the fixed charge's impacts on customer bills and affordability. Under-enrollment in the high-income tier would raise the fixed charge level for the middle-income tier. As described in Section D, the CPUC should evaluate the success of the income qualification process with respect to accuracy, accessibility, and other priorities. This evaluation should consider information on customer participation and findings from routine audits, as collected by the TPA conducting income verification on behalf of the IOUs. These assessments should inform improvements to the income qualification system in future years to ensure rates achieve equity and electrification objectives.

Revenue collected from residential rates must also recover electric system costs and allow recovery of authorized IOU annual revenue requirements. Over or under collection of authorized fixed charge revenues should be trued up annually. If the collected revenue from the fixed charge exceeds the forecast, that surplus should be applied to reduce the next year's fixed charge revenue requirement; if revenue falls short, the difference should be recouped similarly. A mismatch in collection should not affect the IOUs revenue requirements apart from the fixed charge and should not impact volumetric rates.

[49] *See* affordability metrics established in D.20-07-032 of R.18-07-006

APPENDIX A: WITNESS QUALIFICATIONS

Mohit Singh Chhabra

Technical Lead and Advisor, Natural Resources Defense Council • (720) 251-3561 • mchhabra@NRDC.org

Mohit Chhabra provides analysis and strategic guidance to policymakers and other stakeholders at the state, regional, and national levels. He is currently working on redesigning electricity pricing to facilitate decarbonization and enhance affordability, developing cost-effective pathways to reduce greenhouse gas emissions and pollution from California's energy sector, and serving as a technical advisor to other regional teams. He holds a master's degree in civil environmental and architectural engineering from the University of Colorado Boulder and a bachelor's degree in mechanical engineering from the University of Pune in India. He is based in NRDC's New York City office.

RECENT WORK EXPERIENCE

Natural Resources Defense Council | San Francisco, CA

Senior Scientist — *January 2017 – 2022*
Technical Lead and Advisor — *January 2023 - Present*

Advisor, Power Sector and Rates: Advise state and regional teams within NRDC on power sector, electricity and gas rates, and cost-effectiveness related issues.

National Academy of Sciences: Coauthor on the upcoming NAS Net Energy Metering Report.

Net Energy Metering: Represent NRDC in the CPUC net energy metering (NEM) 3.0 proceeding and served as NRDC's expert witness in this case. Conduct analysis and develop a cost-effective, equitable, and statutory compliant NEM 3.0 tariff. Developed a set of joint recommendations with consumer advocates for fair and equitable NEM policy in California.

Energy Efficiency and Distributed Energy Resources: Represent NRDC at CPUC's energy efficiency and various distributed energy resource (DER) related proceedings at the CPUC to ensure that all DERs are accurately valued for their contribution to meeting California's carbon reduction targets. Developed the basis for CPUC's energy efficiency policy reform and a new method to measure energy DER benefits. Presented to California's energy commissioners at multiple public workshops. Serve as a technical resource for NRDC's energy efficiency and DER advocacy in other states in the country as needed.

Integrated Resource Planning: Lead NRDC's efforts in the CPUC led statewide integrated resource planning (IRP) proceeding to comply with California's greenhouse gas reduction targets. Responsibilities include technical review of statewide IRP models, developing feedback to ensure that the state IRP meets SB350 and SB100 's greenhouse gas reduction requirements while minimizing electric sector spending, impact on customer rates, and considering the unique needs of disadvantaged communities.

Resource Adequacy: Manage NRDC advocacy at CPUC resource adequacy proceeding to ensure reliability through the clean energy transition.

Cost Effectiveness: Worked to improve energy sector cost effectiveness practices in California. Intervention in the Integrated Distributed Energy Resources (IDER) proceeding at the CPUC to develop accurate cost effectiveness policy. Also serve on the Advisory Committee for the development of the National Standard Practice Manual. Focus on carbon valuation in California resource procurement.

Climate Adaptation: Advocate for integrating climate change impacts in energy sector planning at the CPUC.

Northwest Energy Sector Planning: Appointed to the Northwest Power Council's Conservation Resources Advisory Committee to participate in development of regional power plans and provide expert feedback. Served on the RTF, an independent forum of energy efficiency experts, as a voting member.

Regional Technical Forum | Ptarmigan Research LLC, Oakland, CA
Contract Analyst *April 2013 – December 2016*

Measure Analysis for the Regional Technical Forum – Developed estimates of energy efficiency measure savings, incremental cost, and benefit-cost ratios. Summarized and presented analysis to the RTF on an almost monthly basis.

Developing Protocols and Research Documents for the RTF – Developed protocols to estimate reliable energy savings for industrial pumps, efficient new homes, and industrial air compressors. Developed research strategies required to reliably estimate energy savings for multiple measures including residential weatherization. Helped draft the RTF report on the health impacts of reduced wood burning due to heat pump installations.

Regional Coordination for the RTF – Managed technical subcommittees for the RTF; these subcommittees included the RTF's Research & Evaluation, Health Impacts of Wood Smoke, New Efficient Manufactured Homes, and Refrigerator Decommissioning subcommittees

Assisted in Developing Energy Efficiency Potential in the 7th Power Plan – Developed estimates for the 7th Plan for residential and commercial energy efficiency measures.

Navigant Consulting, Inc. (Formerly Summit Blue Consulting, LLC.) | Walnut Creek, CA
Managing Consultant *March 2007 – March 2013*

California Public Utilities Commission (CPUC) Potential Goals & Targets Study (2011, and 2013). Helped develop a potential model to estimate achievable energy savings potential in California. This model analyzed energy savings potential in the Residential, Commercial, Industrial and Agricultural sector. Responsible for developing the technical inputs for all sectors across all Investor Owned Utilities (IOUs).

Impact Evaluations for Puget Sound Energy (PSE), PacifiCorp Commercial & Industrial Program Evaluations. Led a multi-year impact evaluation of prescriptive C&I program in PacifiCorp and PSE service territory. This evaluation included sampling and on-site M&V activity to achieve evaluation statistically significant results. The evaluation activity included data logging at customer sites, site level analysis, reporting, and presentation. Managed and led similar evaluations for Tucson Electric Power's residential energy efficiency portfolio.

Regional Technical Forum (RTF) Unit Energy Savings (UES) Measure Compliance. Project manager and technical lead for a project with the RTF to develop standardized workbooks for 10 UES measures and bring them into compliance with RTF guidelines. Mr. Chhabra managed the day to day working of this project and provides in-person measure updates to the RTF every month.

CPUC Evaluation 2006 – 08. Worked with a team across consulting firms to develop the Evaluation Reporting Template for the 2006 – 08 evaluations. Developed code to do Net to Gross analysis for a subset of California IOU programs based on CPUC NTG guidelines.

TECHNICAL EXPERTISE

Building Energy Simulation: eQuest, DOE2, Energy Plus and TRNSYS

Database Analysis and Data Management: Database analysis using R, SAS, Access, basic SQL skills.

Modeling: Analytica™, R, and Excel.

PUBLICATIONS

Chhabra Mohit. 2022. "One metric to rule them all: A common metric to comprehensively value all distributed energy resources." Electricity Journal, Vol. 35.

Ziaja, Sonya and Chhabra Mohit, "Climate Adaption for Energy Utilities: Lessons Learned from California's Pioneering Regulatory Actions" (October 2021)

Chhabra, Mohit, "Restructuring Portfolios to Bring Out the Best in Energy Efficiency" (May, 2021), Submitted to the California Public Utilities Commission.

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Chhabra, Mohit, "Using the Total Economic Value to Set Resource Energy Efficiency Program Goals" (May, 2021), Submitted to the California Public Utilities Commission.

Hay, Catherine and Chhabra, Mohit. 2020. "The Impact of Wildfires and Beneficial Electrification on Electricity Rates in PG&E's Service Territory," Electricity Journal (Volume 33, Issue 3)

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List of NRDC blogs: https://www.nrdc.org/bio/mohit-chhabra

EDUCATION

B.S. in Mechanical Engineering with First Class, University of Pune, India

M.S. in Civil Environmental and Architectural Engineering, University of Colorado at Boulder

Mathematics: 42nd in all Delhi Math Olympiad (High School)

REFERENCES

Merrian Borgeson, Director, California Climate and Clean Energy, NRDC; mborgeson@nrdc.org
Dr. Ryan Firestone, Contract Analyst, Regional Technical Forum; ryan.firestone@samdiego.net

Sylvie Ashford

Schneider Sustainable Energy Fellow, Natural Resources Defense Council • (202) 679-5911 • sashford@NRDC.org

Sylvie Ashford is a Schneider Sustainable Energy Fellow with the NRDC Climate and Clean Energy Program, conducting research and supporting advocacy to decarbonize California's buildings and power sectors. She has commented on proceedings at the CEC and CPUC related to load management and grid reliability. Prior to this position, she was a graduate student at Stanford University. She holds a bachelor's degree in International Relations and a master's in International Policy specialized in Energy, Natural Resources, and the Environment. Previous work includes research and data analysis at policy thinktanks. She is based in NRDC's San Francisco office.

WORK EXPERIENCE

Natural Resources Defense Council | San Francisco, CA
Schneider Sustainable Energy Fellow — *September 2022 – Present*

Power Sector: Supports engagement in CEC and CPUC proceedings related to load management standards, grid reliability, cost-effectiveness, and equitable power sector decarbonization

Building Decarbonization: Supports engagement in CEC proceedings related to building and appliance standards; researches buildings sector emissions and decarbonization costs

List of NRDC blogs: https://www.nrdc.org/bio/sylvie-ashford

The Hoover Institution | Stanford, CA
Research Assistant, LTG H.R. McMaster — *October 2018 – August 2022*

Stanford University | Stanford, CA
Teaching Assistant, Graduate-level Macroeconomics — *September – December 2021*

Center on Democracy, Development, and the Rule of Law | Stanford, CA
Research Assistant, Dr. Stephen Stedman — *July – December 2020*

The Tahrir Institute for Middle East Policy | Washington, DC
Policy Researcher — *July – August 2018*

TECHNICAL SKILLS

Data Analysis: Excel, R, Stata, and Python

EDUCATION

B.A. in International Relations with Honors, Phi Beta Kappa – Stanford University

M.A. in International Policy (Energy, Natural Resources, and the Environment), Stanford University

Graduate Capstone on industrial heating decarbonization pathways in collaboration with the National Renewable Energy Laboratory

REFERENCES

Merrian Borgeson, California Policy Director, NRDC mborgeson@nrdc.org
Dr. Stephen Stedman, Senior Fellow, Freeman Spogli Institute sstedman@stanford.edu

APPENDIX B: GUIDING QUESTIONS

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APPENDIX C: SYNAPSE WHITEPAPER

Establishing Income Based Fixed Charges in California

A review of economic theory, policy tradeoffs, and practical considerations for fixed charge reform

Prepared for The Utility Reform Network and National Resources Defense Council

April 7, 2023

AUTHORS

Eric Borden
Ben Havumaki
Alex Lawton
Melissa Whited

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

Contents

1. INTRODUCTION AND OVERVIEW

The purpose of this white paper is to provide an overview of the theoretical underpinnings of rate design that should be considered when establishing how, and to what extent, a fixed charge is appropriate for inclusion in residential rate design. This was developed to inform the current proceeding in California that was established pursuant to recent legislation, and to aid The Utility Reform Network (TURN) and National Resources Defense Council (NRDC) with development of their fixed charge proposal. The content of this white paper is the work of Synapse Energy Economics and does not necessarily reflect the views or opinions of TURN and NRDC.

We discuss the interaction of sometimes conflicting theoretical economic frameworks with diverse policy goals and considerations. We acknowledge that rate design is both a science and an art to provide a framework for the CPUC to consider how best to implement progressive fixed charges with existing tools and information.

This is spurred by legislative action allowing for higher residential fixed charges in California, subject to a number of provisions and considerations. Namely, in 2022, the California legislature passed Assembly Bill (AB) 205, which among other provisions states,

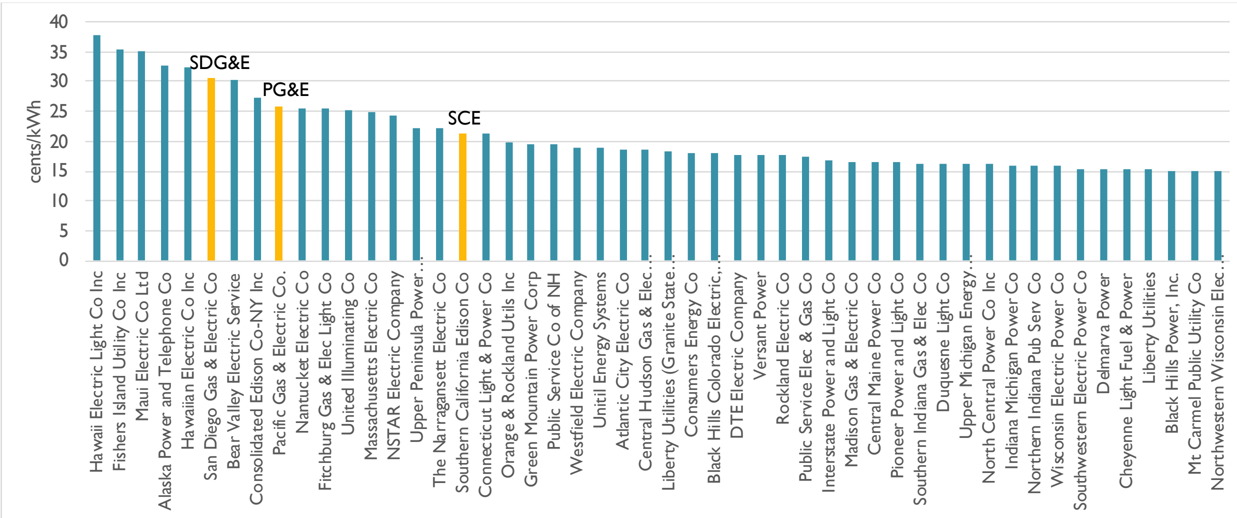
> the commission may authorize fixed charges for any rate schedule applicable to a residential customer account. The fixed charge shall be established on an income-graduated basis with no fewer than three income thresholds so that a low-income ratepayer in each baseline territory would realize a lower average monthly bill without making any changes in usage. The commission shall, no later than July 1, 2024, authorize a fixed charge for default residential rates.[1]

The law is clear that fixed charges are meant to be charged on a relatively progressive basis – e.g. higher-income households should generally be charged higher fixed charges, and vice-versa. The exact implementation and rate schedules are subject to California Public Utilities Commission (CPUC) approval.

At present, California IOU electric rates are among the highest in the country, and set to go higher. With virtually no fixed charge established to-date,[2] revenue requirements are collected almost entirely through volumetric charges.

[1] AB 205, Section 10(e)(1).
[2] IOUs in the state do have fairly low "minimum bills" of around $10, which act differently than fixed charges.

Figure 1. Investor Owned Utility Average Residential Rates in the United States, Top 50 Utilities, 2021[3]



Note that the rates shown above are expected to be significantly higher in 2023 – over 30 cents for PG&E and SCE and over 45 cents for SDG&E.[4] This would make them among the highest in the country unless rates in other jurisdictions grow at the same astonishing pace.

We wish to note upfront the limitations of any rate design to solve or manage the affordability predicament California IOU ratepayers currently find themselves. As stated in a recent CPUC report to the legislature,

> Cost reduction strategies result in a direct impact on electric IOU revenue requirement savings because they reduce the size of the overall "pie" of costs that utilities are authorized to recover through rates, and this benefits all customers. Cost allocation and rate design strategies redistribute costs and have an indirect impact, because they reduce system costs only to the extent that they can alter customer incentives to achieve greater alignment between energy usage and grid conditions over time.[5]

Still, the influence of rate design on customer behavior and its impact on an array of policy goals is significant and must be carefully considered. We provide an overview of these considerations in this paper.

