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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	Rulemaking 22-07-005 Filed: July 14, 2022

COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY
IN RESPONSE TO ORDER INSTITUTING RULEMAKING
TO ADVANCE DEMAND FLEXIBILITY THROUGH ELECTRIC RATES

GAIL L. SLOCUM
JENNIFER REYES LAGUNERO
SHIRLEY A. WOO

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 515-2892
Facsimile: (415) 973-5520
E-Mail: Gail.Slocum@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

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I. INTRODUCTION

Pursuant to direction from the California Public Utilities Commission (Commission or CPUC) in the recently-issued Demand Flexibility Order Instituting Ratemaking (DFOIR, R. 22-07-005), Pacific Gas and Electric Company (PG&E) files these preliminary Opening Comments providing our input on the scope of issues, schedule categorization of and need for evidentiary hearings in this complex, ambitious proceeding, which admirably "seeks to enable widespread demand flexibility through electric rates." (DFOIR, p. 1.)

II. SUMMARY AND BACKGROUND

Demand management, rate affordability, and equity are important issues that a wide range of stakeholders must all work together to address, as California rapidly transitions to meet aggressive climate and electrification goals. PG&E shares California's climate and affordability goals and remains committed to being a leader in demand flexibility and supporting our customers on the path to a clean energy future. PG&E is committed to working with the CPUC and stakeholders to develop a comprehensive load management strategy that unlocks greater load flexibility to meet emerging grid needs and support affordability. We agree that customers would benefit from simplifying rate structures and programs as much as possible with clearer signals and incentives, and that this will support greater integration of renewable resources and help achieve California's longer-term 100 percent clean energy goals.

PG&E applauds this OIR's desire to focus CPUC efforts in a more holistic manner. We can sympathize with the OIR's expression of concern about what may appear at first glance to be an "existing piecemeal approach to load management." (DFOIR, p. 2.) At the same time, PG&E

appreciates the OIR's emphasis on cost-based ratemaking that reflects not only each investor-owned utility's (IOU's) unique adopted marginal costs of service, but also their very different service territory terrains and mixes of customer types. The CPUC adopted the current diverse array of dynamic rates and pilots after considering detailed record evidence about specific customer groups' preferences and needs. The CPUC should be proud of what it has already spearheaded, including important early steps forward on day-ahead hourly dynamic pricing pilots that will provide key lessons about what dynamic pricing rate options appear best suited to different customer groupings' actual operational constraints and technological capabilities for responding to volatile day-ahead hourly prices. It is important to recognize that customers' abilities to succeed on dynamic rates can differ significantly depending on their real-world circumstances, so a one-size fits all dynamic rate does not seem likely to be the result of efforts to streamline.

Some of the phrasing in the OIR's listed "Preliminary Issues" could be read as being presumptive and premature before at least having final, CPUC-approved updated rate design principles and demand flexibility guidelines, as well as before any customer research or several existing CPUC-approved dynamic rate pilots have yielded reports on measurement and evaluation of actual load shifting results. For example, the CPUC currently lacks an adequate basis to assume, as the Energy Division's June 2022 Demand Flexibility Whitepaper[1/] seems to, that a single statewide real time pricing (RTP) rate design, or any particular, specific rate component reforms, would be the result of the type of data-driven inquiries that has been the hallmark of the CPUC's previous, successful major rate reform efforts, like the Residential Rate Reform OIR (RROIR) (R. 12-06-013).

Rather, it would seem more appropriate if the DFOIR's guidance on the issues to be evaluated was phrased with more open-minded wording. Doing so seems likely to result in a range of creative approaches to dynamic rates structures that the CPUC can carefully assess

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1/ Advanced Strategies for Demand Flexibility Management and Customer DER Compensation, Energy Division White Paper and Staff Proposal issued June 22, 2022. (ED Whitepaper.)

before reaching specific conclusions about what future approaches to adopt, as well as how best to transition to them from the various currently adopted rates whose designs were found reasonable based on then-existing information about specific customer needs. [/]

In addition, PG&E heartily agrees with Energy Division that movement toward dynamic pricing should be ***optional***, given that rates like real-time pricing carry a risk of much greater bill volatility than other types of more predictable rate plans, such as Time-of-Use (TOU). It is vitally important that, before making significant rate changes, the CPUC take great care to assess cost-effectiveness of the options, as well [2/]as guard against the potential for harmful and possibly inequitable *cost shifts* that could affect even customers who do not opt into a dynamic rate.

While PG&E generally agrees that pilots should be used to test potential optional dynamic rate offerings in real-world settings, too many different pilots at the same time may be

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2/ *See* the various Scoping Memos (including Amended Scoping Memos) issued in R. 12-06-013, the CPUC's successful Residential Rate Reform OIR. That complex, staged proceeding resulted in numerous default TOU pilots across the state, the results from which guided adoption of a smooth, widespread rollout of TOU rate structures. The move to default (opt-out) TOU for eligible customers in recent years represented a paradigm shift for customers previously accustomed to a monthly, tiered rate with not link of pricing to usage during a particular times of day.

The first Scoping Memo in the successful RROIR was issued November 26, 2012. It began by setting forth the CPUC's ten rate design principles, and, based on those principles, posed a series of open-ended questions to help focus suggestions for potential new residential rate design structures. Importantly, initial RROIR Scoping Memo cautioned that parties' proposals must be "**support[ed]… with evidence citing research conducted in California or other jurisdictions**. " (Emphasis in original). It also asked for proposals to discuss "What unintended consequences may arise as a result of your proposed rate structures and how could the risk of those unintended consequences be minimized. " (p. 2) Especially relevant for this DFOIR, the initial RROIR Scoping Memo's Question 6 required that any rate change proposals show: "*what types of innovative technologies and services are available*?" (emphasis added). Further, in proposing an "optimal rate," each party had to "discuss whether other rate(s) would enable customers opting out to benefit from a *cross-subsidy* they would not enjoy under the optimal rate?" Finally, it required discussion of how proposed rates could "adapt over time to changing load shapes, changing marginal electricity costs, and to changing customer responses. " The RROIR's initial Scoping Memo then set forth a workplan to guide a multistakeholder Working Group process (listing topics and giving desired dates for Working Group recommendations).

