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A link to the copyrighted material in Attachment A can be found at this link: https://www.epri.com/research/programs/072127/results/3002021204

Additional submitted attachment is included below.

Application: 19-11-019
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Exhibit No.: (PG&E-RTP-1)
Date: March 29, 2021
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2020 GENERAL RATE CASE PHASE II

COMMERCIAL & INDUSTRIAL REAL TIME PRICING PILOT AND RESEARCH FOR OTHER CUSTOMER CLASSES

SUPPLEMENTAL TESTIMONY

(PG&E-RTP-1)

PACIFIC GAS AND ELECTRIC COMPANY
2020 GENERAL RATE CASE PHASE II
COMMERCIAL & INDUSTRIAL REAL TIME PRICING PILOT
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
BACKGROUND AND POLICY

A. Introduction

The purpose of this chapter of Pacific Gas and Electric Company's (PG&E) March 29, 2021 Supplemental Testimony in PG&E's 2020 General Rate Case (GRC) Phase II (GRC Ph. II; A.19-11-019) is to provide the policy background and context for PG&E's proposal for an opt-in Real Time Pricing (RTP) pilot for Commercial and Industrial (C&I) customers, and proposed dynamic pricing rate design and preferences research for the Residential and Agricultural (Ag) customer classes. PG&E anticipates the C&I RTP Pilot rate would be available to commence by the summer of 2023 and proposes a pilot duration of 24 months.[1] PG&E estimates the incremental costs of the C&I RTP Pilot to be between $7.8 to $11 million over about three years, and is requesting authority to record those costs in a memorandum account for recovery in a future GRC Phase I (GRC Ph. I) proceeding or through a separate application. PG&E proposes to conduct rate design and preferences research and further benchmarking for the Ag and Residential customer classes because more information is needed regarding Ag and Residential customer interest and ability to respond to an RTP rate versus other dynamic rate structures.

The benchmarking efforts PG&E has undertaken thus far support its proposal for a concurrent two-pronged approach, described in Section 7, as the initial step to evaluate the potential of RTP: Prong I) an RTP Pilot for C&I customers; and Prong II) rate design and preferences research for Residential and Ag customers. If warranted by research results, a further step could be a new dynamic pricing rate or pilot for Residential and/or Ag customers.

Benchmarking results, summarized in Section 3, show ample evidence from 53 active Non-Residential RTP rate schedules offered by regulated U.S. utilities

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1 This estimated timing for the commencement of the C&I RTP Pilot rate is dependent on the timing of PG&E's Complex Billing System replacement project, and the timeline for programming a rate for the Day-Ahead Hourly Real Time Pricing Commercial Electric Vehicle Pilot (DAHRTP-CEV Pilot or CEV RTP Pilot) proposed in Application (A.) 20-10-011. See Chapter 5 for further details on PG&E's Complex Billing System replacement project plans and impacts on implementing the C&I RTP Pilot.

that some large C&I customers have enrolled in and have benefited from RTP, and provided load response to support the electricity grid. On the other hand, PG&E observes that there is limited experience with Residential and Ag RTP programs in the U.S., and the California Energy Commission (CEC) is only in the very early stages of activities to develop automated price responsive technology and standards. Therefore, PG&E has concluded it is premature to propose an RTP pilot for Residential and/or Ag customers, but rather proposes to study these customers' preferences across a range of dynamic pricing options. The proposed rate design and preferences research would evaluate customer preferences for RTP as well as other dynamic pricing rate structures, and how enabling technologies like smart thermostats, including their costs, affect those preferences. Although PG&E has not developed a specific estimate of the costs to conduct this rate design and preferences research, based on previous experience conducting this type of research, PG&E expects the costs to be in the range of $400,000 to $700,000. PG&E is requesting authority to record these costs, in addition to the C&I RTP Pilot costs, in a memorandum account for recovery in a future GRC Ph. I proceeding, or through a separate application.

This chapter is structured as follows: (1) Impetus for Evaluating RTP in California Now; (2) Regulatory Background; (3) RTP Benchmarking; (4) RTP Objectives; (5) RTP Issues From Administrative Law Judge’s (ALJ) August 27, 2020 Ruling; (6) Customer Segmentation; (7) PG&E’s Proposed Two-Pronged Approach for RTP; (8) Cost Recovery; (9) Organization of Exhibit; and (10) Conclusion and Summary of PG&E’s RTP Proposals.

1. Impetus for Evaluating RTP in California Now

California is an international leader in advancing solutions to climate change. Senate Bill 100 (SB) charts the State’s commitment to a carbon-free electricity sector by 2045,[2] while the California Public Utilities Commission’s (CPUC or Commission) Building Decarbonization Proceeding

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[2] SB No. 100, (2017-2018 Reg. Sess.) § 5, codified in Cal. Govt. Code Section 65302, states, “It is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100 percent of all retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045,” at <https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100>, accessed March 27, 2021.

(Rulemaking (R.) 19-01-011) is working to meet the State's building decarbonization goals established pursuant to Assembly Bill (AB) 3232.[3] State policies also call for decarbonizing the transportation sector through electrification,[4] as transportation is the largest source of greenhouse gas (GHG) emissions in California.[5] The dual goals of decarbonizing the electric sector, and electrifying transportation and other sectors, combined with the intermittency of clean energy resources will require coordination between supply and demand to achieve demand flexibility, which is needed to ensure the reliability, and cost-effectiveness of the grid. This can be achieved on the supply side through the deployment of more storage, and on the demand side through load management tools, such as potentially RTP, that can incentivize increased or decreased load response at all hours of the day.

Economists have theorized that RTP is one of the most efficient means of load management to enable a cost-effective transition to a high intermittent renewable generation electricity sector.[6] PG&E proposes a C&I RTP Pilot to evaluate customer interest acceptance, aggregate load response, and customer bill impacts (risk and reward). The proposed C&I RTP Pilot rate structure would replace the generation component of the C&I

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3 AB 3232, Friedman. Zero-emissions buildings and sources of heat energy. "This bill would require the commission, by January 1, 2021, to assess the potential for the state to reduce the emissions of greenhouse gases from the state's residential and commercial building stock by at least 40% below 1990 levels by January 1, 2030." Described at <https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180AB3232>, accessed March 27, 2021.

For example, the State's incentive program for Heat Pump Water heaters is described at <https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442465700>, accessed March 27, 2021.

4 Governor's Executive Order No. B-48-18 (January 26, 2018) calls for at least 250,000 EV charging stations by 2025, and 5 million zero-emission vehicles by 2030, at <https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100>, accessed March 27, 2021.

5 California Air Resources Board, California GHG Emissions for 2000 to 2018; Trends of Emissions and Other Indicators (2020 Ed.), p. 5, Figure 3, at <https://ww2.arb.ca.gov/ghg-inventory-data>, accessed March 27, 2021.

6 Frank A. Wolak, The Role of Efficient Pricing in Enabling A Low-Carbon Electricity Sector (Mar. 31, 2019), at <http://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/eeep8_2_03_Wolak-29-52.pdf>, accessed March 27, 2021.

B-19 and B-20 rate schedules, and is based on California Independent System Operator (CAISO) day-ahead market (DAM) wholesale prices, with a capacity adder based on day-ahead (DA) forecasts of Adjusted Net Load (ANL) and a revenue neutral adder.[7] The specifics of PG&E's C&I RTP Pilot proposal are supported by the results from benchmarking RTP programs offered by regulated utilities in the United States (U.S.).[8] PG&E's C&I RTP Pilot proposal recognizes the need to incorporate unique aspects of PG&E's electric utility regulatory environment, including (1) differences in CAISO wholesale market volatility compared to other regions due to the high penetration of renewables, (2) the form of retail competition in California, and (3) State policy goals driving the development of load management and electrification as the method for achieving a cleaner more efficient electric grid using a variety of load management approaches.[9]

Given that benchmarking results did not indicate that Residential and Ag customers have had much experience with RTP, PG&E proposes that RTP for Residential and Ag customers be evaluated separately, starting with rate design and preferences research and further benchmarking.

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7 The ANL is equal to total customer load minus the total generation from GHG-free resources (wind, solar and other renewables; nuclear; and hydro generation). Thus, ANL represents the amount of load that must be met by thermal generation *plus* unspecified imports and energy storage. The capacity adder is calculated using a Peak Capacity Allocation Factor based on ANL above a threshold, *times* the Marginal Generation Capacity Cost.

8 See Chapter 2 for summary of RTP benchmarking results.

9 Examples that PG&E suggests include but are not limited to: rate riders (e.g., Smart Rate and PDP); DR Programs (e.g., Capacity Bidding Program (CBP) SmartAC, Base Interruptible Program (BIP)); Energy Efficiency (EE) (e.g., EE Pay for Performance); Bilateral Contracts (e.g., a Resource Adequacy (RA) only contract from a DR resource); and, pilots (e.g., the DRAM Pilot or the Emergency Load Reduction Pilot).
See also, CPUC, Capacity Valuation for Behind-the-Meter Hybrid Resources Workshop (PowerPoint presentation, November 2020) Demand Response (DR) Bifurcation, p. 41, at <https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/Official%20BTM%20Workshop%20slides.pdf>, accessed March 27, 2021.

2. Regulatory Background

a. Request for Intervenor Testimony on RTP Issues and Bifurcation

The ALJ in PG&E's 2020 GRC Ph. II issued a ruling on August 27, 2020 in this proceeding encouraging parties to present RTP rate design proposals in their Fall 2020 prepared testimony.[10] On November 20, 2020, the Agricultural Energy Consumers Association (AECA), Joint Advanced Rate Parties (JARP), and Small Business Utility Advocates (SBUA) submitted testimony in PG&E's GRC Ph. II that included proposals related to RTP rate design.[11]

In January 2021 through the date of this testimony, PG&E convened both formal and informal settlement discussions with all known GRC Ph. II parties interested in RTP issues.[12] On January 27, 2021, Public Advocates Office at the California Public Utilities Commission (Cal Advocates) filed a Joint Motion to bifurcate PG&E's GRC Ph. II procedural schedule and establish a separate track for RTP issues, with support from Enel X North America, Energy Users Forum (EUF), JARP, OhmConnect, PG&E and SBUA, noting that no other interested party

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10 "[T]he Commission has previously indicated its support, in principle, for dynamic rates, including RTP rates. In its 2019 decision denying a petition for rulemaking (Decision (D.)19-03-002), … reiterated that new dynamic rate designs can, and should, be addressed in individual utility GRC. The Commission found that the 'analysis of a particular utility's costs and billing determinants in GRC Phase II proceedings is essential to the task of rate design, including … RTP tariffs.' (D.19-03-002, Finding of Fact 12). In other words, a specific RTP rate proposal should be made and evaluated in the individual utility's GRC Phase II proceeding. This email ruling seeks to follow the guidance of D.19-03-002 by inviting intervenor testimony on this rate design issue in the instant proceeding." ALJ Doherty Email Ruling (August 27, 2020).

11 Shortly before that, on October 23, 2020, PG&E filed an application presenting its proposal for an RTP pilot focused on CEV customers (A.20-10-011), discussed in greater detail below. Although the ALJ denied requests to consolidate RTP rate design issues into a single proceeding, the ALJ acknowledged that these two proceedings should be coordinated as they include many aspects of RTP that overlap. PG&E agrees that careful coordination between these two proceedings is important. This Supplemental Testimony's C&I RTP Pilot proposal builds from and expands on the CEV RTP proposal in A.20-10-011, to help facilitate coordination and minimize potential disconnects.

12 The Parties to the GRC Ph. II who have indicated an interest in and have thus far participated in at least one of these RTP settlement discussions include: AECA; California Farm Bureau Federation (CFBF); California Large Energy Consumers Association; Center for Accessible Technology; EUF; Federal Executive Agencies; JARP; Joint Community Choice Aggregators; PG&E; Cal Advocates; and SBUA.

objected to this Joint Motion. On February 2, 2021, the ALJ granted the Joint Motion to bifurcate RTP issues. On February 16, 2021, Assigned Commissioner Shiroma issued an Amended Scoping Memo and Ruling in A.19-11-019, establishing the following schedule for the GRC Ph. II's RTP issues:

TABLE 1-1
SCHEDULE FOR BIFURCATED RTP ISSUES IN GRC PHASE II (A.19-11-019)

Line No.	Event	Date
1	PG&E Supplemental Testimony	March 29, 2021
2	Intervenors' Responsive Testimony	May 28, 2021
3	Rebuttal Testimony	July 30, 2021
4	Evidentiary Hearings	September 2021 (exact dates to be determined)
5	Opening Briefs	Mid-October 2021
6	Reply Briefs	Mid-November 2021
7	Proposed Decision	~February 2022
8	Commission Final Decision expected	~March 2022

Given the bifurcation of RTP issues adopted by the February 2, 2021 ALJ Ruling and the ongoing settlement discussions with Parties, PG&E will not use this March 29 supplemental testimony to address all of the RTP proposals from JARP, SBUA, and AECA that were included in their opening testimony in this proceeding on November 20, 2020. PG&E plans to comprehensively address the Parties' RTP proposals that are included in their opening testimony, and any updated or new proposals that are submitted in Parties' responsive testimony (to be served May 28, 2021), in PG&E's rebuttal testimony (to be served July 30, 2021).

b. Cross-Over Issues With the CEV RTP Pilot

As mentioned above, there is another PG&E proceeding pending before the Commission involving RTP issues that cross-over with the RTP issues in this proceeding. Specifically, on October 23, 2020, PG&E filed its proposal for a CEV RTP Pilot.[13] This proposal was required by D.19-10-055, which directed PG&E to file an application for a dynamic

[13] Application of PG&E for Approval of its Proposal for a CEV RTP Pilot, A.20-10-011 (Oct. 23, 2020).

rate option for CEV customers no later than 12 months after the effective date of D.19-10-055.[14]

On two different occasions, PG&E filed Motions to consolidate all of the RTP rate design issues from both the CEV RTP Pilot proceeding and the GRC Ph. II into a single proceeding,[15] but these requests were denied. Specifically, the more recent of these denial rulings, issued on January 15, 2021 (January 15, 2021 Ruling) cited differences in the objectives for RTP in these two cases:

> While there is a certain amount of overlap between the RTP issues considered in A.19-11-019 and the dynamic electric vehicle (EV) rate option being considered in A.20-10-011, there are important differences that continue to justify separate consideration in distinct proceedings. The dynamic EV rate option being considered in A.20-10-011 was ordered by a previous Commission decision and intends to respond to significant state policy goals that seek to electrify California's transportation sector.[16]

It noted that the August 27, 2020 ALJ Ruling in the GRC II proceeding (inviting intervenor testimony on RTP rates) had cited a different primary objective for GRC Ph. II RTP proposals.[17] Namely, it noted that RTP proposals in the GRC Ph. II were invited: "[i]n the interest of evaluating rate designs that advance the benefits of increased grid reliability and California's goal of addressing GHG emissions."[18]

The January 15, 2021 Ruling did acknowledge that there is a certain amount of overlap between the RTP issues considered in these two cases. Thus, the January 15, 2021 Ruling encouraged coordination between the two proceedings, including having PG&E complement the record of either proceeding with information on the progress made in the other proceeding for parties and decision-makers to consider.

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14 D.19-10-055, p. 75, Ordering Paragraph (OP) 9.

15 PG&E's Motion to Consolidate Its DAHRTP-CEV Pilot Application With PG&E's 2020 GRC Ph. II for Real-Time Pricing Issues, A.19-11-019 (November 10, 2020), and PG&E's Motion to Consolidate RTP Issues Into a Single Proceeding, A.19-11-019 (December 18, 2020).

16 ALJ Doherty Email Ruling (Jan. 15, 2021).

17 ALJ Doherty Email Ruling (Aug. 27, 2020).

18 ALJ Doherty Email Ruling (Aug. 27, 2020).

The currently adopted schedule below in Table 1-2 for the CEV RTP Pilot proceeding is on a schedule with testimony, evidentiary hearings, briefing and decision milestones that are a few months earlier than the schedule in Table 1-1 above for the GRC Ph. II RTP bifurcated track:

TABLE 1–2
PROCEDURAL SCHEDULE FOR CEV RTP PILOT PROCEEDING (A.20-10-011)

Line No.	Event	CEV RTP Pilot Timeline	Bifurcated GRC Phase II RTP Issues Timeline
1	PG&E Supplemental Testimony	March 29, 2021	March 29, 2021
2	Intervenors' Responsive Testimony	March 29, 2021	May 28, 2021
3	Rebuttal Testimony served	April 26, 2021	July 30, 2021
4	Meet and Confer Report	May 12, 2021	N/A
5	Evidentiary Hearings	June 2021 (exact dates to be determined)	September 2021 (exact dates to be determined)
6	Opening Briefs	July, 2021	Mid-October 2021
7	Reply Briefs	August, 2021	Mid-November 2021
8	Proposed Decision	~October 2021	~February 2022
9	Commission Final Decision expected	~November 2021	~March 2022

The GRC Ph. II C&I RTP Pilot proposal presented in this Supplemental Testimony is separate from the CEV RTP Pilot, but in order to facilitate coordination and efficiency, the two RTP Pilots will share a common rate design,[19] a customer enablement platform, billing, and other system interfaces. The detailed plans for these elements of the C&I RTP Pilot are presented in Chapter 4, Rate Design, and Chapter 5, Pilot Plan. If the Commission were to adopt a significantly different RTP rate design approach in its final decision on PG&E's CEV RTP Pilot, that would change assumptions, costs and timing underlying this GRC Ph. II RTP proposal. See Table 1-11 in the Conclusion section below for a summary of PG&E recommendations regarding issues that cross-over between the CEV and C&I RTP Pilots.

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[19] The shared rate design is described in Chapter 4 and consists of DA hourly generation prices from the CAISO wholesale market, a daily forecasted hourly capacity adder and a revenue neutral adder. The non-generation part of the rate remains the same as the customer's otherwise applicable tariff.

c. Other Investor-Owned Utility (IOU) Proceedings Relating to RTP

The issue of RTP rate design is also being addressed in other Commission IOU proceedings, as follows:

- **San Diego Gas & Electric (SDG&E) GRC Ph. II (A.19-03-002)** – In the SDG&E GRC Ph. II proceeding, JARP submitted opening testimony on April 6, 2020, which proposed that RTP rate schedules be provided for "all residential, general service, and agricultural customers."[20] On July 17, 2020 the ALJ in that proceeding issued a ruling authorizing supplemental written testimony on some specific RTP rate issues. On September 15, 2020, SDG&E submitted testimony rebutting JARP's RTP proposals. As of the date of this testimony, a decision was pending in SDG&E's GRC Ph. II proceeding. PG&E notes that SDG&E already has a DA hourly Vehicle-Grid Integration (VGI) RTP rate for CEV customers, that was introduced in January 2016 with their Power Your Drive (PYD) Pilot. As of September 16, 2019, the PYD VGI RTP rate had 254 customers with 3,040 charging ports expected at site completion.[21] SDG&E's PYD Pilot and VGI RTP rate schedule is discussed further in Chapter 2.
- **Southern California Edison Company (SCE) GRC Phase II (A.20-10-012)** - Because SCE's GRC Ph. II proceeding has not yet been scoped, it is not clear if RTP will be addressed in that proceeding. SCE already has RTP rate schedules that have been available for certain Non-Residential customers as early as 1987, with ~102 participants as of September 4, 2019.[22] SCE's offering provides one of seven pre-determined sets of 24-hourly prices

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[20] A.19-03-002. Joint Opening Brief of California Solar & Storage Association, OhmConnect, Inc., and California Energy Storage Alliance ("Joint Advanced Rate Parties") and Enel X North America, Inc. p.v.

[21] Electric VGI Pilot Program ("Power Your Drive") Ninth Semi-Annual Report of SDG&E, R.18-12-006 (October 14, 2020), p. 2. Described at <https://www.sdge.com/sites/default/files/regulatory/R.18-12-006%20Ninth%20Oct%202020%20PYD%20Final%20Report%2010%2014%202020.pdf>, accessed March 27, 2021.

[22] See Chapter 2 for a detailed description of SCE's RTP offerings.

based on a temperature trigger and does not pass through prices from the wholesale market. SCE states in their GRC Ph. II opening testimony, "SCE will continue to explore the opportunity to incorporate wholesale energy prices from the CAISO into the RTP rate design upon implementation of SCE's Customer Service Re-platform (CSRP) initiative."[23]

d. CEC Load Management Activities

The CEC is undertaking significant initiatives to advance RTP for the purpose of load management through the Load Management Rulemaking,[24] the California Flexible Load Research and Deployment Hub (CalFlexHub),[25] and through the Flexible Demand Appliance Standards:[26]

- **CEC Load Management Rulemaking** – The CEC is pursuing hourly and/or sub-hourly energy pricing through its Load Management Rulemaking proceeding. The goal of the Rulemaking is to, "form the foundation for a statewide system of time and location dependent signals that can be used by automation enabled loads to provide real-time load flexibility on the electric grid."[27] The Rulemaking also proposes to require hourly or sub-hourly rates for all customer classes as reflected in their Load Management Standard tariff revisions, "[o]n or prior to March 31, 2023, utilities

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23 A.20-10-012, SCE-04, p. 66, Lines 13 to 15.

24 CEC, 2020 Load Management Rulemaking Docket #19-OIR-01, at <https://www.energy.ca.gov/proceedings/energy-commission-proceedings/2020-load-management-rulemaking>, accessed March 27, 2021.

25 CEC, GFO-19-309 –CalFlexHub, at <https://www.energy.ca.gov/solicitations/2020-09/gfo-19-309-california-flexible-load-research-and-deployment-hub>, accessed March 27, 2021.

26 CEC, Flexible Demand Appliance Standard. Described at <https://www.energy.ca.gov/proceedings/energy-commission-proceedings/flexible-demand-appliances>, accessed March 27, 2021.

27 Herter, Karen, and Gavin Situ. 2020. Analysis of Potential Amendments to the Load Management Standards: Load Management Rulemaking, Docket Number 19-OIR-01. CEC. Publication Number: CEC-400-2021-003-SD. p. iii, at <https://efiling.energy.ca.gov/GetDocument.aspx?tn=237283%3e,%20accessed%20March%2027,%202021.>, accessed March 27, 2021.

shall apply for approval of at least one hourly or sub-hourly marginal cost rate for each customer class."[28]

- **CalFlexHub** – Related to the 2020 Load Management Rulemaking, the CEC launched CalFlexHub, a $16 million pilot hub anticipated to operate from 2021 through 2025 with administration by Lawrence Berkeley National Laboratory. Among other objectives, CalFlexHub will, "[d]evelop advanced signal-responsive (price, marginal GHG emissions, etc.) and interoperable technology solutions that enable commercialization and market adoption of flexible demand resources."[29] Technologies to be considered include but are not limited to, "heat pump water heaters, refrigeration equipment, thermostats and HVAC controls, ductless heat-pumps, pool and spa pumps, and heaters, EV charging equipment and EV-dedicated communications, plug load control devices, batteries, and other end-use technologies in Residential and Commercial buildings that can be cost-effectively controlled to provide load-flexibility."[30] The CEC expects to have the results of CalFlexHub projects by 2024.[31]
- **Flexible Demand Appliance Standards** – The CEC's implementation of SB 49[32] through the CEC's Flexible Demand Appliance Standards aims to "promote technologies to schedule,

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[28] Herter, Karen, and Gavin Situ. January 2021. Draft Analysis of Potential Amendments to the Load Management Standards: Load Management Rulemaking, Docket Number 19-OIR-01. CEC. Publication Number: CEC-400-2021-003-SD. p. 57, at <https://efiling.energy.ca.gov/GetDocument.aspx?tn=237306>, accessed March 29, 2021.

[29] CEC. GFO-19-309 - CalFlexHub. "Application Manual Addendum 02 ADA" p. 11, at <https://www.energy.ca.gov/solicitations/2020-09/gfo-19-309-california-flexible-load-research-and-deployment-hub>, accessed March 27, 2021.

[30] CEC. GFO-19-309 - CalFlexHub. "Application Manual Addendum 02 ADA" p. 11, at <https://www.energy.ca.gov/solicitations/2020-09/gfo-19-309-california-flexible-load-research-and-deployment-hub>, accessed March 27, 2021.

[31] R. 19-OIR-01. CEC. "Presentation LMS Overview – 2020-10-14." March 21, 2021. Slide 25, at <https://efiling.energy.ca.gov/GetDocument.aspx?tn=237248&DocumentContentId=70430>, accessed March 27, 2021.

[32] Sen. Bill 49 (2019-2020 Reg. Sess.), at <https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200SB49>, accessed March 27, 2021.

shift, and curtail appliance operations to support grid reliability, benefit consumers, and reduce GHG emissions associated with electricity generation."[33] The effective date of the initial standards is Q3 of 2023.[34]

1) CEC Load Management Activities – Conclusion

The CEC Load Management Rulemaking, CalFlexHub, and Flexible Demand Appliance Standards indicate that the technology, communication standards, and user acceptance that underpin RTP are nascent and still undergoing piloting and testing. It is important to note that, even if some household devices start arriving with built-in price response technology, for some households it may only represent a small portion of the whole home load. The material portion of the whole home load will not be price responsive. PG&E appreciates that the Commission is doing its part to explore the potential of RTP, and at the same time encourages the Commission to include the CEC's RTP-related efforts and timing to demonstrate automated response to RTP signals when considering the customer-segment specific timelines for implementing RTP. For example, it is more likely that RTP could be successful for large customers that already have battery storage or energy management systems with automated response to prices signals and/or energy managers, rather than a full-scale rollout to all customer classes.

3. RTP Benchmarking

In late 2020 and early 2021, PG&E conducted research to understand the state of RTP offered by regulated utilities in the U.S. through an Electric

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33 CEC. Steffensen. Staff White Paper. Introduction to Flexible Demand Appliance Standards (Nov. 2020), p. i, at <https://efiling.energy.ca.gov/GetDocument.aspx?tn=235899>, accessed March 27, 2021.

34 CEC. Steffensen. Staff White Paper. Introduction to Flexible Demand Appliance Standards (Nov. 2020), p. 12, Table 2: Estimated Timeline of 2022 Flexible Demand Appliances Rulemaking, at <https://efiling.energy.ca.gov/GetDocument.aspx?tn=235899>, accessed March 27, 2021.

Power Research Institute (EPRI) Benchmarking Study,[35] and conducted a deeper evaluation of selected dynamic pricing offerings by SCE, SDG&E, Commonwealth Edison (ComEd), Oklahoma Gas & Electric (OG&E), and Griddy. This research is described in more detail in Chapter 2. The EPRI Benchmarking Study represents a comprehensive review of the universe of RTP plans that have been offered by regulated utilities across the U.S. In addition, the EPRI Benchmarking Study provides a framework and taxonomy for dynamic pricing and RTP also summarized in Chapter 2.

a. RTP Benchmarking Key Findings

Table 1-3 below provides a summary of the key findings of the benchmarking research. See Chapter 2 for more details and references.

[35] EPRI, Benchmarking Study of US Regulated Utility RTP Programs, Architecture and Design Final Report (March 2021). See Appendix A for the complete report.

TABLE 1-3
KEY FINDINGS FROM EPRI BENCHMARKING STUDY AND OTHER RTP PROGRAM RESEARCH

Line No.	Energy Service Provider (ESP)	Topic	Key Findings
1	EPRI Benchmarking Study of RTP Programs offered by U.S. Regulated Utilities	Availability	The study verified 55 currently active RTP rate schedules offered by regulated utilities in the U.S.; 51 open for new enrollment, while 4 are operating only for customers currently on the service and not available for new subscribers.
2		RTP Objectives	The impetus for most utilities' RTP offerings were to: offer required Provider of Last Resort (POLR)[(a)] service in a fully competitive retail energy market; as an economic development incentive to encourage customers to expand load; to encourage peak demand reduction and associated environmental and system benefits; to provide options for customers to save money on their bills; and/or to promote successful and cost-effective transportation electrification. Load management was not specifically cited as an objective of RTP programs, although the markets where these RTP rates are offered do not share the characteristics of the CAISO market that are driving the need for a comprehensive load management approach.
3		Customer Interest in RTP	Most active RTP programs offered by regulated utilities in the U.S. have been optional[(b)] and have involved large C&I customers. Only two of the 55 active RTP rate schedules were specifically for Residential customers. Only two of the 55 active RTP rate schedules ere specifically for Ag customers, both offered by SCE.
		Eligibility	10 of the 55 active RTP rate schedules are mandatory as POLR offerings in New York, Pennsylvania, and Delaware, states with full retail choice. Eligibility is typically related to a megawatt (MW) size threshold, based on minimum demand or monthly peak demand, and often limited to those with larger electric loads. • 35 of the 55 active RTP rate schedules are limited to customers with demand greater than 100 kilowatt (kW)
4		Cost Shift and Revenue Under-collection	Interviewees cited cost shift and revenue under-collection as sensitive topics; however, none indicated that they have been required to track, study or address them.

TABLE 1-3
KEY FINDINGS FROM EPRI BENCHMARKING STUDY AND OTHER RTP PROGRAM RESEARCH
(CONTINUED)

Line No.	Energy Service Provider (ESP)	Topic	Key Findings
5	EPRI Benchmarking Study of RTP Programs offered by U.S. Regulated Utilities (cont.)	RTP Rate Design	The most common type of RTP program features hourly pricing based on regional wholesale energy market postings (RTOs/ISOs), with DA notification and no intra-territory spatial differentiation. • 35 of the 55 active RTP rate schedules feature marginal energy prices based on regional wholesale energy market price postings (Pennsylvania-New Jersey-Maryland Interconnection (PJM) - 17, MISO - 8, New York Independent System Operator (NYISO) - 7, SPP - 2, CAISO - 1). • 50 of the 55 active RTP rate schedules base their RTP energy rate on DA hourly prices. • Only 4 of the 55 active RTP rate schedules have pricing elements that account for spatial granularity that differs by location. 18 of the 55 active RTP rate schedules include a two-part design, with a Customer Baseline Load (CBL) subscription amount which allows customers to sell back electricity below the CBL at the marginal energy price. The CBL RTP rate structure also provides a built-in hedge in every hour, because it includes the option for a customer to avoid high RTP prices by limiting usage to the CBL. 6 of the 55 active RTP rate schedules have price protection option.
6		Bill Impacts/Load Response	A review of RTP price elasticity of demand studies shows some indication of load response, but the results were inconclusive and could not be extrapolated to the CAISO market. Most utilities interviewed were not forthcoming with information about load response, some citing the need to protect their RTP customers' competitive information, and others indicating load response analysis is not conducted.

TABLE 1-3
KEY FINDINGS FROM EPRI BENCHMARKING STUDY AND OTHER RTP PROGRAM RESEARCH
(CONTINUED)

Line No.	Energy Service Provider (ESP)	Topic	Key Findings
7	California IOU RTP Programs	SCE RTP	SCE's RTP program, introduced in 1987, does not pass through CAISO wholesale energy prices, but charges participants based on one of seven sets of hourly prices selected according the type of day (day of week, season) and temperature. SCE's RTP is designed to be revenue neutral to the respective rate class and is designed using the same marginal energy and capacity costs embedded in the otherwise appliable tariff. SCE's RTP program is available through seven rate schedules to most non-Residential customers. SCE's RTP program had 150 participants in 2016, and enrollment declined to 102 participants in 2019, due to high bills from a particularly hot 2018 summer. In 2016, 82 percent of SCE's load on RTP schedules was from transmission level customers, 99 percent was from customers with maximum demand > 500 kW, and 39 percent was from dually enrolled Base Interruptible Program customers. On SCE's 2019 system peak day, September 4, 102 customers enrolled in SCE's RTP program delivered load reductions of approximately 31 percent, with an aggregate impact of 14.31 MW, all from customers with maximum demand > 200 kW.
8		SDG&E PYD Pilot and VGI RTP Rate Schedule	SDG&E's RTP rate, introduced in 2016, is an electric VGI rate that passes through CAISO DAM hourly wholesale prices and includes locational and capacity adders. The VGI rate is mandatory for participants in the PYD pilot who receive an SDG&E owned and operated facility (charging station). There are two versions of SDG&E's VGI rate, one for individual EV customers (Billed to Driver) and one for site hosts providing charging through SDG&E's charging stations (Billed to Host). As of September 2019, SDG&E's VGI rate had 254 sites enrolled, with ~3,040 charging ports expected at site completion. Load impact evaluation indicates that SDG&E's VGI Pilot rate was immaterially better at shifting usage from peak to off peak hours than one of their EV time-of-use (TOU) rates.