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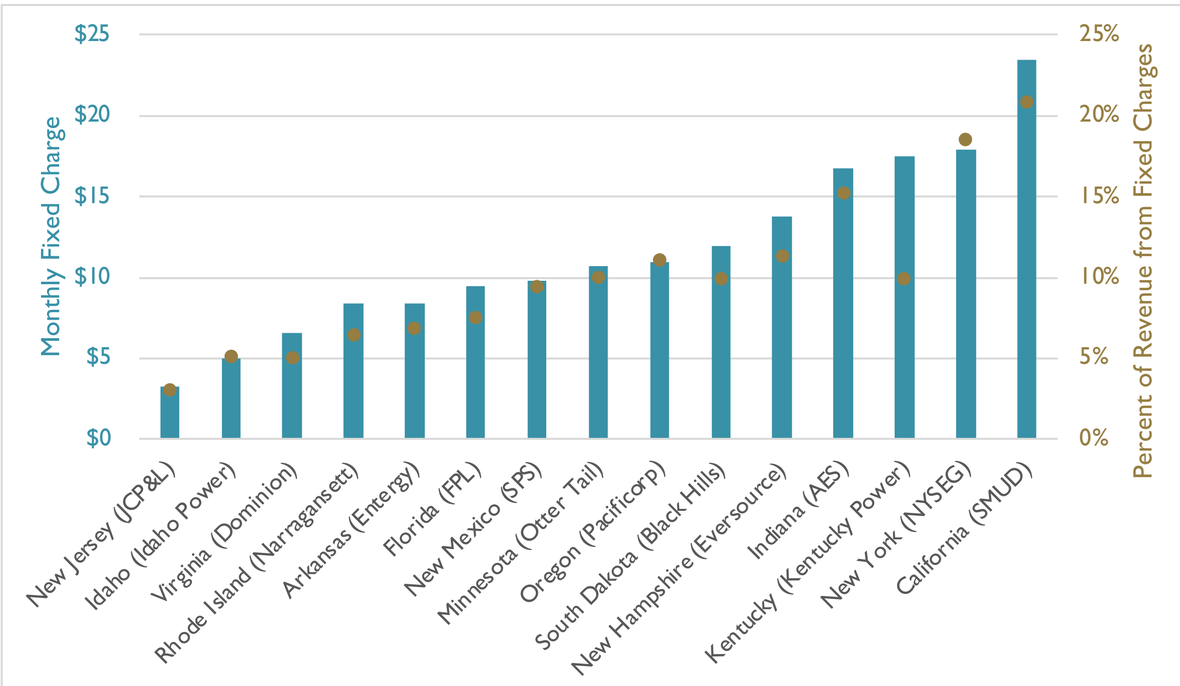
[3] Energy Information Administration (EIA), https://www.eia.gov/electricity/sales_revenue_price/, Table 6.
[4] Calculated from the E3 Tool's total revenue requirements for default rates divided by total 2023 load.
[5] CPUC 2022 Senate Bill 695 Report, May 2022, p. 48, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2022/2022-sb-695-report.pdf.

2. FIXED CHARGES IN THE UNITED STATES AND CALIFORNIA

Residential customer charges (also called "fixed charges") vary significantly across the country. Synapse analyzed a sample of utilities' residential customer charges contained in the National Renewable Energy Laboratory's OpenEI utility rates database. These were selected to provide a recent, diverse sample of electric fixed charges across the country, but are not meant to be representative of the entire country.[6]

Figure 2. Electric Bill Fixed Charge Levels and Percentage of Residential Revenue across the United States



In general, the level of fixed charge scaled linearly with the percentage of revenue collected. As a percentage of revenue, customer charges collect 9 percent of the residential revenue requirement on average, but range significantly from nearly 0 percent to greater than 20 percent. We are not aware of any fixed charge that has been assessed on a progressive basis, by either income or usage, for the residential class.

[6] The OpenEI database was cross referenced with actual current utility tariff data to ensure accuracy. Customer counts and residential revenues from EIA-861 – schedules 4A&4D and EIA-861S, downloaded from the Energy Information Administration's (EIA's) website.

3. Economic Theory and Fixed Charges

3.1. Varying conceptions of the fixed charge

Fixed charges are common in utility rate design, yet there isn't a consensus on how they should be implemented or calculated. Discussion of fixed charges in utility regulatory proceedings is frequently attended by both theoretical disagreements and more pragmatic, policy-related ones. On one hand are variations on the plain argument that fixed charges should recover the share of the utility bill that represents fixed costs. On the other are what is "fixed," policy aims of rate design, the time horizon across which rates are set, and other considerations. Since rate design provides price signals to customers regarding their consumption, the effect of design on customer behavior – consumption patterns and investment incentives - is a key consideration.

Fixed charges are most commonly applied in the residential sector to recover customer-related costs. These are the costs of physically connecting customers to the grid that do not vary with the amount of customer usage – in other words, these costs do not change - relative to energy consumption. There is little debate that meters, service drops, and some amount of billing and services may be categorized as customer-related fixed costs.[7] Yet even within this simple-sounding parameter, there are differing theoretical perspectives and differences in methodologies to calculate these costs. These different perspectives are frequently on display in California regulatory proceedings.[8]

There is also a recurring debate over whether additional facets of the distribution system ought to be categorized as customer-related.[9] Utilities may argue that there is an overarching customer-related function that characterizes the entire distribution grid, including those parts of the distribution grid that do not vary with the number of customers or other marginal elements.[10] The implication of this argument is that a portion of the costs of distribution grid facilities not proximate to individual customers or explicitly deployed to provide grid connection to these customers should nonetheless be conceptualized as customer-related or fixed – with potentially large consequences for both cost allocation and rate design.

What about other purportedly "fixed" costs? Utilities may seek to use fixed charges to recover non-customer related costs that do not obviously vary with energy or peak demand.[11] Examples

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[7] National Association of Regulatory Utility Commissioners (NARUC). 1992. Electric Utility Cost Allocation Manual, pp. 87-88 and 102-104.

[8] See Regulatory Assistance Project (RAP), *Electric Cost Allocation for a New Era. 2020, pp. 207-208.*

[9] Weston, Frederick, et al. 2000. Charging for Distribution Utility Services: Issues in Rate Design. Regulatory Assistance Project (RAP), pp 29-30.

[10] See, for example, Direct Testimony of Larry T. Legg on behalf of Georgia Power Company. Docket No. 42516. June 28, 2019, p. 7.

[11] Faruqui, Ahmad and Kirby Leyshon. 2016. Methodologies for Establishing Fixed Charges in Residential Tariffs: A Survey. Prepared for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, p. 4.

of such costs include administrative costs and the costs of public policy compliance. We discuss the economic basis of considering these questions in the following section.

3.2. Principles of rate design and fixed charges

The claim that fixed charges should recover fixed costs may be an allusion to foundational rate design goals. First is the objective of fairness. The second goal connecting fixed charges and fixed costs is economic efficiency. While both of these aims appear clear in the abstract, there may be considerable dispute over how they should best be balanced, especially given the utility imperative to recover the costs of past investments, which comprises the vast majority of revenue requirement.

The fairness objective is often related to the principle of "cost causation," which requires that customers pay according to the costs that they impose on the system. For example, in the case of customer connection costs that can be attributed to a single class of customers, these costs are *caused* by the customer connection to the grid, so they should be allocated accordingly. This may be extended to rate design with the conclusion that customers should pay for the costs they are responsible for, in the manner the costs were imposed.[12] This often has implications for future costs that are incurred in the same way, which may be avoided through accurate price signals and consumer understanding of those price signals.

The objective of economic efficiency supports some degree of fixed charge cost recovery. Economic theory holds that efficiency is maximized by setting price equal to short run social marginal cost, which is the cost borne by society to producing an additional unit of a good or service. By invoking "efficiency," economics is ultimately talking about maximizing wellbeing by appropriating limited resources according to societal need; by maximizing efficiency, the competitive market with marginal cost pricing is predicted to maximize combined consumer and producer wellbeing to an optimal level. When price is not equal to marginal costs, the level of production and consumption is deemed inefficient because total wellbeing generated is less than the theoretical maximum. This inefficiency is measured by "deadweight loss," which directly relates to the over- or under-consumption of a given good relative to efficient levels.

The cost causation and efficiency principles are related but may not always lead to the same result. To the extent that the cost causation principle is applied retrospectively to utility recovery of past investments, it may be in tension with the efficiency objective. Maximizing economic efficiency requires looking ahead, assessing the future cost implications of consumption decisions. Other principles and policy considerations may add further complication such that a narrow fidelity to efficiency or fairness criteria is usually unworkable. However, these principles provide guidance for how to think about and ultimately apply economically defensible fixed charges.

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[12] Similarly, costs caused by peak demand, or consumption at certain times, should be allocated to those times and charged accordingly. This can be accomplished with a variety of price mechanisms including time of use (TOU) rates, critical peak pricing (CPP), demand charges, and others.

Rate Design Principles

The authoritative source on rate design principles is James Bonbright's 1961 "Principles of Public Utilities." This work sets out eight core rate design principles, which address fairness and economic efficiency among other considerations:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
    - in the control of the total amounts of service supplied by the company:
    - in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).[13]

Bonbright addresses fairness in his sixth principle, while economic efficiency is addressed through the eighth principle. Under Bonbright's framing, it is easy to see how these principles could be in conflict, as explained in the previous section. Achieving "fairness" (with respect to historical costs) could require increasing class rates to the extent that some (future) "justified" use of service is stifled.

The CPUC's rate design principles build on this theoretical framework, and reflect some additional policy priorities of the state. The current CPUC proposal for these principles, which have been modified over time, is shown here.

[13] James Bonbright. 1961. Principles of Public Utility Rates, p. 155.

1. All residential customers (including low-income customers and those who receive a medical baseline or discount) should have access to enough electricity to ensure that their essential needs are met at an affordable cost.
2. Rates should be based on marginal cost.
3. Rates should be based on cost causation.
4. Rates should encourage economically efficient (i) use of energy, (ii) reduction of greenhouse gas emissions, and (iii) electrification.
5. Rates should encourage customer behaviors that improve electric system reliability in an economically efficient manner.
6. Rates should encourage customer behaviors that optimize the use of existing grid infrastructure to reduce long-term electric system costs.
7. Customers should be able to understand their rates and rate incentives and should have options to manage their bills.
8. Rates should avoid cross-subsidies that do not transparently and appropriately support explicit state policy goals.
9. Rate design should not be technology-specific and should avoid creating unintended cost-shifts.
10. Transitions to new rate structures should (i) include customer education and outreach that enhances customer understanding and acceptance of new rates, and (ii) minimize or appropriately consider the bill impacts associated with such transitions.[14]

3.3. Identifying customer-related costs for fixed charges

As discussed above, recovery of marginal customer costs through a fixed charge is consistent with theoretical efficiency-maximizing criteria. The marginal costs to be included in the monthly fixed charge are those principally driven by the number of customers connected to the grid, and not by customer demand or energy consumption. This approach turns out to be commonplace across many jurisdictions. Meanwhile, inclusion of non-marginal customer-related costs, or other costs that are otherwise fixed relative to the standard determinants is more contentious.

[14] Many of these principles were set forth in R.12-06-013 and incorporated into D.15-07-001, D.17-01-006, and D.17-08-030. CPUC, *Basics of Rate Design* Presentation, 2018, https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/r/6442457672-ratedesign101-for-evs-june-7-2018-june-6-final.pdf. The currently proposed revisions reflected here are from R.22-07-005, *Proposed Decision of ALJ Wang Adopting Electric Rate Design Principles and Demand Flexibility Design Principles,* March 17, 2023, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M503/K824/503824406.PDF.

Distribution plant costs are contained in the FERC distribution account numbers 360 to 374. While certain costs in this category are clearly customer-related (e.g., meters and services), other accounts are sometimes classified as customer-related, sometimes as demand-related, and sometimes as a combination of the two. According to the 1992 NARUC Electric Utility Cost Allocation Manual,[15] the distribution plant accounts that may be classified as some combination of demand and customer include:

360 Land and land rights
361 Structures and improvements
364 Poles, towers and fixtures
365 Overhead conductors and devices
366 Underground conduit
367 Underground conductors and devices
368 Line transformers

Distribution expenses are contained in FERC account numbers 580 through 598. These are also sometimes classified as demand-related and sometimes classified as customer-related. In particular, the following costs may be classified as either demand-related, customer-related, or some combination thereof:

Operation
580 Operation supervision and engineering
583 Overhead line expenses (Major only)
584 Underground line expenses (Major only)
588 Miscellaneous distribution expenses
589 Rents

Maintenance
590 Maintenance supervision and engineering (Major only)
591 Maintenance of structures (Major only)
593 Maintenance of overhead lines (Major only)
594 Maintenance of underground lines (Major only)
595 Maintenance of line transformers
598 Maintenance of miscellaneous distribution plant

Where costs are thought to be jointly related to demand and the number of customers, there are several methods for splitting the costs into their respective demand and customer components. The “minimum system” or “minimum size” method is a common method for apportioning these costs. Under the minimum system method, the analyst estimates the cost of building a hypothetical system from scratch employing the smallest size components typically installed, and then deems those costs customer-related.[16] While this method has some intuitive

[15] NARUC. 1992.
[16] *Ibid*, p. 95.

appeal, it is also widely critiqued on a number of methodological grounds beyond the scope of this report.[17]

4. Fixed charges and Interaction with Equity, Energy Efficiency, and Decarbonization Goals

The inverse relationship between fixed charges and volumetric charges – higher fixed charges means lower volumetric charges, and vice-versa - means that when fixed charges are raised, customers have less control over managing their bills, though this depends on the level of fixed charge established. On the other hand, customers are not penalized for using more electricity, which is desirable when the short-run social marginal cost is low. As discussed further below, low-usage customers experience a larger percentage increase in their bills as a result and are disproportionately impacted by higher fixed charges. While this is generally seen as regressive due to the correlation of income and usage discussed herein, this is also distorted by high levels of DG in California.

AB 205 presents a paradigm shift in these traditional concerns by allowing for a progressive fixed charge, but it is likely impossible to completely alleviate these issues due to practical and data limitations. California has recognized in AB 205 that rates must be set to not only satisfy traditional rate design principles, but also must promote equity and protect incentives for policies encouraging energy efficiency, energy conservation, beneficial electrification, and GHG emission reductions. These goals can help provide positive distributional impacts and contribute to decarbonization efforts. This law comes at a time of increasing fixed charges nationally.[18] This section explores some of these interacting policy issues to explain why they should be considered in setting a fixed charge. Better understanding the interplay between policy considerations and fixed charges helps to lay a foundation for setting reasonable, progressively increasing fixed charges, as outlined in AB 205.

4.1. Equity and Fairness Considerations

Fixed charges must be carefully considered due to their disproportionate impact on equity and fairness. As we show in this section, when fixed charges are increased, low-usage customers – who are more likely to be low income - will experience a significantly greater percentage bill

[17] Weston, Frederick, et al. 2000, p. 34.

[18] *A Troubling Trend in Rate Design: Proposed Rate Design Alternatives to Harmful Fixed Charges*, Southern Environmental Law Center (Dec 2015). Available at: https://legacy.uploads.southernenvironment.org/news-feed/A_Troubling_Trend_in_Rate_Design.pdf; Trabish, H. *Are regulators starting to rethink fixed charges,* UtilityDive (Aug 2018). Available at: https://www.utilitydive.com/news/are-regulators-starting-to-rethink-fixed-charges/530417/

increase than high-usage, higher income customers. This means a fixed charge can compound the already regressive nature of utility bills.

National data reveals that income is correlated with energy usage, and that low-income customers tend to be lower-usage customers.[19] The Department of Energy's Lead Tool also demonstrates the correlation between energy usage and income in California when electricity spending is used as a proxy for usage.[20]

Table 1. Average site electricity consumption (kWh per household using the end use).[21]

2015 annual household income	Total (kWh) usage
Less than $20,000	11,819
$20,000 to $39,999	12,321
$40,000 to $59,999	13,477
$60,000 to $79,999	13,843
$80,000 to $99,999	13,932
$100,000 to $119,999	14,825
$120,000 to $139,999	14,683
$140,000 or more	15,693

Similarly, TURN has analyzed the relationship between income and usage by climate zone for California customers and determined they are correlated at all levels.[22] Under California's steeply inclining block rate structure in 2012, the average rate paid corresponded directly to a customer's kWh usage levels (i.e. there were higher marginal rates at higher usage levels), so overall rates and usage were directly correlated. This was matched with income data by climate zone, whereby significant correlations between usage and income were found.