It would seem logical for this DFOIR's final list of issue to leverage what the CPUC successfully did in its successful RROIR (and other such proceedings), which used a similarly staged and tracked process with a carefully structured multi-stakeholder collaborative Working Group. This type of approach seems most likely to result in cost-effective outcomes that meet customers' real world needs to best support achievement of our State's climate goals.

inefficient. The CPUC should first take into account results from the numerous “in flight” RTP pilots that have already been planned and offered to multiple customer classes. By doing so, the CPUC can ensure data-driven learnings are applied to any future pilots, which will yield a more cost-effective process which recognizes that there are staffing resource constraints not only for interested parties but also the CPUC.

As discussed in greater detail below, PG&E recommends that the CPUC’s initial Scoping Memo for this proceeding consider the following:

A. Issues

As a general matter, PG&E suggests that the CPUC carefully refine the wording of certain of the DFOIR’s initial list of thirteen “Preliminary Issues” (as set forth in detail further below), to better support more open-minded explorations of hypotheses. It is inadvisable to make premature assumptions about what types of rate design options the CPUC may ultimately adopt once it has been able to review a full factual record, including the results from the seven “in flight” Real Time Pricing Pilots,[3/] five of which have been approved in PG&E’s service territory. In addition, PG&E suggests the CPUC consider adding two topics of consideration that could further help make cost-effective progress on enabling more widespread decarbonization, as PG&E agrees this is a critical element of our State’s efforts to meaningfully address the climate crisis. Specifically:

> (1) Should dynamic rates be rolled out in stages so that the most impactful or easiest to implement features are brought online first (for example generation before distribution, no transactive element initially)?

3/ *See* Appendix A, which lists the seven “in-flight” Rate Timing Pricing Pilots that have been considered by the CPUC, along with their expected timelines for providing reported results, as discussed further in Footnote 4 of these comments, below.

> (2) As the Commission considers recovery of incremental costs of the new initiatives approved through this DFOIR, what can be done to facilitate collection through the State's General Fund of certain revenues needed to carry out the types of climate action envisioned in this DFOIR, in coordination with R. 18-07-006, so as to promote electrification while managing affordability of electric rates?

B. Schedule

PG&E respectfully requests a staged schedule with multiple tracks, along the lines of the discussion draft schedule attached hereto as Appendix A. The earliest track of such a staged approach should prioritize foundational policy guidance (Issues a and b, which would be part of Track 1a), for which the envisioned Working Group could meet and provide input starting soon after the final initial DFOIR Scoping Memo is issued. This schedule should also ensure that parties' testimony regarding residential fixed charges (Issue e.) will be received by Q2 2023 (in Track 1b.). This is necessary because the hard deadline of July 1, 2024, mandated in Assembly Bill (AB) No. 205 (2021-2022 Reg. Sess.) § 10(e)(1) is likely to be challenging to meet, given the complexity and novelty of implementing income graduated residential fixed charges. Another early track (Track 1c) should explore some initial version of a statewide, internet-based price portal or platform (Issue g.), once key California Energy Commission (CEC) input is available; however, if it proves too difficult for the initial platform to include prices "specific to each customer at any time," the CPUC may want to plan for flexibility and explore a staged statewide pricing portal approach. Specific scheduling for all of the rest of the Preliminary Issues, if included in this ambitious proceeding, could probably best be considered at a second Prehearing Conference, after the CPUC has at least issued foundational policy guidance (probably by early 2024), and probably also decided the structure for residential fixed charges (required by July 1, 2024). A potential Third Prehearing Conference could be held after the CPUC and all parties have received the results of the ongoing Real Time Pricing pilots and customer preference surveys (expected to be received serially between summer 2023 and 2026).

The CPUC successfully used a similar staged and tracked approach for its successful Residential Rate Reform OIR (RROIR, R. 12-06-013) and should consider doing so here as well.

In addition to providing a flexible framework that allows the DFOIR's schedule to be staged and topics refined as more information is available, the CPUC should also determine early how it can more effectively coordinate with the CEC, to further help customers in their decarbonization transition, including steps to facilitate using dynamic rates for the differing types of new technologies and automation capabilities that are believed to be essential for various types of customers to succeed on dynamic rate options. For example, at the Energy Division's July 21, 2022, Demand Flexibility Workshop ("Workshop"), several commentors underscored the advisability of moving forward first with day-ahead hourly price signals before considering whether to add much more complex potential sub-hourly/real-time prices. Similar comments supported moving forward early by focusing primarily on implementing dynamic *generation* price signals for optional RTP rates, because designing and implementing more complex, distribution RTP price signals at this stage could not only cause delays but should be more fully tested, through pilots. In deciding how to proceed with the scheduling of not only the issues prioritized for the earliest tracks, but also for the other more complex issues that are likely better suited to later tracks, the CPUC should continue to be mindful of not only cost-effectiveness but also of the limited resources available to the various stakeholders as well as CPUC staff itself.

Ideally, the CPUC should prioritize the topics most likely to get bigger and/or earlier load shifting "bang for the buck," so as not to exacerbate concerns about the affordability of electric rates, which is also key to achieving decarbonization through electrification.

C. Categorization

PG&E agrees with the preliminary categorization of this OIR (p. 10) as "ratesetting," given the nature of the topics the Preliminary Issues list envisions be considered at some point in this DFOIR.

D. Need for Hearings

PG&E agrees with the DFOIR's preliminary determination (p. 11) that hearings are necessary for this proceeding. PG&E hopes that if the DFOIR's envisioned Working Group process were to result in a large degree of consensus on one or more matters the Workshops discuss, this might help streamline the traditional testimony and hearings process, to some degree. However, it has proven difficult in the past to obtain settlements on utility-specific rate design issues without the submittal of at least opening testimony if not responsive and rebuttal testimony, to provide the CPUC with the necessary record to support approval of any settlement under the CPUC's settlement rules.

E. Substance of ED's Whitepaper Beyond the Scope of These Comments.

PG&E appreciates the clarity provided at the July 22, 2022, Workshop that interested parties' Opening Comments in this DFOIR (due August 15, 2022) are not expected to also specifically address the many complex substantive matters discussed in ED's recent, over 110-page Demand Flexibility Whitepaper. PG&E's Opening Comments have aimed to follow this guidance.