TABLE 1-3
KEY FINDINGS FROM EPRI BENCHMARKING STUDY AND OTHER RTP PROGRAM RESEARCH
(CONTINUED)

Line No.	Energy Service Provider (ESP)	Topic	Key Findings
9	Residential RTP Programs	ComEd Hourly Pricing	ComEd's Residential Hourly Pricing program, introduced in 2008, incorporates an hourly energy price based on the PJM real-time market (RTM), and is an average of the 12 5-minute prices from that hour, and also includes a capacity charge. Less than 2 percent of ComEd's bundled Residential customers are enrolled on Hourly Pricing after 13 years of program operation. Recent aggressive marketing to Peak Time Savings DR customers has boosted new enrollments, but attrition is high (11 percent in 2019). Hourly Pricing program hourly energy charges cannot be known in advance, so ComEd provides RTP alerts when the 5-minute price is at or above 14 cents per kilowatt-hour (kWh) for 30 consecutive minutes. The program administrator has recommended that the real-time day-of hourly pricing be changed to be based on the DA market, in order to allow customers to save more money and avoid larger and more unpredictable price spikes. ComEd has enabled If This Then That as a free, online automation platform to support compatible smart home devices. No reports were found of other 3rd parties or technology marketplaces that have developed yet to support ComEd's Residential customers on RTP. Evaluations have shown that societal benefits have been positive. Hourly Pricing Participants have saved money and reduced their summer peak usage by 0.51 kW per customer in response to high peak prices. However, the environmental benefits due to load shift are negative or close to zero, as a result of coal production becoming a larger part of the fuel mix in marginal off-peak hours compared to marginal on -peak hours on summer peak days.

TABLE 1-3
KEY FINDINGS FROM EPRI BENCHMARKING STUDY AND OTHER RTP PROGRAM RESEARCH
(CONTINUED)

Line No.	Energy Service Provider (ESP)	Topic	Key Findings
10		OG&E Variable Peak Pricing (VPP)	OG&E's SmartHours VPP program, introduced in 2012, is a dynamic pricing program that sets a summer season daily peak period price based on an algorithm that evaluates the forecasted marginal energy prices for the next day. The original objective of SmartHours was to achieve enough load reduction to delay capital investment in generation. About 60 percent of SmartHours customers use a programmable thermostat provided and installed by OG&E at the time of enrollment, which are set based on preferences for comfort versus bill savings. OG&E sends daily signals to the programmable thermostat to adjust the temperature based on the customer defined settings. Approximately 11 percent (~93,000) of OG&E's customers are enrolled on SmartHours, and attrition is only 2 percent. Load impacts are significant from customers with a controlled thermostat: Average peak period load reduction at system peak for customers with the free OG&E installed programmable thermostat during a high price day is .92 kW, and during a critical price day is 1.31 kW (.14 kW and .35 kW for customers without the programmable thermostat, respectively).

TABLE 1-3
KEY FINDINGS FROM EPRI BENCHMARKING STUDY AND OTHER RTP PROGRAM RESEARCH
(CONTINUED)

Line No.	Energy Service Provider (ESP)	Topic	Key Findings
11		Griddy	Griddy offered an RTP rate that passed Electric Reliability Council of Texas (ERCOT) real time market prices through to their 29,000 Residential customers in Texas. During the February 2021 winter freeze, prices hit ERCOT's cap of $9 per kWh for several days. Many Griddy customers saw bills in the multiple thousands of dollars for the week of the winter freeze and some customers faced overdrawn bank accounts since participation in the program required customers to authorize Griddy to direct debit their bank accounts. ERCOT revoked Griddy's REP license when it defaulted on February 2021 payments for generation. It is unclear if Griddy's former Residential customers will receive any relief for the exorbitant amounts already paid to Griddy during the winter freeze. The Griddy experience highlights the challenges and risks for Residential RTP customers in markets that can become volatile. It is unclear if there are price protection products that could mitigate the risk without eroding customer bill savings. The cost of these kind of insurance products will likely vary by market based on expectations of price volatility.

(a) POLR is a common term in competitive electricity markets for Energy Service Providers (ESP), Retail Energy Providers (REP), and Local Distribution Companies (LDC) that are required by their regulator to provide a service for customers that do not pick a competitive supplier, or when their supplier goes out of business. The POLR offering tends to be higher priced than the competitive offerings by ESPs/REPs as it is more costly to acquire and manage those electricity contracts. In several states with full retail choice, including New York, Pennsylvania, and Delaware, which are jurisdictions where the LDC is required to offer RTP for the largest customers to minimize their need to continue to operate in the supply business, since RTP requires no energy contract management.

(b) With the exception of POLR RTP offerings.

b. RTP Benchmarking Summary

1) RTP Offerings

There are currently very few active RTP rate schedules (55) offered by regulated U.S. utilities, and only two of them are for Residential customers. The impetus for offering RTP varies with load management sometimes cited. Other reasons RTP was instituted include being required by regulators as a POLR offering or as a means of economic development to attract new load. The majority of the active RTP rate schedules (35 of 55) are limited to very large customers with demand > 100 kW, although there are some RTP offerings more broadly available to smaller customers. Participation is relatively low, and stable, and consists of mostly very large C&I customers.

The definition of RTP varies in terms of whether prices are hourly or are in blocks, and whether a wholesale price is passed through to the rate. Most of the active RTP rate schedules (35 of 55) pass through prices from regional wholesale markets including PJM, MISO and NYISO, several of the active RTP schedules are based on pre-set prices (9) and some are based on a supplier forecast (11). Almost all the active RTP rate schedules (50 of 55) have hourly pricing, 3 are comprised of less than 24 daily price blocks, and two consist of an average of 12 five-minute sub-hourly real-time prices. Only 2 of the 55 active RTP schedules do not provide advanced notice of the settlement energy prices, and only four have pricing elements that account for distribution costs that differ by location.

About a third of the active RTP rates schedules (18 of 55) incorporate a CBL subscription amount that includes a built-in hourly hedge which allows customers to avoid the wholesale market price by not exceeding their baseline. Only a few other active RTP rate schedules (6 of 55) offer other types of price protection options.

2) California IOU RTP Offerings

RTP offerings by other California IOUs are atypical. SCE’s RTP rate schedules are based on pre-set prices that provide more stability than RTP rate designs that pass through wholesale prices, yet about a third of their RTP customers have left the program in the past few years due to high bills in a hot summer.

SDG&E’s VGI RTP rate schedule is only for CEV customers who install SDG&E-owned charging equipment, and then the VGI rate schedule is mandatory. It is not clear if any other SDG&E CEV customers or C&I/Ag customers would enroll if the VGI rate schedule were available to them.

SCE's RTP customers have shown significant load response compared to Residential TOU, while load response results for SDG&E's VGI RTP Pilot customers are pending. SDG&E's VGI RTP rate design is unique, with a critical peak adder on the highest cost hours of the year, and a charge that varies by location to reflect distribution conditions.

3) Residential RTP Offerings

The two Residential RTP rate schedules offered by ComEd and Ameren as required by the Illinois regulator have very low enrollment after 13 years. ComEd's RTP offerings (both Residential and Non-Residential) are the only active RTP rate schedules that bill based on a day-of real-time price (average of 12 five-minute real-time prices) and therefore cannot provide advanced notice of the settlement price. This may have been sustainable due to relatively low market volatility in the PJM (see Chapter 3 for a discussion of wholesale market price volatility, and PJM price volatility versus that of ERCOT and CAISO). In addition, the Hourly Pricing program Administrator, Elevate Energy, has recommended that the real time day of hourly pricing be changed to be based on the DA market, in order to allow customers to save more money and avoid larger and more unpredictable price spikes.

On the other hand, 11 percent of OG&E's Residential customers are enrolled in VPP, a dynamic rate that incorporates elements of RTP. VPP applies one of four prices during the peak period every summer season day based on a DA wholesale market forecast.

In addition, recent experience in Texas has highlighted the challenges and risks for Residential customers that participate in RTP.

4. RTP Objectives

a. RTP High Level Objectives

As describe in Table 1-3 above and in more detail in Chapter 2, PG&E's Benchmarking efforts found that the impetus for most utilities' RTP offerings were to: offer required POLR service in a fully competitive retail energy market; as an economic development incentive to encourage customers to expand load; to encourage peak demand reduction and associated environmental and system benefits; to provide options for customers to save money on their bills; and/or to promote successful and cost effective transportation electrification. With the exception of SDG&E's VGI RTP program, load management was not specifically cited as an objective of RTP programs, although the markets where these RTP rates are offered do not share the characteristics of the CAISO market that are driving the need for a comprehensive load management approach.

PG&E supports evaluating RTP and other Dynamic Pricing rate structures for the additional objectives of load management and decarbonization, as directed in ALJ Doherty's August 27, 2020 E-mail Ruling. The ruling also referred parties to the "Final Report of the California Public Utilities Commission's (CPUC's) Working Group on Load Shift" for "principles and guidance about the potential for pricing design impacts on load shift."[36]

The Load Shift Working Group Report[37] (Working Group Report) resulted from a year-long effort within the Commission's DR proceeding and included the task of developing new load shift products which could

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36 ALJ Doherty's Email Ruling (Aug. 27, 2020).

37 Final Report of the CPUC's Working Group on Load Shift (Jan. 31, 2019), at <https://gridworks.org/2019/07/new-report-final-report-of-the-california-public-utilities-commissions-working-group-on-load-shift/>, accessed March 27, 2021.

include load consumption and bi-directional products.[38] The Load Shift Working Group's guiding principles were rooted in DR and specifically in D.16-09-056. While the Working Group Report outlined many benefits that can serve as a litmus of what to test for in an RTP pilot,[39] the report's conclusions and guidance on the development of load shift products did not specifically address pricing design.

PG&E believes that the Working Group Report did not provide principles that can be directly applied to the development of RTP as a load shift product. However, the Working Group Report defined the following key benefits of load shift that that can be shared with DR programs and applied to RTP: load shift should result in environmental benefits, energy cost reductions, lower bills for customers, reduce costs of distribution and transmission systems, and may reduce the need to procure RA.[40]

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38 The tasks of this Working Group were described in D.17-10-017, including: Defining and developing new load consumption and bi-directional products; developing a proposal of whether and how to pay a capacity value for load consuming and bi-directional products to provide to the resource adequacy (RA) proceeding prior to January 31, 2019; developing a list of data access issues relevant to new models that should be addressed prior to launching new models; developing a proposal on how to better coordinate the efforts of the CAISO and the Commission to integrate new models of DR into the CAISO market; and, developing a proposal to identify the value of new products to provide to the RA proceeding prior to January 31, 2019. (D.17-10-017, p. 76, Table 2.)

39 "Beyond avoided renewable generator curtailment, additional benefits can accrue through well-timed, well-placed Load Shift resources … Energy Cost Reductions … Emissions Reductions … System, Local, and Flexible Resource Adequacy … Transmission Capacity…Distribution System Services … Customer Bill Savings." Final Report of the CPUC's Working Group on Load Shift (January 31, 2019), pp. 3-4, at <https://gridworks.org/2019/07/new-report-final-report-of-the-california-public-utilities-commissions-working-group-on-load-shift/>, accessed March 27, 2021.

40 Resource Adequacy is an administrative "insurance program against blackouts" that requires forward procurement of capacity sufficient to meet the highest forecasted demand in a month. According to the CPUC, "The Commission's RA policy framework – implemented as the RA program - guides resource procurement and promotes infrastructure investment by requiring that LSEs procure capacity so that capacity is available to the CAISO when and where needed. The CPUC's RA program now contains three distinct requirements: System RA requirements (effective June 1, 2006), Local RA requirements (effective January 1, 2007) and Flexible RA requirements (effective January 1, 2015)." CPUC. Resource Adequacy, at <https://www.cpuc.ca.gov/ra/>, accessed March 27, 2021.

PG&E incorporates the Working Group Report's key benefit of load shift in its objectives for the proposed C&I RTP Pilot discussed in the next section. These RTP objectives should also be evaluated in the context of the existing portfolio of time varying rates, DR programs, and enabling technologies that may be most effective for different customer segments.

b. Proposed C&I RTP Pilot Objectives

PG&E's proposed C&I RTP Pilot aims to gather quantitative and qualitative data that can help evaluate the effectiveness of RTP in achieving the load shift objective defined in the previous section. Given the uncertainty in the number of customers that will be willing to participate, it may not be possible to conclude that observed relationships are statistically significant. However, as described in further detail in Chapter 5, PG&E plans at a minimum to provide a qualitative evaluation of the following questions:

- Customer Interest – Which customer types are interested in RTP and can benefit and why are some customers unwilling to participate?
- Individual Load Response – What is the individual load response potential of customers on an RTP rate?
- Aggregate Load Response – What is the potential aggregate load response which will depend on the number of customers that will likely participate, persistence and attrition rates?
- Load Response versus Other Load Management Programs[41] – How does load response on RTP compare to response of other load management programs?
- GHG impact – Based on marginal emissions rates and the time-stamped load response data collected above, what is the GHG impact potential of RTP?
- Revenue Collection – What is the potential magnitude of revenue short-falls from an RTP rate?

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[41] PG&E proposes that C&I RTP Pilot customers are considered ineligible for dual enrollment on a DR program. See Chapter 5 for further discussion of the RTP value proposition compared to existing load management programs.

- Bill Impact - Will the proposed C&I RTP Pilot rates provide bill savings or result in bill increases for participating customers?
- Operational Systems – What will it take for PG&E to implement this rate for bundled customers and provide enablement for Community Choice Aggregators (CCA)/Direct Access (DA) customers?

5. RTP Issues From ALJ's August 27, 2020 Ruling

The ALJ August 27, 2020 Ruling included a list of six issues the Commission wished to have parties address in their RTP testimony in this GRC Ph. II proceeding. Table 1-4 below presents the RTP issues, the questions PG&E sees relating to each issue, a summary response to each question, and then a reference to the subsequent portions of this Supplemental Testimony addressing those questions in more detail.

TABLE 1–4
ALJ'S LIST OF GRC PHASE II RTP TESTIMONY ISSUES IN A.20-10-011 WITH PG&E'S HIGH-LEVEL SUMMARY OF RESPONSES AND REFERENCE TO DETAILED SHOWING

Line No.	ALJ 8/27/20 Ruling on GRC2 RTP Issues	PG&E's Questions/Summary Responses Reference	Reference
1	1) An explanation of why existing rates are not sufficient to meet the objectives of potential RTP rates, and how a pilot RTP rate or an optional RTP rate with capped enrollment would not be duplicative of existing rates. Testimony could also address whether there is customer interest in a new RTP rate.	**What are the potential objectives of RTP and what are PG&E's objectives for RTP?** The EPRI Benchmarking Study found RTP program objectives established for various reasons, including to: offer required POLR[a] service in a fully competitive retail energy market; as an economic development incentive to encourage customers to expand load; to encourage peak demand reduction and associated environmental and system benefits; to provide options for customers to save money on their bills; and/or to promote successful and cost-effective transportation electrification. With the exception of SDG&E's VGI RTP program, load management was not specifically cited as an objective of RTP programs, although the markets where these RTP rates are offered do not share the characteristics of the CAISO market that are driving the need for a comprehensive load management approach. The C&I RTP Pilot aims to test the hypothesis that RTP could potentially provide incremental load management benefits to support the State's decarbonization goals, such as reflected in SB 100.[b] Data from the C&I RTP Pilot can be evaluated to assess whether RTP might provide worthwhile load response to assist in reducing renewable energy curtailments and better support adoption of technologies that enable strategic electrification.	Chapter 1
2		**What is the potential incremental load management benefit of RTP, beyond what is achieved by PG&E's existing rates and programs (would there be duplication of existing rates and programs)?** PG&E's C&I RTP Pilot will evaluate whether the RTP rate provides worthwhile load management benefits beyond those already achieved under existing rates and programs, such as time-varying and other dynamic rates, DR programs, and CAISO market models. RTP's potential for incremental load management benefits will be determined by these factors: (1) individual RTP customers' response (price elasticity of demand); (2) aggregate RTP customers' load response; (3) persistence of load response; (4) and customer attrition. These factors will be influenced by the level of customer enrollment and the degree of price volatility in the C&I RTP Pilot Rate, which feeds into customer risk/reward profiles. In addition, the C&I RTP Pilot will assess whether those on the new RTP program who had previously been on a DR program can provide more, or more targeted, load response. In addition, load impact results from Non-Residential TOU time period and PDP event hour change are pending.	Chapter 5

TABLE 1–4
ALJ'S LIST OF GRC PHASE II RTP TESTIMONY ISSUES IN A.20-10-011 WITH PG&E'S HIGH-LEVEL SUMMARY OF RESPONSES AND REFERENCE TO DETAILED SHOWING (CONTINUED)

Line No.	ALJ 8/27/20 Ruling on GRC2 RTP Issues	PG&E's Questions/Summary Responses Reference	Reference
3		**Is there customer interest in a new RTP rate?** The EPRI Benchmarking Study shows that most existing programs have been optional[(c)] and have involved large C&I customers, with only two of the 55 currently active rate schedules including Residential customers. Southern Edison Company's FERC Form No. 1 data shows 98 percent of the load in their 33-year-old RTP program is from customers > 500 kW. PG&E's proposed C&I RTP Pilot will assess load response of C&I customers and assess why some eligible C&I customers may choose not to join the C&I RTP Pilot. PG&E also proposes to conduct wider research, evaluating Residential and Ag customer interest in various types of dynamic pricing rate structures.	Chapter 2
4	2) How cost shifts and the risk of under collection could be tracked, studied, and addressed in the future.	**What did the EPRI Benchmarking Study show about tracking, studying, or addressing the potential for RTP to cause revenue under collections and/or cost shifts among customer classes?** The EPRI Benchmarking Study did not reveal any evidence that other utilities with RTP rate offerings have tracked, studied, or addressed the potential for revenue under collections or cost shifts among customer classes.	Chapter 2
5		**How does PG&E propose that its RTP Pilot track, study and address the potential for cost shifts and the risk of revenue under-collection?** Because C&I RTP Pilot enrollment levels are expected to be low and only operate for a limited time, PG&E is not proposing any rate design mechanism to address potential over or under collections at this time. However, PG&E's proposed C&I RTP Pilot will track relevant data such as: customer load profiles before and after going on RTP, RTP prices compared to TOU prices, system load of non-participating customers, etc. Post-pilot workshops to consider collected data could help the Commission and parties to assess potential revenue under collections and mitigation solutions. For example, if price protections are included as part of RTP, this could cause and/or increase the degree to which RTP costs might be shifted to other customers. PG&E notes the important distinction between (1) an under/over revenue collection relative to what was forecasted and (2) an under/over collection relative to the utility's cost (which can also involve cost shift among customer classes). Only the second of these is a true cost shift. Given that standard TOU rates already cause a cost shift and that RTP rates are more cost-based than TOU rates, customers on RTP may **reduce** overall cost shifts, even if their usage is different from forecasts.	Chapter 4

TABLE 1–4
ALJ'S LIST OF GRC PHASE II RTP TESTIMONY ISSUES IN A.20-10-011 WITH PG&E'S HIGH-LEVEL SUMMARY OF RESPONSES AND REFERENCE TO DETAILED SHOWING (CONTINUED)

Line No.	ALJ 8/27/20 Ruling on GRC2 RTP Issues	PG&E's Questions/Summary Responses Reference	Reference
6	3) A review of how other time-varying rates have addressed the risk of cost shifting and under collection. Sources could include RTP rates in other jurisdictions, recent dynamic rate pilots in California, and the results of the Residential time-of-use pilots.	**How were cost shifts and under-collections tracked in recent dynamic and TOU pilots in California**? For Peak Day Pricing (PDP), "[u]nder- and over-collections due to first year bill stabilization/protection and the variation in the number of PDP events shall be allocated to all customers by class, by spreading adjustments on an even percentage basis among all generation demand and energy charges."[(d)] For PG&E's Residential Default TOU Pilot, under-collections from structural benefiters during the pilot were allocated to all customer classes. After the Residential Default TOU Pilot, during full rollout of Default TOU, under-collections are being allocated to all Residential customers, not just Default TOU Pilot participants.	Chapter 4
7	4) The estimated cost of designing and automating a rate that includes an RTP component.	**What is the estimated cost of designing and automating a rate that includes an RTP component?** PG&E will calculate the full costs of the C&I RTP Pilot at its conclusion. PG&E estimates the incremental cost to conduct the C&I RTP Pilot is $7.8 to $11 million. This assumes the CEV Pilot is approved and uses the same platform to calculate and disseminate the RTP prices to participating customers and the same billing system interfaces.	Chapter 5
8	5) The design of illustrative RTP rates, comparisons with existing PG&E rate options, and bill impact analysis based on PG&E's billing determinants.	**Should the RTP rate's generation prices be based on the CAISO DAM or a Day-Of market—such as CAISO's fifteen-minute market (FMM) or 5-minute RTM?** PG&E's proposed C&I RTP Pilot uses CAISO DAM hourly prices and a capacity adder based on DA forecasts of ANL in the calculation of the generation component of the rate. The CAISO DAM provides a good indication of PG&E's short run energy costs because well over 90 percent of PG&E's load is settled at CAISO DAM hourly prices. In addition, a DA price gives customers advanced notice and time to adjust load, which is not available under a Day-Of rate. In addition, using a DA hourly price is supported by EPRI Benchmarking Study results that indicate all but two of the active RTP rate schedules are based on DA hourly prices. A DA hourly RTP price signal provides customers time to make adjustments to their operating plans before closing time on the prior day, which is important for C&I customers that typically rely on shifting native load rather than batteries. Also, once capacity costs are included in the prices, DA prices provide almost as much potential for customer savings as day of prices do; while forecasts of FMM and RTM prices are significantly less accurate than forecasts of DAM prices, so the risks to customers due to sub optimal operations are much greater under day of pricing.	Chapter 3

TABLE 1–4
ALJ'S LIST OF GRC PHASE II RTP TESTIMONY ISSUES IN A.20-10-011 WITH PG&E'S HIGH-LEVEL SUMMARY OF RESPONSES AND REFERENCE TO DETAILED SHOWING (CONTINUED)

Line No.	ALJ 8/27/20 Ruling on GRC2 RTP Issues	PG&E's Questions/Summary Responses Reference	Reference
9		**What is PG&E's proposed rate design for the C&I RTP Pilot?** PG&E proposes that the DA hourly RTP rate will apply to two existing C&I rates, B-19 and B-20 (i.e., pilot rates: DAHRTP-B19, DAHRTP-B20), with the same rate design as DAHRTP-CEV proposed in A.20-10-011. DARHTP-CEV is a rate rider that completely replaces the generation rates on a participating customer's base schedule with a set of rates that vary in each hour but are known the day before. Non-generation rates would remain the same as the base schedule. PG&E's proposed C&I DAHRTP rates, the same as the proposed DAHRTP-CEV rate, are composed of (1) an energy rate based on the CAISO DAM hourly price plus line losses; (2) a capacity adder based on each hour's forecasted ANL; and (3) a flat adder in each hour to make the rate revenue neutral to base schedules. There is no need for generation demand charges on this rate, even if the base schedule included them, because capacity costs are addressed by the capacity adder.	Chapter 4
10		**Can bill impact analysis provide any insight into actual bill impacts for RTP customers?** Bill impact analysis will not provide insights to actual customer impacts at this time. RTP rates are intended to influence customer behavior, however, typical bill impact evaluations assume no change in customer load. Thus, a key factor necessary to estimate participating customers' likely bill results under RTP are the assumptions to be made in the evaluation of the price elasticity of demand. These assumptions cannot be developed without studying actual customer response to CAISO DAM prices. PG&E proposes to study price elasticity of demand in the C&I RTP Pilot. The EPRI Benchmarking Study includes a review of RTP price elasticity of demand that shows some indication of load response, but these results are inconclusive and could not be extrapolated to the CAISO market. For example, as discussed in Chapter 3, the PJM market has less volatility than the CAISO market, with similar ability to forecast—providing less risk and less reward than an RTP based on CAISO prices. On the other hand, Texas' ERCOT market has significantly greater volatility and is also harder to forecast than CAISO's market—providing much greater risk along with somewhat greater potential reward than an RTP based on CAISO prices. A comparison with existing rates can be found in Attachment B.[e]	Chapter 4

TABLE 1–4
ALJ'S LIST OF GRC PHASE II RTP TESTIMONY ISSUES IN A.20-10-011 WITH PG&E'S HIGH-LEVEL SUMMARY OF RESPONSES AND REFERENCE TO DETAILED SHOWING (CONTINUED)

Line No.	ALJ 8/27/20 Ruling on GRC2 RTP Issues	PG&E's Questions/Summary Responses Reference	Reference
11	6. Recommendations as to how to structure an RTP pilot (e.g., customer eligibility, program caps, Measurement and Evaluation (M&E)) should the Commission wish to pilot any proposal(s).	**What is PG&E's proposed Pilot structure, beyond rate design?** PG&E intends that bundled and unbundled customers can participate in the C&I RTP Pilot through their Load Serving Entity; PG&E would like to work with one or two CCAs to implement the RTP Pilot. PG&E is not proposing an enrollment cap. The RTP Pilot will evaluate: • Customer preferences • Load response • Environmental (GHG) impact • Potential revenue under/over collection • Bill impacts Operational systems and resources needed	Chapter 5

(a) POLR is a common term in competitive electricity markets for ESPs, REPs, and LDC that are required by their regulator to provide a service for customers that do not pick a competitive supplier, or when their supplier goes out of business. The POLR offering tends to be higher priced than the competitive offerings by ESPs/REPs as it is more costly to acquire and manage those electricity contracts. In several states with full retail choice, including New York, Pennsylvania, and Delaware, which are jurisdictions where the LDC is required to offer RTP for the largest customers to minimize their need to continue to operate in the supply business, since RTP requires no energy contract management.

(b) "[T]he Public Utilities Commission, State Energy Resources Conservation and Development Commission, and State Air Resources Board should plan for 100 percent of total retail sales of electricity in California to come from eligible renewable energy resources and zero-carbon resources by December 31, 2045." (SB No. 100, (2017-2018 Reg. Sess.) § 1(b).)

(c) With the exception of POLR RTP offerings.

(d) D.10-02-032 OP 7.

(e) See Attachment B: PG&E's Data Response to Joint Parties 01 Data Request.

6. Customer Segmentation

a. C&I Customers

1) Size of Target C&I RTP Pilot Customer Group

The EPRI Benchmarking Study shows most existing RTP programs have been optional[42] and have involved large C&I customers, with only two programs thus far including Residential customers. This uptake of RTP by larger customers stems primarily from the concentration of energy costs as a portion of their total operational costs, and the risk/reward profile of an RTP rate. An RTP rate provides, on a normal daily basis, the potential opportunity

[42] With the exception of POLR RTP offerings.

for load response to result in lower bills, but also the risk that a lack of response or extreme grid conditions could result in higher bills, such as the recent experience of many Texans during the February 2021 snowstorms.[43] Larger customers with a high concentration of energy costs tend to have staff that monitors energy usage and costs on a daily basis, and/or batteries or automated load management technologies, and therefore the involvement and possibly the tools needed to manage the risk/reward profile. Accordingly, PG&E's proposed RTP Pilot will initially focus on large C&I customers for enrollment in the C&I RTP Pilot. The RTP Pilot will study participant's responses and assess why some eligible large C&I customers may choose not to join the RTP pilot.

Table 1-5 below shows 12,143 PG&E C&I distribution customers (two percent) with greater than 200 kW maximum demand, half of which are already on large customer rates (E-19, B-19, E-20, B-20). PG&E proposes to build the C&I RTP Pilot rate on the B-19 and B-20 rate schedules.[44]

TABLE 1-5
PG&E C&I DISTRIBUTION CUSTOMER SERVICE AGREEMENTS BY SIZE

Line No.		< 200 kW	> 200 kW	% > 200 kW
1	Total C&I	641,521	12,143	2%
2	Total E-19, B-19, E-20, B-20	25,501	6,110	19%
3	Percent on Large Customer Rates	4%	50%	

43 See Chapter 2 for more background on the high bills experienced by some Texas electricity customers during the February 2021 winter storms.

44 All C&I customers would be eligible to participate in this proposed C&I RTP Pilot. B-20 is mandatory for customers with demand >1 MW. B-19 is mandatory for customers with demand >500 kW, and available on an optional basis for all customers with demand <500 kW. There are legacy versions of the rates with E-19 and E-20, with a peak period of noon to 6 p.m., that some solar customers are eligible to continue service on after the B rates, became mandatory in March 2021. The B rates have a peak period of 4 p.m. to 9 p.m. PG&E's Electric Rate Schedules are at <https://www.pge.com/tariffs/index.page>, accessed March 27, 2021.

2) CCA/DA Participation

An additional consideration that could affect when any RTP pilot can be implemented for roll-out to eligible potential participants is coordination with and participation of CCA and DA providers within PG&E's service territory. Because more than half of, and a continually increasing portion of, PG&E customers receive their generation supply from CCAs, the potential for a PG&E RTP program to result in significant load response could be dependent on the level of CCA participation. Table 1-6 below shows that 53 percent of C&I customers with >200 kW maximum demand receive their electricity supply from CCAs.

TABLE 1-6
PG&E C&I CUSTOMERS SERVICE AGREEMENTS BY SIZE
CCA CONCENTRATION

Line No.		< 200 kW	> 200 kW	% > 200 kW
1	Total C&I	641,521	12,143	2%
2	CCA/DA	340,932	6,513	2%
3	CCA/CA % of Total	54%	53%	
4	Total E-19, B-19, E-20, B-20	25,501	6,110	19%
5	CCA/DA	8,386	1,690	17%
6	CCA/CA % of Total	33%	28%	

In order to participate, a CCA/DA would need to create an RTP rate for their customers, communicate the daily prices (which could be different than PG&E's) to their customers, and possibly coordinate with PG&E on outreach. This will be a time and resource intensive effort for PG&E as well, due to the outreach and coordination needed with the large number of CCAs (12 total at this time) in PG&E's service territory, and the complexity of implementing RTP for CCA customers in the best way to leverage PG&E's infrastructure.

Because of this complexity, CCA policy and business objectives and the unknown benefits of RTP for CCAs, it is unclear how many of them will be interested in participating. PG&E requests that the

Commission consider whether a C&I RTP Pilot would be justified without enough CCA participation.

b. Residential Customers

1) Research is Needed to Determine the Best Approach for Expanding PG&E's Existing Portfolio of Residential Rate Options

PG&E's Residential customers already have a robust set of electric rate plan options, and many will be transitioned to a default TOU rate over the next year. PG&E believes rate design and preferences research should be conducted to determine how this portfolio of rate options should be expanded, whether the best dynamic rate for Residential customers is RTP or some other construct, and the potential for customer confusion from so many options.[45] PG&E's current portfolio of Residential rate options is as follows:

- PG&E's bundled Residential customers can already enroll in a dynamic rate option called SmartRate™ which is a critical peak pricing (CPP) program called on up to 15 days during the summer season. PG&E will be updating the SmartRate event hours in early 2022 from 2 p.m. to 7 p.m. to 4 p.m. to 9 p.m.[46] CCA customers are not eligible for SmartRate and would have

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45 PG&E conducted rate design preferences research on several occasions to support Residential rate design proposals, including:

1) Rate Design Reform Proposal of PG&E May 29, 2013, R.12-06-013 (May 29, 2013), Appendix A.1, Customer Research Key Findings Report.
2) PG&E Rate Design Window 2015 Prepared Testimony, A.14-11-014 (November 25, 2014), Chapter 4, Attachment A, TOU Rate Development Conjoint Research Report Among Residential Customers, p. 4-AtchA-1.
3) PG&E Rate Design Window 2018, A.17-12-011 (December 20, 2017), Appendices Supporting Prepared Testimony, Vol. 2, Appendix 2D, TOU and SmartRate Rate Development Conjoint Research Report Among Residential Customers, p. App2D-1.
4) PG&E 2017 GRC Ph. II, A.16-06-013 (June 30, 2016), Exhibit (PG&E-1) Vol. 2, Appendix H, Customer Survey – TOU Periods.

46 D.19-07-004 initially approved new SmartRate event hours of 5 p.m. to 8 p.m. D.21-03-056, in the Reliability OIR (R.20-11-003) issued March 25, 2021, instead requires PG&E to update the SmartRate event hours to 4 p.m. to 9 p.m. no later than June 1, 2022. pp. 15-18.

to look to their CCA to provide a comparable program. Consideration of a new dynamic rate offering for Residential customers should expand beyond RTP, examine how CCA customers can participate, and whether it should replace SmartRate, given the likely cannibalization that would occur if there were two Residential dynamic rate options.