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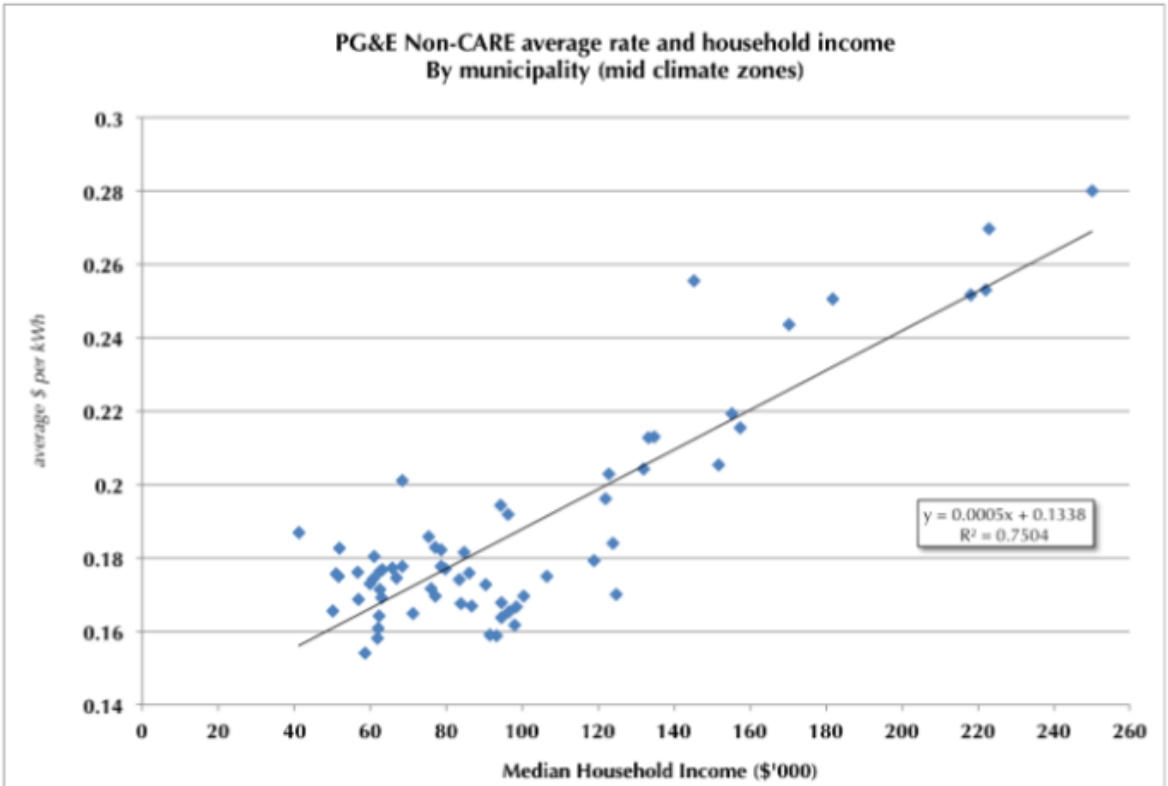
[19] U.S. Energy Information Administration, *Table CE5.3a Detailed household site electricity end-use consumption, part 1—averages.*, EIA (2015). Available at: https://www.eia.gov/consumption/residential/data/2015/c&e/ce5.3a.xlsx;

[20] U.S. Department of Energy, *Low-Income Energy Affordability Data (LEAD) Tool: Avg. Annual Energy Cost for Census Tracts in California*, Office of State and Community Energy Programs (2018). Available at: https://www.energy.gov/scep/slsc/lead-tool

[21] U.S. Energy Information Administration, *Table CE5.3a Detailed household site electricity end-use consumption, part 1—averages.*, EIA (2015). Available at: https://www.eia.gov/consumption/residential/data/2015/c&e/ce5.3a.xlsx

[22] Analysis by the Residential Appliance Saturation Study also confirms the positive correlation between income and usage; KEMA, Inc., 2009 California Residential Appliance Saturation Study, October 2010, CEC-200-2010-004-ES (hereinafter KEMA RASS Report).

Figure 3. Relationship between income and usage in California.[23]

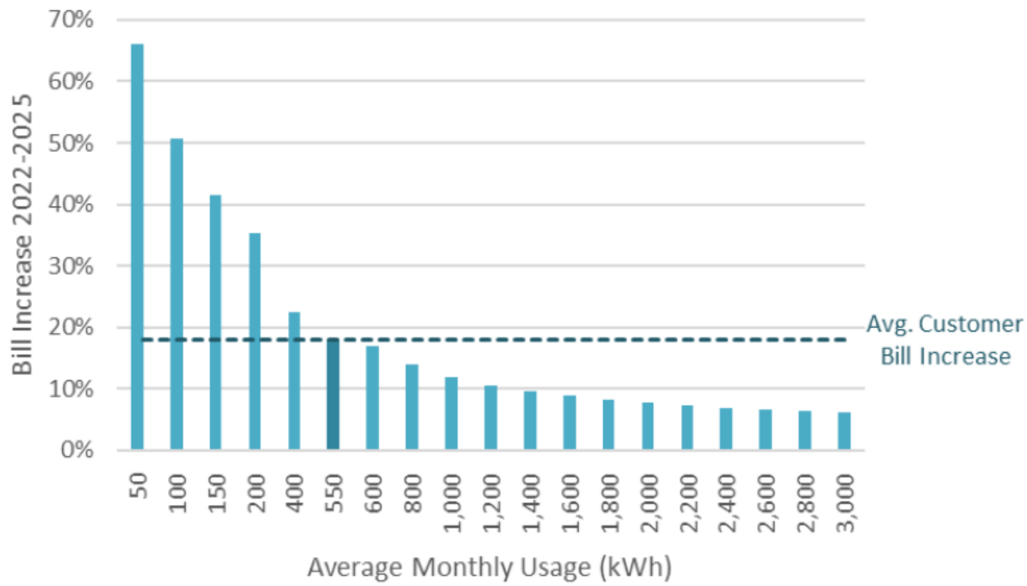


The correlation between income and usage relate directly to implications of establishing a fixed charge. The figure below, from an analysis Synapse conducted in Maine,[24] illustrates a typical distributional result of the impact of a fixed charge. For higher-usage customers, there is essentially a negligible bill increase or bill decrease, while lower-usage customers see significant bill increases.

[23] *Reply Comments of The Utility Reform Network on Rate Proposals*, Rulemaking 12-06-013, Public Utilities Commission of the State of California (June 2012), 23.

[24] Direct Testimony of Melissa Whited and Eric Borden, On Behalf of Maine Office of the Public Advocate, December 2, 2022.

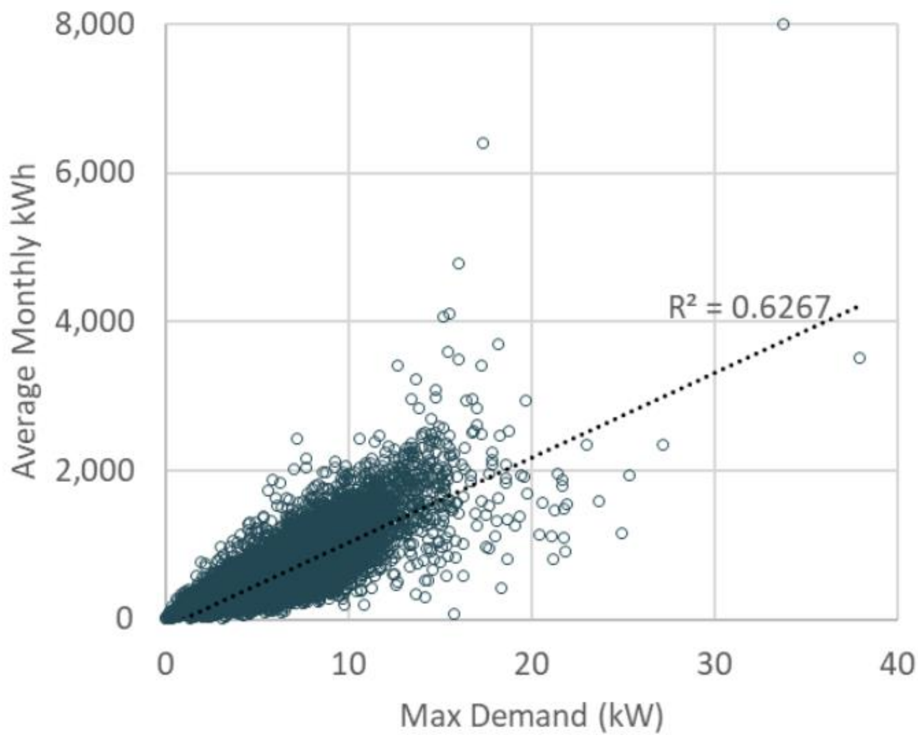
Figure 4. Percentage change in average monthly bill



We have also found that there is a strong correlation between electricity consumption (kWh) and electricity demand (kW).[25]

[25] Larry Blank and Doug Gegax, "Residential Winners and Losers behind the Energy versus Customer Charge Debate," The Electricity Journal, 27, no. 4 (May 2014)

Figure 5. Correlation between residential energy consumption and non-coincident peak demand.[26]



If demand-related costs are recovered through fixed charges, this raises equity considerations, since these may unfairly burden low-usage, low-income customers.

While reconfiguring prices to minimize fixed charges on low-income customers can have positive distributional impacts to reduce inequities, needs-based programs can also help reduce adverse impacts to lower-income customers, though they cannot be considered a panacea. As recognized in AB 205, income-based fixed charges can ameliorate the inequitable impacts that a flat increase in a fixed charge would produce while still leaving sufficient financial incentives for these customers to further lower energy use through conservation or distributed generation technology. This introduces parallel issues regarding how fixed charges interact with policies concerning energy efficiency, decarbonization, and distributed generation, discussed in the next section.

4.2. Energy efficiency, Distributed Generation, and Decarbonization Policy Impacts of Fixed Charges

Energy and climate policies like promoting energy efficiency, energy conservation, distributed generation, GHG emission reductions, electrification, and overall decarbonization are key state policies that are affected by rate design, including the level of fixed charges. These policies are promoted because they have garnered broad consensus as a means to keep energy costs low,

[26] Analysis of Massachusetts D.P.U. Docket 15-155, response to data request DPU-1-12-1.

achieve state climate goals, bolster the local economy, and improve overall economic competitiveness. This is evidenced by the proliferation of ratepayer funded energy efficiency programs throughout the US, which are in effect in all 50 states and the District of Columbia.[27] Governments have also advanced these policies through building codes, appliance standards, federal weatherization assistance, and tax incentives. Establishing and modernizing net metering programs and tax incentives to promote distributed generation policies also highlights efforts to advance these policies.

Layered into all of this, including the equity discussion, is how technological advances enable greater customer control over energy usage monitoring and management than ever before. Utilities often tout how smart meters, online information portals, and other programs can empower customers to better manage bills. Time of use (TOU) rates are predicated on customers ability to react to changing grid dynamics. Yet raising fixed charges for customers can reduce customer control and ability to reduce their bill, decreasing the incentive to respond to price signals. The relationship between the magnitude of a fixed charge and the customer's level of control over their energy costs therefore has implications for energy and climate policies, and should be considered in setting the level of any fixed charge.

Energy Efficiency and Energy Conservation

Energy efficiency denotes installation of a measure (such as installing an appliance or insulation) that maintains the same level of performance while using less energy. All else equal, the more that costs are embedded in volumetric charges, the greater the incentive is for customers to upgrade to energy efficient appliances and to implement weatherization measures since lowering their usage saves more, relative to higher fixed charges. Lower fixed charges may also encourage energy conservation, which is similar yet distinct from efficiency. Energy conservation is defined as instances where customers avoid consumption altogether, such as by turning off lights, unplugging appliances, and lowering their thermostats. When more costs are placed in volumetric charges, customer have greater ability to save through lowering usage.

Distributed Generation

In the same way as energy efficiency, the economics of distributed generation (DG) are affected by a fixed charge. In general, net metering compensation schemes offset the variable portion of the electric bill, so a higher fixed charge necessarily decreases this offset. At the same time, it is possible that higher fixed charges for net metering participants will alleviate cost shifts between DG customers and customers who do not have access to DG.[28] These cost shifts depend on the design of net metering tariffs – in general, since DG production offsets a portion or all of the volumetric charges that would have been paid by those utility customers, the utility must collect more revenue from customers without access to DG technology. The presence of this cost shift means that these customers do not adequately contribute to the fixed costs of the

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[27] American Council for an Energy Efficient Economy, *The 2022 State Energy Efficiency Scorecard* (2022). Available at: [The State Energy Efficiency Scorecard | ACEEE]

[28] This principle also applies to customers who have invested in energy efficiency or conservation measures.

grid. At the same time, cost shifts among these customers are mitigated by avoided costs due to DG production, including generation, transmission, and distribution costs. In a state like California, where fixed charges (not fixed costs) are very low and volumetric charges among the highest in the country, cost shifts from DG are likely exacerbated by the lack of a significant fixed charge.

Electrification

As increased electrification penetration becomes a priority under California's commitments to electrify transport and buildings as part of its larger decarbonization efforts,[29] electricity consumption will rise. Decrease in overall consumption through continued energy efficiency and conservation efforts will likely be partially or completely offset in coming years as the state promotes beneficial electrification throughout its economy as a strategy to meet GHG emission reduction targets.[30] Higher fixed charges generally benefit the economics of electrification since, as explained above, higher usage customers benefit from fixed charges through lower volumetric rates. This should also be considered as California addresses its rate design objectives. However, there are differences between a customer who buys an electric vehicle and seldomly drives and one who buys an electric heat pump. Furthermore, electrification will occur heterogeneously across different types of consumers, and over a long time period.

Balancing Rate Design Objectives

Compliance with AB 205 will require fixed charges to be designed in a manner that preserves incentives to advance state policy. At the same time, rates must be designed to fulfill other rate design principles such as fairness, cost-causation, and preventing inequitable intra-class cost-shifting.[31] Varying levels of fixed charges could be a step in the right direction if it can be designed in such a way that protects the incentives for energy efficiency, conservation, and decarbonization while satisfying broader objectives. Admittedly, this is no simple task. Such a design should balance the interests of (1) protecting low-income customers from the disproportionate impacts of high fixed costs; (2) appropriate incentives for energy and climate policies; (3) recovering more utility costs through fixed charges without unduly burdening customers, and (4) addressing cost-shifting concerns appropriately.

[29] Governor Newsom, *Letter to Chair Randolph*, Office of the Governor (July 22, 2022). Available at: https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf?emrc=1054d6. California Releases World's First Plan to Achieve Net Zero Carbon Pollution, Office of the Governor (November 2022). Available at: https://www.gov.ca.gov/2022/11/16/california-releases-worlds-first-plan-to-achieve-net-zero-carbon-pollution/.

[30]

5. Common Approaches to Setting Fixed Charges

There are a range of policy options that Commission considers what level of fixed charge to implement across income tiers. We seek here to outline the bookends of what prevalent rate design theory supports in terms of the level of fixed charge that can appropriately be levied on ratepayers. Our discussion and calculations presented below focuses on an average fixed charge across all residential ratepayers, with an understanding that the charge would be lower for low-income customers and higher for high-income customers.

5.1. Low Case: Fixed Charge Based on the Marginal Customer Access Cost

As detailed above, one approach to fixed charges considers only those costs which can be attributed to an individual customer's connection to the grid as "fixed." This is because these costs do not vary with the level of demand (or energy) of an individual customer. Put another way, *when, how, and to what degree* a customer consumes energy will not increase or decrease these costs, which is why including them in a fixed charge is seen as appropriate based on economic principles.

As stated in the NARUC manual "most analysts agree that distribution equipment that is uniquely dedicated to individual customers or specific customer classes can be classified as customer rather than demand related." These costs include the service drop and meter, which are costs incurred due to an individual customer, and a customer's portion of billing, customer service, and O&M costs for customer equipment.[32]

These costs have been estimated in California using the "new customer only" (NCO) and "rental" methods, as part of California's rate design and cost allocation proceedings which estimate marginal costs, which are scaled up to on an equal percentage basis to recover embedded costs. The public tool for this proceeding estimates these costs directly, based on each utility's calculation methodology.