In general, while PG&E applauds ED for this important Whitepaper's significant views on the development of Demand Flexibility policy, there simply has not been adequate time to conduct discovery on it, nor has it been otherwise subjected to peer review and discussion. The CPUC has already made much progress and has initiated several new RTP rate pilots, by each of the three major electric IOUs.[4/] The results of these pilots are designed to meet certain

4/ *See* the end of Appendix A, attached hereto, for an overview of the CPUC's several "in flight" RTP pilot efforts and their expected timelines for delivering reported results. These pilots include: (1) the Valley Clean Energy (VCE) Pilot, taking place within PG&E's service territory; (2) the SCE RTP Pilot; (3) the DAHRTP-CEV optional rate adopted for PG&E in D. 21-11-017, which will be tracked and reported on in the same manner as a large-scale pilot; (4) the three new PG&E RTP rate pilots just adopted in D. 22-08-002 (which approved an innovative all-party settlement, forged by a wide range of stakeholders through over a year of collaborative negotiations); and, finally, (5) the RTP proposal(s) currently being evaluated in SDG&E's ongoing GRC Phase II proceeding.

objectives and test numerous hypotheses, and their reported data appear directly relevant to many of the topics raised in ED Whitepaper.[5/]

PG&E believes it is premature to assume that all of the strategies/specific tactics suggested in the ED Whitepaper should necessarily be "established" in this OIR (as suggested by item (iii) on page 7 of the DFOIR). Thus, we suggest that the initial DFOIR Scoping Memo focus on the Preliminary Issues and Schedule for the earlier Tracks and allow a Working Group process to help inform later potential scoping refinements for later Tracks. If the wording from the middle of page 7 of the DFOIR is included in the Scoping Memo, PG&E respectfully requests that its wording be tempered to be more neutral and centered on the type of collaborative Working Group process that worked well for the RROIR.

PG&E's recommendation for potentially better phrasing for item (iii) would be for this OIR to anticipate considering: (iii) potential policies and programs to advance demand flexibility recommended by a multi-stakeholder Working Group that would, among other things, discuss the concepts suggested in the ED Whitepaper's six "strategies." Unfortunately, the ED Whitepaper's list of six "strategies," while a helpful guide for the Working Group, actually reads more like a list of specific *tactics*, rather than guiding strategies.

PG&E believes that it is simply too early to conclude that all of ED's presumptions about the most appropriate tactics would be proven out after they are evaluated in the context of a factual record that should, among other things, incorporate data and lessons learned from dynamic rate pilots and demand response programs, including those that the CPUC has already approved. If the Working Group recommends targeted additional pilots, then, if and when the CPUC finds them to be cost-effective and reasonable to pursue, additional real-world data could

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5/ Examples of neutrally-worded objectives and hypotheses that the CPUC has already adopted for testing of and reporting on dynamic pricing pilots are presented in Appendix B, attached hereto. Appendix B presents testimony excerpts from A. 19-11-019 relating to PG&E's three RTP pilots (adopted by the CPUC in D. 22-08-002). PG&E believes such a rigorous statement of the objectives and hypotheses can provide the CPUC and parties with further helpful input on how to pose open-ended questions to be answered through the data to be gathered as part of this DFOIR, whether through pilots or other forms of customer research.

be gathered to be brought to bear when deciding whether such approaches should be applied on a more widespread basis. The CPUC should take great care not to make presumptions about what might best achieve demand flexibility goals in the real world, or what approaches will, in fact, be found reasonable after applying the updated Rate Design Principles and any additional Demand Flexibility policy guidance – which we recommend be developed in the earliest Track of this OIR.

III. DISCUSSION

A. The Scoping Memo Should Amend the DFOIR's List of Preliminary Issues.

1. A Statement Should Be Added About the Importance of Carefully Staging these Many Complex Issues, to Ensure that Whatever New Dynamic Price Signals Might be Adopted are Data-Driven, Reasonably Timed, and Cost-Effective.

PG&E agrees with the many voices at the July 22 Workshop who advocated a staged implementation approach, given that the OIR's broad range of diverse and consequential issues that are novel, complex, and likely to each entail costly implementation budgets. For example, PG&E agrees with July 22 Workshop participants that the DFOIR's early considerations should focus on dynamic signals for generation pricing only, as this can be implemented more quickly with fewer unintended consequences. The much more complex issues of potential addition of distribution price signals and/or transactive features should be carefully studied in later Tracks.

<u>Distribution pricing</u> has many more complications and unanswered questions compared to generation, such as:

- What marginal cost categories are appropriately captured at the circuit/feeder level, and would the process of doing so for thousands of different circuits be cost-effective?
- How accurate are circuit-level forecasts and how could that level of accuracy impact hourly prices?
- Because some circuits can have one customer or a small number of customers, how can day-ahead forecasts be developed for load that will be reacting to the forecast itself? Also, what privacy protections need to be in place on the price/load curves for such circuits?

- What customer education would be needed to adequately explain complex locationally-based distribution pricing, such as to address potential customer confusion and/or perceptions about locational distribution price differences where costs for one customer can be affected by the actions of another customer or set of customers on a circuit (e.g., through new or increased load)?
- What mitigations are available for fixed cost recovery when a potential subscription amount varies greatly from actual usage?
- How does cost-causation at the distribution level account for dynamic "load switching" of customer loads between circuits, which is commonly used by distribution providers to efficiently manage load and maintain reliability?

Transactive features also have many unanswered questions that will likely take years to resolve and build technology solutions. The Whitepaper itself acknowledges that transactive features could be implemented at a later stage. (ED Whitepaper, p. 73.

Therefore, PG&E recommends that the Scoping Memo at least generally flag the following consideration to guide further actions (whether it is specifically added to the list of preliminary issues or not), and that this question be answered in an early track of this DFOIR:

> n. Should dynamic rates be rolled out in stages so that the most impactful or easiest to implement features are brought online first (for example generation before distribution, no transactive element initially)?

PG&E specifically recommends that many of the items on the ambitious preliminary issues list, including those relating to dynamic distribution rates and transactive features, should be reflected in later Tracks of this proceeding, as reflected in the potential Staged Schedule with Multiple Tracks offered for discussion in Appendix A.

2. A New Issue Should be Added to Explore Obtaining Certain Decarbonization-related Revenue Requirements from the State's General Fund, because Putting such Climate Action Costs into IOU Rate Bases Makes Electricity Less Affordable and Undercuts Efforts to Promote Transportation and Building Electrification.