- All Residential customers have the option to enroll in either E-TOU-C, with a baseline quantity and peak period from 4 p.m. to 9 p.m., or E-TOU-D, with no baseline quantity, a peak period from 5 p.m. to 8 p.m., and a somewhat higher peak to off-peak price ratio.
- Eligible Residential EV and storage customers can enroll on EV-2A, which is a rate option with a 4 p.m. to 9 p.m. peak period that has the highest peak to off-peak price ratio of PG&E's Residential TOU rates.
- PG&E has also proposed, in this GRC Ph. II, E-ELEC, which is a Residential TOU rate with a fixed charge and lower volumetric rates, designed to encourage electrification.[47]

In addition, PG&E believes any new dynamic rate for Residential customers should not be introduced until the completion of the default transition of Residential customers to TOU rates, which provides some time to conduct rate design and preferences research. PG&E's rollout of default TOU rates to its eligible Residential customers is being conducted in waves, and will be completed in early 2023, when annual bill protection results will be provided to the final wave of customers scheduled to transition. At the conclusion of the rollout of default TOU, about half of PG&E's Residential customers are expected to be enrolled on TOU rates.[48] It is likely that the Residential customers best suited for dynamic

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47 A.19-11-019, Exhibit (PG&E-5).

48 About half of customers will remain on the tiered E-1 rate schedule either because they were ineligible to be transitioned (i.e., for reasons including being on Medical Baseline, a CARE customer in a hot climate zone, or lacking 12 months of interval metering data needed for a rate comparison) or they were transitioned and then opted out.

rates would be TOU customers, not customers who were exempt from TOU default because they were CARE hot climate or Medical baseline, or chose to opt-out of TOU. millions of dollars have been spent in education and outreach as part of the default TOU transition to build Residential customer understanding of the idea that they should pay attention to when they are using energy during the day (reducing usage during the new peak from 4 p.m. to 9 p.m.). Given the effort associated with continuing this educational campaign through Q1 of 2023, PG&E is concerned that introducing another new Residential rate option, (in addition to SmartRate, the existing TOU rates, the EV rate and the new electrification rate) would be confusing for Residential customers, especially for those who would have just recently been transitioned to the E-TOU-C default rate. Sending another, different message (e.g., encouraging them to opt-in to an RTP or other dynamic rate which does not have a static peak period), could undercut the success of getting customers to accept the default TOU rate.

2) Appropriateness of RTP for Residential Customers

It is unclear if RTP is the best type of dynamic rate design or load management tool for price responsive Residential customers. First, as demonstrated by the Griddy RTP offering in Texas described in Chapter 2, the risks posed by an RTP rate for Residential customers can be substantial. Second, given the risks posed by RTP rates and the lack of RTP program experience by Residential customers of regulated utilities (besides the two programs mandated in Illinois with very low enrollment), it is unclear if RTP is the best type of dynamic rate option for Residential customers, with their relatively lower level of energy sophistication as compared to large C&I and Ag customers. Residential research may indicate other dynamic rate options are a better fit for Residential customers. In addition, once TOU roll out is completed at the end of 2021, PG&E will be interested to see if flexible Residential load can optimize for TOU. Third, it is unclear if RTP is the best load management tool for Residential customers, as compared to other load management approaches (e.g., market integrated DR programs).

All customers who participate in an RTP rate face both potential bill savings and bill increases depending on their ability to respond to the rate by making load adjustments in real time, day-in and day-out, until there is both reliable technology that will automate load response and a large enough flexible load. The potential increase in their bills can be significant, depending on market volatility, rate design, and the customer's ability to respond to the price signals. Importantly, RTP is not a "carrot-only" program, that only provides potential bill savings for customers, such as DR programs like SmartAC.[49] Rather, RTP inherently includes both low-cost (carrot) and high-cost (stick) incentives, that require day in and day out attention and management accordingly, whether by the individual customer or by an "aggregator" as with DR programs. The potential "stick" inherent in RTP can result in unexpected high bills when customers are not appropriately educated, not fully engaged, or unable to respond. These situations are more typical with less sophisticated Residential customers.

In addition, customers also face increased bills when a price response technology malfunctions, a communications signal is interrupted, high prices coincide with the customer's high energy demand,[50] the user incorrectly programs his or her device, or the user is preoccupied with other things.

PG&E believes these additional considerations are more relevant for Residential customers than for C&I customers. The

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49 SmartAC is a CAISO market integrated DR program in which PG&E provides customers with a smart thermostat and pays customers a one-time $50 enrollment incentive to be able to remotely control air conditioning units in response to CAISO awards. There is no penalty for non-performance.

50 High prices naturally correlate with high aggregate demand, and also with many individual customers' demand profiles. For example, if a customer in a hot zone has a large or poorly-insulated house, their cooling needs will naturally be significant during a heat wave, and the coincidence of this cooling need with high prices could result in elevated bills even if the customer took actions to reduce their electricity usage below their usage in prior years' heat waves or below the usage of comparable customers not on RTP.

EPRI study found that, for Non-Residential RTP customers, electricity tends to be a significant portion of operational costs and typically energy managers and/or energy management systems tend to be already in place. In addition, Marketing, Education and Outreach (ME&O) can be made more effective if it can be targeted to a smaller number of C&I customers and can be supplemented with person-to-person outreach which would not be cost-effective for Residential customers.

3) Coordination With CCAs

Because almost 60 percent of PG&E's Residential customers receive their generation supply from one of 12 CCAs, significant coordination and collaboration will be necessary to provide a Residential dynamic rate that can be offered to CCA customers. It will be necessary for a limited number of CCAs to participate in a Residential RTP pilot to ensure a coordinated effort to overcome enrollment challenges posed by a new rate offering. PG&E notes the history of collaboration among CCAs and the IOUs on the Residential TOU transition. Three CCAs participated in the default TOU pilot (Marin Clean Energy (MCE), Sonoma Clean Power (SCP), Silicon Valley Clean Power[51]). All but one of the 12 CCAs are participating in the post-pilot roll out of default TOU and are proceeding on a similar timeline as PG&E (April 2021 to March 2022) for the transition of their Residential customers to default TOU.[52]

PG&E's proposal to schedule any Residential RTP Pilot or dynamic pricing roll-out to a later phase will allow CCAs to engage in the rate design and preferences research, and will enable PG&E and the CCAs to work together to determine the best approach to

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51 Initially, only MCE and SCP were participating in the default TOU Pilot. Because the city of Milpitas had already been transitioned by the time Silicon Valley Clean Energy (SVCE) was formed, SVCE was also included.

52 The 12 CCAs in PG&E's service territory include: Central Coast Community Energy; Clean Power SF; East Bay Community Energy; King City Community Power; MCE; Peninsula Clean Energy; Pioneer Community Energy; Redwood Coast Energy Authority; San Jose Clean Energy; SVCE; SCP; and, Valley Clean Energy.

ME&O as well as how to handle certain operational issues related to billing. Based on experience from the Residential Default TOU transition, such collaboration with PG&E's 12 CCAs will take time.

c. Ag Customers

AECA stated in opening testimony that a dynamic rate for Ag customers should accommodate key Ag challenges:

> For example, irrigation schedules, which are often out of an individual growers' control, are usually set days in advance. If a field is scheduled to be irrigated on a particular day, equipment deployment and field preparation has to occur well before that day, inducing labor and capital costs. Likewise, irrigation schedules are often coordinated with other agencies (e.g., local water suppliers, California Department of Water Resources) days or weeks in advance. Under PG&E's current Peak Day Pricing program, coordinated responses to a DA call for a shift in usage is nearly impossible, as conveyance facilities and other agencies' operational standards are reliant on a predetermined irrigation schedule that has already been submitted by the grower or the local water agency...[53]

AECA proposed an Ag RTP rate design similar to SCE's RTP structure that does not pass through wholesale prices, and is based on weather forecasts at a specific location with prices tied to differing temperatures because Ag customers are able to track weather forecasts (which they do for irrigation planning), and can incorporate those into irrigation scheduling with sufficient notice.[54]

In addition, CFBF argued in a previous dynamic pricing proceeding that dynamic pricing would harm Ag customers with pumping loads that are difficult to access and not variable, leaving only the option to entirely shut off a pump, and that dynamic pricing should be opt-in only.[55]

> CFBF argues that mandatory dynamic pricing would harm agricultural customers and would result in little if any load reductions. CFBF explains that agricultural loads are primarily

[53] AECA Direct Testimony, pp. 49-50.

[54] AECA Direct Testimony, pp. 49-50. AECA also recommended this alternative dynamic pricing scheme in A.09-02-022 as an alternative to PDP, citing a decision that the significant flexibility for making operational changes would encourage voluntary participation within the Ag class. (D.10-02-032, pp. 46).

[55] The 2009 Rate Design Window proceeding (A.09-02-022) that established the original dynamic pricing program for Non-Residential customers, PDP. (D.08-07-045, p. 29.)

related to pumping water, and the pumps tend to be spread out over many acres which would make them difficult to access in response to a dynamic pricing event. Also, the pumps are generally not variable, so an agricultural customer's only possible response is to entirely shut off a pump. CFBF states that TOU rates, on the other hand, have benefited agricultural customers and the grid. CFBF recommends keeping dynamic pricing voluntary, with possible incentives for enabling technologies.[56]

On February 1, 2011, D.10-02-032 established that eligible large Ag customers (with minimum demand >200 kW) must be defaulted into PDP, while smaller Ag customers would not be required to default into PDP. In D.08-07-045, the Commission concluded that because many small and medium Ag customers did not have TOU or interval meters, there was not sufficient data to assess how and when they use electricity, and found it reasonable to implement CPP on optional basis for them.[57]

Table 1-7 below shows that 44 percent of large bundled Ag customers and less than 1 percent of small bundled Ag customers are enrolled in PDP. This certainly indicates that dynamic pricing may be appropriate for large Ag customers, however, it is unclear what the impact will be of changing the event hours for summer 2021 to 5 p.m. to 8 p.m.[58]

TABLE 1-7
PG&E AG DISTRIBUTION CUSTOMERS SERVICE AGREEMENTS BY SIZE

Line No.		< 200 kW	> 200 kW	% > 200 kW
1	Total Ag	87,127	12,143	3%
2	Total Bundled Ag	70,195	2,618	4%
3	Total Bundled on Large Ag Rates	15,500	1,949	11%
4	Percent of Bundled on Large Ag Customer Rates	4%	50%	
5	Ag PDP Customers	283	1,156	80%
6	Percent of Bundled on PDP	0.4%	44%	

56 D.08-07-045, p. 29.

57 D.08-07-045, pp. 31-32.

58 The Reliability OIR (R.20-11-003) issued March 25, 2021, will requires PG&E to update the PDP event hours to 4 p.m. to 9 p.m.no later than June 1, 2022.

As explained in Chapter 2, SCE's RTP program has been in operation for 33 years. Given SCE's long experience with this structure, it might be possible to learn enough from further benchmarking with SCE, in addition to the Ag rate design and preferences research, to not need to conduct a Pilot. Preliminary rate design preferences research could assess Ag customer interest in a rate structure similar to SCE's RTP, versus PDP and potentially other dynamic rate structures including PG&E's C&I RTP Pilot rate structure.

d. Customer Support and ME&O

PG&E is supportive of third-party efforts to develop business models in California that can prosper from customer success on dynamic rates. However, it is critical for PG&E to be involved in customer recruitment, education and outreach for the proposed C&I RTP Pilot and any future RTP offering. Due to the potential negative bill impacts from RTP described above for customers in all classes, PG&E will need to be involved in the recruitment and ongoing education of bundled RTP customers in order to ensure they are aware of the inherent risks of RTP and have the customer support required. Because any negative impacts of RTP will emerge on a customer's PG&E bill, PG&E is responsible for ensuring that the bundled customer is billed correctly and that customers understand the charges on their bill.

The Griddy experience in Texas highlights the magnitude of the risk for customers of RTP, especially Residential customers. Because Texas has a completely deregulated, competitive retail electricity market structure, the Texas distribution utilities were not responsible for explaining to a Griddy customer why their bill for a few days was in the thousands of dollars. However, because regulated California utilities are still responsible for bundled retail customers, PG&E would still be responsible for ensuring bundled RTP customers are aware of the risks and helping them when they incur negative impacts. PG&E's C&I RTP Pilot proposal in Chapter 5 details PG&E's proposed customer recruitment, education and outreach efforts.

In addition, as described above, the CalFlexHub is conducting research to demonstrate the technologies and communication that can support RTP. This indicates that, although Smart Home technology is promising, it still has not been proven to be effective in supporting customers on RTP. CalFlexHub's research is focused on developing technology, demonstrating strategies that increase demand-side flexibility, and documenting performance and customer acceptance. Below is an excerpt[59] from the CalFlexHub solicitation showing the following research objectives:

- Develop New Technologies: The Hub will be expected to have partners that will develop new demand flexibility technologies consistent with California's building energy efficiency, appliance, and load management standards;
- Conduct Pilot tests and demonstrations of advanced technologies and operational strategies that increase demand flexibility, with a goal of mass-market technology advancement, customer interface and experience understanding, and commercialization; and
- Document the results: Document the performance, consumer acceptance, and value of the economic and environmental benefits (i.e., GHG), to the customer and the system, of flexible demand technologies and strategies.

7. PG&E's Proposed Two-Pronged Approach for RTP

PG&E proposes a concurrent two-pronged approach as the initial step to evaluate the potential of RTP: Prong I) an RTP Pilot for C&I customers; and Prong II) rate design and preference research for Residential and Ag customers.

a. Prong I: RTP Pilot for C&I Customers

PG&E proposes to begin with a pilot for C&I customers, which is described in detail in Chapter 5. PG&E proposes to focus initial RTP rates on large C&I customers where enrollment and load response has been demonstrated in other utility jurisdictions. PG&E also believes a pilot is needed in order to evaluate the potential of RTP for load

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59 CEC, CalFlexHub – GFO 19-309 Application Manual Addendum 02 ADA, at <https://www.energy.ca.gov/solicitations/2020-09/gfo-19-309-california-flexible-load-research-and-deployment-hub>, accessed March 27, 2021.

response, overcome operational challenges and test ME&O. PG&E proposes the Commission adopt the C&I RTP Pilot structure summarized in the conclusion of this Chapter in Table 1-10 and in detail in Chapter 5.

TABLE 1-8
C&I RTP PILOT PROPOSAL SUMMARY

Line No.	Pilot Feature	Pilot Design
1	Eligibility	Open to customers eligible for Schedules B-19/B-19V and B-20 (C&I) with no cap
2	Rate Design	Pricing based on the hourly CAISO DAM market, with an added hourly capacity component and adder for revenue neutrality, in alignment with CEV RTP Pilot design
3	Timeline	• Timeline aligned with that proposed for PG&E's CEV Pilot, starting no earlier than the end of Q1 2022 (after GRC 2 and CEV RTP decisions)[(a)] • Pre-pilot customer survey – two months after the final decision • Recruit – starting approximately one month after completion of the pre-pilot customer survey • Build technology platform and billing system – Approximately five months from final decision • Run Pilot – 24 months from completion of the rate plans • Mid-pilot progress report – 12 months after the start of the pilot. • Assess – Three to five months, after two pilot summers.
4	Pilot Evaluation Plan	• Test ME&O • Evaluate benefits and trade-offs inherent to RTP pricing • Assess individual, aggregate, and incremental load response • Assess GHG impacts based on load responses described above • Conduct customer bill analysis compared to the OAT and/or other load management programs • Track program costs • Track revenue under-collection/over-collection

(a) As described above in Table 1-2, the CEV RTP Pilot decision is expected in Q4 2021, and the GRC II RTP decision is expected in Q1 2022.

b. Prong II: Rate Design and Preferences Research

1) Residential Customers

As described in Chapter 2, the EPRI Benchmarking Study identified only two active regulated utility RTP offerings for Residential customers, at Commonwealth Edison and Ameren in

Illinois, with very low participation after 14 years of operation.[60] In addition, the Customer Segmentation section above described several other factors that support a phased approach for Residential customers, including how best to expand the existing full portfolio of Residential rate options, the appropriateness of RTP for Residential customers versus other potential dynamic pricing structures, the need to coordinate with CCAs, and the parallel work underway in the CalFlexHub. Given these factors, PG&E proposes to conduct rate design and preference research as the first step to determine what type of dynamic rate (e.g., VPP, CPP, RTP with adders, two-part RTP with CBL, etc.) is likely to result in the greatest customer acceptance and aggregate load response for PG&E's Residential customers. As explained above, PG&E has employed conjoint analysis to support its rate design proposals in several past rate design proceedings.[61]

PG&E's proposed timeline to evaluate RTP for Residential customers includes a workshop with Parties to define research objectives, qualitative and quantitative research, an advice letter with a proposal for a Residential dynamic pricing pilot if warranted, and development and implementation of the pilot, and is detailed below in Table 1-9.

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60 Other identified Residential RTP offerings from competitive suppliers include Griddy's now defunct offering in Texas, and Amber Electric in Australia. In addition, Spain has a POLR Residential RTP option offered by LDCs to customers that do not select a competitive supplier.

61 See footnote 46 for conjoint analysis report references.

TABLE 1-9
RESIDENTIAL AND AGRICULTURAL CUSTOMER RTP RESEARCH AND POTENTIAL PILOT TIMELINE

Line No.	Activity	Duration	Completion (time from Decision in this Proceeding)
1	Workshop to define rate design and preferences research	Month 0 – Month 1 (1 month)	60 days
2	Rate design and preferences research (including hiring Vendor and final results)	Month 1 – Month 11 (10 months)	11 months
3	*Decision Point - Should new dynamic pricing rate(s) and/or pilot(s) be proposed*	Month 10 – Month 11 (1 month)	12 months
4	Workshops to design the potential new Residential and Ag dynamic pricing rate(s) and/or pilot(s)	Month 11 – Month 14 (3 months)	12 months
5	Prepare and file proposal(s) for any new dynamic rate(s) and/or pilot(s), including cost estimates, in Tier 3 Advice Letter(s) or Application(s)	Month 15 – Month 21 (6 months)	20 months
6	Commission Decision on new dynamic rate(s) and/or pilot(s)	Month 27	28 months (assuming timely approval of Tier 3 Advice Letter(s))
7	Build operational systems and recruit participants	Month 28 – Month 34 (6 months)	34 months (assuming timely approval of Tier 3 Advice Letter(s))
8	Launch	Month 35	35 months (assuming through Tier 3 Advice Letter(s))
9	Run Pilot(s)	Month 35 – TBD	TBD

2) Ag Customers

PG&E proposes a timeline similar to the Residential plan to evaluate dynamic pricing structures for Ag customers. Because AECA has already proposed an Ag RTP rate design similar to

SCE's RTP structure that does not pass through wholesale prices,[62] it may be possible to shorten the timeline, and a Pilot may not be necessary. SCE's RTP rate design structure may not have the level of risks and unknowns to warrant a Pilot. Preliminary rate design preferences research could assess Ag customer interest in the RTP rate structure similar to SCE's, versus a DA RTP, PDP, and potentially other dynamic rate structures. PG&E proposes a timeline similar to the Residential plan to evaluate dynamic pricing structures for Ag customers and conduct further benchmarking with SCE regarding the experience of Ag customers in their RTP program.

8. Cost Recovery

As detailed in Chapter 5, on a preliminary basis and subject to further refinement, PG&E forecasts $7.8 million to $11 million in incremental costs to implement the C&I RTP Pilot assuming the CEV RTP Pilot is approved.[63] In addition, PG&E estimates needing between $400,000 and $700,000 for Residential and Ag rate design and preferences research. In A.20-10-011, PG&E requested the establishment of the Dynamic and Real-Time Pricing Memorandum Account (DRTPMA) to record costs, for future recovery in a GRC Ph. I proceeding or separate application, for $3.9 million to $6.0 million to implement the CEV RTP Pilot. PG&E requests authorization to also record the incremental costs of the C&I RTP Pilot in the DRTPMA. PG&E estimates the total incremental costs in 2022, 2023, 2024, and 2025 for the two RTP pilot proposals at $12.1 million to $17.7 million.[64] In this application, PG&E is not seeking immediate approval of the reasonableness of the costs it incurred to implement the C&I RTP Pilot. PG&E proposes to record in the DRTPMA the actual costs it incurs pursuant to the Commission's orders for the RTP Pilots, RTP rate design and preferences research, and any other activities ordered in this proceeding. The costs in

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62 AECA Direct Testimony, pp. 49-50.

63 If the CEV RTP Pilot is not approved PG&E will need to reevaluate the costs of the C&I RTP Pilot, because the C&I RTP Pilot as proposed assumes leveraging some of the infrastructure from the CEV RTP Pilot.

64 Costs for any potential new Residential and/or an Ag dynamic rate or pilot would need to be estimated by PG&E in the future.

the DRTPMA would be reviewed in a future GRC I proceeding or separate application, before being recovered in customer rates. If the Commission's decision requires PG&E to revise its proposal and incur costs that are greater or lesser than the forecasted costs set forth above, PG&E may adjust the amounts to be reviewed in a future GRC 1 proceeding or separate application, to reflect the actual costs recorded during this period. If the DRTPMA is not approved in the CEV proceeding, PG&E requests to establish a new memo account in this proceeding to record C&I RTP Pilot costs.

PG&E proposes that the C&I RTP Pilot costs discussed in Chapter 5 be recovered in the distribution component of rates. The costs described in testimony are largely related to the development of infrastructure (i.e., the platform to communicate pricing) which is beneficial to all customers. The proposed C&I RTP Pilot pricing tool is specifically structured to be able to take in prices from CCAs/ESPs.

9. Organization of Exhibit

This exhibit has a total of five chapters. The remainder of the exhibit is organized as follows:

Chapter 2 – Benchmarking Results and Other Data Supporting PG&E's Proposal

Chapter 3 – Analysis of Wholesale Markets

Chapter 4 – Rate Design

Chapter 5 – C&I RTP Pilot Plan

10. Conclusion and Summary of PG&E's RTP Proposals

In this chapter, PG&E has discussed the general policy objectives and context that have guided its proposal for a C&I RTP Pilot (to be conducted over a three-year period) and rate design and preferences research for the Residential and Ag customer classes (expected to yield results approximately one year after approval). PG&E also addressed specific issues posed by the Commission to be considered in the further development of RTP.

PG&E's proposed C&I RTP Pilot enables the evaluation of the potential for a dynamic rate option with fluctuating hourly prices to encourage C&I

customers to shift their load. The C&I RTP Pilot will also allow PG&E to evaluate whether its proposed rate is consistent with the Commission's ten rate design principles that were adopted in the Residential Rate OIR (RROIR) Phase II decision (D.14-06-029) and the Modern Rate Architecture framework outlined by PG&E in its 2018 Rate Design Window (RDW) rate design principles. It will also allow PG&E to assess if there are any unforeseen consequences, such as unintended or unreasonable cross-subsidies, before determining whether the rate should be adopted more broadly.

PG&E's proposal to conduct rate design and preferences research is consistent with its observation that there is limited experience with Residential and Ag RTP programs in the U.S., and the CEC is only in the very early stages of activities to develop automated price responsive technology and standards. Specifically, for Residential customers, the success of OG&E's VPP hybrid RTP rate, in contrast with the low adoption of ComEd and Ameren's RTP programs, combined with the recent failure of RTP in Texas to mitigate Residential customer risks, supports careful study before concluding what type of dynamic rate will best achieve load reduction goals while minimizing unintended consequences.[65] And as further support for this approach, activities by the CEC in the Load Management Rulemaking, the CalFlexHub, and in the development of Flexible Demand Appliance Standards have only just started. The results of these CEC activities, focused on the necessary technologies, communication standards, and customer response are a necessary foundation to inform any Commission decision on the appropriate type of dynamic pricing offering (including RTP) for Residential customers.

Benchmarking results, summarized in Section 3, show ample evidence from 53 active Non-Residential RTP rate schedules offered by regulated U.S. utilities that some large C&I customers have enrolled in and have

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65 See Chapter 2 for details of OG&E SmartHours and ComEd Hourly Pricing programs. OG&E SmartHours residential customers: ~93,000 (11 percent of OG&E residential customers). ComEd Hourly Pricing residential customers: ~35K (<2 percent of ComEd bundled customers). OG&E load Impacts at system peak: 1.31 kW critical peak day, .92 kW high price day, ComEd Hourly Pricing program load impacts at system peak: .51 kW.

benefited from RTP, and provided load response to support the electricity grid.

PG&E respectfully requests approval of its RTP proposals in this application summarized in Table 1-10 below:

TABLE 1-10
PG&E'S RTP PROPOSALS IN A.19-11-019

Line No.	Category	Topic	PG&E's Proposal
1	C&I RTP Pilot (Chapter 5)	a. Scale (Chapter 5)	Opt-in pilot with no cap.
		b. Eligibility (Chapter 5)	Limited to C&I customers Open to customers eligible for Schedules B-19/B-19V and B-20. (C&I customers > 500 kW are eligible for B-20. All C&I customers less than 500 kW are eligible for B-19 or B-19V.) Limit participation in the Pilot to a total of 2 CCAs and/or other ESPs. Participants with solar-paired storage > 10 kW required to purchase and install Net Generator Output Metering (NGOM) No dual participation in other load management approaches such as DR programs or PDP for the duration of this pilot.[a]
		c. Pricing Structure (Chapter 4)	One-part RTP with no CBL. Same rate design as CEV RTP Pilot proposed rate, with a capacity adder that replaces generation-related demand charges, and a revenue neutral adder, in B-19 and B-20 rates and retains B-19 and B-20 underlying transmission and distribution rate design including demand charges.
		d. Energy Price Formation and Price Granularity (Chapter 4)	Hourly prices based on CAISO DAM market. No locational pricing.
		e. Revenue Neutrality (Chapter 4)	Flat revenue neutral adder.
		f. Incentives (Chapter 5)	No customer, vendor or third-party incentives.
		g. Pricing Engine and Pricing Dissemination (Chapter 5)	Daily price calculations available via API and flat web site by a pre-determined time on a DA basis.
		h. Price Protections (Chapter 4)	No price protections (such as price caps or bill protection).
		i. Revenue under-collection risk (Chapter 4)	Track customer load profiles before and after going on RTP, RTP prices compared to TOU prices, system load of non-participating customers. Convene workshop after pilot to evaluate and discuss revenue under-collection data.

TABLE 1-10
PG&E'S RTP PROPOSALS IN A.19 11 019
(CONTINUED)

		j. ME&O (Chapter 5)	Targeted primarily to Large C&I Customers with > 100 kW maximum demand.
2	C&I RTP Pilot (Chapter 5)	k. Ongoing Customer Support (Chapter 5)	Metered usage data sharing through Your Account's Share My Data platform and procedures. For instantaneous data access, customers can install a KYZ Pulse module into their SmartMeter or MV90 meter as allowed by Electric Rule 2.
		l. M&E Plan (Chapter 5)	Qualitative and quantitative customer research to evaluate the effectiveness and attractiveness of RTP and identify barriers, risks, benefits, and motivations for participants and non-participants. Evaluate benefits and trade-offs inherent in RTP pricing, including whether and to what extent it could result in revenue shortfall. Assess individual, aggregate, and incremental load response. Assess GHG impacts based on load response metrics. Conduct customer bill analysis compared to their OAT and/or other load management approaches, such as PDP, DR programs and Pilots. Track program costs. Track customer load profiles before and after going on RTP, RTP prices compared to TOU prices, and system load of non-participating customers. Convene workshop after pilot to review M&E results.
		m. Cost and Timeline (Chapter 5)	Assuming PG&E's C&I RTP Pilot is adopted as proposed, PG&E anticipates the pilot rate would be available by Summer of 2023 and the pilot would run for 24 months (2 summers). Timeline coordinated with that proposed for PG&E's CEV Pilot, with billing system work starting no earlier than October 2022.) PG&E estimates $7.8 to $11 million in incremental C&I RTP Pilot costs.

TABLE 1-10
PG&E'S RTP PROPOSALS IN A.19 11 019
(CONTINUED)

3	Dynamic Pricing (and RTP) Rate Design and Preferences Research	a. Cost (Chapter 1)	Cost TBD based on research design (anticipated to be between $400,000 and $700,000).
		b. Timeline (Chapter 1)	Workshop within 60 days of decision in this proceeding to define objectives and methodology for Residential and Ag rate design and preferences research. Conduct Research (completed approximately 9 months from workshop) Evaluate results to determine appropriate Dynamic Pricing rate design(s) proposals for Ag and Residential customers. (1 month after research completed) Timing of Commission decision on any proposals dependent on procedural approach and other factors.
4	Cost Recovery	a. Dynamic and Real Time Pricing Memorandum Account (DRTPMA) (Chapter 1)	Record incremental costs from this proceeding in the DRTPMA if approved in the CEV proceeding, or if not approved, a new memo account established in this proceeding. Recover incremental costs in future GRC Ph. I proceeding or through separate application at the conclusion of the C&I RTP Pilot.

(a) See Attachment A. PG&E's CEV RTP Pilot Supplemental Testimony: Chapter 1: Dual Participation.

In addition, Table 1-11 has identified several issues that are relevant to both the CEV RTP Pilot proceeding and the C&I RTP Pilot proposed in this proceeding. Consideration should be made regarding which items should be addressed the same in both proceedings, and if addressed differently, it could affect PG&E's proposed costs and timelines.

TABLE 1-11
CEV RTP AND C&I RTP PILOT SHARED ISSUES AND PG&E'S RECOMMENDATION

Line No.	CEV RTP and C&I RTP Pilot Shared Issues	PG&E Recommendation For Addressing Shared Issues
1	Definition of Pilot Objectives to Optimize M&E Work	PG&E recommends that the C&I RTP Pilot high level objective be focused on load shift.
2	RTP Rate Design	PG&E recommends the same Rate Design Structure for both Pilots - Rate rider replacing generation component - DA hourly energy prices - Marginal capacity cost adder based on daily ANL forecast - Flat revenue neutral adder to retain parity relative to base rate schedules - No locational component
3	Pilot Cost Recovery	PG&E recommends costs for both Pilots be recorded to the same memorandum account for future recovery (DRTPMA). The Pilots share infrastructure such as the Pricing and Communications platform which would be difficult to track and recover in different venues.
4	Dual Participation on PDP or other DR Programs	PG&E recommends no Dual Participation in either Pilot, in order to evaluate incremental load impacts.
5	Timelines	PG&E recommends that the pilot timelines be coordinated for the most efficient use of implementation resources, including the billing system.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

ATTACHMENT A

COMMERCIAL ELECTRIC-VEHICLE DAY-AHEAD HOURLY

REAL TIME PRICING PILOT SUPPLEMENTAL TESTIMONY

CHAPTER 1 DUAL PARTICIPATION, SERVED MARCH 29, 2021

PACIFIC GAS AND ELECTRIC COMPANY

SUPPLEMENTAL TESTIMONY - CHAPTER 1

DUAL PARTICIPATION

PACIFIC GAS AND ELECTRIC COMPANY
SUPPLEMENTAL TESTIMONY - CHAPTER 1
DUAL PARTICIPATION

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PACIFIC GAS AND ELECTRIC COMPANY
SUPPLEMENTAL TESTIMONY - CHAPTER 1
DUAL PARTICIPATION

A. Introduction

At the December 7, 2020 prehearing conference, Administrative Law Judge Sisto commented that it could be helpful for Pacific Gas and Electric Company (PG&E) to provide supplemental testimony on the subject of dual participation by customers participating in its Day Ahead Hourly Real-Time Pricing Commercial Electric Vehicle (DAHRTP-CEV) Pilot (or CEV RTP Pilot). This March 29, 2021 supplemental testimony expands the discussion in Chapter 2, page 2-17 of PG&E’s original testimony proposing a CEV RTP Pilot rate, served on October 23, 2020.

This testimony provides justification for prohibiting dual participation for the duration of the CEV RTP Pilot, explains the history of dual participation rules, and highlights the growing need for more robust dual participation rules. PG&E recommends that CEV RTP Pilot customers be prohibited from also participating on other load management approaches, such as DR programs or Peak Day Pricing (PDP) for the duration of the pilot. This will allow the CPUC and interested parties in the proceeding to understand CEV RTP Pilot load response in isolation and determine the potential for incremental load impacts. PG&E further recommends that permanent changes to dual participation rules and new use cases should not be considered or directed in this narrow proceeding but rather should be the subject of future CPUC-led workshops.