5.2. High Case: Fixed Charge Based on Short Run Social Marginal Costs

At the high end of the spectrum, a fixed charge could include all costs *other than* short run social marginal costs, which would remain variable and collected on an energy (per kWh) or power (per kW) basis. Social marginal costs are defined as marginal costs - the cost of producing or consuming the next unit of electricity (e.g. kilowatt or kilowatt hour) - *plus* the marginal cost of environmental externalities. A classic example of the latter is pollution, which can be directly linked to consumption of energy at certain times, but it also includes the societal cost of carbon to reflect the marginal impact on climate change. Without a price signal that incorporates this

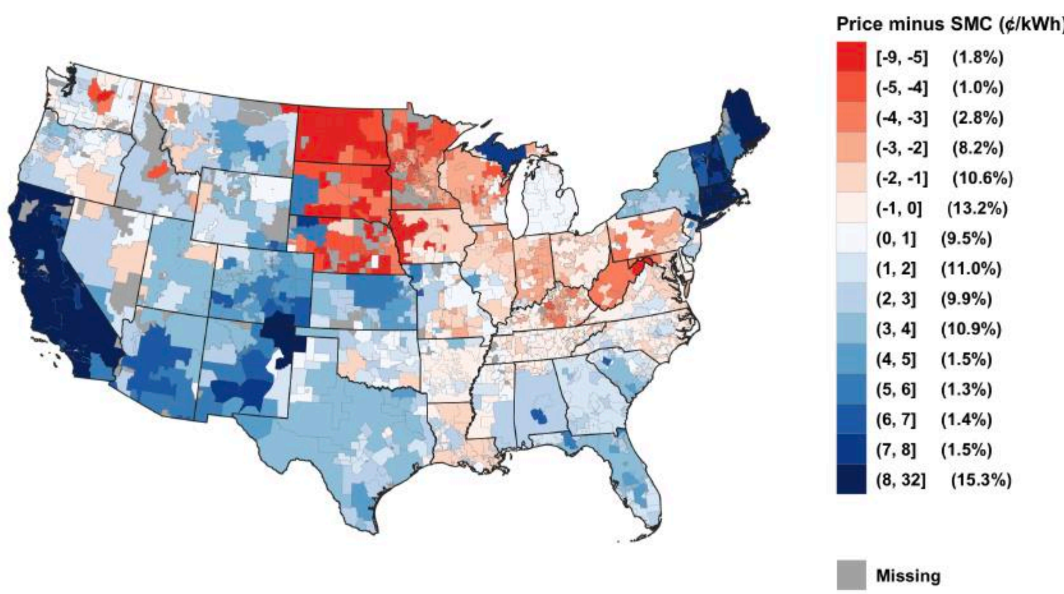
[32] RAP Cost Allocation Manual, pp. 207-211.

externality, a consumer has no financial incentive or dis-incentive to consume electricity in a way that minimizes environmental harm or maximizes private gain from the use of electricity.

The economic theory behind this option is that in order to minimize “deadweight loss” (DWL), the cost incurred by society due to market inefficiency, prices to which the consumer can respond should reflect the social marginal cost. Deadweight loss is incurred from over or under-consumption of electricity relative to the societal optimum. While a fixed charge does not vary, and thus cannot be affected by consumption patterns, variable charges on a per kWh or per kW basis do, by definition, vary over time or by time period, and can therefore provide price signals that effect customer behavior.

In their paper quantifying the difference between social marginal cost and retail prices seen by residential customers across the U.S., Borenstein and Bushnell found that variable retail prices in California significantly exceed social marginal costs, rivaled only by utilities in the Northeast – this is indicated by the dark blue areas of the map shown below.

Figure 6. Difference Between Price and Social Marginal Cost in the U.S.



Calculating Fixed Charges Based on Marginal Customer Access Costs and Social Marginal Cost

Synapse used the public spreadsheet tool created for the fixed charge Rulemaking (“E3 Tool”) to calculate fixed charges based on the marginal customer access costs and social marginal cost theories described above. We show fixed charges for all customers below; these can be considered to be an “average” fixed charge across multiple income tiers (and CARE) in the context of AB 205.

Marginal customer access costs were estimated directly by each utility and incorporated into the E3 tool. The figure shows the average fixed charge across all residential customers.

Figure 7. Monthly Fixed Charges Based on Marginal Customer Access Cost

Calculating social marginal costs required the summation of multiple cost categories, as well as a separate estimation of externality costs by utility, which were not incorporated into the E3 tool.

Short-run social marginal costs (SRSMCs) are comprised of three primary components – 1. Marginal energy costs (plus losses); 2. Societal externality costs of pollution; 3. Societal externality costs of carbon.[33]

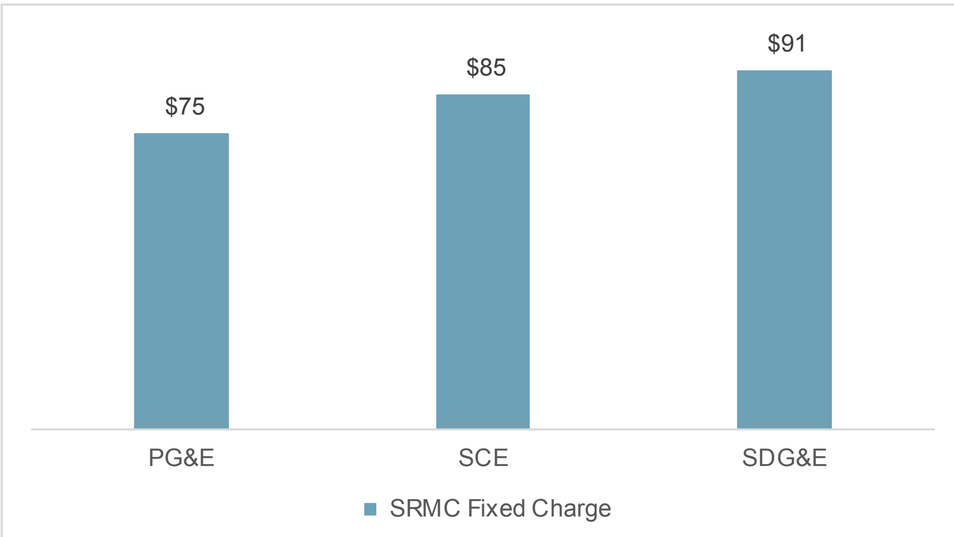
Marginal energy costs and losses have been estimated for each IOU in the CPUC’s avoided cost calculator (ACC).[34] Further, the CPUC has directly estimated the cost of pollution due to marginal gas generation in California in a recent study, which we adopt here.[35]

[33] Additional societal externalities, if quantifiable, may also be included in this calculation.
[34] See E3, https://www.ethree.com/public_proceedings/energy-efficiency-calculator/.
[35] We adopt the statewide average value of $14/MWh. See CPUC, *Societal Cost Test Impact Evaluation,* January 2022, p. 14.

For the social cost of carbon we adopt the latest estimate from the White House Interagency Working Group of $76 per tonne in 2020, based on a 2.5 percent discount rate.[36] To calculate what this signifies in the California context, we derive a weighted average marginal emission rate in the avoided cost calculator,[37] which allows for a calculation of marginal CO_2 emissions in tonnes per MWh across the year (2023). We multiply this factor by the social cost of carbon ($76 per tonne) to calculate the marginal social cost of carbon in dollars per MWh, which is multiplied by each IOU's total annual load to derive an annual cost of carbon impacts.

Incorporating all costs into a fixed charge *other than* the social marginal cost results in the following fixed charges for each IOU. The figure shows the average fixed charge across all residential customers.

Figure 8. Monthly Fixed Charges Based on Social Marginal Cost Approach to Fixed Charges



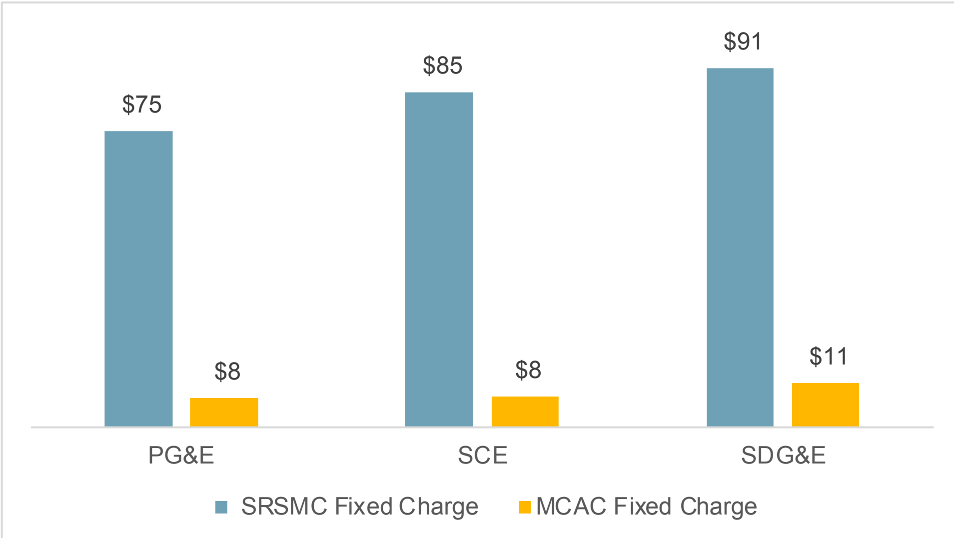
As seen above, monthly fixed charges vary among utilities. The exact drivers of this difference is beyond the scope of this report, but likely relate to how various cost categories were calculated by each utility, revenue requirements, total load and customer base, past investments, CARE population percentages, and other factors.

The figure below provides a comparison of fixed charges based on monthly customer access costs (calculated in the section above) to those based on the exclusion of social marginal costs.

[36] Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 1399, *Interagency Working Group on Social Cost of Greenhouse Gases*, United States Government, Table ES-1, p. 5.

[37] This is accomplished by using each IOU's hourly load profile from the E3 tool multiplied by average statewide marginal emissions rates in each hour.

Figure 9. Monthly Fixed Charges Based on Marginal Customer Access Cost and Social Marginal Cost Approach to Fixed Charges



6. Guidance For How to Assign Fixed Charges to Cost Categories

It is important that a fixed charge is instituted based on sound economic principles, discussed in the sections above, to guide practical decisions about the economic rationale for which utility costs ought to be included in a fixed charge.

A fixed charge should be set no lower than the marginal customer access cost, and no higher than the exclusion of social marginal cost, both calculated above for each IOU using E3 tool inputs and assumptions. We note that pure economic theory might simply follow the latter approach, whereby variable charges should be set at social marginal costs, with all other costs embedded in a fixed charge. However, utilities operate far from the idealized competitive market equilibrium, and pricing schemes, that underlies this theory. A practical approach to rate design that balances policy goals, fairness, and economic efficiency is required.

For purposes of the exercise of assigning certain cost categories for inclusion (or not) in a fixed charge, we find that the principle of cost causation, which is central to fair and economically supported rate design,[38] is a helpful guide to what can appropriately be included in a fixed charge. Namely, understanding and examining cost causation can help determine whether a certain type of cost should be included in the variable or fixed charge. To determine this, we

[38] This principle often surfaces in the context of cost allocation – not an issue here since we are only considering fixed charges for the residential class.

encourage stakeholders to examine the purpose or function of each cost – why has it been incurred, and can it be reasonably be avoided through shifts in consumption behavior? If a utility cost can be reasonably avoided by customer behavior – i.e. by reducing or shifting electricity usage – it does not belong in a fixed charge.

The foregoing sections quantified a range of outcomes for the CPUC's consideration and provides underlying economic theory to help guide stakeholders and the Commission in its deliberation on a progressive fixed charge. California is on the forefront of energy policy issues and should move deliberately to address unnecessary inequities in its current rate design.

APPENDIX D: Printable Results (Default Rates)

Fixed Charge Tool Outputs - Cover Sheet

Purpose:
This section of the tool is formatted to be easily printed or saved as a PDF and filed as a part of testimony.

Instructions:
This worksheet automatically draws values from the rest of the tool.
This worksheet displays both rate design details and bill impacts for all three IOUs.
Please run the macro (button above) to re-generate model results using current inputs to ensure that the rate design details and bill impacts are aligned.
This macro can also be run from the Rate Design Dashboard worksheet. Please see the Rate Design Dashboard worksheet for further details.

How to Save as PDF:
Click "File", then "Print", then select "Microsoft Print to PDF". Click the large "Print" button to choose a file location and name.

How to Print:
Click "File", then "Print", then select your choice of printer.

Table of Contents

Energy+Environmental Economics

Energy and Environmental Economics, Inc.
44 Montgomery Street, Suite 1500
San Francisco, CA 94104
Phone: 415-391-5100

Model Release Date: April 13, 2023

Revenue Requirement Allocations

PG&E

Cost Category	Cost Component (See "Glossary" tab for descriptions)	Residential Revenue Requirement	CARE-Exempt	Bundled Generation	Percent to Include in Customer Charge	Percent to Include in Demand Charge	Percent to Include in Volumetric Charge
		$	T/F	T/F	%	%	%
Generation	PCIA	$ 183,408,243	FALSE	FALSE	100.00%	0.00%	0.00%
Generation	Marginal Energy Cost	$ 538,263,216	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 218,481,550	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 865,996,766	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal Customer Access	$ 454,792,861	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal Distribution Capacity Cost - Primary	$ 439,382,040	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal Distribution Capacity Cost - New Business	$ 476,043,853	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal Distribution Capacity Cost - Secondary	$ 29,945,145	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Non-Marginal Distribution	$ 1,833,578,625	FALSE	FALSE	20.00%	0.00%	80.00%
Transmission	Transmission	$ 1,447,654,612	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 58,854,252	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Fund Charge	$ 63,120,120	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Wildfire Hardening Charge	$ 68,921,008	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Charge	$ 215,256,658	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Recovery Bond Credit	$ (215,256,658)	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 230,732,710	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Nuclear Decommissioning	$ 37,938,712	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	New System Generation Charge	$ 96,956,158	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Competition Transition Charge	$ 8,518,646	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Energy Cost Recovery Account	$ (19,846,861)	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	100.00%	0.00%	0.00%
	See "New Rates" Section (pg. 7 - 9)						
Line Items	2023 Total Estimated CARE Discount	$ (891,914,356)					
	Note: included for comparison to model-calculated values						
	Delivery RR - Before CARE Bill Discount	**$ 7,032,741,656**					

SCE

Cost Category	Cost Component (See "Glossary" tab for descriptions)	Residential Revenue Requirement	CARE-Exempt	Bundled Generation	Percent to Include in Customer Charge	Percent to Include in Demand Charge	Percent to Include in Volumetric Charge
		$	T/F	T/F	%	%	%
Generation	PCIA	$ 18,066,203	FALSE	FALSE	100.00%	0.00%	0.00%
Generation	Marginal Energy Cost	$ 606,708,166	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 584,831,167	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 1,378,829,544	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal - Customer	$ 427,567,610	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal - Grid	$ 888,543,196	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal - Peak	$ 503,372,326	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Non-Marginal Distribution	$ 1,845,967,040	FALSE	FALSE	45.00%	0.00%	55.00%
Transmission	Base Transmission	$ 599,320,433	FALSE	FALSE	0.00%	0.00%	100.00%
Transmission	Transmission Balancing Accounts	$ (1,839,212)	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 23,619,309	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Fund Charge	$ 103,390,404	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Wildfire Hardening Charge	$ 17,556,861	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Charge	$ -	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Recovery Bond Credit	$ (40,575,857)	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 313,291,510	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Nuclear Decommissioning	$ 2,364,701	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	New System Generation Charge	$ 148,976,188	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	100.00%	0.00%	0.00%
	See "New Rates" Section (pg. 7 - 9)						
Line Items	2023 Total Estimated CARE Discount	$ (660,034,291)					
	Note: included for comparison to model-calculated values						
	Delivery RR - Before CARE Bill Discount	**$ 6,995,933,045**					

SDG&E

Cost Category	Cost Component (See "Glossary" tab for descriptions)	Residential Revenue Requirement	CARE-Exempt	Bundled Generation	Percent to Include in Customer Charge	Percent to Include in Demand Charge	Percent to Include in Volumetric Charge
		$	T/F	T/F	%	%	%
Generation	PCIA	$ 180,005,950	FALSE	FALSE	100.00%	0.00%	0.00%
Generation	Marginal Energy Cost	$ 100,915,850	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 57,547,258	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 163,094,812	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal - Customer	$ 183,005,936	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal Demand - Non-Coincident Peak	$ 198,205,378	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal Demand - Coincident Peak	$ 26,974,391	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Non-Marginal Distribution	$ 490,650,411	FALSE	FALSE	7.00%	0.00%	93.00%
Transmission	Base Transmission	$ 537,401,722	FALSE	FALSE	0.00%	0.00%	100.00%
Transmission	Transmission Balancing Accounts	$ (111,012,377)	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 8,781,000	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Fund Charge	$ 29,143,070	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 61,433,000	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Nuclear Decommissioning	$ 526,530	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Local Generation Charge/New System Generation Cha	$ 81,949,029	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Competition Transition Charge	$ 11,052,908	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Total Rate Adjustment Component - Baseline adjustme	$ 1,000,000	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Reliability Services	$ 177,809	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	100.00%	0.00%	0.00%
	See "New Rates" Section (pg. 7 - 9)						
Line Items	2023 Total Estimated CARE Discount	$ (178,549,476)					
	Note: included for comparison to model-calculated values						
	Delivery RR - Before CARE Bill Discount	**$ 2,020,852,676**					