Certainly, the issue of costs will arise as the CPUC considers proposals to be made by interested parties in response to the wide range of issues envisioned for this DFOIR proceeding, either in its earlier or later tracks of this proceeding. As the CPUC has already made clear, in its

Spring 2022 *en banc* hearing on Affordability (R. 18-07-006), a variety of proposals are being considered to limit or mitigate energy prices. One important approach has been to consider paying for initiatives to address climate change (as well as Public Purpose Programs) through the State's General Fund, rather than solely through the IOUs' base rates through ratepayer cost recovery. Securing State funding could not only improve affordability and spur electrification but could also reduce the electric revenue requirements without affecting the peak to off-peak spread in marginal costs. Such an "off-loading" of Public Purpose Program (PPP), climate, and other costs (including the costs of future DFOIR efforts) has the potential to bring revenue requirements more in line with marginal costs, reducing the complexities and unintended outcomes associated with accounting for the current misalignment. Therefore, PG&E recommends adding the following to the DFOIR's list of preliminary issues:

> o. In considering recovery of incremental costs of the new initiatives approved through this DFOIR, by what means can the CPUC facilitate collection through the State's General Fund of certain revenues needed to carry out the types of climate action envisioned in this DFOIR (in coordination with R. 18-07-006), so as to promote electrification while managing affordability of electric rates?

3. The Wording of Several Specific Preliminary Issues Listed in the Original DFOIR Should be Amended in the Scoping Memo.

PG&E respectfully requests that the CPUC consider modifying the wording of several of the Preliminary Issues listed in the initial DFOIR, as follows:

Preliminary Issue (b). *What guidance principles should the Commission adopt regarding demand flexibility rate design and evaluation? What statutory mandates or constraints should the Commission consider in developing this guidance?*

PG&E supports inclusion of this question in the earliest track of this proceeding. PG&E also recommends the Scoping Memo should clearly state that specific rate designs should continue to be made in each of the IOUs' General Rate Case proceedings,[6/] as follows: "What guidance principles should the Commission adopt regarding demand flexibility rate design and evaluation *to be applied to utility-specific rate proposals to be considered in each IOU's General Rate Case Phase II or interim Rate Design Window proceedings*?. . . " It should be noted that, during the Residential Rate Reform OIR (R. 12-06-013), the CPUC first adopted general rate design policy guidance in D. 15-07-001, and then, after important input from a Working Group, invited each IOU to file its own default TOU rate and implementation proposals (for PG&E, Application (A.)17-12-011). The three IOUs' rate proposals based on their individual marginal costs were considered in the OIR on a consolidated basis, resulting in a CPUC decision that took into account unique, utility-specific circumstances that affected the nature of their specific rate design as well as the timing and details of each IOU's approach to implementation. In addition, PG&E recommends the Commission consider how these guidance principles differ from or can be better aligned with guidance in related proceedings, including demand response, energy efficiency, electric vehicles, etc.

> SUGGESTED REVISION TO ISSUE b: *Beyond the updated Rate Design Principles (in Item a.), should the Commission also provide other guidance specifically regarding demand flexibility rate design and evaluation? What statutory mandates or constraints should the Commission consider in developing any such guidance?*

Preliminary Issue d. *How should the Commission reform demand charges for consistency with the updated rate principles and demand flexibility guidance?*

PG&E respectfully requests that issue d. be rephrased so as not to necessarily presume that the CPUC would conclude that demand charges will necessarily be reformed, which cannot be assessed until there is a full evidentiary record. Further, there appears to be a potential path dependency that may require demand charge issues to be considered in a later track of this proceeding, *after* the CPUC has decided not only issues a and b, but also issue e. on fixed charge rate design.

6/ *See* R. 19-01-011, Comments of Pacific Gas and Electric Company on Order Instituting Rulemaking R. 19-01-011 and Responses to Questions in Preliminary Scoping Memo (Mar. 11, 2019), pp. 6-7, *see also*, A. 22-03-010, Pacific Gas and Electric Company's Opening Brief (May 23, 2022), p. 20.

More appropriately neutral wording for Issue d., such as the following, would be worth considering for the Scoping Memo:

> SUGGESTED REVISION TO ISSUE d. *Should the Commission reform demand charges, if necessary to better align with the updated rate design principles and any additional demand flexibility guidance and if so, when during this proceeding should the necessary evidentiary record be created on potential demand charge reform?*

Preliminary Issue e. *How should the CPUC reform fixed charges for recovery of certain authorized utility costs in accordance with the adopted rate principles and demand flexibility guidance?*

PG&E respectfully requests that issue e. be rephrased to clearly call out an initial focus on residential fixed charges, as that is the only customer class whose rates do not universally include a fixed charge component at this time (rather fixed charges are collected through volumetric rates). Because AB 205 recently amended Section 739. 9 of the Public Utilities Code, the CPUC is now required to, "no later than July 1, 2024," adopt income graduated fixed charges for the IOUs' default residential rates (which in PG&E's case is Schedule E-TOU-C); the statute also allows that the CPUC "may" also authorize income-graduated fixed charges for residential rates beyond each IOU's default rate. As a practical matter PG&E believes that the complexity of any proceeding to consider Revised Issue e. is likely to take 18 months from submittal of initial testimony to a final CPUC decision. Therefore, because of the hard deadline of July 1, 2024, PG&E's scheduling recommendation calls for including Issue e. in this OIR's earliest track.

> SUGGESTED REVISION to Preliminary Issue e. *How should the CPUC reform residential fixed charges for recovery of certain authorized utility costs in accordance with the CPUC's updated rate principles, any additional demand flexibility guidance, and summer 2022 amendments to P.U.Code 739.9, and when during this proceeding should the necessary evidentiary record be created on residential fixed charge proposals?*

Issue f.: *How should the Commission consolidate, modify or eliminate existing tariffs for consistency with adopted rate design principles and demand flexibility guidance?*