B. Goals and Hypotheses of the Pilot

One of the goals of the proposed CEV RTP Pilot is to gather information on how participating CEV customers respond to DA RTP price signals and whether the CEV RTP Pilot rate supports decarbonization as well as strategic transportation electrification. The first hypothesis is that DA RTP prices that change hourly could induce customers to shift their usage (load shift) from high price time intervals to low price time intervals, with the result of benefiting the grid and reducing Greenhouse Gas (GHG) emissions. A second related hypothesis is that the load shift could support strategic electrification by adding load at low price time intervals and would promote decarbonization through fuel switching in a manner that minimizes increased demands on the grid.[1]

C. Arguments for Prohibiting Dual Participation During the Pilot, a History of Dual Participation Rules, and a Recommendation for Future Workshops

1. Dual Participation Should be Prohibited During the Pilot

a. A Controlled Experiment Should Only Test One Variable at a Time

PG&E's CEV RTP Pilot is designed to test the Pilot Rate's impact on load shift. PG&E will also examine how the pilot population's load shift compares to customers not on this rate and/or customers that engage with certain other load management approaches.[2] However, conducting a pilot to test the DAHRTP-CEV rate with customers who are also participating in another load management approach is not a prudent approach as it could skew the results related to the load shift associated with customers on this CEV RTP Pilot rate. To enable PG&E, the CPUC, and all parties to determine the extent to which RTP itself produces load shift or reduction, PG&E proposes that participants of the CEV RTP Pilot cannot also participate in other load management approaches.

b. If Dual Participation Were Allowed With Demand Response (DR) Programs or Pilots, It Would be Difficult to Identify if the Load Shift Was Attributable to DR or the Real Time Pricing (RTP) Pilot Rate, Due to the Complexities of Aggregator Managed DR Programs, Market Integration and Community Choice Aggregators (CCA)

PG&E's DR programs were initially focused on individual customers, but have moved to (1) relying significantly on aggregators who hold the customer relationship, and (2) being integrated into the California

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[1] For instance, from a gasoline- or diesel-powered vehicle to an EV.

[2] Other load management approaches are also the scenarios for dual participation with a real time rate. Examples include but are not limited to rate riders (e.g., Smart Rate and PDP), DR Programs [e.g., Capacity Bidding Program (CBP), SmartAC, Base Interruptible Program (BIP)], Energy Efficiency (EE) (e.g., EE Pay for Performance), Bilateral Contracts (e.g., a Resource Adequacy (RA) only contract from a DR resource), and pilots (e.g., the DRAM Pilot or the Emergency Load Reduction Pilot).

Independent System Operator (CAISO) market.[3] Of note, wholesale settlement occurs at the aggregate, not individual customer level, at the Sub Load Aggregation Point (Sub-LAP).[4] Below, PG&E provides four examples of settlement occurring at the aggregate, not individual customer level:

- CBP: CBP is an aggregator-managed program,[5] in which customers are organized into Proxy Demand Response (PDR) resources which are bid into the CAISO market. Moreover, the aggregator holds the customer relationship and decides how to use individual customers in its portfolio. CAISO wholesale settlement is on an aggregated basis at the PDR level, not at the customer level.
- BIP: PG&E's BIP program allows individual customers to participate either on their own or with an aggregator. Looking at a March 2021 snapshot of PG&E's BIP program, 74 percent of the customers, with an estimated 48 percent of the current megawatts (MW) in the program, participate through aggregators who hold the relationship with their customers. As with CBP, the BIP aggregators decide how to use the individual customers in their CAISO portfolios. PG&E's incentive calculation with BIP aggregators is also on an aggregated basis by CAISO sub-Lap, and not at the customer level.[6]

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3 *See* CPUC D.14-03-026, issued March 27, 2014, Ordering Paragraph (OP) 1: "The bifurcation of current demand response programs into load modifying resource and supply resource is adopted. Operational bifurcation will occur beginning with the 2017 demand response program year."

4 PG&E's sub-Load Aggregation Points (sub-LAPs) are defined by the CAISO as (relatively) continuous geographic areas that do not include significant transmission constraints within that area. PG&E has 16 sub-LAPs in its service territory. The market functions for sub-LAPs are twofold: (1) aggregations of DR and other DERs must fall within a single sub-LAP for resource registration and dispatch purposes; and (2) sub-LAPs are the basis for assigning congestion revenue rights.

5 PG&E CBP Tariff. https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-CBP.pdf.

6 This pertains to retail settlements. Per the BIP tariff, "Incentives will be paid on a monthly basis based on the directly enrolled customer's or **DR aggregator's CAISO sub-LAP portfolio** monthly Potential Load Reduction (PLR) amount." https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-BIP.pdf.

- Emergency Load Reduction Program (ELRP): As approved on March 25, 2021[7] (Rulemaking (R.) 20-11-003), ELRP will span a five-year period, 2021 to 2025 (subject to review for 2023 to 2025 in the DR Application cycle). The purpose of the ELRP is to allow the IOUs and CAISO to access incremental non-market integrated load reduction during times of high grid stress and emergencies involving inadequate market resources, with the goal of avoiding rotating outages.[8] Compensation may be calculated akin to a PDR Portfolio, called "Level Net Event Compensation" across all resources in the DR Provider's (DRP) ELRP Portfolio.[9]
- DRAM: The DRAM pilot was created in 2014 and has now progressed to the 7th pilot DRAM Auction for 2022, which launched in February 2021.[10] In DRAM, the DRAM Seller provides Resource Adequacy (RA) to the IOU based on its contract with the IOU. The Seller acquires retail customers which it registers with the CAISO and

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7 *See* R. 20-11-003 Proposed Decision (Rev. 1) issued March 24, 2021. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M373/K404/373404483.pdf.

8 The ELRP would be available through PG&E (direct and aggregator enrolled) and through third-party DRP with a market-integrated PDR resource. Aggregators that are in PG&E's programs would also be able to participate in ELRP, including CBP aggregators' resources that are bid in as PDR and PG&E's BIP aggregators' resources that are bid into CAISO's market as Reliability Demand Response Resources (RDRR). In addition, ELRP participation would be open to an aggregator managed behind-the-meter hybrid virtual power plant that meets certain criteria. Lastly, certain types of individual customers who can export through Rule 21 could also participate in ELRP.

9 "[T]he DRP shall submit an aggregate invoice for the Cumulative Portfolio Level Net Event Compensation of each PDR Portfolio … The Cumulative Portfolio Level Net Event Compensation of a PDR Portfolio over one Quarter is determined by summing the Portfolio Level Net Event Compensation across all ELRP events in that Quarter." R.20-11-003. Proposed Decision (Rev.1) issued March 24, 2021, Attachment 1 Guidance, pp. 16-17 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M373/K387/373387787.pdf.

10 On December 4, 2014, the CPUC issued D.14-12-024 which ordered the three IOUs to file an advice letter for the design and implementation of the DRAM pilot for 2016 & 2017 (2016 & 2017 DRAM), together with a standard contract. The DRAM pilot was intended to test: (a) the feasibility of procuring DR Supply Resources for RA from third party DRPs through an auction mechanism; and (b) the ability of winning bidders to integrate their DR Resources directly into the CAISO market. PG&E's resulting advice letter was approved by the CPUC in Resolution (Res.) E-5110, p. 2.

organizes into PDRs. The Seller owns the relationship with its customers. The Seller bids into the CAISO market, as required by the DRAM contract, and is expected to respond appropriately if it receives a CAISO award. However, how the Seller calls upon its customers to reduce load when it receives an award is up to the Seller. Again, PG&E's settlement with the Seller for the contract capacity payment is on an aggregate basis at the PDR level.

One critical feature that these IOU-DR programs and the DRAM Pilot share is the central position of aggregators, which own the DR relationship with the customer and settle for wholesale energy at the aggregate level, not at the individual customer level. If dual participation were allowed, and a DR customer also participated in RTP, it would be extremely challenging to attribute the load response due to RTP versus a DR program due to how the data are aggregated. The DR baselines cannot distinguish DR impacts from RTP impacts, particularly if RTP and DR events happen in the same time interval.

In addition, we expect DRPs to expand their activities with non-IOU Load Serving Entity (LSE), like CCAs. CCAs serve over half of PG&E's customers, and they have their own RA responsibilities. In D.20-06-039, the CPUC confirmed that Load-Serving Entities can use DR resources to satisfy up to 8.3 percent of their RA caps.[11] To the extent that RTP customers might be in a non-IOU LSE's DR program, PG&E would not have any insight into the non-IOU's DR program, and could not differentiate between the impacts of DR programs and RTP if dual participation were to be allowed between RTP and a CCA's DR program.

c. Dual Participation with Rate Riders Provide Double Compensation and Send Inaccurate Price Signals

As both RTP and Critical Peak Pricing (CPP) programs (e.g., PDP), incorporate the full market price for both energy and capacity, allowing

[11] Presumably non-IOU LSEs can use bundled and unbundled customers for that purpose, just as unbundled customers are eligible for PG&E's Smart AC, CBP, BIP programs as well as the DRAM pilot.

dual participation would provide compensation twice for the same energy and same capacity. In addition, allowing dual participation would send exaggerated price signals on CPP event days and lead to excessive cost shifting. RTP should send accurate pricing signals to customers, to support economically efficient behavior while also avoiding double compensation.

As an example, consider the combination of RTP with PDP. As described in PG&E's CEV RTP Pilot proposal in Chapter 2, page 2-17, the RTP rate incorporates the full utility marginal cost for capacity and energy. If PDP were allowed as a rider on top of the RTP rate, the price signal of this combination would depart from the RTP market basis. In fact, during PDP event hours two sets of price signals would be sent to the customers (once as a block of four equal prices for PDP event hours, and once for overlapping individual hourly prices for RTP). PDP and RTP together can result in significant deviations from the marginal cost level. In those PDP event hours, the combined generation price signal of RTP plus the PDP surcharge would be far above the marginal cost level. In the summer season, when a PDP credit is applied, it has the effect of bringing the combined price signal in the non-PDP event hours below the marginal cost level.[12] In addition, PDP and RTP may both produce a load response, but it would not be possible to attribute the load shift impact of PDP from RTP.[13] For these reasons, customers in the DAHRTP-CEV Pilot should not be eligible for PDP.

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12 C.f., Schedule B-19, section 21, b, "Customers will receive PDP credits on summer usage above the CRL on all summer-period days." CRL is the Capacity Reservation Level: Customers may elect a CRL and pay for a fixed level of capacity (kilowatt).

13 The Commission has already adopted limitations on combining PDP with DR programs, c.f. Schedule B-19, section 21, j. "Interaction with Other PG&E Demand Response Programs: Pursuant to D.18-11-029, customers on a PDP rate may no longer participate in another demand response program offered by PG&E or a third-party DRP as of October 26, 2018."

2. There is a Long History of Dual Participation Rules that Provide a Regulatory Foundation for Why Dual Participation Rules are Necessary.

a. The California Public Utilities Commission (CPUC) DR Dual Participation Rules

The Commission has had dual participation rules for DR programs since 2009.[14] These rules were repeated in D.17-12-003,[15] which confirmed earlier decisions' dual participation rules.[16] In D.17-12-003, the CPUC did not revise its policies on dual participation,[17] including Electric Rule 24/32's prohibition disallowing customers from simultaneously participating in a program provided by a third party and bid into the CAISO market, as well as in an event-based utility-administered DR program. Thus, the Commission's current dual participation rules go back over a decade, to a time when the Commission was just beginning to establish the rules for third party DRPs, eventually to use retail customers to provide DR and/or to bid PDR into the CAISO market.

The Commission created these dual participation rules to allow customers to simultaneously participate in two DR programs *as long as they do not inappropriately receive two payments for the same load reduction.* PG&E restates the highlights of the Commission's three rules for dual participation as follows:[18]

1) Duplicative payments for a single instance of load reduction or load drop is prohibited;

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[14] D.09-08-027. Section 18. pp. 142-158. https://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/106008.htm.

[15] D.17-12-003, pp. 31-32, citing D.12-04-045.

[16] D.12-04-045, pp. 47-48.

[17] D.17-12-003, pp. 33-34, referenced D.12-04-045 and a resolution (Res.E-4630) that classified CPP and PDP programs as event-based programs. D.17-12-003 also cited D.15-11-042's designation of CPP and RTP as non-event-based load modifying programs as presenting a differing view. However, D.17-12-003 did change existing policy.

[18] D.17-12-003, pp. 31-32, citing D.12-04-045.

2) Dual participation is permitted in two DR activities if one provides an energy payment and the other provides capacity payments; and

3) Dual participation in two DA or two day-of programs is prohibited.

A more recent 2018 decision, Decision (D.) 18-11-029, further restricted the ability for new dual participation between a CPP program and another utility or third-party administered DR program.[19]

PDP customers are ineligible for dual participation in other DR programs. Electric Rule 24 mandates that PG&E unenroll customers from PDP when a third party enrolls the customer in a CAISO wholesale market DR program.[20] Prohibiting such dual enrollment serves a number of purposes. First, it prevents potential conflicts between the operations of the PDP program and the DRP's use of the customer for DR in the wholesale market. Second, it avoids complexities that would arise over identifying the incremental effects of PDP on customer load versus the customer's load drop in response to the DRP's signal (in response to CAISO market awards). Third, if PDP and CAISO wholesale market participation through a DRP were allowed on a dual participation basis, customers who participated in both programs would be paid twice for some of the same load response.

PDP dual participation with the BIP also is not allowed, except for a BIP customers' legacy MWs as of October 2018.[21] If PDP is combined with BIP, the effect of PDP events can cause double payment. For instance, if the customer is responding to PDP as well as a BIP event, the incremental effect of one program versus the other would need to be separated, or there would be double compensation.

When necessary (e.g., for legacy BIP MWs where the dual participation rules are not in effect), PG&E manages evaluation of dual

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19 D.18-11-029, OP 1.

20 Electric Rule C.2.d.

21 *See* BIP Tariff Eligibility, Sheet 1 and Interaction with Customer's other Applicable Programs and Charges, Sheet 14, in https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_E-BIP.pdf "Grandfathered" has been used at times in the past to describe this exemption. For purposes of this testimony, PG&E refers to the exemption using the word "legacy".

participation in PDP and BIP by using non-PDP event days to estimate separate impacts. Should both BIP and PDP be called on the same day, the load impacts are allocated to BIP, not to PDP. However, this solution would not be available for RTP because RTP operates every day with hourly prices that are different every day. In other words, there are no similar non-RTP days that can be used to measure the customer's response absent RTP.[22]

b. CAISO Dual Participation Rules with Net Energy Metering (NEM) and the Distributed Energy Resource Provider (DERP) Agreement

The DERP Agreement is a CAISO market model that allows for an aggregation of Distributed Energy Resource (DER) to provide energy and ancillary services to the CAISO wholesale market. Currently the CAISO tariff[23] prohibits resources that are on a NEM tariff from participation in its DERP Agreement. In CAISO's DERP Initiative Application to the Federal Energy Regulatory Commission (FERC), CAISO explained, "The rationale for this rule is that under California's current NEM program a participating resource already receives benefits from netting its excess energy against subsequent electricity bills."[24]

c. The CPUC Energy Storage Order Instituting Rulemaking (OIR) Incrementality Rules

In its Energy Storage OIR decision (D.18-01-003), the CPUC adopted eleven rules to guide the formation of multiple use applications for energy storage. Rule 11 states, "In paying for performance of

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[22] Dual participation on PDP and PG&E's CBP is not allowed under the dual participation rules discussed in the next section because both are DA programs. However, the basic problem with RTP also applies with CBP (i.e., there is no way to determine what the customer's usage would have been absent RTP); so, there is no reliable way to develop the baseline for measurement of CBP performance.

[23] CAISO Corporation Fifth Replacement FERC Electric Tariff. Effective as of February 17, 2021. Section 4.17.3(d) Requirements for Distributed Energy Resource Aggregations. "A Distributed Energy Resource participating in a Distributed Energy Resource Aggregation may not also participate in a retail net energy metering program that does not expressly permit wholesale market participation."

[24] CAISO Corporation Docket No. ER16-1085 DERP Initiative. March 4, 2016, p. 7. https://www.caiso.com/Documents/Mar4_2016_TariffAmendment_DistributedEnergyResourceProvider_ER16-1085.pdf.

services, compensation and credit may only be permitted for those services which are incremental or distinct. Services provided must be measurable, and the same service only counted and compensated once to avoid double compensation."[25] While this rule was developed in the Energy Storage Proceeding, PG&E suggests that the Commission similarly prohibit dual participation in instances when the "services" resulting from load reduction are not incremental or distinct. The principle is especially relevant today. In the years since D.12-04-045, the universe of possible customer programs has expanded, creating the potential for "stacking" programs in ways that can make application of the basic principles difficult.

d. Existing Dual Participation Rules are Neither Complete Nor Contemplate Increasing Complexity

PG&E outlines some examples of the possible combinations of stacking of different load management tools (e.g., rates, programs, and incentives) below, including some areas of dual participation that were not discussed above.

[25] D.18-01-003, issued January 11, 2018, Appendix A – Adopted Rules, Rule 11.

TABLE 1-1
LOAD MANAGEMENT TOOLS TO CONSIDER WITH RTP DUAL PARTICIPATION

Line No.	(A) Rate Riders	(B) Programs	(C) Wholesale Market Integrated Pathways	(D) Pilots	(E) Tariffs
1	• PDP • Smart Rate • NEM	EE Pay for Performance	• PDR as a result of a bilateral contract (e.g., RA-only contract) • PDR through the CBP tariff • PDR through the SmartAC tariff • RDRR through the Base Interruptible tariff • Proxy Demand Response-Load Shift Resource (PDR-LSR) • DERP Agreement	• ELRP • DRAM[(a)]	DER Tariffs for Distribution Deferral

(a) DRAM is also wholesale market integrated and could also appear in column D because it participates in CAISO's market using the PDR model. It was placed in column E because it is not a program but remains a pilot.

3. Permanent Changes to Dual Participation Rules and New Use Cases Should Be Considered in Future Broader Workshops, Not Decided in this Narrow Proceeding for a Commercial Electric Vehicle (CEV) Dynamic Rate

PG&E maintains that dual participation rules need to be considered in a much broader context. The specific applications of dual participation rules across various programs to use cases need to be studied and possibly revised so as to avoid double compensation for the same energy or capacity at the same time. This broader context of dual participation rules and new use cases should not be considered or directed in this narrowly focused proceeding given that RTP is just one of many programs where dual participation may be contemplated, but rather should be the subject of future broader workshops. RTP would be one of the dual participation cases considered, rather than the focus of the workshop. The workshop would also help inform what dual participation rules should be permissible for RTP as well as other load management approaches.

PG&E recommends that the broader context of dual participation can be address through workshops hosted by the CPUC. Such workshops could serve as a fact-finding venue regarding existing CPUC and CAISO dual participation rules and policies and can initiate the establishment of principals and goals for dual participation.

D. Conclusion

In conclusion, dual participation with RTP should be prohibited for the duration of the CEV RTP Pilot to allow the CPUC and all interested parties in the proceeding to understand the load shift response from the CEV RTP Pilot rate in isolation. This testimony recommends that the CPUC approve PG&E's proposal that dual participation for CEV RTP Pilot customers be prohibited. PG&E further recommends that permanent changes to dual participation rules and new use cases should not be considered or directed in this narrow proceeding but rather should be the subject of broader CPUC-hosted workshops.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

ATTACHMENT B

DATA RESPONSES TO JOINT PARTIES-001 DATA REQUEST

PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase II
Application 19-11-019
Data Response

PG&E Data Request No.:	JointParties_001-Q01		
PG&E File Name:	GRC-2020-PhII_DR_JointParties_001-Q01		
Request Date:	March 10, 2021	Requester DR No.:	001
Date Sent:	March 23, 2021	Requesting Party:	California Solar and Storage Association/ Small Business Utility Advocates
PG&E Witness:	Tysen Streib	Requester:	Brad Heavner/ John Wilson

QUESTION 01

Please provide illustrative, detailed schedule level rate changes for all rate classes using the March 1, 2021 revenue requirement for the class default rate (present, proposed and proposed with PCIA and generation unbundled). Please provide both bundled and unbundled (DA/CCA) rates.

For marginal costs, please provide PG&E's understanding of the positions advocated in direct and as amended in rebuttal testimony by PG&E, TURN, CLECA and AECA. For revenue allocation, please assume a limit of movement to marginal costs to 25%, limit the combined generation, distribution, and PPP revenue requirement allocation to a 1.5% cap (bundled) on increases for each rate class and a 3% cap for DA/CCA customer rates.

For any other contested issues, please use PG&E's position. Please include a complete description of all assumptions utilized in developing the schedule level rates.

ANSWER 01

Per a discussion on March 15, 2021, CALSSA and SBUA have agreed to revise this data request to use May 1, 2020 revenue requirements.

Please see the attachment "GRC-2020-PhII_DR_JointParties_001-Q01_Atch01.xlsx".

To develop marginal cost assumptions, PG&E used its rate model developed for February 2021 Rebuttal testimony, and changed the following values where appropriate:

Party	Gen Cap Cost (transmission)	Gen Energy Cost	Primary Distribution Cap Cost	New Business Primary Marginal Cap Cost	Secondary Marginal Cap Cost	Marginal Customer Access Cost
CLECA	$274.64/kW-yr		$30.84/PCAF-kW-yr	$12.32/FLT-kW-yr	$2.83/FLT-kW-yr	
TURN	57.18/kW-yr w/reserve adder	Adds 1.7%				(see below)
AECA	$56.10/kW-yr w/reserve adder	Uses REC adder $0.00478 per kWh	Adjust PCAF and FLT for differences in customer growth rates in the revenue allocation step. (See table below)			(see below)

Proposed Marginal Customer Access Costs:

Customer Class	Subgroup	TURN	AECA w/RCS
Residential	Residential	40.31	81.55
Agriculture	AG A	202.90	388.28
Agriculture	AG B	1462.76	1,214.53
Agriculture	AG C	2057.18	1,253.36
Small Coml	Single phase	145.93	203.68
Small Coml	Poly phase	530.70	754.46
Medium	A10S/E19VS	415.61	2,088.31
Medium	A10P/E19VP	1234.30	1,744.89
Large	E19S	1048.65	4,259.36
	E19P	1350.62	3,111.68
	E19T	1350.62	3,695.92
	E20S	1633.58	4,687.40
	E20P	1350.62	3,142.63
	E20T	1350.62	3,167.21
Traffic Control	TC1	138.12	213.62

AECA Proposed PCAF and FLT Adjustments:

Rate Class	Gen Growth Adjustment	Dist Growth Adjustment
Residential	101.9%	100.6%
Commercial	97.8%	98.6%
Industrial	99.2%	102.7%
Agricultural	99.0%	98.1%

Pacific Gas and Electric Company
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E-TOU-C (Tiered)	PRESENT RATES (May 1, 2020)							PROPOSED RATES								With PCIA
	Distr	Gen	PPP	CIA	Other	Total		Distr	Gen	PCIA	PPP	CIA	Other	Total		Gen
SUMMER ENERGY CHARGE ($/kWh)																
Peak	.12767	.16735	.01296	.05339	.05196	.41333		.13640	.14506	.04327	.01343	.04678	.05196	.43689		.18833
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989		.11640	.08162	.04327	.01343	.04678	.05196	.35345		.12489
Baseline Credit				(.08633)		(.08633)						(.08709)		(.08709)		
WINTER ENERGY CHARGE ($/kWh)																
Peak	.07935	.11859	.01296	.05338	.05196	.31624		.08680	.07902	.04327	.01343	.04678	.05196	.32125		.12229
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891		.08348	.05399	.04327	.01343	.04678	.05196	.29290		.09726
Baseline Credit				(.08633)		(.08633)						(.08709)		(.08709)		
MINIMUM CHARGE																
(/meter/day)	*		.02123		.00166	.32854	10.00	*			.02199		.00166	.32854	10.00	
(/kWh)					.05160								.05160			

* Calculated residually as total less sum of other charges. (Present Rates)

* Calculated residually as total less sum of other charges. (Proposed Rates)

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Present and Proposed Rates
Year 3 Transition Rates

B-1

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
ENERGY CHARGE (/kWh)														
Summer														
Peak	.09551	.17737	.01299	.04218	.32805		.10104	.13455	.04107	.01211	.04218	.33095		.17562
Part-Peak	.09551	.12814	.01299	.04218	.27882		.10104	.08532	.04107	.01211	.04218	.28172		.12639
Off-Peak	.09551	.10733	.01299	.04218	.25801		.10104	.06451	.04107	.01211	.04218	.26091		.10558
Winter														
Peak	.07534	.12212	.01299	.04218	.25263		.08087	.07930	.04107	.01211	.04218	.25553		.12037
Off-Peak	.07534	.10600	.01299	.04218	.23651		.08087	.06318	.04107	.01211	.04218	.23941		.10425
Super Off-Peak	.07534	.08958	.01299	.04218	.22009		.08087	.04676	.04107	.01211	.04218	.22299		.08783
CUSTOMER CHARGE (/meter/day)														
Single-phase	.32854				.32854	10.00	.32854					.32854	10.00	
Polyphase	.82136				.82136	25.00	.82136					.82136	25.00	

B-10

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGE (/kW)														
Secondary														
Summer	4.75			8.84	13.59		4.87				8.84	13.72		
Winter	4.75			8.84	13.59		4.87				8.84	13.72		
ENERGY CHARGE (/kWh)														
Secondary														
Summer														
Peak	.04539	.20191	.01205	.01474	.27409		.04627	.15521	.04189	.01202	.01474	.27014		.19711
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04627	.09352	.04189	.01202	.01474	.20845		.13542
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04627	.06095	.04189	.01202	.01474	.17588		.10285
Winter														
Peak	.02716	.14386	.01205	.01474	.19781		.02804	.09716	.04189	.01202	.01474	.19386		.13906
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02804	.06168	.04189	.01202	.01474	.15838		.10358
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02804	.02534	.04189	.01202	.01474	.12204		.06724
CUSTOMER CHARGE (/meter/day)	4.77841				4.77841	145.44	4.90148					4.90148	149.19	

B-19 Secondary

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGES (/kW)														
Summer														
Peak	10.87	14.92			25.79		10.11	14.69				24.80		14.69
Part-Peak	3.13	2.17			5.30		2.91	2.14				5.05		2.14
Maximum	12.53			8.91	21.44		11.65				8.91	20.57		
Winter														
Peak	.00	1.77			1.77		.00	1.74				1.74		1.74
Maximum	12.53			8.91	21.44		11.65				8.91	20.57		
DEMAND CHARGES - OPTION R ($/kW)														
Summer														
Peak	2.72				2.72		2.53					2.53		
Part-Peak	.78				.78		.73					.73		
Maximum	12.53			8.91	21.44		11.65				8.91	20.57		
Winter														
Peak	.00						.00					.00		
Maximum	12.53			8.91	21.44		11.65				8.91	20.57		
ENERGY CHARGES (/kWh)														
Summer														
Peak	.00000	.13878	.01177	.01465	.16520		.00000	.09703	.03965	.01375	.01466	.16509		.13668
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000	.06770	.03965	.01375	.01466	.13575		.10734
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000	.04694	.03965	.01375	.01466	.11500		.08659
Winter														
Peak	.00000	.11986	.01177	.01465	.14628		.00000	.07807	.03965	.01375	.01466	.14613		.11772
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000	.04691	.03965	.01375	.01466	.11496		.08655
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000	.00509	.03965	.01375	.01466	.07315		.04474
ENERGY CHARGES - OPTION R (/kWh)														
Summer														
Peak	.07499	.26625	.01177	.01465	.36766		.07326	.22489	.03965	.01375	.01466	.36620		.26453
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02499	.08932	.03965	.01375	.01466	.18236		.12896
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00303	.05081	.03965	.01375	.01466	.12189		.09045
Winter														
Peak	.00000	.13442	.01177	.01465	.16084		.00000	.09306	.03965	.01375	.01466	.16111		.13270
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000	.05074	.03965	.01375	.01466	.11879		.09038
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000	.01492	.03965	.01375	.01466	.08297		.05456
CUSTOMER CHARGE (/meter/day)														
B-19	24.77594				24.77594	754.12	23.23957					23.23957	707.35	
Rate V	4.77841				4.77841	145.44	4.90148					4.90148	149.19	

B-20 Secondary

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGES (/kW)														
Summer														
Peak	11.13	14.61			25.74		10.04	14.41				24.46		14.41
Part-Peak	3.19	2.12			5.31		2.88	2.09				4.97		2.09
Maximum	11.66	.00		9.75	21.41		10.52				9.74	20.26		
Winter														
Peak	.00	1.86			1.86		.00	1.84				1.84		1.84
Maximum	11.66	.00		9.75	21.41		10.52				9.74	20.26		
DEMAND CHARGES - OPTION R ($/kW)														
Summer														

Peak	2.78	.00			2.78		2.51					2.51		
Part-Peak	.80	.00			.80		.72					.72		
Maximum	11.66	.00		9.75	21.41		10.52				9.74	20.26		
Winter														
Peak	.00	.00			.00		.00					.00		
Maximum	11.66	.00		9.75	21.41		10.52				9.74	20.26		
ENERGY CHARGES (/kWh)														
Summer														
Peak	.00000	.13233	.01146	.01413	.15792		.00000	.09249	.03807	.01251	.01413	.15720		.13056
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000	.06594	.03807	.01251	.01413	.13065		.10401
Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000	.04498	.03807	.01251	.01413	.10968		.08304
Winter														
Peak	.00000	.11630	.01146	.01413	.14189		.00000	.07638	.03807	.01251	.01413	.14108		.11444
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000	.04484	.03807	.01251	.01413	.10955		.08291
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000	.00260	.03807	.01251	.01413	.06731		.04067
ENERGY CHARGES - OPTION R (/kWh)														
Summer														
Peak	.07547	.25843	.01146	.01413	.35949		.07325	.21892	.03807	.01251	.01413	.35687		.25698
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02317	.08617	.03807	.01251	.01413	.17404		.12423
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00160	.04871	.03807	.01251	.01413	.11501		.08677
Winter														
Peak	.00000	.13182	.01146	.01413	.15741		.00000	.09231	.03807	.01251	.01413	.15701		.13037
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000	.04858	.03807	.01251	.01413	.11328		.08664
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000	.01283	.03807	.01251	.01413	.07753		.05089
CUSTOMER CHARGE														
(/meter/day)	45.08771				45.08771	1372.36	40.67787					40.67787	1238.13	

AG-C	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGE (/kW)														
Secondary														
Summer Max Peak Period	6.17	12.52			18.69		6.27	12.34				18.61		12.34
Summer Maximum	11.21				11.21		11.40	.00				11.40		.00
Winter Maximum	11.21				11.21		11.40	.00				11.40		.00
ENERGY CHARGE (/kWh)														
Summer														
Peak	.02005	.11604	.01135	.03624	.18368		.02251	.07628	.03850	.01381	.03625	.18735		.11478
Part-Peak														
Off-Peak	.01009	.08656	.01135	.03624	.14424		.01255	.04680	.03850	.01381	.03625	.14791		.08530
Winter														
Peak	.00690	.10140	.01135	.03624	.15589		.00936	.06164	.03850	.01381	.03625	.15956		.10014
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00919	.03612	.03850	.01381	.03625	.13387		.07462
CUSTOMER CHARGE														
(/meter/day)	1.43343				1.43343	43.63	1.43343				.00000	1.43343	43.63	

E-TOU-C (Tiered)	PRESENT RATES (May 1, 2020)							PROPOSED RATES								With PCIA
	Distr	Gen	PPP	CIA	Other	Total		Distr	Gen	PCIA	PPP	CIA	Other	Total		Gen
SUMMER ENERGY CHARGE ($/kWh)																
Peak	.12767	.16735	.01296	.05339	.05196	.41333		.13625	.14555	.04327	.01344	.04684	.05196	.43729		.18882
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989		.11625	.08211	.04327	.01344	.04684	.05196	.35385		.12538
Baseline Credit				(.08633)		(.08633)						(.08720)		(.08720)		
WINTER ENERGY CHARGE ($/kWh)																
Peak	.07935	.11859	.01296	.05338	.05196	.31624		.08664	.07951	.04327	.01344	.04684	.05196	.32165		.12277
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891		.08332	.05448	.04327	.01344	.04684	.05196	.29330		.09774
Baseline Credit				(.08633)		(.08633)						(.08720)		(.08720)		
MINIMUM CHARGE																
(/meter/day)	*		.02123		.00166	.32854	10.00	*			.02200		.00166	.32854	10.00	
(/kWh)					.05160								.05160			

* Calculated residually as total less sum of other charges.