Rate Design Inputs

		PG&E	SCE	SDG&E
Customer charge option		User-Defined CARE Charges	User-Defined CARE Charges	User-Defined CARE Charges
Customer Charge Weighting is used when Customer Charge Option is set to "Uniform Weights"				
Customer Charge Weighting	[0,25]	1.0000	1.0000	1.0000
	[25,50]	1.0000	1.0000	1.0000
	[50,75]	2.0000	2.0000	2.0000
	[75,100]	2.0000	2.0000	2.0000
	[100,150]	3.0000	3.0000	3.0000
	[150,200]	3.0000	3.0000	3.0000
	200+	3.0000	3.0000	3.0000
Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
CARE Customer Charge ($/mo)	[0,25]	5.0000	5.0000	5.0000
	[25,50]	5.0000	5.0000	5.0000
	[50,75]	5.0000	5.0000	5.0000
	[75,100]	5.0000	5.0000	5.0000
	[100,150]	5.0000	5.0000	5.0000
	[150,200]	5.0000	5.0000	5.0000
	200+	5.0000	5.0000	5.0000
Non-CARE Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Non-CARE Customer Charge Weighting	[0,25]	1.0000	1.0000	1.0000
	[25,50]	1.0000	1.0000	1.0000
	[50,75]	1.0000	1.0000	1.0000
	[75,100]	1.0000	1.0000	1.0000
	[100,150]	1.0000	1.0000	1.0000
	[150,200]	1.5000	1.5000	1.5000
	200+	1.5000	1.5000	1.5000
Average CARE Program Discount is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Average CARE Program Discount	($/month)	$ -	$ -	$ -
Demand Charge Options	Billing determinant to use	X Highest Demand Months	X Highest Demand Months	X Highest Demand Months
	No. of highest demand months to include	$ 3.0000	$ 3.0000	$ 3.0000
Adjustments to distribution rate		Equal Cents	Equal Cents	Equal Cents
Include baseline credit from existing rate	(if applicable)	TRUE	TRUE	TRUE

Revenue Requirement Components

PG&E

Based on CARE program size from E-TOU-C

Delivery - excluding CARE-exempt		
Rev Req - Customer	**Rev Req - Demand**	**Rev Req - Volumetric**
$ 1,846,588,263	$ -	$ 3,372,516,482

Delivery - CARE-exempt		
Rev Req - Customer	**Rev Req - Demand**	**Rev Req - Volumetric**
$ 341,241,016	$ -	$ 63,120,120

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 1,936,190,085
NBCs	$ 8,518,646
Non-Dist	$ 1,427,807,751

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ 63,120,120
Non-Dist	$ -

SDG&E

Based on CARE program size from TOU-DR1

Delivery - excluding CARE-exempt		
Rev Req - Customer	**Rev Req - Demand**	**Rev Req - Volumetric**
$ 541,265,974	$ -	$ 1,120,104,712

Delivery - CARE-exempt		
Rev Req - Customer	**Rev Req - Demand**	**Rev Req - Volumetric**
$ 62,881,643	$ -	$ 29,143,070

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 681,484,650
NBCs	$ 11,052,908
Non-Dist	$ 427,567,154

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ 29,143,070
Non-Dist	$ -

SCE

Based on CARE program size from TOU-D-4-9

Delivery - excluding CARE-exempt		
Rev Req - Customer	**Rev Req - Demand**	**Rev Req - Volumetric**
$ 1,740,951,380	$ -	$ 3,004,678,614

Delivery - CARE-exempt		
Rev Req - Customer	**Rev Req - Demand**	**Rev Req - Volumetric**
$ 195,163,485	$ -	$ 62,814,547

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 2,407,197,393
NBCs	$ -
Non-Dist	$ 597,481,220

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ 103,390,404
Non-Dist	$ (40,575,857)

New Rates

	PG&E E-1 Non-CARE	PG&E E-1 CARE	PG&E E-TOU-C Non-CARE	PG&E E-TOU-C CARE	[redacted]
Income Bracket (1000$):					
[0,25]	$ 41.4688	$ 5.0000	$ 41.4242	$ 5.0000	
[25,50]	$ 41.4688	$ 5.0000	$ 41.4242	$ 5.0000	
[50,75]	$ 41.4688	$ 5.0000	$ 41.4242	$ 5.0000	
[75,100]	$ 41.4688	$ 5.0000	$ 41.4242	$ 5.0000	
[100,150]	$ 41.4688	$ 5.0000	$ 41.4242	$ 5.0000	
[150,200]	$ 62.2032	$ 5.0000	$ 62.1363	$ 5.0000	
200+	$ 62.2032	$ 5.0000	$ 62.1363	$ 5.0000	
Tier Credits/Charges ($/kWh)					
Baseline Credit	$ 0.0589	$ 0.0383	$ 0.0589	$ 0.0383	
High Usage Charge	$ -	$ -	$ -	$ -	
Demand Charges ($/kW)					
Billing Determinant	X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand	
No. of Highest Demand Months	$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	
Demand Charge ($/kW-mo)	$ -	$ -	$ -	$ -	
Energy Charges ($/kWh)					
Summer - Peak	$ 0.2996	$ 0.1928	$ 0.3901	$ 0.2516	
Summer - Part-Peak	$ 0.2996	$ 0.1928	$ -	$ -	
Summer - Off-Peak	$ 0.2996	$ 0.1928	$ 0.3267	$ 0.2104	
Winter - Peak	$ 0.2996	$ 0.1928	$ 0.2930	$ 0.1885	
Winter - Part-Peak	$ 0.2996	$ 0.1928	$ -	$ -	
Winter - Off-Peak	$ 0.2996	$ 0.1928	$ 0.2757	$ 0.1773	
Total CARE Program Funding - Modeled					
Customer		$ -		$ -	
Demand		$ -		$ -	
Volumetric - Delivery		$ (363,796,732)		$ (363,796,732)	
Volumetric - Generation		$ (431,894,113)		$ (423,536,307)	
Total CARE Credits		$ (795,690,844)		$ (787,333,039)	
Residential CARE Funding		$ 215,731,768		$ 213,465,757	
Non-Res CARE Funding		$ 579,959,077		$ 573,867,282	
Total IOU forecast CARE program size					
2023 Forecast (Existing Rates)		$ (891,914,356)		$ (891,914,356)	
Modeled Credits as % of Forecast		-11%		-12%	

[redacted]

SCE	SCE	SCE	SCE
D	D	TOU-D-4-9	TOU-D-4-9
Non-CARE	CARE	Non-CARE	CARE
$ 41.2009	$ 5.0000	$ 41.2471	$ 5.0000
$ 41.2009	$ 5.0000	$ 41.2471	$ 5.0000
$ 41.2009	$ 5.0000	$ 41.2471	$ 5.0000
$ 41.2009	$ 5.0000	$ 41.2471	$ 5.0000
$ 41.2009	$ 5.0000	$ 41.2471	$ 5.0000
$ 61.8014	$ 5.0000	$ 61.8706	$ 5.0000
$ 61.8014	$ 5.0000	$ 61.8706	$ 5.0000
$ 0.0684	$ 0.0462	$ 0.0749	$ 0.0505
$ 0.0770	$ 0.0520	$ -	$ -
X Highest Demand I	X Highest Demand I	X Highest Demand I	X Highest Demand I
$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
$ -	$ -	$ -	$ -
$ 0.3125	$ 0.2088	$ 0.4802	$ 0.3220
$ 0.3125	$ 0.2088	$ 0.3718	$ 0.2488
$ 0.3125	$ 0.2088	$ 0.2651	$ 0.1768
$ 0.3125	$ 0.2088	$ 0.4123	$ 0.2761
$ 0.3125	$ 0.2088	$ 0.2898	$ 0.1934
$ 0.3125	$ 0.2088	$ 0.2546	$ 0.1697
	$ -		$ -
	$ -		$ -
	$ (251,497,270)		$ (251,497,270)
	$ (339,559,859)		$ (347,681,851)
	$ (591,057,130)		$ (599,179,121)
	$ 151,899,987		$ 153,987,315
	$ 439,157,143		$ 445,191,806
	$ (660,034,291)		$ (660,034,291)
	-10%		-9%

[redacted]

SDG&E	SDG&E	SDG&E	SDG&E	[redacted]
DR	DR	TOU-DR1	TOU-DR1	
Non-CARE	CARE	Non-CARE	CARE	
$ 41.3677	$ 5.0000	$ 41.2869	$ 5.0000	
$ 41.3677	$ 5.0000	$ 41.2869	$ 5.0000	
$ 41.3677	$ 5.0000	$ 41.2869	$ 5.0000	
$ 41.3677	$ 5.0000	$ 41.2869	$ 5.0000	
$ 41.3677	$ 5.0000	$ 41.2869	$ 5.0000	
$ 62.0515	$ 5.0000	$ 61.9304	$ 5.0000	
$ 62.0515	$ 5.0000	$ 61.9304	$ 5.0000	
$ 0.0956	$ 0.0631	$ 0.0956	$ 0.0631	
$ -	$ -	$ -	$ -	
X Highest Demand	X Highest Demand	X Highest Demand	X Highest Demand	
$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000	
$ -	$ -	$ -	$ -	
$ 0.4711	$ 0.3075	$ 0.7340	$ 0.4810	
$ 0.4711	$ 0.3075	$ 0.4205	$ 0.2742	
$ 0.4711	$ 0.3075	$ 0.2559	$ 0.1655	
$ 0.4711	$ 0.3075	$ 0.5372	$ 0.3512	
$ 0.4711	$ 0.3075	$ 0.4527	$ 0.2954	
$ 0.4711	$ 0.3075	$ 0.4281	$ 0.2792	
	$ -		$ -	
	$ -		$ -	
	$ (92,214,209)		$ (92,214,209)	
	$ (100,157,376)		$ (96,179,165)	
	$ (192,371,585)		$ (188,393,374)	
	$ 55,243,060		$ 54,100,643	
	$ 137,128,525		$ 134,292,731	
	$ (178,549,476)		$ (178,549,476)	
	8%		6%	

Bill Impacts

PG&E

			Customer Average Bill Impact ($/mo)										
Income Bracket	Bill Discount		PG&E	P	Q	R	S	T	V	W	X	Y	Z
$0 - $25,000	None	1	$ 5.95	$ (11.69)	$ (7.80)	$ (11.37)	$ (7.73)	$ 13.78	$ (0.22)	$ (8.42)	$ 3.05	$ 2.37	$ 18.72
$25,000 - $50,000	None	2	$ 1.54	$ (11.32)	$ (7.77)	$ (11.50)	$ (7.49)	$ 13.88	$ (0.37)	$ (8.77)	$ 3.04	$ 2.37	$ 18.74
$50,000 - $75,000	None	3	$ 1.09	$ (10.97)	$ (7.62)	$ (10.34)	$ (6.66)	$ 13.98	$ (0.37)	$ (7.30)	$ 3.22	$ 2.39	$ 18.70
$75,000 - $100,000	None	4	$ 2.02	$ (10.35)	$ (7.65)	$ (8.82)	$ (5.46)	$ 14.06	$ (0.22)	$ (5.20)	$ 3.35	$ 2.41	$ 18.71
$100,00 - $150,000	None	5	$ 3.19	$ (9.64)	$ (7.24)	$ (7.02)	$ (4.12)	$ 14.15	$ (0.07)	$ (2.69)	$ 3.61	$ 2.43	$ 18.74
$150,000 - $200,000	None	6	$ 25.38	$ 12.51	$ 13.80	$ 15.73	$ 18.31	$ 34.95	$ 20.86	$ 20.87	$ 24.67	$ 23.21	$ 39.40
$200,000+	None	7	$ 27.37	$ 14.28	$ 14.81	$ 18.83	$ 20.75	$ 35.10	$ 20.90	$ 24.16	$ 25.62	$ 23.30	$ 39.41
$0 - $25,000	CARE	1	$ (17.74)	$ (27.46)	$ (22.46)	$ (23.54)	$ (21.20)	$ (9.71)	$ (14.27)	$ (22.77)	$ (14.28)	$ (24.02)	$ (17.12)
$25,000 - $50,000	CARE	2	$ (18.19)	$ (27.35)	$ (22.45)	$ (23.06)	$ (20.88)	$ (9.66)	$ (14.28)	$ (22.08)	$ (14.17)	$ (24.02)	$ (17.30)
$50,000 - $75,000	CARE	3	$ (17.49)	$ (27.15)	$ (22.03)	$ (22.57)	$ (20.63)	$ (9.63)	$ (14.15)	$ (21.28)	$ (14.12)	$ (24.00)	$ (17.38)
$75,000 - $100,000	CARE	4	$ (17.22)	$ (27.12)	$ (21.19)	$ (22.38)	$ (20.28)	$ (9.59)	$ (14.02)	$ (20.54)	$ (14.12)	$ (24.00)	$ (17.43)
$100,00 - $150,000	CARE	5	$ (16.81)	$ (26.99)	$ (22.31)	$ (21.80)	$ (19.95)	$ (9.57)	$ (14.23)	$ (20.10)	$ (13.99)	$ (23.99)	$ (17.50)
$150,000 - $200,000	CARE	6	$ (16.10)	$ (26.75)	$ (22.65)	$ (21.43)	$ (19.66)	$ (9.58)	$ (14.25)	$ (19.03)	$ (13.96)	$ (23.98)	$ (17.21)
$200,000+	CARE	7	$ (15.04)	$ (25.99)	$ (22.65)	$ (20.73)	$ (19.15)	$ (9.57)	$ (14.01)	$ (18.58)	$ (13.84)	$ (23.97)	$ (22.01)
$0 - $25,000	FERA	1	$ (1.96)	$ (19.04)	$ (10.88)	$ (11.47)	$ (8.18)	$ 9.95	$ 2.56	$ (10.07)	$ 2.65	$ (13.66)	$ (1.78)
$25,000 - $50,000	FERA	2	$ (2.34)	$ (18.86)	$ (10.84)	$ (10.17)	$ (7.42)	$ 10.05	$ 2.53	$ (8.33)	$ 2.86	$ (13.65)	$ (2.65)
$50,000 - $75,000	FERA	3	$ (1.30)	$ (18.55)	$ (9.90)	$ (8.94)	$ (6.86)	$ 10.11	$ 2.76	$ (6.50)	$ 2.96	$ (13.61)	$ (2.99)
$75,000 - $100,000	FERA	4	$ (0.91)	$ (18.49)	$ (8.13)	$ (8.49)	$ (6.10)	$ 10.19	$ 2.97	$ (4.96)	$ 2.95	$ (13.61)	$ (3.17)
$100,00 - $150,000	FERA	5	$ (0.36)	$ (18.28)	$ (10.52)	$ (7.19)	$ (5.41)	$ 10.24	$ 2.63	$ (4.12)	$ 3.21	$ (13.58)	$ (3.42)
$150,000 - $200,000	FERA	6	$ 17.58	$ (0.90)	$ 5.69	$ 10.55	$ 12.18	$ 27.21	$ 19.59	$ 14.79	$ 20.27	$ 3.42	$ 14.76
$200,000+	FERA	7	$ 18.93	$ 0.28	$ 5.69	$ 11.88	$ 13.15	$ 27.23	$ 19.99	$ 15.52	$ 20.50	$ 3.44	$ 9.99

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	E-1
Select single counterfactual rate (if applicable)	E-1