While PG&E generally applauds this invitation for proposals that can simplify, consolidate, and otherwise streamline rates (indeed we have proposed doing similarly in many GRC Phase 2's and in proposing elimination of the High Usage Charge in light of electrification goals), PG&E is concerned that this Preliminary Issue is currently phrased in a vague, overly broad and presumptive manner. For example, at the outset, the question "*how* should" appears to reflect a presumption that cannot be known until after the updated rate design principles or any other guidance are adopted. Further, issue f. is vague and overbroad because it appears it could apply to any and all types of existing tariffs, whether or not related to Demand Flexibility. Reviews of existing rate designs and tariffs for consistency with the CPUC's rate design principles is precisely what is already done within the scope of each IOU's respective GRC Phase II proceedings, as established under the CPUC's Rate Case Plan. This OIR can provide policy guidance to be applied in each IOUs subsequent GRC Phase II and Rate Design Window (RDW) proceedings where actual rate setting should take place. Thus, PG&E recommends that either Issue f. be deleted in its entirety, at least for now, until after the Working Group provides feedback and the CPUC takes action on issues a. and b. If something is retained in this Scoping Memo for Issue f. it at least should be significantly narrowed:

> SUGGESTED REVISION to Preliminary Issue f.
> Either:
> *Fully delete,*
> Or significantly narrow to something like:
> "*Should the Commission consider other Demand Flexibility tariffs or features, if found consistent with the updated rate design principles and any demand flexibility guidance after feedback from the Working Group and evaluation of pilot results? If so, during what Track of this proceeding should the necessary evidentiary record be created on any such other potential Demand Flexibility rate options the CPUC might wish to evaluate after receiving feedback from the Working Group.* "

Issue g.: *How should the Commission ensure universal access to dynamic electricity prices by customers, devices, distributed energy resources, and third-party service providers? How should systems needed for universal access be funded, built, operated, and maintained?*

PG&E supports inclusion of this type of question in the earliest track of this proceeding. PG&E recommends this question be expanded to specifically discuss (a) alignment with open standards, such as Open ADR, IEEE 2030.5, and Green Button Connect (GBC), and

(b) how to ensure consistency across dynamic electricity price systems and requirements. Both of these topics directly affect outcomes such as adoption of dynamic electricity prices; mobilizing greater load flexibility; implementation across utility, original equipment manufacturers (OEMs), and third parties; integration with distributed energy resources management systems (DERMS); cost effectiveness; and affordability. Thus, in Track 1c, PG&E recommends the Commission fund the IOUs and direct them to coordinate with industrial standardization bodies to further develop universal access to dynamic electricity prices so that it fosters innovation and widespread adoption of the targeted use cases across all stakeholders in an economic fashion. The Commission will also need to coordinate with the CEC's efforts to address universal access such as with Market Informed Demand Automation Server (MIDAS). Participation of non-IOU load serving entities such as ESPs and CCAs are also critical to this goal.

Standards provide utilities, OEMs, and third parties the shared understanding to build and use a common set of data access processes and communication protocols, which allows for consistency, interoperability, privacy protection, and cybersecurity. Alignment with national standards is also necessary for transparency and promotes compatibility of systems and documentation, which enables broad acceptance. Similarly, PG&E urges the Commission to actively align the requirements in this proceeding to the requirements in the CEC's Load Management Standards (LMS) Regulations (Docket Number 21-OIR-03) to avoid development of multiple, disparate systems; but to the extent that the requirements differ and funding is required, support funding of both.[7/] PG&E cautions that, should this proceeding prescribe solutions that require divergence from broadly used standards, California will face an uphill battle in building multiple new systems and processes that may not work well with each other and stunt adoption from third party vendors. This would cause confusion and threaten our State's ability to meet established climate goals. It

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7/ In PG&E's comments in the CEC's LMS proceeding filed on July 21, 2022, PG&E explained that its ability to implement is dependent on funding requested in the current 2024-2027 Demand Response (DR) A. 22-05-002, et al. PG&E also proposed that the CEC provide IOUs funding for implementation via the State's General Fund. To the extent that approval of either of these funding mechanisms is delayed or insufficient, PG&E will be unable to comply with the CEC LMS, and PG&E would appreciate the opportunity to request funding in this proceeding. https://efiling.energy.ca.gov/GetDocument aspx?tn=244174&DocumentContentId=78081 (accessed Aug. 11, 2022).

would also diminish the opportunity for California to convince other states to follow our lead, as has occurred successfully in many other climate action contexts, such as vehicle emission reduction standards:

> SUGGESTED REVISIONS to Issue g. *What kind of access (including potential "universal access") to electricity prices by customers, devices, distributed energy resources and third-party service providers should the CPUC find reasonable and feasible? How should any such systems be funded, built, operated and maintained? What other agencies would need to be involved?*

Issue h.: *How should the Commission inform customers about dynamic rates, ease customers' transitions to these rates, help them manage and plan their electricity usage, and protect them against bill volatility?*

Again, the phrasing of this issue could be read as presuming that the CPUC would eventually adopt mandatory dynamic rates for *everyone*. The CPUC has already adopted implementation plans for PG&E's DAHRTP CEV rate (in D. 21-11-017), and its three RTP rate pilots just approved in D. 22-08-002. The CPUC should simply require that any new proposals for dynamic rates include a transition plan, including how customers would be informed about any new dynamic rate options and how to help them manage and plan their electricity usage. As for the last phrase, PG&E would note that real time pricing inherently poses greater risks of bill volatility, because its very purpose is to send more accurate granular (say hourly day ahead) price signals to customers who enroll because they believe they can respond and manage their usage and thus their bills. For this reason, PG&E's two commercial pilots approved in D. 22-08-002, and its CEV rate approved in D. 21-11-017, do not include special protections against bill volatility (beyond the CAISO's generation price cap).[8/] However, PG&E's RTP pilot for *residential* customers, approved in D. 22-08-002, will test limited additional protections. PG&E continues to strongly believe the results of these and any other RTP pilots should first be gathered so their lessons learned can inform future CPUC decisions on dynamic pricing. Therefore, PG&E recommends deletion of Issue h. for the time being, and in its place, guidelines

8/ The sigmoidal shape and early onset of the capacity price signal proposed by the Marginal Generation Capacity Cost (MGCC) Working Group and adopted in D. 22-08-002 is expected to result in reduced bill volatility compared to other functional forms that increase without limit, such as quadratic or steeper price curves. However, even this would not protect all customers from higher bills in extreme summers such as that experienced in 2020.

on what kinds of implementation proposals the CPUC expects to see submitted along with any dynamic rate design proposals, which should build from lessons learned in the aforementioned pilots. The CPUC has already made good progress on adopting dynamic rate pilots and should ensure that future proceedings looking at follow-on proposals are data-driven and based on results of actual customer engagement on those rates.