* Calculated residually as total less sum of other charges.

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	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
ENERGY CHARGE (/kWh)														
Summer														
Peak	.09551	.17737	.01299	.04218	.32805		.09798	.13657	.04107	.01212	.04218	.32992		.17765
Part-Peak	.09551	.12814	.01299	.04218	.27882		.09798	.08734	.04107	.01212	.04218	.28069		.12842
Off-Peak	.09551	.10733	.01299	.04218	.25801		.09798	.06653	.04107	.01212	.04218	.25988		.10761
Winter														
Peak	.07534	.12212	.01299	.04218	.25263		.07781	.08132	.04107	.01212	.04218	.25450		.12240
Off-Peak	.07534	.10600	.01299	.04218	.23651		.07781	.06520	.04107	.01212	.04218	.23838		.10628
Super Off-Peak	.07534	.08958	.01299	.04218	.22009		.07781	.04878	.04107	.01212	.04218	.22196		.08986
CUSTOMER CHARGE (/meter/day)														
Single-phase	.32854				.32854	10.00	.32854					.32854	10.00	
Polyphase	.82136				.82136	25.00	.82136					.82136	25.00	

(PG&E-RTP-1)

TURN

Pacific Gas and Electric Company
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	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGE (/kW)														
Secondary														
Summer	4.75			8.84	13.59		4.65				8.84	13.49		
Winter	4.75			8.84	13.59		4.65				8.84	13.49		
ENERGY CHARGE (/kWh)														
Secondary														
Summer														
Peak	.04539	.20191	.01205	.01474	.27409		.04465	.15537	.04189	.01203	.01474	.26867		.19726
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04465	.09368	.04189	.01203	.01474	.20698		.13557
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04465	.06111	.04189	.01203	.01474	.17441		.10300
Winter														
Peak	.02716	.14386	.01205	.01474	.19781		.02642	.09732	.04189	.01203	.01474	.19239		.13921
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02642	.06184	.04189	.01203	.01474	.15691		.10373
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02642	.02550	.04189	.01203	.01474	.12057		.06739
CUSTOMER CHARGE (/meter/day)	4.77841				4.77841	145.44	4.67369					4.67369	142.26	

(PG&E-RTP-1)

TURN

B-19 Secondary

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGES (/kW)														
Summer														
Peak	10.87	14.92			25.79		10.13	14.73				24.86		14.73
Part-Peak	3.13	2.17			5.30		2.92	2.14				5.06		2.14
Maximum	12.53			8.91	21.44		11.68				8.91	20.59		
Winter														
Peak	.00	1.77			1.77		.00	1.75				1.75		1.75
Maximum	12.53			8.91	21.44		11.68				8.91	20.59		
DEMAND CHARGES - OPTION R ($/kW)														
Summer														
Peak	2.72				2.72		2.53					2.53		
Part-Peak	.78				.78		.73					.73		
Maximum	12.53			8.91	21.44		11.68				8.91	20.59		
Winter														
Peak	.00						.00					.00		
Maximum	12.53			8.91	21.44		11.68				8.91	20.59		
ENERGY CHARGES (/kWh)														
Summer														
Peak	.00000	.13878	.01177	.01465	.16520		.00000	.09741	.03965	.01376	.01466	.16547		.13705
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000	.06799	.03965	.01376	.01466	.13605		.10763
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000	.04718	.03965	.01376	.01466	.11524		.08683
Winter														
Peak	.00000	.11986	.01177	.01465	.14628		.00000	.07845	.03965	.01376	.01466	.14651		.11810
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000	.04714	.03965	.01376	.01466	.11520		.08678
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000	.00512	.03965	.01376	.01466	.07318		.04476
ENERGY CHARGES - OPTION R (/kWh)														
Summer														
Peak	.07499	.26625	.01177	.01465	.36766		.07331	.22519	.03965	.01376	.01466	.36656		.26484
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02504	.08962	.03965	.01376	.01466	.18272		.12927
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00308	.05111	.03965	.01376	.01466	.12225		.09076
Winter														
Peak	.00000	.13442	.01177	.01465	.16084		.00000	.09336	.03965	.01376	.01466	.16142		.13301
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000	.05104	.03965	.01376	.01466	.11910		.09069
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000	.01522	.03965	.01376	.01466	.08328		.05487
CUSTOMER CHARGE (/meter/day)														
B-19	24.77594				24.77594	754.12	23.18112					23.18112	705.58	
Rate V	4.77841				4.77841	145.44	4.67369					4.67369	142.26	

B-20 Secondary

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGES (/kW)														
Summer														
Peak	11.13	14.61			25.74		10.75	14.45				25.20		14.45
Part-Peak	3.19	2.12			5.31		3.08	2.10				5.18		2.10
Maximum	11.66	.00		9.75	21.41		11.26				9.74	21.00		
Winter														
Peak	.00	1.86			1.86		.00	1.84				1.84		1.84
Maximum	11.66	.00		9.75	21.41		11.26				9.74	21.00		
DEMAND CHARGES - OPTION R ($/kW)														
Summer														

Peak	2.78	.00			2.78		2.69					2.69		
Part-Peak	.80	.00			.80		.77					.77		
Maximum	11.66	.00		9.75	21.41		11.26				9.74	21.00		
Winter														
Peak	.00	.00			.00		.00					.00		
Maximum	11.66	.00		9.75	21.41		11.26				9.74	21.00		
ENERGY CHARGES (/kWh)														
Summer														
Peak	.00000	.13233	.01146	.01413	.15792		.00000	.09282	.03807	.01252	.01413	.15754		.13089
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000	.06621	.03807	.01252	.01413	.13092		.10427
Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000	.04519	.03807	.01252	.01413	.10990		.08325
Winter														
Peak	.00000	.11630	.01146	.01413	.14189		.00000	.07673	.03807	.01252	.01413	.14144		.11479
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000	.04505	.03807	.01252	.01413	.10976		.08311
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000	.00261	.03807	.01252	.01413	.06733		.04068
ENERGY CHARGES - OPTION R (/kWh)														
Summer														
Peak	.07547	.25843	.01146	.01413	.35949		.07469	.21919	.03807	.01252	.01413	.35859		.25725
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02461	.08644	.03807	.01252	.01413	.17576		.12450
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00304	.04898	.03807	.01252	.01413	.11673		.08704
Winter														
Peak	.00000	.13182	.01146	.01413	.15741		.00000	.09258	.03807	.01252	.01413	.15729		.13064
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000	.04885	.03807	.01252	.01413	.11356		.08691
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000	.01310	.03807	.01252	.01413	.07781		.05116
CUSTOMER CHARGE														
(/meter/day)	45.08771				45.08771	1372.36	43.53321					43.53321	1325.04	

AG-C	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGE (/kW)														
Secondary														
Summer Max Peak Period	6.17	12.52			18.69		6.75	11.73				18.48		11.73
Summer Maximum	11.21				11.21		12.26	.00				12.26		.00
Winter Maximum	11.21				11.21		12.26	.00				12.26		.00
ENERGY CHARGE (/kWh)														
Summer														
Peak	.02005	.11604	.01135	.03624	.18368		.02307	.07216	.03850	.01382	.03625	.18380		.11066
Part-Peak														
Off-Peak	.01009	.08656	.01135	.03624	.14424		.01311	.04268	.03850	.01382	.03625	.14436		.08118
Winter														
Peak	.00690	.10140	.01135	.03624	.15589		.00992	.05752	.03850	.01382	.03625	.15601		.09602
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00975	.03200	.03850	.01382	.03625	.13032		.07050
CUSTOMER CHARGE														
(/meter/day)	1.43343				1.43343	43.63	1.43343				.00000	1.43343	43.63	

(PG&E-RTP-1)

TURN

Pacific Gas and Electric Company
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E-TOU-C (Tiered)	PRESENT RATES (May 1, 2020)							PROPOSED RATES								With PCIA
	Distr	Gen	PPP	CIA	Other	Total		Distr	Gen	PCIA	PPP	CIA	Other	Total		Gen
SUMMER ENERGY CHARGE ($/kWh)																
Peak	.12767	.16735	.01296	.05339	.05196	.41333		.13681	.14685	.04327	.01349	.04716	.05196	.43952		.19012
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989		.11681	.08341	.04327	.01349	.04716	.05196	.35609		.12668
Baseline Credit				(.08633)		(.08633)						(.08779)		(.08779)		
WINTER ENERGY CHARGE ($/kWh)																
Peak	.07935	.11859	.01296	.05338	.05196	.31624		.08721	.08080	.04327	.01349	.04716	.05196	.32387		.12407
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891		.08389	.05577	.04327	.01349	.04716	.05196	.29552		.09904
Baseline Credit				(.08633)		(.08633)						(.08779)		(.08779)		
MINIMUM CHARGE																
(/meter/day)	*		.02123		.00166	.32854	10.00	*			.02209		.00166	.32854	10.00	
(/kWh)					.05160								.05160			

* Calculated residually as total less sum of other charges.

* Calculated residually as total less sum of other charges.

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	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
ENERGY CHARGE (/kWh)														
Summer														
Peak	.09551	.17737	.01299	.04218	.32805		.10093	.13455	.04107	.01217	.04218	.33090		.17562
Part-Peak	.09551	.12814	.01299	.04218	.27882		.10093	.08532	.04107	.01217	.04218	.28167		.12639
Off-Peak	.09551	.10733	.01299	.04218	.25801		.10093	.06451	.04107	.01217	.04218	.26086		.10558
Winter														
Peak	.07534	.12212	.01299	.04218	.25263		.08076	.07930	.04107	.01217	.04218	.25548		.12037
Off-Peak	.07534	.10600	.01299	.04218	.23651		.08076	.06318	.04107	.01217	.04218	.23936		.10425
Super Off-Peak	.07534	.08958	.01299	.04218	.22009		.08076	.04676	.04107	.01217	.04218	.22294		.08783
CUSTOMER CHARGE (/meter/day)														
Single-phase	.32854				.32854	10.00	.32854					.32854	10.00	
Polyphase	.82136				.82136	25.00	.82136					.82136	25.00	

Pacific Gas and Electric Company
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	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGE (/kW)														
Secondary														
Summer	4.75			8.84	13.59		4.94				8.84	13.79		
Winter	4.75			8.84	13.59		4.94				8.84	13.79		
ENERGY CHARGE (/kWh)														
Secondary														
Summer														
Peak	.04539	.20191	.01205	.01474	.27409		.04676	.15397	.04189	.01208	.01474	.26944		.19586
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04676	.09228	.04189	.01208	.01474	.20775		.13417
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04676	.05971	.04189	.01208	.01474	.17518		.10160
Winter														
Peak	.02716	.14386	.01205	.01474	.19781		.02853	.09592	.04189	.01208	.01474	.19316		.13781
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02853	.06044	.04189	.01208	.01474	.15768		.10233
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02853	.02410	.04189	.01208	.01474	.12134		.06599
CUSTOMER CHARGE (/meter/day)	4.77841				4.77841	145.44	4.96875					4.96875	151.24	

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B-19 Secondary

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGES (/kW)														
Summer														
Peak	10.87	14.92			25.79		10.03	14.53				24.55		14.53
Part-Peak	3.13	2.17			5.30		2.89	2.11				5.00		2.11
Maximum	12.53			8.91	21.44		11.56				8.91	20.47		
Winter														
Peak	.00	1.77			1.77		.00	1.72				1.72		1.72
Maximum	12.53			8.91	21.44		11.56				8.91	20.47		
DEMAND CHARGES - OPTION R ($/kW)														
Summer														
Peak	2.72				2.72		2.51					2.51		
Part-Peak	.78				.78		.72					.72		
Maximum	12.53			8.91	21.44		11.56				8.91	20.47		
Winter														
Peak	.00						.00					.00		
Maximum	12.53			8.91	21.44		11.56				8.91	20.47		
ENERGY CHARGES (/kWh)														
Summer														
Peak	.00000	.13878	.01177	.01465	.16520		.00000	.09547	.03965	.01381	.01466	.16358		.13512
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000	.06647	.03965	.01381	.01466	.13458		.10611
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000	.04595	.03965	.01381	.01466	.11407		.08560
Winter														
Peak	.00000	.11986	.01177	.01465	.14628		.00000	.07649	.03965	.01381	.01466	.14460		.11614
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000	.04595	.03965	.01381	.01466	.11406		.08560
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000	.00497	.03965	.01381	.01466	.07308		.04462
ENERGY CHARGES - OPTION R (/kWh)														
Summer														
Peak	.07499	.26625	.01177	.01465	.36766		.07307	.22361	.03965	.01381	.01466	.36480		.26326
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02480	.08804	.03965	.01381	.01466	.18096		.12769
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00284	.04953	.03965	.01381	.01466	.12049		.08918
Winter														
Peak	.00000	.13442	.01177	.01465	.16084		.00000	.09178	.03965	.01381	.01466	.15990		.13143
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000	.04946	.03965	.01381	.01466	.11758		.08911
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000	.01364	.03965	.01381	.01466	.08176		.05329
CUSTOMER CHARGE (/meter/day)														
B-19	24.77594				24.77594	754.12	23.09341					23.09341	702.91	
Rate V	4.77841				4.77841	145.44	4.96875					4.96875	151.24	

B-20 Secondary

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGES (/kW)														
Summer														
Peak	11.13	14.61			25.74		9.61	14.14				23.75		14.14
Part-Peak	3.19	2.12			5.31		2.76	2.05				4.81		2.05
Maximum	11.66	.00		9.75	21.41		10.07				9.74	19.82		
Winter														
Peak	.00	1.86			1.86		.00	1.80				1.80		1.80
Maximum	11.66	.00		9.75	21.41		10.07				9.74	19.82		
DEMAND CHARGES - OPTION R ($/kW)														
Summer														

Peak	2.78	.00			2.78		2.40					2.40		
Part-Peak	.80	.00			.80		.69					.69		
Maximum	11.66	.00		9.75	21.41		10.07				9.74	19.82		
Winter														
Peak	.00	.00			.00		.00					.00		
Maximum	11.66	.00		9.75	21.41		10.07				9.74	19.82		
ENERGY CHARGES (/kWh)														
Summer														
Peak	.00000	.13233	.01146	.01413	.15792		.00000	.09001	.03807	.01257	.01413	.15477		.12807
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000	.06396	.03807	.01257	.01413	.12873		.10203
Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000	.04340	.03807	.01257	.01413	.10816		.08146
Winter														
Peak	.00000	.11630	.01146	.01413	.14189		.00000	.07379	.03807	.01257	.01413	.13856		.11186
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000	.04331	.03807	.01257	.01413	.10808		.08138
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000	.00247	.03807	.01257	.01413	.06724		.04054
ENERGY CHARGES - OPTION R (/kWh)														
Summer														
Peak	.07547	.25843	.01146	.01413	.35949		.07237	.21690	.03807	.01257	.01413	.35404		.25497
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02229	.08415	.03807	.01257	.01413	.17121		.12222
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00072	.04669	.03807	.01257	.01413	.11218		.08476
Winter														
Peak	.00000	.13182	.01146	.01413	.15741		.00000	.09029	.03807	.01257	.01413	.15506		.12836
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000	.04656	.03807	.01257	.01413	.11133		.08463
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000	.01081	.03807	.01257	.01413	.07558		.04888
CUSTOMER CHARGE														
(/meter/day)	45.08771				45.08771	1372.36	38.94380					38.94380	1185.35	

AG-C	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGE (/kW)														
Secondary														
Summer Max Peak Period	6.17	12.52			18.69		6.25	12.29				18.54		12.29
Summer Maximum	11.21				11.21		11.36	.00				11.36		.00
Winter Maximum	11.21				11.21		11.36	.00				11.36		.00
ENERGY CHARGE (/kWh)														
Summer														
Peak	.02005	.11604	.01135	.03624	.18368		.02248	.07595	.03850	.01387	.03625	.18705		.11445
Part-Peak														
Off-Peak	.01009	.08656	.01135	.03624	.14424		.01252	.04647	.03850	.01387	.03625	.14761		.08497
Winter														
Peak	.00690	.10140	.01135	.03624	.15589		.00933	.06131	.03850	.01387	.03625	.15926		.09981
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00916	.03579	.03850	.01387	.03625	.13357		.07429
CUSTOMER CHARGE														
(/meter/day)	1.43343				1.43343	43.63	1.43343				.00000	1.43343	43.63	

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	PRESENT RATES (May 1, 2020)							PROPOSED RATES								
E-TOU-C (Tiered)	Distr	Gen	PPP	CIA	Other	Total		Distr	Gen	PCIA	PPP	CIA	Other	Total		With PCIA Gen
SUMMER ENERGY CHARGE ($/kWh)																
Peak	.12767	.16735	.01296	.05339	.05196	.41333		.13689	.14459	.04327	.01343	.04678	.05196	.43691		.18785
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989		.11689	.08114	.04327	.01343	.04678	.05196	.35347		.12441
Baseline Credit				(.08633)		(.08633)						(.08709)		(.08709)		
WINTER ENERGY CHARGE ($/kWh)																
Peak	.07935	.11859	.01296	.05338	.05196	.31624		.08729	.07854	.04327	.01343	.04678	.05196	.32126		.12181
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891		.08397	.05351	.04327	.01343	.04678	.05196	.29291		.09678
Baseline Credit				(.08633)		(.08633)						(.08709)		(.08709)		
MINIMUM CHARGE																
(/meter/day)	*		.02123		.00166	.32854	10.00	*			.02200		.00166	.32854	10.00	
(/kWh)					.05160								.05160			

* Calculated residually as total less sum of other charges. (Present Rates)

* Calculated residually as total less sum of other charges. (Proposed Rates)

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	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
ENERGY CHARGE (/kWh)														
Summer														
Peak	.09551	.17737	.01299	.04218	.32805		.09823	.13583	.04107	.01211	.04218	.32942		.17690
Part-Peak	.09551	.12814	.01299	.04218	.27882		.09823	.08660	.04107	.01211	.04218	.28019		.12767
Off-Peak	.09551	.10733	.01299	.04218	.25801		.09823	.06579	.04107	.01211	.04218	.25938		.10686
Winter														
Peak	.07534	.12212	.01299	.04218	.25263		.07806	.08058	.04107	.01211	.04218	.25400		.12165
Off-Peak	.07534	.10600	.01299	.04218	.23651		.07806	.06446	.04107	.01211	.04218	.23788		.10553
Super Off-Peak	.07534	.08958	.01299	.04218	.22009		.07806	.04804	.04107	.01211	.04218	.22146		.08911
CUSTOMER CHARGE (/meter/day)														
Single-phase	.32854				.32854	10.00	.32854					.32854	10.00	
Polyphase	.82136				.82136	25.00	.82136					.82136	25.00	

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	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGE (/kW)														
Secondary														
Summer	4.75			8.84	13.59		4.83				8.84	13.68		
Winter	4.75			8.84	13.59		4.83				8.84	13.68		
ENERGY CHARGE (/kWh)														
Secondary														
Summer														
Peak	.04539	.20191	.01205	.01474	.27409		.04599	.15497	.04189	.01202	.01474	.26961		.19687
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04599	.09328	.04189	.01202	.01474	.20792		.13518
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04599	.06071	.04189	.01202	.01474	.17535		.10261
Winter														
Peak	.02716	.14386	.01205	.01474	.19781		.02776	.09692	.04189	.01202	.01474	.19333		.13882
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02776	.06144	.04189	.01202	.01474	.15785		.10334
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02776	.02510	.04189	.01202	.01474	.12151		.06700
CUSTOMER CHARGE (/meter/day)	4.77841				4.77841	145.44	4.86153					4.86153	147.97	

B-19 Secondary

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGES (/kW)														
Summer														
Peak	10.87	14.92			25.79		10.22	14.67				24.88		14.67
Part-Peak	3.13	2.17			5.30		2.94	2.13				5.08		2.13
Maximum	12.53			8.91	21.44		11.78				8.91	20.69		
Winter														
Peak	.00	1.77			1.77		.00	1.74				1.74		1.74
Maximum	12.53			8.91	21.44		11.78				8.91	20.69		
DEMAND CHARGES - OPTION R ($/kW)														
Summer														
Peak	2.72				2.72		2.55					2.55		
Part-Peak	.78				.78		.74					.74		
Maximum	12.53			8.91	21.44		11.78				8.91	20.69		
Winter														
Peak	.00						.00					.00		
Maximum	12.53			8.91	21.44		11.78				8.91	20.69		
ENERGY CHARGES (/kWh)														
Summer														
Peak	.00000	.13878	.01177	.01465	.16520		.00000	.09677	.03965	.01375	.01466	.16482		.13641
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000	.06749	.03965	.01375	.01466	.13554		.10713
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000	.04678	.03965	.01375	.01466	.11483		.08642
Winter														
Peak	.00000	.11986	.01177	.01465	.14628		.00000	.07780	.03965	.01375	.01466	.14586		.11745
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000	.04675	.03965	.01375	.01466	.11480		.08639
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000	.00508	.03965	.01375	.01466	.07313		.04472
ENERGY CHARGES - OPTION R (/kWh)														
Summer														
Peak	.07499	.26625	.01177	.01465	.36766		.07351	.22467	.03965	.01375	.01466	.36623		.26432
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02524	.08910	.03965	.01375	.01466	.18239		.12875
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00328	.05059	.03965	.01375	.01466	.12192		.09024
Winter														
Peak	.00000	.13442	.01177	.01465	.16084		.00000	.09284	.03965	.01375	.01466	.16089		.13249
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000	.05052	.03965	.01375	.01466	.11857		.09017
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000	.01470	.03965	.01375	.01466	.08275		.05435
CUSTOMER CHARGE (/meter/day)														
B-19	24.77594				24.77594	754.12	23.44726					23.44726	713.68	
Rate V	4.77841				4.77841	145.44	4.86153					4.86153	147.97	

B-20 Secondary

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGES (/kW)														
Summer														
Peak	11.13	14.61			25.74		10.52	14.41				24.92		14.41
Part-Peak	3.19	2.12			5.31		3.01	2.09				5.10		2.09
Maximum	11.66	.00		9.75	21.41		11.02				9.74	20.76		
Winter														
Peak	.00	1.86			1.86		.00	1.83				1.83		1.83
Maximum	11.66	.00		9.75	21.41		11.02				9.74	20.76		
DEMAND CHARGES - OPTION R ($/kW)														
Summer														

(PG&E-RTP-1)

AECA

Peak	2.78	.00			2.78		2.63					2.63		
Part-Peak	.80	.00			.80		.75					.75		
Maximum	11.66	.00		9.75	21.41		11.02				9.74	20.76		
Winter														
Peak	.00	.00			.00		.00					.00		
Maximum	11.66	.00		9.75	21.41		11.02				9.74	20.76		
ENERGY CHARGES (/kWh)														
Summer														
Peak	.00000	.13233	.01146	.01413	.15792		.00000	.09242	.03807	.01251	.01413	.15713		.13049
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000	.06589	.03807	.01251	.01413	.13059		.10395
Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000	.04493	.03807	.01251	.01413	.10964		.08300
Winter														
Peak	.00000	.11630	.01146	.01413	.14189		.00000	.07631	.03807	.01251	.01413	.14101		.11437
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000	.04480	.03807	.01251	.01413	.10951		.08287
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000	.00260	.03807	.01251	.01413	.06730		.04066
ENERGY CHARGES - OPTION R (/kWh)														
Summer														
Peak	.07547	.25843	.01146	.01413	.35949		.07422	.21886	.03807	.01251	.01413	.35779		.25693
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02414	.08611	.03807	.01251	.01413	.17496		.12418
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00257	.04865	.03807	.01251	.01413	.11593		.08672
Winter														
Peak	.00000	.13182	.01146	.01413	.15741		.00000	.09225	.03807	.01251	.01413	.15696		.13032
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000	.04852	.03807	.01251	.01413	.11323		.08659
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000	.01277	.03807	.01251	.01413	.07748		.05084
CUSTOMER CHARGE														
(/meter/day)	45.08771				45.08771	1372.36	42.60312					42.60312	1296.73	
AG-C	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total		Gen
DEMAND CHARGE (/kW)														
Secondary														
Summer Max Peak Period	6.17	12.52			18.69		6.24	12.48				18.72		12.48
Summer Maximum	11.21				11.21		11.33	.00				11.33		.00
Winter Maximum	11.21				11.21		11.33	.00				11.33		.00
ENERGY CHARGE (/kWh)														
Summer														
Peak	.02005	.11604	.01135	.03624	.18368		.02246	.07729	.03850	.01381	.03625	.18831		.11579
Part-Peak														
Off-Peak	.01009	.08656	.01135	.03624	.14424		.01250	.04781	.03850	.01381	.03625	.14887		.08631
Winter														
Peak	.00690	.10140	.01135	.03624	.15589		.00931	.06265	.03850	.01381	.03625	.16052		.10115
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00914	.03713	.03850	.01381	.03625	.13483		.07563
CUSTOMER CHARGE														
(/meter/day)	1.43343				1.43343	43.63	1.43343				.00000	1.43343	43.63	

PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase II
Application 19-11-019
Data Response

PG&E Data Request No.:	JointParties_001-Q02		
PG&E File Name:	GRC-2020-PhII_DR_JointParties_001-Q02		
Request Date:	March 10, 2021	Requester DR No.:	001
Date Sent:	March 23, 2021	Requesting Party:	California Solar and Storage Association/ Small Business Utility Advocates
PG&E Witness:	Tysen Streib	Requester:	Brad Heavner/ John Wilson

QUESTION 02

Please provide the same report as item 1 for an illustrative energy and capacity Real-Time-Pricing rate design, as follows.

- All energy charges and generation capacity charges collected in hourly dynamic rates based on day-ahead forecasts
- Marginal energy costs based on line-loss-adjusted day-ahead locational marginal prices for the PG&E DLAP
- Marginal generation costs based on hourly dynamic costs from adjusted net load, using a peak capacity allocation factor methodology
- A uniform, system average Revenue Neutral Rate Adder as described in PG&E testimony in A.20-10-011, but excluding the PCIA in the "proposed with PCIA" schedule rates.

ANSWER 02

Per a discussion on March 15, 2021, CALSSA and SBUA have agreed to revise this data request to use May 1, 2020 revenue requirements.

Please see the attachment "GRC-2020-PhII_DR_JointParties_001-Q02_Atch01.xlsx".

Please note that, for the CLECA scenario, the marginal generation capacity value was so large that if it were to be used in the manner described in A.20-10-011, it would produce a negative Revenue Neutral Rate Adder because the marginal cost revenues it produces are larger than the revenue requirement. For this response, PG&E reduced CLECA's capacity value to 58% of its stated value so as to produce a Revenue Neutral Rate Adder of zero.

Pacific Gas and Electric Company
2020 General Rate Case - Phase II
Exhibit (PG&E-4), Appendix C (Update May, 2020)
Present and Proposed Rates
Year 3 Transition Rates

E-TOU-C (Tiered)

	PRESENT RATES (May 1, 2020)							PROPOSED RATES							
	Distr	Gen	PPP	CIA	Other	Total		Distr	Gen	PCIA	PPP	CIA	Other	Total	
SUMMER ENERGY CHARGE ($/kWh)															
Peak	.12767	.16735	.01296	.05339	.05196	.41333		.13640	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01953	.04327	.01343	.04678	.05196	.29184	
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989		.11640		.04327	.01343	.04678	.05196	.27184	
Baseline Credit				(.08633)		(.08633)						(.08709)		(.08709)	
WINTER ENERGY CHARGE ($/kWh)															
Peak	.07935	.11859	.01296	.05338	.05196	.31624		.08680		.04327	.01343	.04678	.05196	.24223	
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891		.08348		.04327	.01343	.04678	.05196	.23891	
Baseline Credit				(.08633)		(.08633)						(.08709)		(.08709)	
MINIMUM CHARGE															
(/meter/day)	*		.02123		.00166	.32854	10.00	*			.02199		.00166	.32854	10.00
(/kWh)					.05160								.05160		

* Calculated residually as total less sum of other charges. (Present rates)

* Calculated residually as total less sum of other charges. (Proposed rates)

Pacific Gas and Electric Company
2020 General Rate Case - Phase II
Exhibit (PG&E-4), Appendix C (Update May, 2020)
Present and Proposed Rates
Year 3 Transition Rates

B-1

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.09551	.17737	.01299	.04218	.32805		.10104	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01953	.04107	.01211	.04218	.19640	
Part-Peak	.09551	.12814	.01299	.04218	.27882		.10104		.04107	.01211	.04218	.19640	
Off-Peak	.09551	.10733	.01299	.04218	.25801		.10104		.04107	.01211	.04218	.19640	
Winter													
Peak	.07534	.12212	.01299	.04218	.25263		.08087		.04107	.01211	.04218	.17623	
Off-Peak	.07534	.10600	.01299	.04218	.23651		.08087		.04107	.01211	.04218	.17623	
Super Off-Peak	.07534	.08958	.01299	.04218	.22009		.08087		.04107	.01211	.04218	.17623	
CUSTOMER CHARGE (/meter/day)													
Single-phase	.32854				.32854	10.00	.32854					.32854	10.00
Polyphase	.82136				.82136	25.00	.82136					.82136	25.00

Pacific Gas and Electric Company
2020 General Rate Case - Phase II
Exhibit (PG&E-4), Appendix C (Update May, 2020)
Present and Proposed Rates
Year 3 Transition Rates

B-10

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGE (/kW)													
Secondary													
Summer	4.75			8.84	13.59		4.87				8.84	13.72	
Winter	4.75			8.84	13.59		4.87				8.84	13.72	
ENERGY CHARGE (/kWh)													
Secondary													
Summer													
Peak	.04539	.20191	.01205	.01474	.27409		.04627	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01953	.04189	.01202	.01474	.11492	
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04627		.04189	.01202	.01474	.11492	
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04627		.04189	.01202	.01474	.11492	
Winter													
Peak	.02716	.14386	.01205	.01474	.19781		.02804		.04189	.01202	.01474	.09669	
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02804		.04189	.01202	.01474	.09669	
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02804		.04189	.01202	.01474	.09669	
CUSTOMER CHARGE (/meter/day)	4.77841				4.77841	145.44	4.90148					4.90148	149.19

B-19 Secondary

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGES (/kW)													
Summer													
Peak	10.87	14.92			25.79		10.11					10.11	
Part-Peak	3.13	2.17			5.30		2.91					2.91	
Maximum	12.53			8.91	21.44		11.65				8.91	20.57	
Winter													
Peak	.00	1.77			1.77		.00					.00	
Maximum	12.53			8.91	21.44		11.65				8.91	20.57	
DEMAND CHARGES - OPTION R ($/kW)													
Summer													
Peak	2.72				2.72		2.53					2.53	
Part-Peak	.78				.78		.73					.73	
Maximum	12.53			8.91	21.44		11.65				8.91	20.57	
Winter													
Peak	.00						.00					.00	
Maximum	12.53			8.91	21.44		11.65				8.91	20.57	
ENERGY CHARGES (/kWh)													
Summer													
Peak	.00000	.13878	.01177	.01465	.16520		.00000	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01953	.03965	.01375	.01466	.06805	
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000		.03965	.01375	.01466	.06805	
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000		.03965	.01375	.01466	.06805	
Winter													
Peak	.00000	.11986	.01177	.01465	.14628		.00000		.03965	.01375	.01466	.06805	
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000		.03965	.01375	.01466	.06805	
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000		.03965	.01375	.01466	.06805	
ENERGY CHARGES - OPTION R (/kWh)													
Summer													
Peak	.07499	.26625	.01177	.01465	.36766		.07326	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01953	.03965	.01375	.01466	.14132	
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02499		.03965	.01375	.01466	.09305	
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00303		.03965	.01375	.01466	.07109	
Winter													
Peak	.00000	.13442	.01177	.01465	.16084		.00000		.03965	.01375	.01466	.06805	
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000		.03965	.01375	.01466	.06805	
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000		.03965	.01375	.01466	.06805	
CUSTOMER CHARGE (/meter/day)													
B-19	24.77594				24.77594	754.12	23.23957					23.23957	707.35
Rate V	4.77841				4.77841	145.44	4.90148					4.90148	149.19

B-20 Secondary

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total
DEMAND CHARGES (/kW)												
Summer												
Peak	11.13	14.61			25.74		10.04					10.04
Part-Peak	3.19	2.12			5.31		2.88					2.88
Maximum	11.66	.00		9.75	21.41		10.52				9.74	20.26
Winter												
Peak	.00	1.86			1.86		.00					.00
Maximum	11.66	.00		9.75	21.41		10.52				9.74	20.26

DEMAND CHARGES - OPTION R ($/kW)
Summer

Peak	2.78	.00			2.78		2.51					2.51	
Part-Peak	.80	.00			.80		.72					.72	
Maximum	11.66	.00		9.75	21.41		10.52				9.74	20.26	
Winter													
Peak	.00	.00			.00		.00					.00	
Maximum	11.66	.00		9.75	21.41		10.52				9.74	20.26	
ENERGY CHARGES (/kWh)													
Summer													
Peak	.00000	.13233	.01146	.01413	.15792		.00000	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01953	.03807	.01251	.01413	.06471	
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000		.03807	.01251	.01413	.06471	
Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000		.03807	.01251	.01413	.06471	
Winter													
Peak	.00000	.11630	.01146	.01413	.14189		.00000		.03807	.01251	.01413	.06471	
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000		.03807	.01251	.01413	.06471	
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000		.03807	.01251	.01413	.06471	
ENERGY CHARGES - OPTION R (/kWh)													
Summer													
Peak	.07547	.25843	.01146	.01413	.35949		.07325	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01953	.03807	.01251	.01413	.13795	
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02317		.03807	.01251	.01413	.08787	
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00160		.03807	.01251	.01413	.06630	
Winter													
Peak	.00000	.13182	.01146	.01413	.15741		.00000		.03807	.01251	.01413	.06471	
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000		.03807	.01251	.01413	.06471	
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000		.03807	.01251	.01413	.06471	
CUSTOMER CHARGE													
(/meter/day)	45.08771				45.08771	1372.36	40.67787					40.67787	1238.13
AG-C	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGE (/kW)													
Secondary													
Summer Max Peak Period	6.17	12.52			18.69		6.27					6.27	
Summer Maximum	11.21				11.21		11.40					11.40	
Winter Maximum	11.21				11.21		11.40					11.40	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.02005	.11604	.01135	.03624	.18368		.02251	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $68.56/kW-yr 3) A flat adder of $0.01953	.03850	.01381	.03625	.11107	
Part-Peak													
Off-Peak	.01009	.08656	.01135	.03624	.14424		.01255		.03850	.01381	.03625	.10111	
Winter													
Peak	.00690	.10140	.01135	.03624	.15589		.00936		.03850	.01381	.03625	.09792	
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00919		.03850	.01381	.03625	.09775	
CUSTOMER CHARGE													
(/meter/day)	1.43343				1.43343	43.63	1.43343				.00000	1.43343	43.63

(PG&E-RTP-1)

PG&E

E-TOU-C (Tiered)

PRESENT RATES (May 1, 2020)

	Distr	Gen	PPP	CIA	Other	Total	
SUMMER ENERGY CHARGE ($/kWh)							
Peak	.12767	.16735	.01296	.05339	.05196	.41333	
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989	
Baseline Credit				(.08633)		(.08633)	
WINTER ENERGY CHARGE ($/kWh)							
Peak	.07935	.11859	.01296	.05338	.05196	.31624	
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891	
Baseline Credit				(.08633)		(.08633)	
MINIMUM CHARGE							
(/meter/day)	*		.02123		.00166	.32854	10.00
(/kWh)					.05160		

* Calculated residually as total less sum of other charges.