SDG&E

Income Bracket	Bill Discount		Customer Average Bill Impact ($/mo) SDG&E	Inland	Coastal	Desert	Mountain
$0 - $25,000	None	1	$ 1.96	$ 0.23	$ 3.05	$ (0.85)	$ (18.08)
$25,000 - $50,000	None	2	$ 1.78	$ (0.55)	$ 3.05	$ (1.51)	$ (15.81)
$50,000 - $75,000	None	3	$ 1.39	$ (0.63)	$ 3.14	$ 0.40	$ (15.13)
$75,000 - $100,000	None	4	$ 1.54	$ (0.26)	$ 3.27	$ 2.96	$ (14.13)
$100,00 - $150,000	None	5	$ 2.33	$ 1.00	$ 3.72	$ 1.32	$ (11.57)
$150,000 - $200,000	None	6	$ 24.22	$ 23.52	$ 24.96	$ 35.20	$ 12.64
$200,000+	None	7	$ 26.27	$ 26.09	$ 26.45	$ 21.34	$ 17.09
$0 - $25,000	CARE	1	$ (17.01)	$ (19.59)	$ (14.03)	$ (41.00)	$ (44.87)
$25,000 - $50,000	CARE	2	$ (17.10)	$ (19.53)	$ (14.03)	$ (42.23)	$ (44.39)
$50,000 - $75,000	CARE	3	$ (16.95)	$ (19.43)	$ (13.99)	N/A	$ (44.46)
$75,000 - $100,000	CARE	4	$ (16.43)	$ (19.37)	$ (13.85)	N/A	$ (45.05)
$100,00 - $150,000	CARE	5	$ (16.09)	$ (19.47)	$ (13.91)	N/A	N/A
$150,000 - $200,000	CARE	6	$ (13.30)	N/A	$ (13.30)	N/A	N/A
$200,000+	CARE	7	N/A	N/A	N/A	N/A	N/A
$0 - $25,000	FERA	1	$ 2.24	$ (1.02)	$ 6.63	$ (29.04)	$ (37.62)
$25,000 - $50,000	FERA	2	$ 2.13	$ (0.87)	$ 6.63	$ (31.84)	$ (36.59)
$50,000 - $75,000	FERA	3	$ 2.40	$ (0.68)	$ 6.70	N/A	$ (36.76)
$75,000 - $100,000	FERA	4	$ 3.16	$ (0.56)	$ 6.96	N/A	$ (37.96)
$100,00 - $150,000	FERA	5	$ 3.62	$ (0.75)	$ 6.85	N/A	N/A
$150,000 - $200,000	FERA	6	$ 24.88	N/A	$ 24.88	N/A	N/A
$200,000+	FERA	7	N/A	N/A	N/A	N/A	N/A

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	DR
Select single counterfactual rate (if applicable)	DR

SCE

Income Bracket	Bill Discount		Customer Average Bill Impact ($/mo) SCE	5	6	8	9	10	13	14	15	16
$0 - $25,000	None	1	$ 1.10	$ (1.54)	$ 8.27	$ 6.01	$ (2.48)	$ (3.63)	$ (12.16)	$ (9.27)	$ (16.10)	$ 3.96
$25,000 - $50,000	None	2	$ (0.41)	$ (1.54)	$ 8.32	$ 5.86	$ (3.04)	$ (5.07)	$ (11.41)	$ (8.78)	$ (17.42)	$ 4.07
$50,000 - $75,000	None	3	$ (0.12)	$ (1.54)	$ 8.39	$ 5.85	$ (3.09)	$ (4.89)	$ (10.05)	$ (8.18)	$ (16.53)	$ 4.18
$75,000 - $100,000	None	4	$ 0.34	$ (1.54)	$ 8.44	$ 5.97	$ (2.89)	$ (4.28)	$ (9.00)	$ (7.27)	$ (15.71)	$ 4.52
$100,00 - $150,000	None	5	$ 1.09	$ (1.54)	$ 8.55	$ 6.15	$ (2.60)	$ (3.18)	$ (7.68)	$ (6.34)	$ (14.96)	$ 4.88
$150,000 - $200,000	None	6	$ 22.58	$ 19.06	$ 29.29	$ 27.03	$ 18.52	$ 18.47	$ 13.87	$ 15.31	$ 6.52	$ 25.87
$200,000+	None	7	$ 24.08	$ 19.06	$ 29.57	$ 27.65	$ 19.29	$ 19.77	$ 15.85	$ 16.63	$ 8.02	$ 26.14
$0 - $25,000	CARE	1	$ (17.94)	N/A	$ (10.56)	$ (12.71)	$ (16.25)	$ (21.95)	$ (24.31)	$ (24.67)	$ (27.46)	$ (19.36)
$25,000 - $50,000	CARE	2	$ (17.65)	N/A	$ (10.53)	$ (12.69)	$ (16.22)	$ (21.80)	$ (23.95)	$ (24.31)	$ (26.94)	$ (19.22)
$50,000 - $75,000	CARE	3	$ (17.48)	N/A	$ (10.52)	$ (12.68)	$ (16.19)	$ (21.57)	$ (23.69)	$ (24.10)	$ (26.67)	$ (19.24)
$75,000 - $100,000	CARE	4	$ (17.45)	N/A	$ (10.51)	$ (12.66)	$ (16.18)	$ (21.44)	$ (23.41)	$ (24.06)	$ (26.41)	$ (19.24)
$100,00 - $150,000	CARE	5	$ (17.20)	N/A	$ (10.48)	$ (12.64)	$ (16.16)	$ (21.19)	$ (23.37)	$ (23.66)	$ (26.24)	$ (19.03)
$150,000 - $200,000	CARE	6	$ (16.75)	N/A	$ (10.46)	$ (12.59)	$ (16.10)	$ (20.76)	$ (23.06)	$ (23.24)	$ (25.82)	$ (18.75)
$200,000+	CARE	7	$ (16.11)	N/A	$ (10.45)	$ (12.53)	$ (16.02)	$ (20.43)	$ (22.57)	$ (22.93)	$ (25.05)	$ (18.45)
$0 - $25,000	FERA	1	$ 1.16	N/A	$ 11.21	$ 8.18	$ 3.10	$ (4.56)	$ (7.58)	$ (8.43)	$ (12.35)	$ (1.64)
$25,000 - $50,000	FERA	2	$ 1.45	N/A	$ 11.26	$ 8.23	$ 3.14	$ (4.25)	$ (6.76)	$ (7.70)	$ (11.25)	$ (1.39)
$50,000 - $75,000	FERA	3	$ 1.63	N/A	$ 11.27	$ 8.26	$ 3.20	$ (3.81)	$ (6.20)	$ (7.30)	$ (10.71)	$ (1.42)
$75,000 - $100,000	FERA	4	$ 1.68	N/A	$ 11.29	$ 8.29	$ 3.22	$ (3.55)	$ (5.60)	$ (7.22)	$ (10.19)	$ (1.43)
$100,00 - $150,000	FERA	5	$ 2.02	N/A	$ 11.34	$ 8.34	$ 3.25	$ (3.09)	$ (5.54)	$ (6.48)	$ (9.87)	$ (1.05)
$150,000 - $200,000	FERA	6	$ 19.54	N/A	$ 28.27	$ 25.33	$ 20.26	$ 14.57	$ 11.97	$ 11.15	$ 7.81	$ 16.30
$200,000+	FERA	7	$ 20.41	N/A	$ 28.29	$ 25.44	$ 20.39	$ 15.13	$ 12.86	$ 11.66	$ 9.18	$ 16.79

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	D
Select single counterfactual rate (if applicable)	D

Bill Impacts

PG&E

Income Bracket	Bill Discount		Customer Average Bill Impact ($/mo) PG&E	P	Q	R	S	T	V	W	X	Y	Z
$0 - $25,000	None	1	$ 5.03	$ (13.07)	$ (9.09)	$ (12.70)	$ (8.96)	$ 13.05	$ (1.27)	$ (9.66)	$ 2.07	$ 1.32	$ 18.09
$25,000 - $50,000	None	2	$ 0.52	$ (12.68)	$ (9.06)	$ (12.83)	$ (8.71)	$ 13.15	$ (1.43)	$ (10.02)	$ 2.06	$ 1.32	$ 18.11
$50,000 - $75,000	None	3	$ 0.07	$ (12.32)	$ (8.90)	$ (11.63)	$ (7.86)	$ 13.26	$ (1.43)	$ (8.51)	$ 2.24	$ 1.35	$ 18.06
$75,000 - $100,000	None	4	$ 1.02	$ (11.68)	$ (8.93)	$ (10.06)	$ (6.62)	$ 13.34	$ (1.27)	$ (6.34)	$ 2.38	$ 1.37	$ 18.08
$100,00 - $150,000	None	5	$ 2.22	$ (10.94)	$ (8.51)	$ (8.21)	$ (5.24)	$ 13.43	$ (1.12)	$ (3.75)	$ 2.64	$ 1.39	$ 18.11
$150,000 - $200,000	None	6	$ 24.42	$ 11.23	$ 12.52	$ 14.59	$ 17.22	$ 34.21	$ 19.80	$ 19.88	$ 23.69	$ 22.15	$ 38.75
$200,000+	None	7	$ 26.47	$ 13.07	$ 13.57	$ 17.79	$ 19.74	$ 34.37	$ 19.84	$ 23.26	$ 24.68	$ 22.25	$ 38.75
$0 - $25,000	CARE	1	$ (18.51)	$ (28.58)	$ (23.41)	$ (24.50)	$ (22.09)	$ (10.22)	$ (14.92)	$ (23.70)	$ (14.94)	$ (25.02)	$ (17.86)
$25,000 - $50,000	CARE	2	$ (18.98)	$ (28.47)	$ (23.40)	$ (24.01)	$ (21.75)	$ (10.16)	$ (14.94)	$ (22.99)	$ (14.83)	$ (25.02)	$ (18.04)
$50,000 - $75,000	CARE	3	$ (18.25)	$ (28.26)	$ (22.96)	$ (23.50)	$ (21.50)	$ (10.13)	$ (14.80)	$ (22.16)	$ (14.78)	$ (25.00)	$ (18.12)
$75,000 - $100,000	CARE	4	$ (17.98)	$ (28.23)	$ (22.10)	$ (23.30)	$ (21.14)	$ (10.09)	$ (14.66)	$ (21.40)	$ (14.78)	$ (25.00)	$ (18.17)
$100,00 - $150,000	CARE	5	$ (17.55)	$ (28.09)	$ (23.25)	$ (22.70)	$ (20.79)	$ (10.06)	$ (14.88)	$ (20.94)	$ (14.65)	$ (24.99)	$ (18.25)
$150,000 - $200,000	CARE	6	$ (16.81)	$ (27.85)	$ (23.61)	$ (22.32)	$ (20.49)	$ (10.08)	$ (14.91)	$ (19.82)	$ (14.62)	$ (24.98)	$ (17.95)
$200,000+	CARE	7	$ (15.72)	$ (27.05)	$ (23.61)	$ (21.59)	$ (19.96)	$ (10.07)	$ (14.65)	$ (19.36)	$ (14.49)	$ (24.97)	$ (22.86)
$0 - $25,000	FERA	1	$ (2.89)	$ (20.43)	$ (12.05)	$ (12.61)	$ (9.25)	$ 9.31	$ 1.74	$ (11.18)	$ 1.82	$ (14.90)	$ (2.71)
$25,000 - $50,000	FERA	2	$ (3.28)	$ (20.24)	$ (12.02)	$ (11.27)	$ (8.47)	$ 9.42	$ 1.72	$ (9.38)	$ 2.04	$ (14.89)	$ (3.60)
$50,000 - $75,000	FERA	3	$ (2.20)	$ (19.91)	$ (11.04)	$ (10.01)	$ (7.89)	$ 9.48	$ 1.94	$ (7.49)	$ 2.14	$ (14.84)	$ (3.95)
$75,000 - $100,000	FERA	4	$ (1.80)	$ (19.86)	$ (9.22)	$ (9.54)	$ (7.11)	$ 9.56	$ 2.17	$ (5.91)	$ 2.14	$ (14.85)	$ (4.14)
$100,00 - $150,000	FERA	5	$ (1.24)	$ (19.63)	$ (11.69)	$ (8.20)	$ (6.39)	$ 9.61	$ 1.81	$ (5.04)	$ 2.40	$ (14.81)	$ (4.39)
$150,000 - $200,000	FERA	6	$ 16.70	$ (2.26)	$ 4.49	$ 9.54	$ 11.19	$ 26.56	$ 18.75	$ 13.91	$ 19.44	$ 2.17	$ 13.80
$200,000+	FERA	7	$ 18.09	$ (1.03)	$ 4.49	$ 10.91	$ 12.19	$ 26.58	$ 19.16	$ 14.67	$ 19.68	$ 2.20	$ 8.90

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	E-TOU-C
Select single counterfactual rate (if applicable)	E-TOU-C

SDG&E

Income Bracket	Bill Discount		Customer Average Bill Impact ($/mo) SDG&E	Inland	Coastal	Desert	Mountain
$0 - $25,000	None	1	$ 2.25	$ 0.53	$ 3.33	$ (0.53)	$ (17.60)
$25,000 - $50,000	None	2	$ 2.07	$ (0.24)	$ 3.33	$ (1.18)	$ (15.35)
$50,000 - $75,000	None	3	$ 1.68	$ (0.32)	$ 3.41	$ 0.71	$ (14.67)
$75,000 - $100,000	None	4	$ 1.83	$ 0.05	$ 3.55	$ 3.24	$ (13.69)
$100,00 - $150,000	None	5	$ 2.62	$ 1.30	$ 4.00	$ 1.61	$ (11.15)
$150,000 - $200,000	None	6	$ 24.46	$ 23.76	$ 25.19	$ 35.33	$ 12.98
$200,000+	None	7	$ 26.48	$ 26.31	$ 26.66	$ 21.61	$ 17.39
$0 - $25,000	CARE	1	$ (16.82)	$ (19.38)	$ (13.86)	$ (40.62)	$ (44.46)
$25,000 - $50,000	CARE	2	$ (16.91)	$ (19.32)	$ (13.86)	$ (41.84)	$ (43.97)
$50,000 - $75,000	CARE	3	$ (16.76)	$ (19.22)	$ (13.83)	N/A	$ (44.05)
$75,000 - $100,000	CARE	4	$ (16.25)	$ (19.17)	$ (13.69)	N/A	$ (44.64)
$100,00 - $150,000	CARE	5	$ (15.91)	$ (19.26)	$ (13.75)	N/A	N/A
$150,000 - $200,000	CARE	6	$ (13.14)	N/A	$ (13.14)	N/A	N/A
$200,000+	CARE	7	N/A	N/A	N/A	N/A	N/A
$0 - $25,000	FERA	1	$ 2.47	$ (0.75)	$ 6.82	$ (28.53)	$ (37.04)
$25,000 - $50,000	FERA	2	$ 2.36	$ (0.61)	$ 6.83	$ (31.30)	$ (36.01)
$50,000 - $75,000	FERA	3	$ 2.63	$ (0.42)	$ 6.89	N/A	$ (36.18)
$75,000 - $100,000	FERA	4	$ 3.38	$ (0.30)	$ 7.15	N/A	$ (37.38)
$100,00 - $150,000	FERA	5	$ 3.84	$ (0.49)	$ 7.04	N/A	N/A
$150,000 - $200,000	FERA	6	$ 25.02	N/A	$ 25.02	N/A	N/A
$200,000+	FERA	7	N/A	N/A	N/A	N/A	N/A

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	TOU-DR1
Select single counterfactual rate (if applicable)	TOU-DR1