> SUGGESTED REVISION to Issue h.:*Delete in its entirety* (Instead, consider including general guidance, either now or in a future Amended Scoping Memo, on the elements of showings the CPUC expects to see in support of any future rate proposals to be made (such as after the results of "in-flight" dynamic pricing rates and pilots have been received and reviewed.)

Issue l.: *What tools and policies are necessary to enable bundled and unbundled customers to participate more fully in demand flexibility rates?*

This issue seems to assume there are no existing tools and policies in place that help enable bundled and unbundled customers to participate in demand flexibility rates. For example, again, PG&E's just-approved three RTP pilots are seeking to get one or two CCAs to agree to mirror the rates so learnings about unbundled customers' participation can be gleaned for one or more of these RTP pilots. Results from the ongoing pilots should provide helpful lessons learned to help inform discussions about additional tools and policies in the future.

> SUGGESTED REVISION to Issue l. *<u>Are additional</u> tools and policies <u>needed, beyond those being tested in current pilots</u>, to enable bundled and unbundled customers to participate more fully in <u>any additional future</u> demand flexibility rates? <u>If so, applicants proposing such rates should include recommendations about desired tools and policies including plans for implementation and attendant costs, etc., drawing upon results of dynamic pricing pilots.</u>*

Issue m. *How should the Commission support the implementation of the amendments to the California Energy Commission's Load Management Standard, if adopted? What actions should the Commission consider, if any, in addition to reviewing dynamic rates proposed by utilities and ensuring universal access to dynamic electricity prices?*

As stated in PG&E's response to Preliminary Scoping Issue g., above, PG&E strongly recommends that the Commission actively align the requirements in this proceeding with the requirements coming out of the CEC's Load Management Standard proceeding. This is necessary to avoid the inefficient development of various disparate systems, and instead would ideally allow pursuit of a single system that incorporates both CEC and CPUC sets of requirements (or at least results in compatible systems, in the event the CEC's standards or the CPUC's actions end up leading to separate implementation for each utility).

PG&E provided comments in the CEC's LMS proceeding on its proposed regulatory language, which include (but were not limited to) adequate and timely funding authorization, leveraging the existing ShareMyData (SMD) system, and recognition of CPUC authority over retail rate design. It is unclear how this DFOIR's Preliminary Scoping Issue m. envisions the process for alignment with the CEC's Load Management Standard. PG&E requests that Issue m. be revised to clearly state that there should be active collaboration and consideration with provisions in the Load Management Standard

> SUGGESTED REVISION to Issue m.: *How should the Commission support the implementation of the amendments to the California Energy Commission's (CEC) Load Management Standards, if adopted)<u>, including, but not limited to, funding authorization, leveraging existing standards, and approval of dynamic rates, pursuant to its jurisdiction as the IOU rate setting authority</u>? What steps are necessary to ensure active and transparent collaboration by the Commission with the CEC's ongoing Load Management Standard proceeding? Once the CEC adopts the Load Management Standard, how can alignment best be achieved within relevant CPUC proceedings?*

B. The Scoping Memo's Schedule Should Include Staging with Multiple Tracks

As discussed in the Introduction above, PG&E strongly supports the CPUC in carefully designing this very wide-ranging DROIR, with strategic staging that includes multiple tracks, some of which could potentially overlap or run in parallel with others.

1. The Earliest Tracks Should Include Foundational Policy Issues (Track 1a) and the Fixed Charge Rate Reform Required by Statute (Track 1b).

As shown in the conceptual staged schedule, offered by PG&E for discussion here in Appendix A, the earliest track of this DROIR should prioritize at least three items from the

Preliminary Issues list: (a) adopting updated rate design principles, (b) adopting guiding principles for demand flexibility rate design and evaluation, and (e) reforming residential fixed charges for recovery of costs in accordance with the adopted rate principles, demand flexibility guidance, and legislative requirements. These three issues should proceed on the highest priority track with greatest urgency, especially because the Legislature set a deadline of July 1, 2024, by which the CPUC must have adopted an AB 205-compliant income graduated residential fixed charge. While fixed charge rate changes per AB 205 will affect residential customers broadly, including all those on the default residential rate, the types of demand flexibility rate proposals expected in later tracks of this DFOIR seem likely to be for *optional* rates that would first be focused on targeted customers (such as large commercial customers with the necessary control technologies, or people in a range of customer classes who have electric vehicles or battery storage). While there will be overlap between the parties interested in the foundational rate design principles and demand flexibility policy guidance, and those interested in the residential fixed charge, not all parties may be interested in both. Therefore, to support time-efficiency, the Working Group, or subcommittees of it, may be encouraged to work in parallel on these earliest issues, if and as appropriate

2. Another Relatively Early Issue (Track 1c) Could Support Initial Efforts toward an Online Statewide Platform for Universal Access to At Least a Generation Price.

Another important scheduling issue to consider for an early track of this OIR should be how to make first steps towards (g) providing universal access through a statewide internet-based portal, at least to rates that reflect CAISO day-ahead energy prices and Commission approved day-ahead generation capacity rate components, for use by all market participants/devices. However, continued coordination with the California Energy Commission, in particular to align with its final Load Management Standard, is a critically important prerequisite to ensure that systems are not built that later have to be rebuilt, causing additional (potentially avoidable) costs. While climate action is urgent, so is affordability, so while aiming to move forward as quickly as feasible, it is vital to "get it right" and make cost-effective choices. Achieving the right balance quickly will be difficult here, given the emergent nature of the technologies believed necessary to succeed on rates such as real time pricing.

3. The Schedule for Other DFOIR Tracks Should Be Designed to Ensure Data and Lessons Learned from Pilots Will Be Available for Inclusion in Testimony Development, as well as to Support Proper Coordination with the California Energy Commission.