PROPOSED RATES

	Distr	Gen	PCIA	PPP	CIA	Other	Total	
SUMMER ENERGY CHARGE ($/kWh)								
Peak	.13625	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $49.72/kW-yr 3) A flat adder of $0.02346	.04327	.01344	.04684	.05196	.29175	
Off-Peak	.11625		.04327	.01344	.04684	.05196	.27175	
Baseline Credit					(.08720)		(.08720)	
WINTER ENERGY CHARGE ($/kWh)								
Peak	.08664		.04327	.01344	.04684	.05196	.24214	
Off-Peak	.08332		.04327	.01344	.04684	.05196	.23882	
Baseline Credit					(.08720)		(.08720)	
MINIMUM CHARGE								
(/meter/day)	*			.02200		.00166	.32854	10.00
(/kWh)						.05160		

* Calculated residually as total less sum of other charges.

TURN

Pacific Gas and Electric Company
2020 General Rate Case - Phase II
Exhibit (PG&E-4), Appendix C (Update May, 2020)
Present and Proposed Rates
Year 3 Transition Rates

B-1

	Distr	Gen	PPP	Other	Total	
ENERGY CHARGE (/kWh)						
Summer						
Peak	.09551	.17737	.01299	.04218	.32805	
Part-Peak	.09551	.12814	.01299	.04218	.27882	
Off-Peak	.09551	.10733	.01299	.04218	.25801	
Winter						
Peak	.07534	.12212	.01299	.04218	.25263	
Off-Peak	.07534	.10600	.01299	.04218	.23651	
Super Off-Peak	.07534	.08958	.01299	.04218	.22009	
CUSTOMER CHARGE (/meter/day)						
Single-phase	.32854				.32854	10.00
Polyphase	.82136				.82136	25.00

	Distr	Gen	PCIA	PPP	Other	Total	
ENERGY CHARGE (/kWh)							
Summer							
Peak	.09798	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $49.72/kW-yr 3) A flat adder of $0.02346	.04107	.01212	.04218	.19335	
Part-Peak	.09798		.04107	.01212	.04218	.19335	
Off-Peak	.09798		.04107	.01212	.04218	.19335	
Winter							
Peak	.07781		.04107	.01212	.04218	.17318	
Off-Peak	.07781		.04107	.01212	.04218	.17318	
Super Off-Peak	.07781		.04107	.01212	.04218	.17318	
CUSTOMER CHARGE (/meter/day)							
Single-phase	.32854					.32854	10.00
Polyphase	.82136					.82136	25.00

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	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGE (/kW)													
Secondary													
Summer	4.75			8.84	13.59		4.65				8.84	13.49	
Winter	4.75			8.84	13.59		4.65				8.84	13.49	
ENERGY CHARGE (/kWh)													
Secondary													
Summer													
Peak	.04539	.20191	.01205	.01474	.27409		.04465	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $49.72/kW-yr 3) A flat adder of $0.02346	.04189	.01203	.01474	.11331	
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04465		.04189	.01203	.01474	.11331	
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04465		.04189	.01203	.01474	.11331	
Winter													
Peak	.02716	.14386	.01205	.01474	.19781		.02642		.04189	.01203	.01474	.09508	
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02642		.04189	.01203	.01474	.09508	
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02642		.04189	.01203	.01474	.09508	
CUSTOMER CHARGE (/meter/day)	4.77841				4.77841	145.44	4.67369					4.67369	142.26

B-19 Secondary

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGES (/kW)													
Summer													
Peak	10.87	14.92			25.79		10.13					10.13	
Part-Peak	3.13	2.17			5.30		2.92					2.92	
Maximum	12.53			8.91	21.44		11.68				8.91	20.59	
Winter													
Peak	.00	1.77			1.77		.00					.00	
Maximum	12.53			8.91	21.44		11.68				8.91	20.59	
DEMAND CHARGES - OPTION R ($/kW)													
Summer													
Peak	2.72				2.72		2.53					2.53	
Part-Peak	.78				.78		.73					.73	
Maximum	12.53			8.91	21.44		11.68				8.91	20.59	
Winter													
Peak	.00						.00					.00	
Maximum	12.53			8.91	21.44		11.68				8.91	20.59	
ENERGY CHARGES (/kWh)													
Summer													
Peak	.00000	.13878	.01177	.01465	.16520		.00000	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $49.72/kW-yr 3) A flat adder of $0.02346	.03965	.01376	.01466	.06806	
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000		.03965	.01376	.01466	.06806	
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000		.03965	.01376	.01466	.06806	
Winter													
Peak	.00000	.11986	.01177	.01465	.14628		.00000		.03965	.01376	.01466	.06806	
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000		.03965	.01376	.01466	.06806	
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000		.03965	.01376	.01466	.06806	
ENERGY CHARGES - OPTION R (/kWh)													
Summer													
Peak	.07499	.26625	.01177	.01465	.36766		.07331	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $49.72/kW-yr 3) A flat adder of $0.02346	.03965	.01376	.01466	.14137	
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02504		.03965	.01376	.01466	.09310	
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00308		.03965	.01376	.01466	.07114	
Winter													
Peak	.00000	.13442	.01177	.01465	.16084		.00000		.03965	.01376	.01466	.06806	
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000		.03965	.01376	.01466	.06806	
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000		.03965	.01376	.01466	.06806	
CUSTOMER CHARGE (/meter/day)													
B-19	24.77594				24.77594	754.12	23.18112					23.18112	705.58
Rate V	4.77841				4.77841	145.44	4.67369					4.67369	142.26

B-20 Secondary

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total
DEMAND CHARGES (/kW)												
Summer												
Peak	11.13	14.61			25.74		10.75					10.75
Part-Peak	3.19	2.12			5.31		3.08					3.08
Maximum	11.66	.00		9.75	21.41		11.26				9.74	21.00
Winter												
Peak	.00	1.86			1.86		.00					.00
Maximum	11.66	.00		9.75	21.41		11.26				9.74	21.00
DEMAND CHARGES - OPTION R ($/kW)												
Summer												
Peak	2.78	.00			2.78		2.69					2.69

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TURN

Part-Peak	.80	.00			.80		.77					.77	
Maximum	11.66	.00		9.75	21.41		11.26				9.74	21.00	
Winter													
Peak	.00	.00			.00		.00					.00	
Maximum	11.66	.00		9.75	21.41		11.26				9.74	21.00	
ENERGY CHARGES (/kWh)													
Summer													
Peak	.00000	.13233	.01146	.01413	.15792		.00000	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $49.72/kW-yr 3) A flat adder of $0.02346	.03807	.01252	.01413	.06471	
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000		.03807	.01252	.01413	.06471	
Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000		.03807	.01252	.01413	.06471	
Winter													
Peak	.00000	.11630	.01146	.01413	.14189		.00000		.03807	.01252	.01413	.06471	
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000		.03807	.01252	.01413	.06471	
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000		.03807	.01252	.01413	.06471	
ENERGY CHARGES - OPTION R (/kWh)													
Summer													
Peak	.07547	.25843	.01146	.01413	.35949		.07469	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $49.72/kW-yr 3) A flat adder of $0.02346	.03807	.01252	.01413	.13940	
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02461		.03807	.01252	.01413	.08932	
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00304		.03807	.01252	.01413	.06775	
Winter													
Peak	.00000	.13182	.01146	.01413	.15741		.00000		.03807	.01252	.01413	.06471	
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000		.03807	.01252	.01413	.06471	
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000		.03807	.01252	.01413	.06471	
CUSTOMER CHARGE													
(/meter/day)	45.08771				45.08771	1372.36	43.53321					43.53321	1325.04
												.00000	

AG-C	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGE (/kW)													
Secondary													
Summer Max Peak Period	6.17	12.52			18.69		6.75					18.48	
Summer Maximum	11.21				11.21		12.26					12.26	
Winter Maximum	11.21				11.21		12.26					12.26	
												.00000	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.02005	.11604	.01135	.03624	.18368		.02307	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $49.72/kW-yr 3) A flat adder of $0.02346	.03850	.01382	.03625	.18380	
Part-Peak												.00000	
Off-Peak	.01009	.08656	.01135	.03624	.14424		.01311		.03850	.01382	.03625	.14436	
Winter												.00000	
Peak	.00690	.10140	.01135	.03624	.15589		.00992		.03850	.01382	.03625	.15601	
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00975		.03850	.01382	.03625	.09831	
												.00000	
CUSTOMER CHARGE													
(/meter/day)	1.43343				1.43343	43.63	1.43343				.00000	1.43343	43.63
												.00000	

TURN

Pacific Gas and Electric Company
2020 General Rate Case - Phase II
Exhibit (PG&E-4), Appendix C (Update May, 2020)
Present and Proposed Rates
Year 3 Transition Rates

PRESENT RATES (May 1, 2020) | **PROPOSED RATES**

E-TOU-C (Tiered)

	Present Distr	Present Gen	Present PPP	Present CIA	Present Other	Present Total		Proposed Distr	Proposed Gen	Proposed PCIA	Proposed PPP	Proposed CIA	Proposed Other	Proposed Total	
SUMMER ENERGY CHARGE ($/kWh)															
Peak	.12767	.16735	.01296	.05339	.05196	.41333		.13681		.04327	.01349	.04716	.05196	.29268	
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989		.11681		.04327	.01349	.04716	.05196	.27268	
Baseline Credit				(.08633)		(.08633)						(.08779)		(.08779)	
WINTER ENERGY CHARGE ($/kWh)															
Peak	.07935	.11859	.01296	.05338	.05196	.31624		.08721		.04327	.01349	.04716	.05196	.24308	
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891		.08389		.04327	.01349	.04716	.05196	.23976	
Baseline Credit				(.08633)		(.08633)						(.08779)		(.08779)	
MINIMUM CHARGE															
(/meter/day)	*		.02123		.00166	.32854	10.00	*			.02209		.00166	.32854	10.00
(/kWh)					.05160								.05160		

Generation is an RTP rate made up of:
1) CAISO market price plus line losses
2) Capacity adder as determined by the capacity equation and a capacity price of $137.37/kW-yr
3) A flat adder of $0.00000

* Calculated residually as total less sum of other charges.

* Calculated residually as total less sum of other charges.

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	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.09551	.17737	.01299	.04218	.32805		.10093	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $137.37/kW-yr 3) A flat adder of $0.00000	.04107	.01217	.04218	.19636	
Part-Peak	.09551	.12814	.01299	.04218	.27882		.10093		.04107	.01217	.04218	.19636	
Off-Peak	.09551	.10733	.01299	.04218	.25801		.10093		.04107	.01217	.04218	.19636	
Winter													
Peak	.07534	.12212	.01299	.04218	.25263		.08076		.04107	.01217	.04218	.17619	
Off-Peak	.07534	.10600	.01299	.04218	.23651		.08076		.04107	.01217	.04218	.17619	
Super Off-Peak	.07534	.08958	.01299	.04218	.22009		.08076		.04107	.01217	.04218	.17619	
CUSTOMER CHARGE (/meter/day)													
Single-phase	.32854				.32854	10.00	.32854					.32854	10.00
Polyphase	.82136				.82136	25.00	.82136					.82136	25.00

(PG&E-RTP-1)

CLECA

Pacific Gas and Electric Company
2020 General Rate Case - Phase II
Exhibit (PG&E-4), Appendix C (Update May, 2020)
Present and Proposed Rates
Year 3 Transition Rates

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	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGE (/kW)													
Secondary													
Summer	4.75			8.84	13.59		4.94				8.84	13.79	
Winter	4.75			8.84	13.59		4.94				8.84	13.79	
ENERGY CHARGE (/kWh)													
Secondary													
Summer													
Peak	.04539	.20191	.01205	.01474	.27409		.04676	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $137.37/kW-yr 3) A flat adder of $0.00000	.04189	.01208	.01474	.11547	
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04676		.04189	.01208	.01474	.11547	
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04676		.04189	.01208	.01474	.11547	
Winter													
Peak	.02716	.14386	.01205	.01474	.19781		.02853		.04189	.01208	.01474	.09724	
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02853		.04189	.01208	.01474	.09724	
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02853		.04189	.01208	.01474	.09724	
CUSTOMER CHARGE (/meter/day)	4.77841				4.77841	145.44	4.96875					4.96875	151.24

B-19 Secondary

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGES (/kW)													
Summer													
Peak	10.87	14.92			25.79		10.03					10.03	
Part-Peak	3.13	2.17			5.30		2.89					2.89	
Maximum	12.53			8.91	21.44		11.56				8.91	20.47	
Winter													
Peak	.00	1.77			1.77		.00					.00	
Maximum	12.53			8.91	21.44		11.56				8.91	20.47	
DEMAND CHARGES - OPTION R ($/kW)													
Summer													
Peak	2.72				2.72		2.51					2.51	
Part-Peak	.78				.78		.72					.72	
Maximum	12.53			8.91	21.44		11.56				8.91	20.47	
Winter													
Peak	.00						.00					.00	
Maximum	12.53			8.91	21.44		11.56				8.91	20.47	
ENERGY CHARGES (/kWh)													
Summer													
Peak	.00000	.13878	.01177	.01465	.16520		.00000	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $137.37/kW-yr 3) A flat adder of $0.00000	.03965	.01381	.01466	.06811	
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000		.03965	.01381	.01466	.06811	
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000		.03965	.01381	.01466	.06811	
Winter													
Peak	.00000	.11986	.01177	.01465	.14628		.00000		.03965	.01381	.01466	.06811	
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000		.03965	.01381	.01466	.06811	
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000		.03965	.01381	.01466	.06811	
ENERGY CHARGES - OPTION R (/kWh)													
Summer													
Peak	.07499	.26625	.01177	.01465	.36766		.07307	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $137.37/kW-yr 3) A flat adder of $0.00000	.03965	.01381	.01466	.14119	
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02480		.03965	.01381	.01466	.09292	
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00284		.03965	.01381	.01466	.07096	
Winter													
Peak	.00000	.13442	.01177	.01465	.16084		.00000		.03965	.01381	.01466	.06811	
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000		.03965	.01381	.01466	.06811	
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000		.03965	.01381	.01466	.06811	
CUSTOMER CHARGE (/meter/day)													
B-19	24.77594				24.77594	754.12	23.09341					23.09341	702.91
Rate V	4.77841				4.77841	145.44	4.96875					4.96875	151.24

B-20 Secondary

	Distr	Gen	PPP	Other	Total	Distr	Gen	PCIA	PPP	Other	Total
DEMAND CHARGES (/kW)											
Summer											
Peak	11.13	14.61			25.74	9.61					9.61
Part-Peak	3.19	2.12			5.31	2.76					2.76
Maximum	11.66	.00		9.75	21.41	10.07				9.74	19.82
Winter											
Peak	.00	1.86			1.86	.00					.00
Maximum	11.66	.00		9.75	21.41	10.07				9.74	19.82
DEMAND CHARGES - OPTION R ($/kW)											
Summer											
Peak	2.78	.00			2.78	2.40					2.40

Part-Peak	.80	.00			.80		.69					.69	
Maximum	11.66	.00		9.75	21.41		10.07				9.74	19.82	
Winter													
Peak	.00	.00			.00		.00					.00	
Maximum	11.66	.00		9.75	21.41		10.07				9.74	19.82	
ENERGY CHARGES (/kWh)													
Summer													
Peak	.00000	.13233	.01146	.01413	.15792		.00000	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $137.37/kW-yr 3) A flat adder of $0.00000	.03807	.01257	.01413	.06477	
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000		.03807	.01257	.01413	.06477	
Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000		.03807	.01257	.01413	.06477	
Winter													
Peak	.00000	.11630	.01146	.01413	.14189		.00000		.03807	.01257	.01413	.06477	
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000		.03807	.01257	.01413	.06477	
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000		.03807	.01257	.01413	.06477	
ENERGY CHARGES - OPTION R (/kWh)													
Summer													
Peak	.07547	.25843	.01146	.01413	.35949		.07237	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $137.37/kW-yr 3) A flat adder of $0.00000	.03807	.01257	.01413	.13714	
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02229		.03807	.01257	.01413	.08706	
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00072		.03807	.01257	.01413	.06549	
Winter													
Peak	.00000	.13182	.01146	.01413	.15741		.00000		.03807	.01257	.01413	.06477	
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000		.03807	.01257	.01413	.06477	
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000		.03807	.01257	.01413	.06477	
CUSTOMER CHARGE													
(/meter/day)	45.08771				45.08771	1372.36	38.94380					38.94380	1185.35

AG-C	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGE (/kW)													
Secondary													
Summer Max Peak Period	6.17	12.52			18.69		6.25					6.25	
Summer Maximum	11.21				11.21		11.36					11.36	
Winter Maximum	11.21				11.21		11.36	#REF!				#REF!	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.02005	.11604	.01135	.03624	.18368		.02248	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $137.37/kW-yr 3) A flat adder of $0.00000	.03850	.01387	.03625	#REF!	
Part-Peak													
Off-Peak	.01009	.08656	.01135	.03624	.14424		.01252		.03850	.01387	.03625	#REF!	
Winter													
Peak	.00690	.10140	.01135	.03624	.15589		.00933		.03850	.01387	.03625	.09795	
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00916		.03850	.01387	.03625	.09778	
CUSTOMER CHARGE													
(/meter/day)	1.43343				1.43343	43.63	1.43343				.00000	1.43343	43.63

(PG&E-RTP-1)

CLECA

E-TOU-C (Tiered)

	PRESENT RATES (May 1, 2020)							PROPOSED RATES							
	Distr	Gen	PPP	CIA	Other	Total		Distr	Gen	PCIA	PPP	CIA	Other	Total	
SUMMER ENERGY CHARGE ($/kWh)									Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $48.78/kW-yr 3) A flat adder of $0.02364						
Peak	.12767	.16735	.01296	.05339	.05196	.41333		.13689		.04327	.01343	.04678	.05196	.29233	
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989		.11689		.04327	.01343	.04678	.05196	.27233	
Baseline Credit				(.08633)		(.08633)						(.08709)		(.08709)	
WINTER ENERGY CHARGE ($/kWh)															
Peak	.07935	.11859	.01296	.05338	.05196	.31624		.08729		.04327	.01343	.04678	.05196	.24273	
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891		.08397		.04327	.01343	.04678	.05196	.23941	
Baseline Credit				(.08633)		(.08633)						(.08709)		(.08709)	
MINIMUM CHARGE															
(/meter/day)	*		.02123		.00166	.32854	10.00	*			.02200		.00166	.32854	10.00
(/kWh)					.05160								.05160		

* Calculated residually as total less sum of other charges. (present rates)

* Calculated residually as total less sum of other charges. (proposed rates)

(PG&E-RTP-1)

AECA

B-1

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.09551	.17737	.01299	.04218	.32805		.09823	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $48.78/kW-yr 3) A flat adder of $0.02364	.04107	.01211	.04218	.19360	
Part-Peak	.09551	.12814	.01299	.04218	.27882		.09823		.04107	.01211	.04218	.19360	
Off-Peak	.09551	.10733	.01299	.04218	.25801		.09823		.04107	.01211	.04218	.19360	
Winter													
Peak	.07534	.12212	.01299	.04218	.25263		.07806		.04107	.01211	.04218	.17343	
Off-Peak	.07534	.10600	.01299	.04218	.23651		.07806		.04107	.01211	.04218	.17343	
Super Off-Peak	.07534	.08958	.01299	.04218	.22009		.07806		.04107	.01211	.04218	.17343	
CUSTOMER CHARGE (/meter/day)													
Single-phase	.32854				.32854	10.00	.32854					.32854	10.00
Polyphase	.82136				.82136	25.00	.82136					.82136	25.00

Pacific Gas and Electric Company
2020 General Rate Case - Phase II
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Present and Proposed Rates
Year 3 Transition Rates

B-10

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGE (/kW)													
Secondary													
Summer	4.75			8.84	13.59		4.83				8.84	13.68	
Winter	4.75			8.84	13.59		4.83				8.84	13.68	
ENERGY CHARGE (/kWh)													
Secondary													
Summer													
Peak	.04539	.20191	.01205	.01474	.27409		.04599	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $48.78/kW-yr 3) A flat adder of $0.02364	.04189	.01202	.01474	.11464	
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04599		.04189	.01202	.01474	.11464	
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04599		.04189	.01202	.01474	.11464	
Winter													
Peak	.02716	.14386	.01205	.01474	.19781		.02776		.04189	.01202	.01474	.09641	
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02776		.04189	.01202	.01474	.09641	
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02776		.04189	.01202	.01474	.09641	
CUSTOMER CHARGE (/meter/day)	4.77841				4.77841	145.44	4.86153					4.86153	147.97

Pacific Gas and Electric Company
2020 General Rate Case - Phase II
Exhibit (PG&E-4), Appendix C (Update May, 2020)
Present and Proposed Rates
Year 3 Transition Rates

B-19 Secondary

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGES (/kW)													
Summer													
Peak	10.87	14.92			25.79		10.22					10.22	
Part-Peak	3.13	2.17			5.30		2.94					2.94	
Maximum	12.53			8.91	21.44		11.78				8.91	20.69	
Winter													
Peak	.00	1.77			1.77		.00					.00	
Maximum	12.53			8.91	21.44		11.78				8.91	20.69	
DEMAND CHARGES - OPTION R ($/kW)													
Summer													
Peak	2.72				2.72		2.55					2.55	
Part-Peak	.78				.78		.74					.74	
Maximum	12.53			8.91	21.44		11.78				8.91	20.69	
Winter													
Peak	.00						.00					.00	
Maximum	12.53			8.91	21.44		11.78				8.91	20.69	
ENERGY CHARGES (/kWh)													
Summer													
Peak	.00000	.13878	.01177	.01465	.16520		.00000	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $48.78/kW-yr 3) A flat adder of $0.02364	.03965	.01375	.01466	.06805	
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000		.03965	.01375	.01466	.06805	
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000		.03965	.01375	.01466	.06805	
Winter													
Peak	.00000	.11986	.01177	.01465	.14628		.00000		.03965	.01375	.01466	.06805	
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000		.03965	.01375	.01466	.06805	
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000		.03965	.01375	.01466	.06805	
ENERGY CHARGES - OPTION R (/kWh)													
Summer													
Peak	.07499	.26625	.01177	.01465	.36766		.07351	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $48.78/kW-yr 3) A flat adder of $0.02364	.03965	.01375	.01466	.14156	
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02524		.03965	.01375	.01466	.09329	
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00328		.03965	.01375	.01466	.07133	
Winter													
Peak	.00000	.13442	.01177	.01465	.16084		.00000		.03965	.01375	.01466	.06805	
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000		.03965	.01375	.01466	.06805	
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000		.03965	.01375	.01466	.06805	
CUSTOMER CHARGE (/meter/day)													
B-19	24.77594				24.77594	754.12	23.44726					23.44726	713.68
Rate V	4.77841				4.77841	145.44	4.86153					4.86153	147.97

B-20 Secondary

	Distr	Gen	PPP	Other	Total	Distr	Gen	PCIA	PPP	Other	Total
DEMAND CHARGES (/kW)											
Summer											
Peak	11.13	14.61			25.74	10.52					10.52
Part-Peak	3.19	2.12			5.31	3.01					3.01
Maximum	11.66	.00		9.75	21.41	11.02				9.74	20.76
Winter											
Peak	.00	1.86			1.86	.00					.00
Maximum	11.66	.00		9.75	21.41	11.02				9.74	20.76
DEMAND CHARGES - OPTION R ($/kW)											
Summer											
Peak	2.78	.00			2.78	2.63					2.63

Part-Peak	.80	.00			.80		.75					.75	
Maximum	11.66	.00		9.75	21.41		11.02				9.74	20.76	
Winter													
Peak	.00	.00			.00		.00					.00	
Maximum	11.66	.00		9.75	21.41		11.02				9.74	20.76	
ENERGY CHARGES (/kWh)													
Summer													
Peak	.00000	.13233	.01146	.01413	.15792		.00000	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $48.78/kW-yr 3) A flat adder of $0.02364	.03807	.01251	.01413	.06471	
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000		.03807	.01251	.01413	.06471	
Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000		.03807	.01251	.01413	.06471	
Winter													
Peak	.00000	.11630	.01146	.01413	.14189		.00000		.03807	.01251	.01413	.06471	
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000		.03807	.01251	.01413	.06471	
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000		.03807	.01251	.01413	.06471	
ENERGY CHARGES - OPTION R (/kWh)													
Summer													
Peak	.07547	.25843	.01146	.01413	.35949		.07422	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $48.78/kW-yr 3) A flat adder of $0.02364	.03807	.01251	.01413	.13892	
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02414		.03807	.01251	.01413	.08884	
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00257		.03807	.01251	.01413	.06727	
Winter													
Peak	.00000	.13182	.01146	.01413	.15741		.00000		.03807	.01251	.01413	.06471	
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000		.03807	.01251	.01413	.06471	
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000		.03807	.01251	.01413	.06471	
CUSTOMER CHARGE													
(/meter/day)	45.08771				45.08771	1372.36	42.60312					42.60312	1296.73

AG-C	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	PPP	Other	Total	
DEMAND CHARGE (/kW)													
Secondary													
Summer Max Peak Period	6.17	12.52			18.69		6.24					6.24	
Summer Maximum	11.21				11.21		11.33					11.33	
Winter Maximum	11.21				11.21		11.33	#REF!				#REF!	
ENERGY CHARGE (/kWh)													
Summer													
Peak	.02005	.11604	.01135	.03624	.18368		.02246	Generation is an RTP rate made up of: 1) CAISO market price plus line losses 2) Capacity adder as determined by the capacity equation and a capacity price of $48.78/kW-yr 3) A flat adder of $0.02364	.03850	.01381	.03625	#REF!	
Part-Peak													
Off-Peak	.01009	.08656	.01135	.03624	.14424		.01250		.03850	.01381	.03625	#REF!	
Winter													
Peak	.00690	.10140	.01135	.03624	.15589		.00931		.03850	.01381	.03625	.09787	
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00914		.03850	.01381	.03625	.09770	
CUSTOMER CHARGE													
(/meter/day)	1.43343				1.43343	43.63	1.43343				.00000	1.43343	43.63

PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase II
Application 19-11-019
Data Response

PG&E Data Request No.:	JointParties_001-Q03		
PG&E File Name:	GRC-2020-PhII_DR_JointParties_001-Q03		
Request Date:	March 10, 2021	Requester DR No.:	001
Date Sent:	March 23, 2021	Requesting Party:	California Solar and Storage Association/ Small Business Utility Advocates
PG&E Witness:	Tysen Streib	Requester:	Brad Heavner/ John Wilson

QUESTION 03

Please provide the same report as item 1 for an illustrative energy-only Real-Time-Pricing rate design, as follows.

- All energy charges collected in hourly dynamic rates based on day-ahead forecasts
- Marginal energy costs based on line-loss-adjusted day-ahead locational marginal prices for the PG&E DLAP
- TOU period generation charges reduced from the default rate by the forecast marginal energy cost revenues

ANSWER 03

Per a discussion on March 15, 2021, CALSSA and SBUA have agreed to revise this data request to use May 1, 2020 revenue requirements.

Please see the attachment “GRC-2020-PhII_DR_JointParties_001-Q03_Atch01.xlsx”.

To produce these rates, PG&E calculated the average CAISO price with line losses for each TOU period weighted by the forecasted load in each hour for each class. That average price was then subtracted from the generation energy prices provided in Answer 1. This results in classes having: (1) an hourly RTP rate, (2) a residual TOU-based energy rate, and (3) a demand rate, where appropriate.

Please note that this methodology produced inverted residual TOU energy rates for Schedule B-1 in the winter.

PRESENT RATES (May 1, 2020) / **PROPOSED RATES**

E-TOU-C (Tiered)	Present Distr	Present Gen	Present PPP	Present CIA	Present Other	Present Total		Proposed Distr	Proposed Gen	Proposed PCIA	Proposed RTP	Proposed PPP	Proposed CIA	Proposed Other	Proposed Total		With PCIA Gen	Average CAISO
SUMMER ENERGY CHARGE ($/kWh)																		
Peak	.12767	.16735	.01296	.05339	.05196	.41333		.13640	.08296	.04327	RTP consists of CAISO market price plus line losses	.01343	.04678	.05196	.37479		.18833	.06211
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989		.11640	.04794	.04327		.01343	.04678	.05196	.31978		.12489	.03368
Baseline Credit				(.08633)		(.08633)							(.08709)		(.08709)			
WINTER ENERGY CHARGE ($/kWh)																		
Peak	.07935	.11859	.01296	.05338	.05196	.31624		.08680	.02568	.04327		.01343	.04678	.05196	.26791		.12229	.05334
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891		.08348	.02422	.04327		.01343	.04678	.05196	.26313		.09726	.02977
Baseline Credit				(.08633)		(.08633)							(.08709)		(.08709)			
MINIMUM CHARGE																		
(/meter/day)	*		.02123		.00166	.32854	10.00	*				.02199		.00166	.32854	10.00		
(/kWh)					.05160									.05160				

* Calculated residually as total less sum of other charges.

* Calculated residually as total less sum of other charges.