SCE

			Customer Average Bill Impact ($/mo)									
Income Bracket	Bill Discount		SCE	5	6	8	9	10	13	14	15	16
$0 - $25,000	None	1	$ 1.00	$ (1.50)	$ 8.21	$ 5.92	$ (2.62)	$ (3.77)	$ (12.36)	$ (9.49)	$ (16.23)	$ 3.94
$25,000 - $50,000	None	2	$ (0.53)	$ (1.50)	$ 8.26	$ 5.77	$ (3.19)	$ (5.22)	$ (11.60)	$ (9.00)	$ (17.56)	$ 4.05
$50,000 - $75,000	None	3	$ (0.24)	$ (1.50)	$ 8.33	$ 5.76	$ (3.23)	$ (5.04)	$ (10.23)	$ (8.40)	$ (16.66)	$ 4.15
$75,000 - $100,000	None	4	$ 0.23	$ (1.50)	$ 8.38	$ 5.87	$ (3.03)	$ (4.42)	$ (9.17)	$ (7.48)	$ (15.84)	$ 4.50
$100,00 - $150,000	None	5	$ 0.98	$ (1.50)	$ 8.49	$ 6.06	$ (2.74)	$ (3.31)	$ (7.85)	$ (6.54)	$ (15.08)	$ 4.85
$150,000 - $200,000	None	6	$ 22.50	$ 19.13	$ 29.26	$ 26.96	$ 18.41	$ 18.37	$ 13.73	$ 15.13	$ 6.42	$ 25.87
$200,000+	None	7	$ 24.01	$ 19.13	$ 29.54	$ 27.59	$ 19.18	$ 19.68	$ 15.73	$ 16.46	$ 7.93	$ 26.14
$0 - $25,000	CARE	1	$ (17.98)	N/A	$ (10.55)	$ (12.73)	$ (16.26)	$ (22.03)	$ (24.40)	$ (24.80)	$ (27.49)	$ (19.41)
$25,000 - $50,000	CARE	2	$ (17.69)	N/A	$ (10.52)	$ (12.71)	$ (16.24)	$ (21.87)	$ (24.04)	$ (24.43)	$ (26.96)	$ (19.27)
$50,000 - $75,000	CARE	3	$ (17.53)	N/A	$ (10.51)	$ (12.69)	$ (16.21)	$ (21.65)	$ (23.78)	$ (24.22)	$ (26.69)	$ (19.29)
$75,000 - $100,000	CARE	4	$ (17.50)	N/A	$ (10.50)	$ (12.68)	$ (16.20)	$ (21.51)	$ (23.49)	$ (24.18)	$ (26.43)	$ (19.29)
$100,00 - $150,000	CARE	5	$ (17.24)	N/A	$ (10.47)	$ (12.66)	$ (16.18)	$ (21.26)	$ (23.46)	$ (23.77)	$ (26.27)	$ (19.07)
$150,000 - $200,000	CARE	6	$ (16.79)	N/A	$ (10.45)	$ (12.61)	$ (16.12)	$ (20.83)	$ (23.14)	$ (23.35)	$ (25.84)	$ (18.80)
$200,000+	CARE	7	$ (16.15)	N/A	$ (10.44)	$ (12.55)	$ (16.04)	$ (20.50)	$ (22.65)	$ (23.04)	$ (25.07)	$ (18.49)
$0 - $25,000	FERA	1	$ 1.09	N/A	$ 11.23	$ 8.16	$ 3.07	$ (4.67)	$ (7.73)	$ (8.61)	$ (12.43)	$ (1.74)
$25,000 - $50,000	FERA	2	$ 1.38	N/A	$ 11.27	$ 8.20	$ 3.10	$ (4.36)	$ (6.89)	$ (7.88)	$ (11.32)	$ (1.49)
$50,000 - $75,000	FERA	3	$ 1.57	N/A	$ 11.28	$ 8.24	$ 3.16	$ (3.92)	$ (6.33)	$ (7.48)	$ (10.77)	$ (1.53)
$75,000 - $100,000	FERA	4	$ 1.61	N/A	$ 11.31	$ 8.27	$ 3.19	$ (3.66)	$ (5.73)	$ (7.40)	$ (10.26)	$ (1.53)
$100,00 - $150,000	FERA	5	$ 1.95	N/A	$ 11.35	$ 8.31	$ 3.21	$ (3.19)	$ (5.66)	$ (6.65)	$ (9.93)	$ (1.15)
$150,000 - $200,000	FERA	6	$ 19.49	N/A	$ 28.30	$ 25.32	$ 20.24	$ 14.49	$ 11.87	$ 11.00	$ 7.77	$ 16.22
$200,000+	FERA	7	$ 20.38	N/A	$ 28.32	$ 25.43	$ 20.37	$ 15.05	$ 12.76	$ 11.51	$ 9.14	$ 16.71

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	TOU-D-4-9
Select single counterfactual rate (if applicable)	TOU-D-4-9

APPENDIX D: Printable Results (Electrification Rates)

Fixed Charge Tool Outputs - Cover Sheet

Purpose:
This section of the tool is formatted to be easily printed or saved as a PDF and filed as a part of testimony.

Instructions:
This worksheet automatically draws values from the rest of the tool.
This worksheet displays both rate design details and bill impacts for all three IOUs.
Please run the macro (button above) to re-generate model results using current inputs to ensure that the rate design details and bill impacts are aligned.
This macro can also be run from the Rate Design Dashboard worksheet. Please see the Rate Design Dashboard worksheet for further details.

How to Save as PDF:
Click "File", then "Print", then select "Microsoft Print to PDF". Click the large "Print" button to choose a file location and name.

How to Print:
Click "File", then "Print", then select your choice of printer.

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Energy+Environmental Economics

Energy and Environmental Economics, Inc.
44 Montgomery Street, Suite 1500
San Francisco, CA 94104
Phone: 415-391-5100

Model Release Date: April 13, 2023

Revenue Requirement Allocations

PG&E

Cost Category	Cost Component (See "Glossary" tab for descriptions)	Residential Revenue Requirement	CARE-Exempt	Bundled Generation	Percent to Include in Customer Charge	Percent to Include in Demand Charge	Percent to Include in Volumetric Charge
		$	T/F	T/F	%	%	%
Generation	PCIA	$ 183,408,243	FALSE	FALSE	100.00%	0.00%	0.00%
Generation	Marginal Energy Cost	$ 538,263,216	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 218,481,550	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 865,996,766	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal Customer Access	$ 454,792,861	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal Distribution Capacity Cost - Primary	$ 439,382,040	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal Distribution Capacity Cost - New Business	$ 476,043,853	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal Distribution Capacity Cost - Secondary	$ 29,945,145	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Non-Marginal Distribution	$ 1,833,578,625	FALSE	FALSE	55.00%	0.00%	45.00%
Transmission	Transmission	$ 1,447,654,612	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 58,854,252	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Fund Charge	$ 63,120,120	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Wildfire Hardening Charge	$ 68,921,008	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Charge	$ 215,256,658	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Recovery Bond Credit	$ (215,256,658)	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 230,732,710	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Nuclear Decommissioning	$ 37,938,712	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	New System Generation Charge	$ 96,956,158	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Competition Transition Charge	$ 8,518,646	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Energy Cost Recovery Account	$ (19,846,861)	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	100.00%	0.00%	0.00%
	See "New Rates" Section (pg. 7 - 9)						
Line Items	2023 Total Estimated CARE Discount	$ (891,914,356)					
	Note: included for comparison to model-calculated values						
	Delivery RR - Before CARE Bill Discount	**$ 7,032,741,656**					

SCE

Cost Category	Cost Component (See "Glossary" tab for descriptions)	Residential Revenue Requirement	CARE-Exempt	Bundled Generation	Percent to Include in Customer Charge	Percent to Include in Demand Charge	Percent to Include in Volumetric Charge
		$	T/F	T/F	%	%	%
Generation	PCIA	$ 18,066,203	FALSE	FALSE	100.00%	0.00%	0.00%
Generation	Marginal Energy Cost	$ 606,708,166	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 584,831,167	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 1,378,829,544	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal - Customer	$ 427,567,610	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal - Grid	$ 888,543,196	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal - Peak	$ 503,372,326	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Non-Marginal Distribution	$ 1,845,967,040	FALSE	FALSE	76.00%	0.00%	24.00%
Transmission	Base Transmission	$ 599,320,433	FALSE	FALSE	0.00%	0.00%	100.00%
Transmission	Transmission Balancing Accounts	$ (1,839,212)	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 23,619,309	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Fund Charge	$ 103,390,404	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Wildfire Hardening Charge	$ 17,556,861	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Recovery Bond Charge	$ -	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Recovery Bond Credit	$ (40,575,857)	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 313,291,510	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Nuclear Decommissioning	$ 2,364,701	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	New System Generation Charge	$ 148,976,188	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	100.00%	0.00%	0.00%
	See "New Rates" Section (pg. 7 - 9)						
Line Items	2023 Total Estimated CARE Discount	$ (660,034,291)					
	Note: included for comparison to model-calculated values						
	Delivery RR - Before CARE Bill Discount	**$ 6,995,933,045**					

SDG&E

Cost Category	Cost Component (See "Glossary" tab for descriptions)	Residential Revenue Requirement	CARE-Exempt	Bundled Generation	Percent to Include in Customer Charge	Percent to Include in Demand Charge	Percent to Include in Volumetric Charge
		$	T/F	T/F	%	%	%
Generation	PCIA	$ 180,005,950	FALSE	FALSE	100.00%	0.00%	0.00%
Generation	Marginal Energy Cost	$ 100,915,850	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Marginal Generation Capacity Cost	$ 57,547,258	FALSE	TRUE	0.00%	0.00%	100.00%
Generation	Non-Marginal Generation	$ 163,094,812	FALSE	TRUE	0.00%	0.00%	100.00%
Distribution	Marginal - Customer	$ 183,005,936	FALSE	FALSE	100.00%	0.00%	0.00%
Distribution	Marginal Demand - Non-Coincident Peak	$ 198,205,378	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Marginal Demand - Coincident Peak	$ 26,974,391	FALSE	FALSE	0.00%	0.00%	100.00%
Distribution	Non-Marginal Distribution	$ 490,650,411	FALSE	FALSE	43.00%	0.00%	57.00%
Transmission	Base Transmission	$ 537,401,722	FALSE	FALSE	0.00%	0.00%	100.00%
Transmission	Transmission Balancing Accounts	$ (111,012,377)	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - SGIP	$ 8,781,000	TRUE	FALSE	100.00%	0.00%	0.00%
Line Items	Wildfire Fund Charge	$ 29,143,070	TRUE	FALSE	0.00%	0.00%	100.00%
Line Items	Public Purpose Programs - Not CARE Exempt	$ 61,433,000	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Nuclear Decommissioning	$ 526,530	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Local Generation Charge/New System Generation Cha	$ 81,949,029	FALSE	FALSE	100.00%	0.00%	0.00%
Line Items	Competition Transition Charge	$ 11,052,908	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Total Rate Adjustment Component - Baseline adjustme	$ 1,000,000	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Reliability Services	$ 177,809	FALSE	FALSE	0.00%	0.00%	100.00%
Line Items	Residential CARE Contribution		TRUE	FALSE	100.00%	0.00%	0.00%
	See "New Rates" Section (pg. 7 - 9)						
Line Items	2023 Total Estimated CARE Discount	$ (178,549,476)					
	Note: included for comparison to model-calculated values						
	Delivery RR - Before CARE Bill Discount	**$ 2,020,852,676**					

Rate Design Inputs

		PG&E	SCE	SDG&E
Customer charge option		User-Defined CARE Charges	User-Defined CARE Charges	User-Defined CARE Charges
Customer Charge Weighting is used when Customer Charge Option is set to "Uniform Weights"				
Customer Charge Weighting	[0,25]	1.0000	1.0000	1.0000
	[25,50]	1.0000	1.0000	1.0000
	[50,75]	2.0000	2.0000	2.0000
	[75,100]	2.0000	2.0000	2.0000
	[100,150]	3.0000	3.0000	3.0000
	[150,200]	3.0000	3.0000	3.0000
	200+	3.0000	3.0000	3.0000
Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
CARE Customer Charge ($/mo)	[0,25]	15.0000	15.0000	15.0000
	[25,50]	15.0000	15.0000	15.0000
	[50,75]	15.0000	15.0000	15.0000
	[75,100]	15.0000	15.0000	15.0000
	[100,150]	15.0000	15.0000	15.0000
	[150,200]	15.0000	15.0000	15.0000
	200+	15.0000	15.0000	15.0000
Non-CARE Customer Charge Weighting is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Non-CARE Customer Charge Weighting	[0,25]	1.0000	1.0000	1.0000
	[25,50]	1.0000	1.0000	1.0000
	[50,75]	1.0000	1.0000	1.0000
	[75,100]	1.0000	1.0000	1.0000
	[100,150]	1.0000	1.0000	1.0000
	[150,200]	1.5000	1.5000	1.5000
	200+	1.5000	1.5000	1.5000
Average CARE Program Discount is used when Customer Charge Option is set to "User-Defined CARE Charges"				
Average CARE Program Discount	($/month)	$ -	$ -	$ -
Demand Charge Options	Billing determinant to use	X Highest Demand Months	X Highest Demand Months	X Highest Demand Months
	No. of highest demand months to include	$ 3.0000	$ 3.0000	$ 3.0000
Adjustments to distribution rate		Equal Cents	Equal Cents	Equal Cents
Include baseline credit from existing rate	(if applicable)	TRUE	TRUE	TRUE

Revenue Requirement Components

PG&E

;

Based on CARE program size from E-TOU-C

Delivery - excluding CARE-exempt		
Rev Req - Customer	**Rev Req - Demand**	**Rev Req - Volumetric**
$ 2,488,340,781	$ -	$ 2,730,763,963

Delivery - CARE-exempt		
Rev Req - Customer	**Rev Req - Demand**	**Rev Req - Volumetric**
$ 322,470,160	$ -	$ 63,120,120

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 1,294,437,566
NBCs	$ 8,518,646
Non-Dist	$ 1,427,807,751

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ 63,120,120
Non-Dist	$ -

SDG&E

Based on CARE program size from TOU-DR1

Delivery - excluding CARE-exempt		
Rev Req - Customer	**Rev Req - Demand**	**Rev Req - Volumetric**
$ 717,900,122	$ -	$ 943,470,564

Delivery - CARE-exempt		
Rev Req - Customer	**Rev Req - Demand**	**Rev Req - Volumetric**
$ 58,700,312	$ -	$ 29,143,070

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 504,850,502
NBCs	$ 11,052,908
Non-Dist	$ 427,567,154

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ 29,143,070
Non-Dist	$ -

SCE

Based on CARE program size from TOU-D-4-9

Delivery - excluding CARE-exempt		
Rev Req - Customer	**Rev Req - Demand**	**Rev Req - Volumetric**
$ 2,313,201,163	$ -	$ 2,432,428,832

Delivery - CARE-exempt		
Rev Req - Customer	**Rev Req - Demand**	**Rev Req - Volumetric**
$ 182,853,737	$ -	$ 62,814,547

Delivery - excluding CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ 1,834,947,611
NBCs	$ -
Non-Dist	$ 597,481,220

Delivery - CARE-exempt	
Volumetric Rev Req Breakdown	
Distribution	$ -
NBCs	$ 103,390,404
Non-Dist	$ (40,575,857)

New Rates

	[redacted]	PG&E	PG&E
		EV2-A	EV2-A
		Non-CARE	CARE
Income Bracket (1000$):			
[0,25]		$ 50.4005	$ 15.0000
[25,50]		$ 50.4005	$ 15.0000
[50,75]		$ 50.4005	$ 15.0000
[75,100]		$ 50.4005	$ 15.0000
[100,150]		$ 50.4005	$ 15.0000
[150,200]		$ 75.6008	$ 15.0000
200+		$ 75.6008	$ 15.0000
Tier Credits/Charges ($/kWh)			
Baseline Credit		$ -	$ -
High Usage Charge		$ -	$ -
Demand Charges ($/kW)			
Billing Determinant		X Highest Demand	X Highest Demand
No. of Highest Demand Months		$ 3.0000	$ 3.0000
Demand Charge ($/kW-mo)		$ -	$ -
Energy Charges ($/kWh)			
Summer - Peak		$ 0.4459	$ 0.2879
Summer - Part-Peak		$ 0.3354	$ 0.2161
Summer - Off-Peak		$ 0.1334	$ 0.0847
Winter - Peak		$ 0.3188	$ 0.2053
Winter - Part-Peak		$ 0.3021	$ 0.1944
Winter - Off-Peak		$ 0.1334	$ 0.0847
Total CARE Program Funding -			
Customer			$ -
Demand			$ -
Volumetric - Delivery			$ (294,563,540)
Volumetric - Generation			$ (418,748,960)
Total CARE Credits			$ (713,312,499)
Residential CARE Funding			$ 193,396,930
Non-Res CARE Funding			$ 519,915,569
Total IOU forecast CARE progra			
2023 Forecast (Existing Rates)			$ (891,914,356)
Modeled Credits as % of Forecas			-20%

PG&E	PG&E	[redacted]	SCE	SCE
E-ELEC	E-ELEC		TOU-D-PRIME	TOU-D-PRIME
Non-CARE	CARE		Non-CARE	CARE
$ 50.3274	$ 15.0000		$ 50.5582	$ 15.0000
$ 50.3274	$ 15.0000		$ 50.5582	$ 15.0000
$ 50.3274	$ 15.0000		$ 50.5582	$ 15.0000
$ 50.3274	$ 15.0000		$ 50.5582	$ 15.0000
$ 50.3274	$ 15.0000		$ 50.5582	$ 15.0000
$ 75.4910	$ 15.0000		$ 75.8373	$ 15.0000
$ 75.4910	$ 15.0000		$ 75.8373	$ 15.0000
$ -	$ -		$ -	$ -
$ -	$ -		$ -	$ -
X Highest Demand	X Highest Demand		X Highest Demand	X Highest Demand
$ 3.0000	$ 3.0000		$ 3.0000	$ 3.0000
$ -	$ -		$ -	$ -
$ 0.4447	$ 0.2871		$ 0.5495	$ 0.3688
$ 0.2828	$ 0.1819		$ 0.2918	$ 0.1948
$ 0.2262	$ 0.1451		$ 0.1695	$ 0.1122
$ 0.2132	$ 0.1366		$ 0.4921	$ 0.3300
$ 0.1911	$ 0.1223		$ 0.1487	$ 0.0982
$ 0.1773	$ 0.1133		$ 0.1487	$ 0.0982
	$ -			$ -
	$ -			$ -
	$ (294,563,540)			$ (203,598,884)
	$ (405,034,979)			$ (354,957,511)
	$ (699,598,518)			$ (558,556,395)
	$ 189,678,725			$ 143,547,391
	$ 509,919,793			$ 415,009,004
	$ (891,914,356)			$ (660,034,291)
	-22%			-15%