Importantly, Appendix A's suggested, staged DFOIR schedule with multiple tracks will also allow the CPUC to receive and evaluate important data and lessons learned from ongoing dynamic pricing pilots and customer surveys, to guide any more widespread future dynamic rate setting efforts. The CPUC should be applauded for already having made progress on enabling Real-Time Pricing options across many customer classes, including through PG&E's Commercial Electric Vehicle (CEV) Real-Time Pricing rate option (adopted in D. 21-11-017), as well as our three day-ahead RTP Pilots recently adopted in Decision (D.)22-08-002 (in PG&E's 2020 GRC Phase II proceeding), in addition to the two pilots mentioned in the OIR (see DFOIR, pp. 2 – 3, presumably referring to the ongoing Valley Clean Energy Agricultural RTP Pilot (D. 21-12-015), and the ongoing SCE TeMix RTP Pilot (also from D. 21-12-015). The most recent RTP Decision, D. 22-08-002 also approved extensive customer research, to be conducted with wider populations of PG&E's agricultural, residential, and smaller business customers, to identify rate preferences and barriers to adoption of dynamic rates, set to begin in late 2022 with early results by summer 2023. Thereafter, in October 2023, PG&E's optional RTP Commercial EV rates and three newly adopted RTP Rate Pilots should become available to eligible customers with an interim report on initial pilot results by mid-2025 and a final report in Q2 2026. Before taking action to make optional dynamic rates significantly more widespread, it is critically important for the CPUC to consider lessons learned from these and any other pilots the CPUC might adopt in the near term (such as for SDG&E in A. 21-12-006).

In carefully designing how this DFOIR's schedule is staged, the CPUC should also reflect timing needs for appropriate coordination with the CEC (such as on the LMS), to further help customers make the transition toward accessing more load flexibility by adopting new technologies and automation capabilities. For example, July 22 Workshop comments have already indicated the likely advisability of moving forward first with day-ahead hourly price signals, before considering whether to add much more complex potential sub-hourly/real-time prices. Similarly, moving forward in the earliest years to at least implement generation price signals for RTP optional rates is likely to support more expeditious action, given that requiring more complex, locational distribution RTP price signals could cause delays and should first be fully tested through the existing pilots.

4. The Overall Time to Fully Consider the Novel, Complex Topics Raised in the Original OIR's Thirteen Preliminary Issues Seems Likely to Require Much More Than 24 Months.

PG&E agrees that the "complexity and number of issues" currently envisioned make this OIR a very ambitious undertaking; indeed, to call this agenda "ambitious" is actually an *understatement*. Based on timescales for other major rate reform efforts at the CPUC,[9/] there is no doubt (as the OIR properly concludes) that the standard 18-month timeline is not achievable here. However, even the OIR's target for a 24-month completion would be challenging if not impossible without staging the proceeding to allow for later prehearing conferences as suggested in below in Appendix A, regarding Track 2. This is because creating the necessary factual record to support resolution of each and every listed preliminary issue requires results of ongoing pilots that will not be available until after that 24-month period is over. The process of well-

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9/ The Residential Rate OIR (R. 12-06-013), which in June 2012. resulted in a long string of results stretching out to the final completion of default TOU roll-out in 2022, ten years later. Specifically, the Rate Design principles were adopted in D. 14-06-029. Then, in July 2015, the CPUC issued D. 15-07-001, setting residential TOU as the basic policy direction to support those rate design principles. That decision also initiated a Working Group process, which was led by an expert independent consultant, to support collaborative efforts on default TOU Pilot design through 2017. During this time, the CPUC directed the IOUs to file three concurrent 2018 Rate Design Window Applications in December 2017 (for PG&E, A. 17-12-011). These three IOUs' detailed default TOU proposals were then consolidated for consideration through the overarching RROIR proceeding. That effort resulted in CPUC decisions in 2019, charting the specific course for the IOUs' rollout of residential default TOU, that for PG&E ran from October 2020 through early May 2022. It is important to remember that the work on issues stemming from R. 12-06-013 was an iterative process that ended up taking ten-years to successfully complete).

crafted rate design should be data driven and thus is often iterative, with advances that build on other lessons learned. PG&E respectfully presents, for discussion, one approach to setting up a staged timeline, for discussion in Reply Comments and both informally before and formally at the Prehearing Conference expected to be held this September. We trust that the parties can work together to help the CPUC set a more flexible and realistic staged schedule, that provides detailed and achievable deadlines for deliverables for the issues determined to merit earliest consideration. Then scheduling for later tracks can be fleshed out in a Second and Third Prehearing Conference, building on initial results. This will allow the CPUC's record to capture important evidence from pilots that will provide critical real-world learnings to support the CPUC in balancing the updated rate design principles and any Demand Flexibility principles it might adopt, rather than by relying on presumptions.

IV. CONCLUSION

PG&E believes that it is vital to the success of this important overall undertaking that: (1) the issues be carefully tailored so as not to presume outcomes, and (2) the schedule use a flexible approach, utilizing multiple parallel tracks which are staged to give top priority to foundational or immediately required actions. As many participants suggested during the CPUC's July 22, 2022, initial Demand Flexibility Workshop, such actions are not only advisable but necessary to ensure both expeditious and cost-effective action that can realistically achieve the important goals of this proceeding.

PG&E looks forward to continuing to work collaboratively with the CPUC and all parties on Demand Flexibility initiatives that are expected to help California achieve our climate action goals. PG&E is proud to have already received CPUC approval for groundbreaking RTP optional rates, pilots and studies of customers' dynamic pricing preferences whose results will provide critical real-world demand flexibility information to the CPUC. PG&E's early efforts to test new dynamic rates will soon begin to provide increasing numbers of customers with Real Time Pricing options as an important tool for supporting our State's vital decarbonization and reliability goals. We look forward to making further progress through this DFOIR, building upon the CPUC's early leadership, in an effort to provide essential grid efficiencies and decarbonization results for climate action. Indeed, PG&E sincerely hopes that California's ongoing, real-life success stories will inspire similar progressive actions on demand flexibility across the rest of our Nation and the World.