Pacific Gas and Electric Company
2020 General Rate Case - Phase II
Exhibit (PG&E-4), Appendix C (Update May, 2020)
Present and Proposed Rates
Year 3 Transition Rates

B-1

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
ENERGY CHARGE (/kWh)																
Summer																
Peak	.09551	.17737	.01299	.04218	.32805		.10104	.07392	.04107		.01211	.04218	.27032		.17562	.06063
Part-Peak	.09551	.12814	.01299	.04218	.27882		.10104	.04280	.04107	RTP consists	.01211	.04218	.23921		.12639	.04252
Off-Peak	.09551	.10733	.01299	.04218	.25801		.10104	.03674	.04107	of CAISO	.01211	.04218	.23314		.10558	.02777
Winter										market price						
Peak	.07534	.12212	.01299	.04218	.25263		.08087	.02853	.04107	plus line	.01211	.04218	.20476		.12037	.05078
Off-Peak	.07534	.10600	.01299	.04218	.23651		.08087	.03240	.04107	losses	.01211	.04218	.20864		.10425	.03078
Super Off-Peak	.07534	.08958	.01299	.04218	.22009		.08087	.04691	.04107		.01211	.04218	.22314		.08783	(.00015)
CUSTOMER CHARGE (/meter/day)																
Single-phase	.32854				.32854	10.00	.32854						.32854	10.00		
Polyphase	.82136				.82136	25.00	.82136						.82136	25.00		

Pacific Gas and Electric Company
2020 General Rate Case - Phase II
Exhibit (PG&E-4), Appendix C (Update May, 2020)
Present and Proposed Rates
Year 3 Transition Rates

B-10	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
DEMAND CHARGE (/kW)																
Secondary																
Summer	4.75			8.84	13.59		4.87					8.84	13.72			
Winter	4.75			8.84	13.59		4.87					8.84	13.72			
ENERGY CHARGE (/kWh)																
Secondary																
Summer																
Peak	.04539	.20191	.01205	.01474	.27409		.04627	.09439	.04189		.01202	.01474	.20931		.19711	.06083
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04627	.05078	.04189	RTP consists	.01202	.01474	.16570		.13542	.04274
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04627	.03306	.04189	of CAISO	.01202	.01474	.14799		.10285	.02789
Winter										market price						
Peak	.02716	.14386	.01205	.01474	.19781		.02804	.04665	.04189	plus line	.01202	.01474	.14334		.13906	.05052
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02804	.03096	.04189	losses	.01202	.01474	.12766		.10358	.03072
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02804	.02535	.04189		.01202	.01474	.12204		.06724	(.00001)
CUSTOMER CHARGE (/meter/day)	4.77841				4.77841	145.44	4.90148						4.90148	149.19		

B-19 Secondary	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
DEMAND CHARGES (/kW)																
Summer																
Peak	10.87	14.92			25.79		10.11	14.69					24.80		14.69	
Part-Peak	3.13	2.17			5.30		2.91	2.14					5.05		2.14	
Maximum	12.53			8.91	21.44		11.65					8.91	20.57			
Winter																
Peak	.00	1.77			1.77		.00	1.74					1.74		1.74	
Maximum	12.53			8.91	21.44		11.65					8.91	20.57			
DEMAND CHARGES - OPTION R ($/kW)																
Summer																
Peak	2.72				2.72		2.53						2.53			
Part-Peak	.78				.78		.73						.73			
Maximum	12.53			8.91	21.44		11.65					8.91	20.57			
Winter																
Peak	.00						.00						.00			
Maximum	12.53			8.91	21.44		11.65					8.91	20.57			
ENERGY CHARGES (/kWh)																
Summer																
Peak	.00000	.13878	.01177	.01465	.16520		.00000	.03569	.03965		.01375	.01466	.10374		.13668	.06135
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000	.02373	.03965	RTP consists	.01375	.01466	.09179		.10734	.04396
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000	.01801	.03965	of CAISO	.01375	.01466	.08606		.08659	.02894
Winter										market price						
Peak	.00000	.11986	.01177	.01465	.14628		.00000	.02715	.03965	plus line	.01375	.01466	.09520		.11772	.05093
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000	.01510	.03965	losses	.01375	.01466	.08315		.08655	.03181
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000	.00521	.03965		.01375	.01466	.07326		.04474	(.00011)
ENERGY CHARGES - OPTION R (/kWh)																
Summer																
Peak	.07499	.26625	.01177	.01465	.36766		.07326	.22489	.03965		.01375	.01466	.36620		.26453	.06135
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02499	.08932	.03965	RTP consists	.01375	.01466	.18236		.12896	.04396
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00303	.05081	.03965	of CAISO	.01375	.01466	.12189		.09045	.02894
Winter										market price						
Peak	.00000	.13442	.01177	.01465	.16084		.00000	.09306	.03965	plus line	.01375	.01466	.16111		.13270	.05093
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000	.05074	.03965	losses	.01375	.01466	.11879		.09038	.03181
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000	.01492	.03965		.01375	.01466	.08297		.05456	(.00011)
CUSTOMER CHARGE (/meter/day)																
B-19	24.77594				24.77594	754.12	23.23957						23.23957	707.35		
Rate V	4.77841				4.77841	145.44	4.90148						4.90148	149.19		

B-20 Secondary	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
DEMAND CHARGES (/kW)																
Summer																
Peak	11.13	14.61			25.74		10.04	14.41					24.46		14.41	
Part-Peak	3.19	2.12			5.31		2.88	2.09					4.97		2.09	
Maximum	11.66	.00		9.75	21.41		10.52					9.74	20.26			
Winter																
Peak	.00	1.86			1.86		.00	1.84					1.84		1.84	
Maximum	11.66	.00		9.75	21.41		10.52					9.74	20.26			
DEMAND CHARGES - OPTION R ($/kW)																
Summer																
Peak	2.78	.00			2.78		2.51						2.51			
Part-Peak	.80	.00			.80		.72						.72			
Maximum	11.66	.00		9.75	21.41		10.52					9.74	20.26			
Winter																
Peak	.00	.00			.00		.00						.00			
Maximum	11.66	.00		9.75	21.41		10.52					9.74	20.26			
ENERGY CHARGES (/kWh)																
Summer																
Peak	.00000	.13233	.01146	.01413	.15792		.00000	.03147	.03807		.01251	.01413	.09618		.13056	.06102
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000	.02212	.03807	RTP consists	.01251	.01413	.08683		.10401	.04382

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Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000	.01601	.03807	of CAISO	.01251	.01413	.08072		.08304	.02896
Winter										market price						
Peak	.00000	.11630	.01146	.01413	.14189		.00000	.02598	.03807	plus line	.01251	.01413	.09069		.11444	.05039
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000	.01322	.03807	losses	.01251	.01413	.07792		.08291	.03163
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000	.00266	.03807		.01251	.01413	.06737		.04067	(.00006)
ENERGY CHARGES - OPTION R (/kWh)																
Summer																
Peak	.07547	.25843	.01146	.01413	.35949		.07325	.21892	.03807		.01251	.01413	.35687		.25698	.06102
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02317	.08617	.03807	RTP consists	.01251	.01413	.17404		.12423	.04382
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00160	.04871	.03807	of CAISO	.01251	.01413	.11501		.08677	.02896
Winter										market price						
Peak	.00000	.13182	.01146	.01413	.15741		.00000	.09231	.03807	plus line	.01251	.01413	.15701		.13037	.05039
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000	.04858	.03807	losses	.01251	.01413	.11328		.08664	.03163
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000	.01283	.03807		.01251	.01413	.07753		.05089	(.00006)
CUSTOMER CHARGE																
(/meter/day)	45.08771				45.08771	1372.36	40.67787						40.67787	1238.13	With PCIA	Average
AG-C	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		Gen	CAISO
DEMAND CHARGE (/kW)																
Secondary																
Summer Max Peak Period	6.17	12.52			18.69		6.27	12.34					18.61		12.34	
Summer Maximum	11.21				11.21		11.40	.00					11.40		.00	
Winter Maximum	11.21				11.21		11.40	.00					11.40		.00	
ENERGY CHARGE (/kWh)																
Summer																
Peak	.02005	.11604	.01135	.03624	.18368		.02251	.01496	.03850	RTP consists	.01381	.03625	.12603		.11478	.06132
Part-Peak										of CAISO						
Off-Peak	.01009	.08656	.01135	.03624	.14424		.01255	.00736	.03850	market price	.01381	.03625	.10847		.08530	.03944
Winter										plus line						
Peak	.00690	.10140	.01135	.03624	.15589		.00936	.00921	.03850	losses	.01381	.03625	.10712		.10014	.05243
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00919	.00109	.03850		.01381	.03625	.09884		.07462	.03503
CUSTOMER CHARGE																
(/meter/day)	1.43343				1.43343	43.63	1.43343					.00000	1.43343	43.63		

Pacific Gas and Electric Company
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E-TOU-C (Tiered)

	PRESENT RATES (May 1, 2020)							PROPOSED RATES										
	Distr	Gen	PPP	CIA	Other	Total		Distr	Gen	PCIA	RTP	PPP	CIA	Other	Total		With PCIA Gen	Average CAISO
SUMMER ENERGY CHARGE ($/kWh)																		
Peak	.12767	.16735	.01296	.05339	.05196	.41333		.13625	.08345	.04327	RTP consists of CAISO market price plus line losses	.01344	.04684	.05196	.37519		.18882	.06211
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989		.11625	.04843	.04327		.01344	.04684	.05196	.32018		.12538	.03368
Baseline Credit				(.08633)		(.08633)							(.08720)		(.08720)			
WINTER ENERGY CHARGE ($/kWh)																		
Peak	.07935	.11859	.01296	.05338	.05196	.31624		.08664	.02617	.04327		.01344	.04684	.05196	.26831		.12277	.05334
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891		.08332	.02471	.04327		.01344	.04684	.05196	.26353		.09774	.02977
Baseline Credit				(.08633)		(.08633)							(.08720)		(.08720)			
MINIMUM CHARGE																		
(/meter/day)	*		.02123		.00166	.32854	10.00	*				.02200		.00166	.32854	10.00		
(/kWh)					.05160									.05160				

* Calculated residually as total less sum of other charges. (Present Rates)

* Calculated residually as total less sum of other charges. (Proposed Rates)

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	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
ENERGY CHARGE (/kWh)																
Summer																
Peak	.09551	.17737	.01299	.04218	.32805		.09798	.07594	.04107	RTP consists of CAISO market price plus line losses	.01212	.04218	.26929		.17765	.06063
Part-Peak	.09551	.12814	.01299	.04218	.27882		.09798	.04482	.04107		.01212	.04218	.23818		.12842	.04252
Off-Peak	.09551	.10733	.01299	.04218	.25801		.09798	.03876	.04107		.01212	.04218	.23211		.10761	.02777
Winter																
Peak	.07534	.12212	.01299	.04218	.25263		.07781	.03055	.04107		.01212	.04218	.20373		.12240	.05078
Off-Peak	.07534	.10600	.01299	.04218	.23651		.07781	.03443	.04107		.01212	.04218	.20761		.10628	.03078
Super Off-Peak	.07534	.08958	.01299	.04218	.22009		.07781	.04893	.04107		.01212	.04218	.22211		.08986	(.00015)
CUSTOMER CHARGE (/meter/day)																
Single-phase	.32854				.32854	10.00	.32854						.32854	10.00		
Polyphase	.82136				.82136	25.00	.82136						.82136	25.00		

B-10	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
DEMAND CHARGE (/kW)																
Secondary																
Summer	4.75			8.84	13.59		4.65					8.84	13.49			
Winter	4.75			8.84	13.59		4.65					8.84	13.49			
ENERGY CHARGE (/kWh)																
Secondary																
Summer																
Peak	.04539	.20191	.01205	.01474	.27409		.04465	.09454	.04189		.01203	.01474	.20785		.19726	.06083
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04465	.05093	.04189	RTP consists	.01203	.01474	.16424		.13557	.04274
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04465	.03322	.04189	of CAISO	.01203	.01474	.14653		.10300	.02789
Winter										market price						
Peak	.02716	.14386	.01205	.01474	.19781		.02642	.04680	.04189	plus line	.01203	.01474	.14188		.13921	.05052
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02642	.03112	.04189	losses	.01203	.01474	.12619		.10373	.03072
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02642	.02550	.04189		.01203	.01474	.12058		.06739	(.00001)
CUSTOMER CHARGE (/meter/day)	4.77841				4.77841	145.44	4.67369						4.67369	142.26		

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
B-19 Secondary																
DEMAND CHARGES (/kW)																
Summer																
Peak	10.87	14.92			25.79		10.13	14.73					24.86		14.73	
Part-Peak	3.13	2.17			5.30		2.92	2.14					5.06		2.14	
Maximum	12.53			8.91	21.44		11.68					8.91	20.59			
Winter																
Peak	.00	1.77			1.77		.00	1.75					1.75		1.75	
Maximum	12.53			8.91	21.44		11.68					8.91	20.59			
DEMAND CHARGES - OPTION R ($/kW)																
Summer																
Peak	2.72				2.72		2.53						2.53			
Part-Peak	.78				.78		.73						.73			
Maximum	12.53			8.91	21.44		11.68					8.91	20.59			
Winter																
Peak	.00						.00						.00			
Maximum	12.53			8.91	21.44		11.68					8.91	20.59			
ENERGY CHARGES (/kWh)																
Summer																
Peak	.00000	.13878	.01177	.01465	.16520		.00000	.03606	.03965		.01376	.01466	.10412		.13705	.06135
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000	.02403	.03965	RTP consists	.01376	.01466	.09209		.10763	.04396
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000	.01824	.03965	of CAISO	.01376	.01466	.08630		.08683	.02894
Winter										market price						
Peak	.00000	.11986	.01177	.01465	.14628		.00000	.02753	.03965	plus line	.01376	.01466	.09559		.11810	.05093
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000	.01533	.03965	losses	.01376	.01466	.08339		.08678	.03181
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000	.00523	.03965		.01376	.01466	.07329		.04476	(.00011)
ENERGY CHARGES - OPTION R (/kWh)																
Summer																
Peak	.07499	.26625	.01177	.01465	.36766		.07331	.22519	.03965		.01376	.01466	.36656		.26484	.06135
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02504	.08962	.03965	RTP consists	.01376	.01466	.18272		.12927	.04396
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00308	.05111	.03965	of CAISO	.01376	.01466	.12225		.09076	.02894
Winter										market price						
Peak	.00000	.13442	.01177	.01465	.16084		.00000	.09336	.03965	plus line	.01376	.01466	.16142		.13301	.05093
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000	.05104	.03965	losses	.01376	.01466	.11910		.09069	.03181
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000	.01522	.03965		.01376	.01466	.08328		.05487	(.00011)
CUSTOMER CHARGE (/meter/day)																
B-19	24.77594				24.77594	754.12	23.18112						23.18112	705.58		
Rate V	4.77841				4.77841	145.44	4.67369						4.67369	142.26		
B-20 Secondary	**Distr**	**Gen**	**PPP**	**Other**	**Total**		**Distr**	**Gen**	**PCIA**	**RTP**	**PPP**	**Other**	**Total**		**With PCIA Gen**	**Average CAISO**
DEMAND CHARGES (/kW)																
Summer																
Peak	11.13	14.61			25.74		10.75	14.45					25.20		14.45	
Part-Peak	3.19	2.12			5.31		3.08	2.10					5.18		2.10	
Maximum	11.66	.00		9.75	21.41		11.26					9.74	21.00			
Winter																
Peak	.00	1.86			1.86		.00	1.84					1.84		1.84	
Maximum	11.66	.00		9.75	21.41		11.26					9.74	21.00			
DEMAND CHARGES - OPTION R ($/kW)																
Summer																
Peak	2.78	.00			2.78		2.69						2.69			
Part-Peak	.80	.00			.80		.77						.77			
Maximum	11.66	.00		9.75	21.41		11.26					9.74	21.00			
Winter																
Peak	.00	.00			.00		.00						.00			
Maximum	11.66	.00		9.75	21.41		11.26					9.74	21.00			
ENERGY CHARGES (/kWh)																
Summer																
Peak	.00000	.13233	.01146	.01413	.15792		.00000	.03181	.03807		.01252	.01413	.09652		.13089	.06102
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000	.02239	.03807	RTP consists	.01252	.01413	.08710		.10427	.04382

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Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000	.01623	.03807	of CAISO	.01252	.01413	.08094		.08325	.02896
Winter										market price						
Peak	.00000	.11630	.01146	.01413	.14189		.00000	.02633	.03807	plus line	.01252	.01413	.09105		.11479	.05039
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000	.01342	.03807	losses	.01252	.01413	.07813		.08311	.03163
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000	.00268	.03807		.01252	.01413	.06739		.04068	(.00006)
ENERGY CHARGES - OPTION R (/kWh)																
Summer																
Peak	.07547	.25843	.01146	.01413	.35949		.07469	.21919	.03807		.01252	.01413	.35859		.25725	.06102
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02461	.08644	.03807	RTP consists	.01252	.01413	.17576		.12450	.04382
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00304	.04898	.03807	of CAISO	.01252	.01413	.11673		.08704	.02896
Winter										market price						
Peak	.00000	.13182	.01146	.01413	.15741		.00000	.09258	.03807	plus line	.01252	.01413	.15729		.13064	.05039
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000	.04885	.03807	losses	.01252	.01413	.11356		.08691	.03163
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000	.01310	.03807		.01252	.01413	.07781		.05116	(.00006)
CUSTOMER CHARGE																
(/meter/day)	45.08771				45.08771	1372.36	43.53321						43.53321	1325.04		
AG-C	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
DEMAND CHARGE (/kW)																
Secondary																
Summer Max Peak Period	6.17	12.52			18.69		6.75	11.73					18.48		11.73	
Summer Maximum	11.21				11.21		12.26	.00					12.26		.00	
Winter Maximum	11.21				11.21		12.26	.00					12.26		.00	
ENERGY CHARGE (/kWh)																
Summer																
Peak	.02005	.11604	.01135	.03624	.18368		.02307	.01084	.03850	RTP consists	.01382	.03625	.12247		.11066	.06132
Part-Peak										of CAISO						
Off-Peak	.01009	.08656	.01135	.03624	.14424		.01311	.00325	.03850	market price	.01382	.03625	.10492		.08118	.03944
Winter										plus line						
Peak	.00690	.10140	.01135	.03624	.15589		.00992	.00509	.03850	losses	.01382	.03625	.10357		.09602	.05243
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00975	(.00303)	.03850		.01382	.03625	.09529		.07050	.03503
CUSTOMER CHARGE																
(/meter/day)	1.43343				1.43343	43.63	1.43343					.00000	1.43343	43.63		

(PG&E-RTP-1)

TURN

Pacific Gas and Electric Company
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E-TOU-C (Tiered)	PRESENT RATES (May 1, 2020)							PROPOSED RATES										
	Distr	Gen	PPP	CIA	Other	Total		Distr	Gen	PCIA	RTP	PPP	CIA	Other	Total		With PCIA Gen	Average CAISO
SUMMER ENERGY CHARGE ($/kWh)																		
Peak	.12767	.16735	.01296	.05339	.05196	.41333		.13681	.08474	.04327	RTP consists of CAISO market price plus line losses	.01349	.04716	.05196	.37742		.19012	.06211
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989		.11681	.04973	.04327		.01349	.04716	.05196	.32241		.12668	.03368
Baseline Credit				(.08633)		(.08633)							(.08779)		(.08779)			
WINTER ENERGY CHARGE ($/kWh)																		
Peak	.07935	.11859	.01296	.05338	.05196	.31624		.08721	.02746	.04327		.01349	.04716	.05196	.27054		.12407	.05334
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891		.08389	.02601	.04327		.01349	.04716	.05196	.26576		.09904	.02977
Baseline Credit				(.08633)		(.08633)							(.08779)		(.08779)			
MINIMUM CHARGE																		
(/meter/day)	*		.02123		.00166	.32854	10.00	*				.02209		.00166	.32854	10.00		
(/kWh)					.05160									.05160				

* Calculated residually as total less sum of other charges. (Present rates)

* Calculated residually as total less sum of other charges. (Proposed rates)

Pacific Gas and Electric Company
2020 General Rate Case - Phase II
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Present and Proposed Rates
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	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
ENERGY CHARGE (/kWh)																
Summer																
Peak	.09551	.17737	.01299	.04218	.32805		.10093	.07392	.04107	RTP consists of CAISO market price plus line losses	.01217	.04218	.27027		.17562	.06063
Part-Peak	.09551	.12814	.01299	.04218	.27882		.10093	.04280	.04107		.01217	.04218	.23915		.12639	.04252
Off-Peak	.09551	.10733	.01299	.04218	.25801		.10093	.03674	.04107		.01217	.04218	.23309		.10558	.02777
Winter																
Peak	.07534	.12212	.01299	.04218	.25263		.08076	.02852	.04107		.01217	.04218	.20471		.12037	.05078
Off-Peak	.07534	.10600	.01299	.04218	.23651		.08076	.03240	.04107		.01217	.04218	.20859		.10425	.03078
Super Off-Peak	.07534	.08958	.01299	.04218	.22009		.08076	.04691	.04107		.01217	.04218	.22309		.08783	(.00015)
CUSTOMER CHARGE (/meter/day)																
Single-phase	.32854				.32854	10.00	.32854						.32854	10.00		
Polyphase	.82136				.82136	25.00	.82136						.82136	25.00		

Pacific Gas and Electric Company
2020 General Rate Case - Phase II
Exhibit (PG&E-4), Appendix C (Update May, 2020)
Present and Proposed Rates
Year 3 Transition Rates

B-10	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
DEMAND CHARGE (/kW)																
Secondary																
Summer	4.75			8.84	13.59		4.94					8.84	13.79			
Winter	4.75			8.84	13.59		4.94					8.84	13.79			
ENERGY CHARGE (/kWh)																
Secondary																
Summer																
Peak	.04539	.20191	.01205	.01474	.27409		.04676	.09314	.04189		.01208	.01474	.20861		.19586	.06083
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04676	.04953	.04189	RTP consists	.01208	.01474	.16500		.13417	.04274
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04676	.03182	.04189	of CAISO	.01208	.01474	.14729		.10160	.02789
Winter										market price						
Peak	.02716	.14386	.01205	.01474	.19781		.02853	.04540	.04189	plus line	.01208	.01474	.14264		.13781	.05052
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02853	.02972	.04189	losses	.01208	.01474	.12696		.10233	.03072
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02853	.02410	.04189		.01208	.01474	.12134		.06599	(.00001)
CUSTOMER CHARGE (/meter/day)	4.77841				4.77841	145.44	4.96875						4.96875	151.24		

(PG&E-RTP-1)

CLECA

B-19 Secondary	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
DEMAND CHARGES (/kW)																
Summer																
Peak	10.87	14.92			25.79		10.03	14.53					24.55		14.53	
Part-Peak	3.13	2.17			5.30		2.89	2.11					5.00		2.11	
Maximum	12.53			8.91	21.44		11.56					8.91	20.47			
Winter																
Peak	.00	1.77			1.77		.00	1.72					1.72		1.72	
Maximum	12.53			8.91	21.44		11.56					8.91	20.47			
DEMAND CHARGES - OPTION R ($/kW)																
Summer																
Peak	2.72				2.72		2.51						2.51			
Part-Peak	.78				.78		.72						.72			
Maximum	12.53			8.91	21.44		11.56					8.91	20.47			
Winter																
Peak	.00						.00						.00			
Maximum	12.53			8.91	21.44		11.56					8.91	20.47			
ENERGY CHARGES (/kWh)																
Summer																
Peak	.00000	.13878	.01177	.01465	.16520		.00000	.03412	.03965		.01381	.01466	.10223		.13512	.06135
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000	.02251	.03965	RTP consists	.01381	.01466	.09062		.10611	.04396
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000	.01702	.03965	of CAISO	.01381	.01466	.08513		.08560	.02894
Winter										market price						
Peak	.00000	.11986	.01177	.01465	.14628		.00000	.02556	.03965	plus line	.01381	.01466	.09368		.11614	.05093
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000	.01414	.03965	losses	.01381	.01466	.08225		.08560	.03181
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000	.00508	.03965		.01381	.01466	.07320		.04462	(.00011)
ENERGY CHARGES - OPTION R (/kWh)																
Summer																
Peak	.07499	.26625	.01177	.01465	.36766		.07307	.22361	.03965		.01381	.01466	.36480		.26326	.06135
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02480	.08804	.03965	RTP consists	.01381	.01466	.18096		.12769	.04396
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00284	.04953	.03965	of CAISO	.01381	.01466	.12049		.08918	.02894
Winter										market price						
Peak	.00000	.13442	.01177	.01465	.16084		.00000	.09178	.03965	plus line	.01381	.01466	.15990		.13143	.05093
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000	.04946	.03965	losses	.01381	.01466	.11758		.08911	.03181
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000	.01364	.03965		.01381	.01466	.08176		.05329	(.00011)
CUSTOMER CHARGE (/meter/day)																
B-19	24.77594				24.77594	754.12	23.09341						23.09341	702.91		
Rate V	4.77841				4.77841	145.44	4.96875						4.96875	151.24		

B-20 Secondary	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
DEMAND CHARGES (/kW)																
Summer																
Peak	11.13	14.61			25.74		9.61	14.14					23.75		14.14	
Part-Peak	3.19	2.12			5.31		2.76	2.05					4.81		2.05	
Maximum	11.66	.00		9.75	21.41		10.07					9.74	19.82			
Winter																
Peak	.00	1.86			1.86		.00	1.80					1.80		1.80	
Maximum	11.66	.00		9.75	21.41		10.07					9.74	19.82			
DEMAND CHARGES - OPTION R ($/kW)																
Summer																
Peak	2.78	.00			2.78		2.40						2.40			
Part-Peak	.80	.00			.80		.69						.69			
Maximum	11.66	.00		9.75	21.41		10.07					9.74	19.82			
Winter																
Peak	.00	.00			.00		.00						.00			
Maximum	11.66	.00		9.75	21.41		10.07					9.74	19.82			
ENERGY CHARGES (/kWh)																
Summer																
Peak	.00000	.13233	.01146	.01413	.15792		.00000	.02899	.03807		.01257	.01413	.09375		.12807	.06102
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000	.02014	.03807	RTP consists	.01257	.01413	.08491		.10203	.04382

Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000	.01443	.03807	of CAISO	.01257	.01413	.07920		.08146	.02896
Winter										market price						
Peak	.00000	.11630	.01146	.01413	.14189		.00000	.02340	.03807	plus line	.01257	.01413	.08817		.11186	.05039
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000	.01168	.03807	losses	.01257	.01413	.07645		.08138	.03163
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000	.00254	.03807		.01257	.01413	.06730		.04054	(.00006)
ENERGY CHARGES - OPTION R (/kWh)																
Summer																
Peak	.07547	.25843	.01146	.01413	.35949		.07237	.21690	.03807		.01257	.01413	.35404		.25497	.06102
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02229	.08415	.03807	RTP consists	.01257	.01413	.17121		.12222	.04382
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00072	.04669	.03807	of CAISO	.01257	.01413	.11218		.08476	.02896
Winter										market price						
Peak	.00000	.13182	.01146	.01413	.15741		.00000	.09029	.03807	plus line	.01257	.01413	.15506		.12836	.05039
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000	.04656	.03807	losses	.01257	.01413	.11133		.08463	.03163
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000	.01081	.03807		.01257	.01413	.07558		.04888	(.00006)
CUSTOMER CHARGE																
(/meter/day)	45.08771				45.08771	1372.36	38.94380						38.94380	1185.35		
AG-C	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
DEMAND CHARGE (/kW)																
Secondary																
Summer Max Peak Period	6.17	12.52			18.69		6.25	12.29					18.54		12.29	
Summer Maximum	11.21				11.21		11.36	.00					11.36		.00	
Winter Maximum	11.21				11.21		11.36	.00					11.36		.00	
ENERGY CHARGE (/kWh)																
Summer																
Peak	.02005	.11604	.01135	.03624	.18368		.02248	.01463	.03850		.01387	.03625	.12573		.11445	.06132
Part-Peak										RTP consists						
Off-Peak	.01009	.08656	.01135	.03624	.14424		.01252	.00703	.03850	of CAISO market price	.01387	.03625	.10817		.08497	.03944
Winter										plus line						
Peak	.00690	.10140	.01135	.03624	.15589		.00933	.00887	.03850	losses	.01387	.03625	.10683		.09981	.05243
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00916	.00076	.03850		.01387	.03625	.09854		.07429	.03503
CUSTOMER CHARGE																
(/meter/day)	1.43343				1.43343	43.63	1.43343					.00000	1.43343	43.63		

E-TOU-C (Tiered)	PRESENT RATES (May 1, 2020)							PROPOSED RATES										
	Distr	Gen	PPP	CIA	Other	Total		Distr	Gen	PCIA	RTP	PPP	CIA	Other	Total		With PCIA Gen	Average CAISO
SUMMER ENERGY CHARGE ($/kWh)																		
Peak	.12767	.16735	.01296	.05339	.05196	.41333		.13689	.08248	.04327	RTP consists of CAISO market price plus line losses	.01343	.04678	.05196	.37481		.18785	.06211
Off-Peak	.11767	.11391	.01296	.05339	.05196	.34989		.11689	.04746	.04327		.01343	.04678	.05196	.31979		.12441	.03368
Baseline Credit				(.08633)		(.08633)							(.08709)		(.08709)			
WINTER ENERGY CHARGE ($/kWh)																		
Peak	.07935	.11859	.01296	.05338	.05196	.31624		.08729	.02520	.04327		.01343	.04678	.05196	.26793		.12181	.05334
Off-Peak	.07705	.10356	.01296	.05338	.05196	.29891		.08397	.02374	.04327		.01343	.04678	.05196	.26315		.09678	.02977
Baseline Credit				(.08633)		(.08633)							(.08709)		(.08709)			
MINIMUM CHARGE																		
(/meter/day)	*		.02123		.00166	.32854	10.00	*				.02200		.00166	.32854	10.00		
(/kWh)					.05160									.05160				

* Calculated residually as total less sum of other charges. (Present Rates)

* Calculated residually as total less sum of other charges. (Proposed Rates)

(PG&E-RTP-1)

AECA

B-1

	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
ENERGY CHARGE (/kWh)																
Summer																
Peak	.09551	.17737	.01299	.04218	.32805		.09823	.07520	.04107		.01211	.04218	.26879		.17690	.06063
Part-Peak	.09551	.12814	.01299	.04218	.27882		.09823	.04408	.04107	RTP consists	.01211	.04218	.23768		.12767	.04252
Off-Peak	.09551	.10733	.01299	.04218	.25801		.09823	.03802	.04107	of CAISO	.01211	.04218	.23161		.10686	.02777
Winter										market price						
Peak	.07534	.12212	.01299	.04218	.25263		.07806	.02980	.04107	plus line	.01211	.04218	.20323		.12165	.05078
Off-Peak	.07534	.10600	.01299	.04218	.23651		.07806	.03368	.04107	losses	.01211	.04218	.20711		.10553	.03078
Super Off-Peak	.07534	.08958	.01299	.04218	.22009		.07806	.04819	.04107		.01211	.04218	.22161		.08911	(.00015)
CUSTOMER CHARGE (/meter/day)																
Single-phase	.32854				.32854	10.00	.32854						.32854	10.00		
Polyphase	.82136				.82136	25.00	.82136						.82136	25.00		

(PG&E-RTP-1)

AECA

B-10	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
DEMAND CHARGE (/kW)																
Secondary																
Summer	4.75			8.84	13.59		4.83					8.84	13.68			
Winter	4.75			8.84	13.59		4.83					8.84	13.68			
ENERGY CHARGE (/kWh)																
Secondary																
Summer																
Peak	.04539	.20191	.01205	.01474	.27409		.04599	.09415	.04189	RTP consists of CAISO market price plus line losses	.01202	.01474	.20879		.19687	.06083
Part-Peak	.04539	.14022	.01205	.01474	.21240		.04599	.05054	.04189		.01202	.01474	.16518		.13518	.04274
Off-Peak	.04539	.10765	.01205	.01474	.17983		.04599	.03283	.04189		.01202	.01474	.14746		.10261	.02789
Winter																
Peak	.02716	.14386	.01205	.01474	.19781		.02776	.04641	.04189		.01202	.01474	.14281		.13882	.05052
Off-Peak	.02716	.10838	.01205	.01474	.16233		.02776	.03073	.04189		.01202	.01474	.12713		.10334	.03072
Super Off-Peak	.02716	.07204	.01205	.01474	.12599		.02776	.02511	.04189		.01202	.01474	.12152		.06700	(.00001)
CUSTOMER CHARGE (/meter/day)	4.77841				4.77841	145.44	4.86153						4.86153	147.97		