[redacted]

SDG&E	SDG&E	SDG&E	SDG&E
EV-TOU-5	EV-TOU-5	TOU-ELEC	TOU-ELEC
Non-CARE	CARE	Non-CARE	CARE
$ 50.6331	$ 15.0000	$ 50.5643	$ 15.0000
$ 50.6331	$ 15.0000	$ 50.5643	$ 15.0000
$ 50.6331	$ 15.0000	$ 50.5643	$ 15.0000
$ 50.6331	$ 15.0000	$ 50.5643	$ 15.0000
$ 50.6331	$ 15.0000	$ 50.5643	$ 15.0000
$ 75.9497	$ 15.0000	$ 75.8464	$ 15.0000
$ 75.9497	$ 15.0000	$ 75.8464	$ 15.0000
$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -
X Highest Demand I	X Highest Demand I	X Highest Demand I	X Highest Demand I
$ 3.0000	$ 3.0000	$ 3.0000	$ 3.0000
$ -	$ -	$ -	$ -
$ 0.7447	$ 0.4881	$ 0.6797	$ 0.4452
$ 0.4097	$ 0.2670	$ 0.3104	$ 0.2015
$ 0.1553	$ 0.0991	$ 0.2618	$ 0.1694
$ 0.4399	$ 0.2870	$ 0.4386	$ 0.2861
$ 0.3762	$ 0.2449	$ 0.2972	$ 0.1928
$ 0.1470	$ 0.0936	$ 0.2530	$ 0.1636
	$ -		$ -
	$ -		$ -
	$ (77,653,661)		$ (77,653,661)
	$ (96,851,978)		$ (93,461,884)
	$ (174,505,638)		$ (171,115,545)
	$ 50,112,523		$ 49,138,995
	$ 124,393,115		$ 121,976,550
	$ (178,549,476)		$ (178,549,476)
	-2%		-4%

Bill Impacts

PG&E

			Customer Average Bill Impact ($/mo)										
Income Bracket	Bill Discount		PG&E	P	Q	R	S	T	V	W	X	Y	Z
$0 - $25,000	None	1	$ 3.10	$ (13.70)	$ (9.74)	$ (12.64)	$ (9.29)	$ 10.21	$ (1.69)	$ (9.94)	$ 0.59	$ (1.42)	$ 14.04
$25,000 - $50,000	None	2	$ (0.92)	$ (13.37)	$ (9.71)	$ (12.75)	$ (9.08)	$ 10.29	$ (1.82)	$ (10.25)	$ 0.58	$ (1.42)	$ 14.05
$50,000 - $75,000	None	3	$ (1.33)	$ (13.06)	$ (9.58)	$ (11.74)	$ (8.37)	$ 10.39	$ (1.81)	$ (8.97)	$ 0.73	$ (1.40)	$ 14.02
$75,000 - $100,000	None	4	$ (0.50)	$ (12.51)	$ (9.61)	$ (10.42)	$ (7.33)	$ 10.46	$ (1.69)	$ (7.14)	$ 0.85	$ (1.37)	$ 14.03
$100,00 - $150,000	None	5	$ 0.55	$ (11.87)	$ (9.26)	$ (8.86)	$ (6.18)	$ 10.54	$ (1.57)	$ (4.95)	$ 1.06	$ (1.36)	$ 14.05
$150,000 - $200,000	None	6	$ 27.02	$ 14.55	$ 16.17	$ 18.05	$ 20.45	$ 35.76	$ 23.76	$ 22.67	$ 26.51	$ 23.86	$ 39.16
$200,000+	None	7	$ 28.83	$ 16.13	$ 17.03	$ 20.74	$ 22.56	$ 35.89	$ 23.79	$ 25.53	$ 27.32	$ 23.96	$ 39.16
$0 - $25,000	CARE	1	$ (14.85)	$ (23.70)	$ (19.15)	$ (19.89)	$ (17.91)	$ (7.79)	$ (11.60)	$ (19.17)	$ (11.85)	$ (20.68)	$ (14.19)
$25,000 - $50,000	CARE	2	$ (15.26)	$ (23.61)	$ (19.14)	$ (19.49)	$ (17.64)	$ (7.74)	$ (11.62)	$ (18.59)	$ (11.76)	$ (20.68)	$ (14.29)
$50,000 - $75,000	CARE	3	$ (14.65)	$ (23.44)	$ (18.79)	$ (19.08)	$ (17.43)	$ (7.72)	$ (11.50)	$ (17.92)	$ (11.72)	$ (20.66)	$ (14.34)
$75,000 - $100,000	CARE	4	$ (14.42)	$ (23.41)	$ (18.10)	$ (18.93)	$ (17.14)	$ (7.68)	$ (11.39)	$ (17.30)	$ (11.72)	$ (20.66)	$ (14.36)
$100,00 - $150,000	CARE	5	$ (14.07)	$ (23.30)	$ (19.02)	$ (18.43)	$ (16.87)	$ (7.66)	$ (11.57)	$ (16.93)	$ (11.61)	$ (20.64)	$ (14.41)
$150,000 - $200,000	CARE	6	$ (13.46)	$ (23.10)	$ (19.31)	$ (18.13)	$ (16.62)	$ (7.67)	$ (11.59)	$ (16.03)	$ (11.58)	$ (20.64)	$ (14.24)
$200,000+	CARE	7	$ (12.54)	$ (22.47)	$ (19.31)	$ (17.54)	$ (16.20)	$ (7.66)	$ (11.38)	$ (15.65)	$ (11.48)	$ (20.63)	$ (16.95)
$0 - $25,000	FERA	1	$ (3.48)	$ (19.03)	$ (11.26)	$ (12.11)	$ (9.09)	$ 7.31	$ 0.95	$ (10.88)	$ 0.67	$ (14.16)	$ (4.16)
$25,000 - $50,000	FERA	2	$ (3.87)	$ (18.88)	$ (11.23)	$ (11.00)	$ (8.45)	$ 7.40	$ 0.93	$ (9.37)	$ 0.86	$ (14.15)	$ (4.95)
$50,000 - $75,000	FERA	3	$ (2.94)	$ (18.61)	$ (10.48)	$ (9.95)	$ (7.97)	$ 7.45	$ 1.13	$ (7.80)	$ 0.94	$ (14.10)	$ (5.26)
$75,000 - $100,000	FERA	4	$ (2.61)	$ (18.57)	$ (9.08)	$ (9.56)	$ (7.33)	$ 7.52	$ 1.33	$ (6.48)	$ 0.93	$ (14.11)	$ (5.42)
$100,00 - $150,000	FERA	5	$ (2.14)	$ (18.39)	$ (10.97)	$ (8.45)	$ (6.74)	$ 7.56	$ 1.01	$ (5.75)	$ 1.15	$ (14.08)	$ (5.64)
$150,000 - $200,000	FERA	6	$ 19.34	$ 2.55	$ 9.03	$ 12.82	$ 14.38	$ 28.17	$ 21.61	$ 16.53	$ 21.84	$ 6.56	$ 16.06
$200,000+	FERA	7	$ 20.56	$ 3.54	$ 9.03	$ 13.95	$ 15.21	$ 28.19	$ 21.98	$ 17.15	$ 22.04	$ 6.58	$ 11.73

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	E-ELEC
Select single counterfactual rate (if applicable)	E-ELEC

SDG&E

Income Bracket	Bill Discount		Customer Average Bill Impact ($/mo) SDG&E	Inland	Coastal	Desert	Mountain
$0 - $25,000	None	1	$ (0.64)	$ (2.31)	$ 0.38	$ (3.73)	$ (18.71)
$25,000 - $50,000	None	2	$ (0.80)	$ (2.96)	$ 0.38	$ (4.28)	$ (16.79)
$50,000 - $75,000	None	3	$ (1.16)	$ (3.02)	$ 0.44	$ (2.68)	$ (16.21)
$75,000 - $100,000	None	4	$ (1.05)	$ (2.71)	$ 0.56	$ (0.55)	$ (15.36)
$100,00 - $150,000	None	5	$ (0.40)	$ (1.66)	$ 0.92	$ (1.92)	$ (13.19)
$150,000 - $200,000	None	6	$ 25.90	$ 25.15	$ 26.65	$ 34.39	$ 15.09
$200,000+	None	7	$ 27.61	$ 27.30	$ 27.86	$ 22.81	$ 18.86
$0 - $25,000	CARE	1	$ (14.96)	$ (17.14)	$ (12.47)	$ (34.25)	$ (37.66)
$25,000 - $50,000	CARE	2	$ (15.05)	$ (17.09)	$ (12.46)	$ (35.42)	$ (37.49)
$50,000 - $75,000	CARE	3	$ (14.92)	$ (17.01)	$ (12.43)	N/A	$ (37.52)
$75,000 - $100,000	CARE	4	$ (14.48)	$ (16.96)	$ (12.32)	N/A	$ (37.73)
$100,00 - $150,000	CARE	5	$ (14.20)	$ (17.04)	$ (12.37)	N/A	N/A
$150,000 - $200,000	CARE	6	$ (11.84)	N/A	$ (11.84)	N/A	N/A
$200,000+	CARE	7	N/A	N/A	N/A	N/A	N/A
$0 - $25,000	FERA	1	$ 0.01	$ (2.81)	$ 3.76	$ (25.98)	$ (32.57)
$25,000 - $50,000	FERA	2	$ (0.10)	$ (2.70)	$ 3.76	$ (28.61)	$ (32.18)
$50,000 - $75,000	FERA	3	$ 0.12	$ (2.54)	$ 3.82	N/A	$ (32.24)
$75,000 - $100,000	FERA	4	$ 0.77	$ (2.44)	$ 4.03	N/A	$ (32.70)
$100,00 - $150,000	FERA	5	$ 1.16	$ (2.60)	$ 3.94	N/A	N/A
$150,000 - $200,000	FERA	6	$ 25.56	N/A	$ 25.56	N/A	N/A
$200,000+	FERA	7	N/A	N/A	N/A	N/A	N/A

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	TOU-ELEC
Select single counterfactual rate (if applicable)	TOU-ELEC

SCE

			Customer Average Bill Impact ($/mo)									
Income Bracket	Bill Discount		SCE	5	6	8	9	10	13	14	15	16
$0 - $25,000	None	1	$ (1.27)	$ (5.43)	$ 5.49	$ 3.54	$ (4.46)	$ (5.64)	$ (13.54)	$ (10.38)	$ (18.18)	$ 0.79
$25,000 - $50,000	None	2	$ (2.58)	$ (5.43)	$ 5.53	$ 3.41	$ (4.96)	$ (6.96)	$ (12.85)	$ (9.92)	$ (19.43)	$ 0.90
$50,000 - $75,000	None	3	$ (2.29)	$ (5.43)	$ 5.59	$ 3.40	$ (5.01)	$ (6.79)	$ (11.60)	$ (9.37)	$ (18.58)	$ 1.01
$75,000 - $100,000	None	4	$ (1.85)	$ (5.43)	$ 5.63	$ 3.51	$ (4.82)	$ (6.23)	$ (10.64)	$ (8.51)	$ (17.82)	$ 1.35
$100,00 - $150,000	None	5	$ (1.16)	$ (5.43)	$ 5.74	$ 3.67	$ (4.56)	$ (5.23)	$ (9.44)	$ (7.64)	$ (17.11)	$ 1.70
$150,000 - $200,000	None	6	$ 24.94	$ 19.85	$ 31.15	$ 29.21	$ 21.18	$ 21.01	$ 16.71	$ 18.62	$ 8.99	$ 27.37
$200,000+	None	7	$ 26.31	$ 19.85	$ 31.41	$ 29.77	$ 21.88	$ 22.19	$ 18.52	$ 19.85	$ 10.41	$ 27.64
$0 - $25,000	CARE	1	$ (15.94)	N/A	$ (9.28)	$ (11.12)	$ (14.54)	$ (19.53)	$ (21.71)	$ (21.71)	$ (25.41)	$ (17.29)
$25,000 - $50,000	CARE	2	$ (15.65)	N/A	$ (9.26)	$ (11.10)	$ (14.52)	$ (19.39)	$ (21.38)	$ (21.37)	$ (24.92)	$ (17.16)
$50,000 - $75,000	CARE	3	$ (15.50)	N/A	$ (9.25)	$ (11.08)	$ (14.49)	$ (19.18)	$ (21.15)	$ (21.18)	$ (24.67)	$ (17.18)
$75,000 - $100,000	CARE	4	$ (15.47)	N/A	$ (9.23)	$ (11.07)	$ (14.47)	$ (19.06)	$ (20.89)	$ (21.14)	$ (24.43)	$ (17.18)
$100,00 - $150,000	CARE	5	$ (15.24)	N/A	$ (9.20)	$ (11.05)	$ (14.46)	$ (18.83)	$ (20.86)	$ (20.77)	$ (24.27)	$ (16.97)
$150,000 - $200,000	CARE	6	$ (14.83)	N/A	$ (9.18)	$ (11.00)	$ (14.39)	$ (18.44)	$ (20.57)	$ (20.38)	$ (23.87)	$ (16.72)
$200,000+	CARE	7	$ (14.27)	N/A	$ (9.17)	$ (10.94)	$ (14.31)	$ (18.14)	$ (20.13)	$ (20.10)	$ (23.14)	$ (16.43)
$0 - $25,000	FERA	1	$ (0.92)	N/A	$ 8.26	$ 5.62	$ 0.63	$ (6.18)	$ (8.90)	$ (9.26)	$ (14.34)	$ (3.36)
$25,000 - $50,000	FERA	2	$ (0.65)	N/A	$ 8.31	$ 5.66	$ 0.67	$ (5.89)	$ (8.14)	$ (8.58)	$ (13.31)	$ (3.12)
$50,000 - $75,000	FERA	3	$ (0.48)	N/A	$ 8.32	$ 5.70	$ 0.74	$ (5.49)	$ (7.64)	$ (8.21)	$ (12.80)	$ (3.15)
$75,000 - $100,000	FERA	4	$ (0.43)	N/A	$ 8.35	$ 5.73	$ 0.76	$ (5.25)	$ (7.09)	$ (8.13)	$ (12.32)	$ (3.16)
$100,00 - $150,000	FERA	5	$ (0.13)	N/A	$ 8.39	$ 5.78	$ 0.79	$ (4.83)	$ (7.03)	$ (7.44)	$ (12.02)	$ (2.80)
$150,000 - $200,000	FERA	6	$ 21.18	N/A	$ 29.17	$ 26.60	$ 21.65	$ 16.60	$ 14.26	$ 13.97	$ 9.44	$ 18.36
$200,000+	FERA	7	$ 21.97	N/A	$ 29.18	$ 26.71	$ 21.79	$ 17.11	$ 15.07	$ 14.45	$ 10.72	$ 18.82

New rate option	User-selected rate across all subclasses
Counterfactual rate option	User-selected rate across all subclasses
Use model-calculated counterfactual rates	TRUE
Select single new rate (if applicable)	TOU-D-PRIME
Select single counterfactual rate (if applicable)	TOU-D-PRIME

APPENDIX E: EXPLANATION OF CHANGES TO TESTIMONY (ERRATA)

In response to ED staff's identification of errors in the E3 Fixed Charge Tool, NRDC and TURN are resubmitting testimony with minor changes as errata in accordance with CPUC guidance.

Changes to testimony are limited to:

- Figure 1 (Label "SRMC" corrected to "SRSMC" in figure and caption)
- Tables 11-14 (Updated outputs from the "electrification dashboard" tab of the April 13 version of tool, replacing those created from the March 23 version of the tool)
- Pages 30-32 (Numbers corrected in discussing bill impacts derived from tables 11-14)
- Appendix D (Printable results from the April 13 version of the tool, replacing those created from the March 23 version of the tool, resulting in minor changes to pages 11-12)
- Addition of Appendix E (Explanation of changes to testimony)