Respectfully submitted,

GAIL L. SLOCUM

By: *___/s/ Gail L. Slocum___*
GAIL L. SLOCUM

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 515-2892
Facsimile: (415) 973-0516
E-Mail: Gail.Slocum@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: August 15, 2022

APPENDIX A

PG&E's INITIAL SUGGESTIONS FOR A STAGED, MULTI-TRACK DFOIR SCHEDULE

	Preliminary Issues	Key Reasons	Approximate Potential Time Range
Track 1a	a. Updated Rate Design Principles b. Any other policy guidance specific to Demand Flexibility, Fixed Charges and Electrification • Establish Demand Flexibility Policy Working Group (*and decide whether an independent consultant should be hired to facilitate*)	Foundational policy guidance will be needed before subsequent Demand Flexibility and Fixed Charge rate setting decisions can be made	Working Group meetings might be envisioned for October 2022 - December 2023, to initially consider parties' suggestions to the CPUC after considering straw person concepts for a. and b. If not a consensus, Opening Comments could be filed by early February 2023, with Reply Comments filed by late February 2023 CPUC Proposed Decision on Issues a. and b. could be possible by early to mid-Q2 2023, with final decision 30 days thereafter, by **late Q2 2023.**
Track 1b	e. Residential Fixed Charges	High Priority to timely litigate the complex, novel issue of income-graduated residential fixed charges in an early Track, to ensure CPUC meets its	IOUs' each submit Fixed Charge proposals (consistent with AB 205), and supporting Testimony, envisioned for mid-February 2023 CPUC scoping memo issued in March to guide consolidated

	Preliminary Issues	Key Reasons	Approximate Potential Time Range
		Statutory deadline of a final decision by July 1, 2024	consideration of Residential Fixed Charges Cal Advocates' Responsive Testimony envisioned for mid-May 2023 Intervenors' Responsive Testimony envisioned in mid-July 2023 Rebuttal Testimony late Sept 2023 (to allow time for discovery) Settlement discussions: October 2023 – mid January 2024 Hearings (if needed) late January 2024 Briefing (if needed) mid-February 2024 Proposed Decision mid-May 2024 with Comments filed in early to mid-June 2024 Final CPUC decision at last decision conference in June (to meet statutory July 1, 2024 deadline)
Track 1c	Issue g,: Initial efforts toward an online statewide platform for universal access to at least a generation price	A universal platform (whether MIDAS or otherwise) could be discussed by the existing Working Group (serially, after completing Issues a and b), or if desired, potentially in parallel through a separate Track 1c Working Group of	Track 1c Pricing Platform Working Group discussions could begin in late 2022 and continue into mid-2023, starting with active CEC coordination, then beginning to flesh out specific options in earnest after the necessary inputs are available (including the CEC's new Load Management Standards), which are currently being developed,

	Preliminary Issues	Key Reasons	Approximate Potential Time Range
		stakeholders with specific pricing platform interests, in close coordination with the CEC.	but have not yet been adopted by the CEC.
Second Prehearing Conference to consider Subsequent, Track 2 Schedule for all other Issues	All issues other than a, b and e.	Results at least on Issues a, b,, as well as Working Group guidance, would seem to be needed before scoping and scheduling Issues for Tracks 2 and beyond	Early 2024, after CPUC issues final decision at least on Track 1a (estimated to happen by end of Q4 2023) and the Working Group has had many months to discuss and make recommendations for this Second PHC
Third Prehearing Conference	Remaining issues	Once a final decision is issued setting residential fixed charges (July 1, 2024) and a decision regarding any initial statewide pricing platform has been received	Q3 or Q4 2024. Note that results from existing Pilots are expected to be received on the following dates, and scheduling on many Issues should call for testimony well after such results can be reviewed and subject to data requests: **TIMELINES OF SEVEN "IN-FLIGHT" RTP PILOTS/NEW RATES** **PG&E's Three GRC II RTP Pilots (D. 22-08-002)** • Customer Preference research begins late 2022, with results expected by **summer 2023** • Three RTP Pilots are planned to start October 2023 • Interim (first year) Results Report expected Q2 2025 • Final (post second year) Results Report expected by **early Q3 2026**. **PG&E's BEV DAHRTP Rate (D. 21-11-017)**

	Preliminary Issues	Key Reasons	Approximate Potential Time Range
			• Planned to start October 2023 • Interim Results Reported Q2 2025 • Final Results expected to be Reported by **<u>early Q3 2026</u>** **VCE RTP Pilot (D. 21-12-015)** • Pilot began to run in May 2022_-2024 • First year results expected to be reported Dec. 31. 2023 • Second year results expected to be reported **<u>March 1, 2025</u>** **SCE RTP Pilot (D. 21-12-015)** • Pilot began to run in May 2022 through December 2024. • First results expected to be reported in January 2023. • Final results expected to be reported in **<u>March 2025.</u>** **SDG&E RTP Pilot (A. 21-12-006)** • Pilot would begin to run in November 2022 until October 31, 2024. • First results expected to be reported in Q4 2023 through a workshop. • Final results report expected in **<u>Q1 2025</u>**.

APPENDIX B

List of Objectives/Hypotheses for PG&E's Three 2020 GRC Phase II RTP Pilots Adopted in D. 22-08-002

Commercial Stage 1 Pilots (Small Business Pilot and Large Commercial and Industrial Pilot) Objectives:[1/]

- Learn from offering an RTP rate option whose prices reflect the California Independent System Operator (CAISO) market
- Assess the degree of customer interest in RTP and determine the risk/reward profile for customers that participate
- Evaluate the load response potential of RTP, relative to what is already achieved through other load management programs available to C&I customers, such as demand response (DR) programs or Critical Peak Pricing (CPP), known as Peak Day Pricing (PDP)
- Evaluate the Greenhouse Gas (GHG) impact potential of RTP, based on the load response evaluation referenced above
- Evaluate the bill savings potential that can be achieved through load response on this pilot
- Test the complex operational systems needed to offer a new RTP, including involvement of Community Choice Aggregators (CCA)

Residential Stage 1 Pilot Hypotheses:[2/]

- Residential customers can adjust electricity usage to respond to hourly price signals.
- Automated control technology is needed for residential customers to effectively respond to price signals (and what type of control technology may be most effective).
- Controlling different technologies separately is less effective than controlling all of the technologies simultaneously at the main electric panel of the house (To test this type of control, the Parties agreed to incentivize Smart Panel installation).
- Enabling a residential RTP price signal would incent the control software market to develop more sophisticated technology for the residential market.
- There can be incremental beneficial load response from residential customers on time-of-use rates.
- The benefits of the incremental load response from RTP outweigh the costs of enabling participation in the Stage 1 RTP Pilot through incentives and bill protection.
- Residential customers are willing to stay on an RTP rate when bill protection ends.

1/ A. 19-11-019, Exhibit (PG&E-RTP-1), p. 5-1.

2/ A. 19-11-019, Joint Motion for Adoption of Joint Settlement Agreement on Real Time Pricing Issues including Stage 1 Pilots, Attachment C, pp. 3-4. January 14, 2022