B-19 Secondary	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
DEMAND CHARGES (/kW)																
Summer																
Peak	10.87	14.92			25.79		10.22	14.67					24.88		14.67	
Part-Peak	3.13	2.17			5.30		2.94	2.13					5.08		2.13	
Maximum	12.53			8.91	21.44		11.78					8.91	20.69			
Winter																
Peak	.00	1.77			1.77		.00	1.74					1.74		1.74	
Maximum	12.53			8.91	21.44		11.78					8.91	20.69			
DEMAND CHARGES - OPTION R ($/kW)																
Summer																
Peak	2.72				2.72		2.55						2.55			
Part-Peak	.78				.78		.74						.74			
Maximum	12.53			8.91	21.44		11.78					8.91	20.69			
Winter																
Peak	.00						.00						.00			
Maximum	12.53			8.91	21.44		11.78					8.91	20.69			
ENERGY CHARGES (/kWh)																
Summer																
Peak	.00000	.13878	.01177	.01465	.16520		.00000	.03542	.03965		.01375	.01466	.10347		.13641	.06135
Part-Peak	.00000	.10899	.01177	.01465	.13541		.00000	.02352	.03965	RTP consists	.01375	.01466	.09158		.10713	.04396
Off-Peak	.00000	.08792	.01177	.01465	.11434		.00000	.01784	.03965	of CAISO	.01375	.01466	.08589		.08642	.02894
Winter										market price						
Peak	.00000	.11986	.01177	.01465	.14628		.00000	.02688	.03965	plus line	.01375	.01466	.09493		.11745	.05093
Off-Peak	.00000	.08784	.01177	.01465	.11426		.00000	.01494	.03965	losses	.01375	.01466	.08299		.08639	.03181
Super Off-Peak	.00000	.04488	.01177	.01465	.07130		.00000	.00519	.03965		.01375	.01466	.07324		.04472	(.00011)
ENERGY CHARGES - OPTION R (/kWh)																
Summer																
Peak	.07499	.26625	.01177	.01465	.36766		.07351	.22467	.03965		.01375	.01466	.36623		.26432	.06135
Part-Peak	.02672	.13068	.01177	.01465	.18382		.02524	.08910	.03965	RTP consists	.01375	.01466	.18239		.12875	.04396
Off-Peak	.00476	.09217	.01177	.01465	.12335		.00328	.05059	.03965	of CAISO	.01375	.01466	.12192		.09024	.02894
Winter										market price						
Peak	.00000	.13442	.01177	.01465	.16084		.00000	.09284	.03965	plus line	.01375	.01466	.16089		.13249	.05093
Off-Peak	.00000	.09210	.01177	.01465	.11852		.00000	.05052	.03965	losses	.01375	.01466	.11857		.09017	.03181
Super Off-Peak	.00000	.05628	.01177	.01465	.08270		.00000	.01470	.03965		.01375	.01466	.08275		.05435	(.00011)
CUSTOMER CHARGE (/meter/day)																
B-19	24.77594				24.77594	754.12	23.44726						23.44726	713.68		
Rate V	4.77841				4.77841	145.44	4.86153						4.86153	147.97		

B-20 Secondary	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
DEMAND CHARGES (/kW)																
Summer																
Peak	11.13	14.61			25.74		10.52	14.41					24.92		14.41	
Part-Peak	3.19	2.12			5.31		3.01	2.09					5.10		2.09	
Maximum	11.66	.00		9.75	21.41		11.02					9.74	20.76			
Winter																
Peak	.00	1.86			1.86		.00	1.83					1.83		1.83	
Maximum	11.66	.00		9.75	21.41		11.02					9.74	20.76			
DEMAND CHARGES - OPTION R ($/kW)																
Summer																
Peak	2.78	.00			2.78		2.63						2.63			
Part-Peak	.80	.00			.80		.75						.75			
Maximum	11.66	.00		9.75	21.41		11.02					9.74	20.76			
Winter																
Peak	.00	.00			.00		.00						.00			
Maximum	11.66	.00		9.75	21.41		11.02					9.74	20.76			
ENERGY CHARGES (/kWh)																
Summer																
Peak	.00000	.13233	.01146	.01413	.15792		.00000	.03141	.03807		.01251	.01413	.09611		.13049	.06102
Part-Peak	.00000	.10542	.01146	.01413	.13101		.00000	.02207	.03807	RTP consists	.01251	.01413	.08677		.10395	.04382

Off-Peak	.00000	.08417	.01146	.01413	.10976		.00000	.01597	.03807	of CAISO	.01251	.01413	.08068		.08300	.02896
Winter										market price						
Peak	.00000	.11630	.01146	.01413	.14189		.00000	.02591	.03807	plus line	.01251	.01413	.09062		.11437	.05039
Off-Peak	.00000	.08400	.01146	.01413	.10959		.00000	.01317	.03807	losses	.01251	.01413	.07788		.08287	.03163
Super Off-Peak	.00000	.04073	.01146	.01413	.06632		.00000	.00266	.03807		.01251	.01413	.06737		.04066	(.00006)
ENERGY CHARGES - OPTION R (/kWh)																
Summer																
Peak	.07547	.25843	.01146	.01413	.35949		.07422	.21886	.03807		.01251	.01413	.35779		.25693	.06102
Part-Peak	.02539	.12568	.01146	.01413	.17666		.02414	.08611	.03807	RTP consists	.01251	.01413	.17496		.12418	.04382
Off-Peak	.00382	.08822	.01146	.01413	.11763		.00257	.04865	.03807	of CAISO	.01251	.01413	.11593		.08672	.02896
Winter										market price						
Peak	.00000	.13182	.01146	.01413	.15741		.00000	.09225	.03807	plus line	.01251	.01413	.15696		.13032	.05039
Off-Peak	.00000	.08809	.01146	.01413	.11368		.00000	.04852	.03807	losses	.01251	.01413	.11323		.08659	.03163
Super Off-Peak	.00000	.05234	.01146	.01413	.07793		.00000	.01277	.03807		.01251	.01413	.07748		.05084	(.00006)
CUSTOMER CHARGE																
(/meter/day)	45.08771				45.08771	1372.36	42.60312						42.60312	1296.73		
AG-C	Distr	Gen	PPP	Other	Total		Distr	Gen	PCIA	RTP	PPP	Other	Total		With PCIA Gen	Average CAISO
DEMAND CHARGE (/kW)																
Secondary																
Summer Max Peak Period	6.17	12.52			18.69		6.24	12.48					18.72		12.48	
Summer Maximum	11.21				11.21		11.33	.00					11.33		.00	
Winter Maximum	11.21				11.21		11.33	.00					11.33		.00	
ENERGY CHARGE (/kWh)																
Summer																
Peak	.02005	.11604	.01135	.03624	.18368		.02246	.01597	.03850	RTP consists	.01381	.03625	.12699		.11579	.06132
Part-Peak										of CAISO						
Off-Peak	.01009	.08656	.01135	.03624	.14424		.01250	.00838	.03850	market price	.01381	.03625	.10944		.08631	.03944
Winter										plus line						
Peak	.00690	.10140	.01135	.03624	.15589		.00931	.01022	.03850	losses	.01381	.03625	.10809		.10115	.05243
Off-Peak	.00673	.07588	.01135	.03624	.13020		.00914	.00211	.03850		.01381	.03625	.09981		.07563	.03503
CUSTOMER CHARGE																
(/meter/day)	1.43343				1.43343	43.63	1.43343					.00000	1.43343	43.63		

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

REAL TIME PRICING BENCHMARKING

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CHAPTER 2
REAL TIME PRICING BENCHMARKING

A. Real Time Pricing Benchmarking Summary

This chapter summarizes research Pacific Gas and Electric Company (PG&E) conducted to understand the state of Real Time Pricing (RTP) offered by regulated utilities in the United States (U.S.), through an Electric Power Research Institute (EPRI) Benchmarking Study, as well as PG&E's own deeper evaluation of RTP offerings by Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Commonwealth Edison (ComEd), Oklahoma Gas & Electric (OG&E) and Griddy LLC.[1] In addition, the EPRI Benchmarking Study provides a framework and taxonomy for RTP also summarized in this chapter.

PG&E's benchmarking efforts support its proposal described in Chapter 1 for a concurrent two-pronged approach as the initial step to evaluate the potential of RTP: Prong I) an RTP Pilot for commercial and industrial (C&I) customers; and Prong II) rate design and preference research for Residential and Ag customers. Benchmarking results show ample evidence from the 53 active Non-Residential RTP rate schedules offered by regulated U.S. utilities that large C&I customers will enroll in and can benefit from RTP and provide load response to support the electricity grid. Various experience with Residential RTP programs in the U.S., and California Energy Commission (CEC) activities to develop automated price responsive technology discussed in Chapter 1, validates PG&E's proposal not to include Residential or Ag customers in the RTP pilot at this time, but rather to study customer preferences for a range of dynamic pricing options. The proposed rate design research would evaluate customer preferences for RTP and other dynamic pricing structures, and the impact of enabling technologies like smart thermostats, including their costs, on those preferences.

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1 Griddy's license to participate in the Texas Electric Reliability Council of Texas (ERCOT) market was cancelled on February 6, 2021, and Griddy filed for Chapter 11 bankruptcy protection on March 15, 2021.

1. EPRI Benchmarking Study

a. Background

In late 2020, PG&E engaged EPRI to conduct research to capture the current landscape of RTP offerings and experience by regulated electricity suppliers in the U.S.[2] The EPRI Benchmarking Study represents a comprehensive review of the universe of RTP plans that are offered by utilities across the U.S. and draws from a combination of sources, principally a 2004 study on RTP programs by Lawrence Berkeley National Laboratory (LBNL)[3] in addition to listings of RTP plans compiled by the U.S. Energy Information Administration (EIA)[4] in 2019. As a further step, EPRI interviewed rate managers at utilities offering RTP to better understand such issues as: (a) the motivations for developing the RTP program, (b) RTP customer enrollment, (c) customer satisfaction, and (d) load shaping results and load shifting persistence.[5]

b. RTP Structure and Taxonomy

The EPRI Benchmarking Study provides a detailed background about, and general context for, how different RTP plans in the U.S. have been structured. The Study describes a rate categorization schema that includes a taxonomy for understanding the basic building blocks of rate structures.

1) RTP Taxonomy

A robust rate categorization schema includes a taxonomy for understanding the basic building blocks of rate structures, including: (a) energy flow (kilowatt-hour (kWh)) based on time-of-use (TOU) or

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2 See Appendix A for the complete EPRI Benchmarking Study.

3 Goldman, et al., *Customer Response to Day-Ahead Wholesale Market Electricity Prices: Case Study of RTP Program Experience in New York* (July 1, 2004). Paper LBNL-54761, at <http://repositories.cdlib.org/lbnl/LBNL-54761>, accessed March 27, 2021.

4 U.S. EIA, Annual Electric Power Industry Report, Form EIA-861 detailed data files. EIA 2019 data as self-identified by utility filings in Form EIA-861, at <https://www.eia.gov/electricity/data/eia861/>, accessed March 27, 2021.

5 See Appendix A, EPRI Benchmarking Study, p. A-2, for the Utility Interview Guide.

volume of consumption; (b) demand (kW); and (c) fixed charges. As a subset of time-varying energy prices, RTP can be differentiated into two categories, one-part and two-part RTP:

- In one-part RTP plans, the posted $/kWh energy price is applied to all metered usage, with fixed charges collected one of three ways: adding a mark-up to the hourly energy prices, assessing a demand charge, or both.
- In two-part RTP plans, an access (or subscription) charge collects fixed supply costs and energy usage charges applicable to Customer Baseline Load (CBL) settled at the non-RTP Otherwise Applicable Tariff. Hourly deviations between actual metered energy use and the CBL are charged or credited the prevailing RTP price reflecting the system marginal cost of supply for that hour. The two-part CBL pricing structure provides a built-in hedge in every hour because it includes the option for a customer to avoid high RTP prices by limiting usage to the CBL.

RTP plans can be distinguished on the basis of the following 14 key design features: (1) Availability; (2) Pricing Structure; (3) CBL Basis; (4) CBL Revision; (5) Price Granularity – Temporal; (6) Price Granularity – Spatial; (7) Routine Price Posting; (8) Price Overcall of Posted Day-Ahead (DA) Prices; (9) Marginal Energy Price Formation; (10) Generation, Transmission and Distribution Capacity Pricing; (11) Marginal Cost Uplift; (12) Contract Term; (13) Hedging and Risk Management; and (14) Eligibility.[6] The EPRI Benchmarking Study applied these design features to categorize and characterize utility RTP rate offerings. Following are the Study's definitions of Dynamic Pricing and RTP used throughout this filing.

a) Dynamic Pricing Definition

In general, time-varying energy rates charge a different amount depending on the time of day, and usually also by the

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6 *Id.*, Chapter 3, for a detailed discussion of RTP design features.

season of the year. Dynamic pricing structures are one type of time-varying rate that introduce the element of price volatility to reflect market conditions and can also include exposure to marginal electricity costs, usually from wholesale generation markets. Dynamic pricing differs from another type of time-varying rates—conventional retail TOU tariffs—which are based on prices that are fixed for months or years at a time to reflect average, embedded supply costs. Dynamic pricing rates include temperature-triggered offerings such as Critical Peak Pricing (CPP), Peak Time Rebate (PTR), and Variable Peak Pricing (VPP), as well as various forms of RTP.[7]

b) RTP Definition

Retail RTP is a particular type of dynamic rate in which the price for electricity fluctuates hourly, or sometimes sub--hourly, to reflect changes in the wholesale price of electricity. Such price signals are typically communicated to customers on a DA basis, although a very small number of programs charge prices based on day-of real time markets. Despite the “real-time” naming convention, a retail RTP rate’s price signal is related to but not identical to the actual wholesale prices that may be transmitted through: (1) DA markets such as the California Independent System Operator (CAISO) Day-Ahead Market (DAM), or hour-ahead (HA) markets, in addition to (2) more granular sub-hourly wholesale markets, such as the California Independent System Operator (CAISO) FMM or 5-minute (RTM) markets.

RTP is also distinguished from other dynamic pricing structures, like CPP and VPP, and load curtailment demand response (DR) programs, because RTP sets a price for every

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7 See Section D, Residential RTP Programs, for a description of CPP and VPP. PTR programs pay customers for reducing usage relative to a modeled baseline on event days announced on a day-ahead basis. PTR has downside for customers who get paid for the calculated reductions, but do not get charged for any increase in usage. See https://www.greentechmedia.com/articles/read/peak-time-rebates-money-for-nothing.

hour based on prevailing (day-of) or expected (DA) market conditions and the corresponding marginal cost of generation supply. Other dynamic pricing structures are event-driven, exposing customers otherwise served on a less dynamic tariff to large price changes, as penalties or incentives, such as during critical peak periods. The typical motivation for employing RTP in rate design is to induce customers to alter their usage based on the prevailing marginal generation energy cost and thus the value of electricity consumption at that time, with higher-priced times serving as an incentive to customers to shift their usage to lower-cost times (with the lower cost hours serving as a “carrot” whereas the higher cost hours serve as the “stick”).

As it turns out, the line between RTP and other dynamic pricing is rather blurry. For example, while SCE’s current RTP rate schedules include hourly prices, posted a day in advance, these prices are selected from a *set of seven pre-set 24-hour pricing schedules, based on a temperature trigger*, rather than on the forecasted marginal cost of electricity supply as with true RTP.[8] In contrast, Oklahoma Gas & Electric Company’s (OG&E) VPP program applies only to peak period hours and selects from a set of four prices based on a daily algorithm that evaluates the forecasted marginal prices for the next day.[9] VPP also has an over-call provision that allows OG&E to designate a critical peak period, at any time during the year with a minimum two-hour notice, for a period lasting between two and eight hours, for no more than 80 hours a year. Although both SCE’s and OG&E’s dynamic pricing offerings reflect some elements of “true” RTP, they could both be viewed as hybrids between RTP and other rate structures. That said, the EPRI Benchmarking

8 See Section C1 for a more detailed discussion of SCE’s RTP rate schedules.

9 See Section D2 for a more detailed discussion of OG&E’s VPP Smart Hours program.

Study classifies SCE's offering as RTP, but not OG&E's VPP program.[10]

c. RTP Definition for Study

EPRI's benchmarking study focused on RTP offerings from regulated electric utilities in the U.S., defined as follows:

1) Full Requirements Electricity Service: Replaces a conventional rate, providing power to all the customer's electrical needs, as an alternative to the tariff rate they otherwise would be served under.
2) Offered by a Regulated Utility: Includes RTP services offered in vertically integrated markets and deregulated markets, if offered by the regulated local distribution company (LDC). RTP programs offered by Regional Transmission System Operators such as price-cap load bidding and DR programs available to retail customers directly or through a utility or competitive supplier were not included in the study.
3) Energy Prices and Price Posting:
    a) Energy prices ($/kWh) set and settled for each hour or shorter periods (e.g., 5-minute intervals) or price blocks (less than 24 daily prices);
    b) Energy prices posted to subscribers a day or less in advance of their effective time;
    c) Energy prices posted for every day of the week throughout the year;
    d) Posted energy prices apply to (at least a portion of) metered kWh usage corresponding to the set pricing interval; and
    e) Posted prices reflect a forecast of the marginal cost of electricity generation supply or are pre-set.

d. EPRI RTP Benchmarking Study Population

The EPRI Benchmarking Study identified 55 active RTP rate offerings by 24 regulated utilities in 41 utility jurisdictions. Table 2-1 below lists the number of RTP rate offerings by customer class for each utility and indicates the number of interviews conducted. It is notable

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[10] Appendix A, EPRI Benchmarking Study, Attachment A, EPRI RTP Program Attributes.

that there are several utility holding companies offering RTP rates in multiple utility jurisdictions, including Consolidated Edison, Inc. (ConEd and Orange & Rockland), Duke Energy Corporation (Duke Energy Carolinas North, Duke Energy Carolinas South, Duke Energy Indiana, Duke Energy Kentucky, Duke Energy Ohio, Duke Energy Progress North Carolina and Duke Energy Progress South Carolina), Exelon Corporation (ComEd, Delmarva Power, Philadelphia Electric Company (PECO)), FirstEnergy Corporation (Jersey Central Power & Light, Met-Ed, OhioEdison, Penelec, PennPower, The Illuminating Company, Toledo Edison), Southern Company (Alabama Power, Georgia Power and Gulf Power) and Xcel Energy (Northern States Power and Xcel Energy).

TABLE 2-1
EPRI RTP BENCHMARKING STUDY POPULATION

Line No.	Utility Holding Company	Regulated U.S. Utility Jurisdictions	RTP Schedules	Customer Classes	Interviews Conducted
1	Alliant Energy Corporation	1	1	Non-Res	
2	Ameren Corporation	1	2	Res/Non-Res	
4	Avangrid	1	1	Non-Res	
5	CH Energy Group	1	2	Non-Res	
6	Consolidated Edison, Inc.	2	2	Non-Res	
7	Dominion Energy, Inc.	2	3	Non-Res	
8	Duke Energy Corporation	7	7	Non-Res	4
9	Duquesne Light Holdings, Inc.	1	1	Non-Res	1
10	Edison International	1	7	Non-Res/Ag	1
11	Evergy	1	1	Non-Res	
12	Exelon Corporation	3	4	Res/Non-Res	3
13	FirstEnergy Corporation	6	6	Non-Res	1
14	MidAmerican Energy	1	1	Non-Res	
15	National Grid plc	1	1	Non-Res	
17	OGE Energy Corp.	1	2	Non-Res	1
18	Otter Tail Corporation	1	1	Non-Res	
	PPL Corporation	1	1	Non-Res	
19	Rochester Gas & Electric	1	1	Non-Res	
20	Sempra Energy	1	1	Non-Res	1
21	Southern Company	3	5	Non-Res	3
22	Upper Peninsula Power Company	1	1	Non-Res	1
23	WEC Energy Group	1	2	Non-Res	
24	Xcel Energy	2	2	Non-Res	
25	Total	41	55		16

e. EPRI Benchmarking Study Findings

Key findings are provided in Table 2-2 below:

TABLE 2-2
KEY FINDINGS FROM EPRI RTP BENCHMARKING STUDY

Line No.	Topic	Findings
1	Availability	55 different active RTP rate schedules were identified, offered by regulated U.S. utilities in 41 utility jurisdictions[(a)] 4 of the 55 active RTP rate schedules are capped and no longer open to new enrollments. Two of the active RTP rate schedules are for Residential customers (ComEd and Ameren), 2 specifically for Agricultural (Ag) customers (SCE) and the remaining 51 are either only for C&I or are open to eligible Ag customers as well. Source: EPRI Benchmarking Study; RTP Program Attribute Detail (Active).
2	Objectives	Utilities interviewed cited that the impetus for their RTP offerings was to: offer required Provider of Last Resort (POLR)[(b)] service in a fully competitive retail energy market; as an economic development incentive to encourage customers to expand load; to encourage peak demand reduction and associated environmental and system benefits; to provide options for customers to save money on their bills; and/or to promote successful and cost-effective transportation electrification. Load management was rarely cited as an objective of RTP programs, although the markets where almost all of these RTP rates are offered do not share the characteristics of the CAISO market that are driving the need for a comprehensive load management approach. Source: EPRI Benchmarking Study; Executive Summary, Key Findings.
3	Maturity	44 of the 55 active RTP rate schedules are permanent. 11 of the 55 active RTP rate schedules are being piloted or are experimental, with limitations on number of customers or size of customer. Source: EPRI Benchmarking Study; Executive Summary, Summary.
4	Eligibility	44 of the 55 active RTP rate schedules are opt-in. 11 of the 55 active RTP rate schedules are mandatory as POLR offerings in New York, Pennsylvania, and Delaware, states with full retail choice, for very large customers that do not select a competitive supplier. Other states with full retail choice, Illinois, Ohio, and New Jersey do not require RTP for large POLR customers. Eligibility is typically related to a (megawatt) MW size threshold, based on minimum demand or monthly peak demand, and often limited to those with larger electric loads: 35 of the 55 active RTP rate schedules are limited to customers with demand greater than 100 kW, 31 > 200 kW, 22 > 500 kW, and 15 > 1 MW. 13 of the 55 active RTP rate schedules are available to all customers in the class 1 of the 55 active RTP rate schedules is available to all customers > 20 kW 6 of the 55 active RTP rate schedules have mixed eligibility. Source: EPRI Benchmarking Study; Section 3, Eligibility Findings and RTP Program Attribute Detail (active).

TABLE 2-2
KEY FINDINGS FROM EPRI RTP BENCHMARKING STUDY
(CONTINUED)

Line No.	Topic	Findings
5	Pricing Structure	18 of the 55 active RTP rate schedules include a two-part design, with a CBL subscription amount and the ability for the customer to sell back electricity below the baseline at the marginal energy price. 5 of the 55 active RTP rate schedules include energy prices only (no capacity adder or demand charge) and 23 include energy prices plus a demand charge. 9 of the 55 active RTP rate schedules have preset prices and do not pass-through prices from a wholesale market or supplier forecast. Source: EPRI Benchmarking Study; Section 3.3., Pricing Structure Findings.
6	Pricing Temporal Granularity	50 of the 55 active RTP rate schedules feature hourly pricing. The exceptions include 2 with five-minute day-of pricing (ComEd) and 3 with pricing blocks with fewer than 24 prices each day (OG&E, Xcel Energy (2)). Source: EPRI Benchmarking Study; Section 3.4; Temporal Price Granularity Findings, and RTP Program Attribute Detail (Active).
7	Price Posting	43 of the 55 active RTP rate schedules feature DA price posting, where the price is known on a DA basis; 1 is known on an HA basis (Georgia Power); 9 are pre-set; and 2 are based on an hourly average of the real time 5-minute market and not known ahead of time (ComEd). Source: EPRI Benchmarking Study; RTP Attribute Detail (Active).
8	Pricing Spatial Granularity	Only 4 of the 55 active RTP rate schedules have pricing elements that account for spatial granularity that differs by location, including SDG&E's Vehicle to Grid Integration rate schedule for their Power Your Drive (PYD) pilot,[c] National Grid's Niagara Mohawk Power (load zone specific) and two Ameren (IL) rate schedules. Source: EPRI Benchmarking Study; RTP Program Attribute Detail (Active).
9	Energy Price Formation	35 of the 55 active RTP rate schedules feature marginal energy prices based on regional wholesale energy market price postings by Regional Transmission Operators (RTOs) or Independent System Operator (ISOs):[d] PJM - 17 RTP rate schedules; MISO - 8 RTP rate schedules; NYISO - 7 RTP rate schedules; SPP - 2 rate schedules; and CAISO - 1 rate schedule. 9 have pre-set prices, and 11 are based on supplier forecasts. Source: EPRI Benchmarking Study; Section 3.8., Energy Price Formation Findings.

TABLE 2-2
KEY FINDINGS FROM EPRI RTP BENCHMARKING STUDY
(CONTINUED)

Line No.	Topic	Findings
10	Price Protection Options	6 of the 55 active RTP rate schedules have price protection options, including both of Georgia Power's RTP rate schedules. ComEd's Residential RTP schedule has a pilot bill protection program. 2 Alabama Power (Georgia Power sister company) RTP rate schedules have a Rate Stabilization and Equalization Factor (RSE) applied to the hourly rate. Upper Peninsula Power Company (UPPCO) RTP customers have an option to pay a premium for greater price certainty. The two-part CBL pricing structure included in 18 of the 55 active RTP rate schedules provides a built-in hedge in every hour, because it includes the option for a customer to avoid high RTP prices by limiting usage to the CBL. Source: EPRI Benchmarking Study; RTP Program Attribute Detail (Active).
11	Summary of Interviews (Ameren Illinois, ComEd - Exelon, Citizens Utility Board of Illinois, Duke Energy Carolinas, Duke Energy Midwest, Duquesne Light Company, FirstEnergy, Georgia Power - Southern Company, Oklahoma Gas & Electric, PECO - Exelon, SDG&E)	The impetus for most utilities' RTP offerings was either: (a) compliance with a regulatory order (actual or anticipated), or (b) preparation for, or response to, retail competition. All but one of the RTP programs discussed with utility representatives are currently active and considered "open for enrollment", yet most RTP programs for large C&I customers do not have high market penetration. Most (80%) of the RTP programs discussed are opt-in with a few default/opt-out for larger C&I customers who do not shop for an alternate service provider. Among the utilities interviewed, there is relatively low participation in RTP programs. Some interviewees expected these relatively low participation levels since their goal was to encourage customers to shop for pricing in competitive markets. Some utilities saw initial success with customer participation and economic development with expanding and new businesses, but most utilities indicate no real growth or a decline in subscription since the program was introduced and initially subscribed. Several interviewees characterized RTP as a niche product for large C&I customers who are able to manage their usage on a meaningful scale. The utilities' current level of enthusiasm for their RTP programs varied widely – from "very happy with it" and "high level of enthusiasm" to "lukewarm, at best" to "indifferent," seeing it as a "just a pass through" or "requirement." However, the majority were either indifferent or thought their program needs improvement. Most utilities review RTP in preparation for their regular rate cases, but few have made or plan to make any significant programmatic changes at this time and none have formal sunset dates.

TABLE 2-2
KEY FINDINGS FROM EPRI RTP BENCHMARKING STUDY
(CONTINUED)

Line No.	Topic	Findings
		Most utilities interviewed do not regularly monitor the price responsiveness of their customers on RTP because there is negligible impact on overall load, possibly due to a lack of price volatility in recent years in the associated ISO/RTO markets. These utilities aren't sure if or why a large C&I customer may have altered operations in response to price or in spite of it – based on the economics of customer orders in production, for example. Similarly, few offered a guess at estimated bill impacts for customers on RTP compared with other pricing programs. Those few utilities that do monitor RTP program results more closely shared that while bill impacts vary by customer, most customers save money on the RTP rate over time (there are good years and bad years). However, how much those customers save depends on their level of response and ability to respond to hourly price fluctuations (e.g., "savvy" customers and/or customers with technology to closely monitor prices). Several utilities mentioned significant investment in modifying or replacing metering, billing and other systems was necessary to accommodate RTP. The majority of utilities interviewed are either indifferent to their RTP offerings or think that their program needs improvement. Most utilities interviewed review RTP in preparation for their regular rate cases, but few have made or plan to make any significant programmatic changes at this time and none have formal sunset dates. Most utilities interviewed reported no real growth nor decline in RTP subscription since programs were introduced and initially subscribed. Almost all utilities interviewed discussed RTP as a "niche product" for large C&I customers who are able to manage their usage on a meaningful scale, according to several interviewees. Customers on RTP generally express high satisfaction to their utility account managers. Only a few utilities have plans or see any likelihood to offer RTP to other customer classes in the future, e.g., in lieu of or in addition to TOU electricity pricing for Residential customers. Marketing to Residential customers requires significant investment to increase market penetration that would still be relatively low. Several utility representatives also reiterated that they view RTP as one of many tools in a pricing portfolio, characterizing it as a niche product for C&I customers with the ability to respond to pricing signals, and adding that RTP has very limited potential in their view due to low price responsiveness of customers generally. Some interviewees commented positively that RTP programs can be difficult to administer but are worth the effort for the Utility and subscribers based on customer satisfaction, economic development and some load management benefits, while others offered more pessimistically that RTP programs are "a lot of effort for little benefit" unless there is capacity shortfall and DR is needed. Source: EPRI Benchmarking Study; Section 4, Key Findings from Interviews.

(a) The EIA estimates that there were almost 3,000 regulated electric distribution companies operating in the U.S. in 2017 (investor--owned, publicly run or managed, and cooperatives).

(b) POLR is a common term in competitive electricity markets for Energy Service Providers, Retail Energy Providers (REP), and LDCs that are required by their regulator to provide a service for customers that do not pick a competitive supplier, or when their supplier goes out of business. The POLR offering tends to be higher priced than the competitive offerings by ESPs/REPs as it is more costly to acquire and manage those electricity contracts. In New York and Pennsylvania, the LDC is required to offer RTP POLR service for the largest customers to minimize their need to continue to operate in the supply business, since RTP requires no energy contract management.

(c) See Section C2 for a more detailed discussion of SDG&E's PYD VGI rate schedule.

(d) PJM – PJM Interconnect RTO serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia; MISO   Midcontinent Independent System Operator serving all or parts of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas and Wisconsin; NYISO – New York Independent System Operator serving New York; SPP – Southwest Power Pool serving all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming; and CAISO serving California).

1) Load Response Potential

The potential for RTP load response depends on both individual customer response to hourly (or sub-hourly) pricing signals and the level of customer participation and persistence. EPRI's study included a search for RTP pilots that evaluated the price responsiveness of customers. EPRI found that thirty-one elasticity estimates were reported to summarize RTP price response.[11] Table 2-3 summarizes EPRI's findings that:[12]

> [E]lasticity estimates varied from zero (RTP prices had no effect on electricity usage) to over 0.58, an outlier as no other value above 0.30 was reported and only two others were above 0.20. **Most were under 0.10 and the majority under 0.05**, especially those involving residences.[13]

TABLE 2-3
DISTRIBUTION OF ELASTICITY ESTIMATES AMONG RTP STUDIES

Line No.	Distribution of Elasticity Estimates (Absolute Values)	
1	0.00 to 0.05	12
2	0.06 to 0.10	9
3	0.11 to 0.20	6
4	0.20 to 0.30	2
5	Over 0.30	2

Note Appendix A, EPRI Benchmarking Study, Chapter 5, Table 5-2.

11 Attachment A, EPRI Benchmarking Study, Chapter 5.

12 An elasticity value of 0.20 means that a 100 percent change in the price ratio produces a 20 percent change in usage ratio. Elasticities are measured as ratios of changes which means that only the price ratio effects consumption.

13 EPRI also found that, "[h]igher elasticities were reported for some customer circumstances [such as] government and educational facilities, electricity intensive facilities like arc furnaces and refineries, and when the RTP design allows for DA prices to be revised within day, particularly to post much higher prices to reflect supply conditions not anticipated the day before." (Attachment A, EPRI Benchmarking Study, pp. x-xi.).

> PG&E's proposed pilot design includes a robust measurement and evaluation plan that will test hypotheses to assess load response and other aspects of RTP in order to inform a rollout to a broader group of customers.[14]

B. RTP Program Objective Examples

Utilities interviewed cited that the impetus for their RTP offerings was to: offer required POLR service in a fully competitive retail energy market; as an economic development incentive to encourage customers to expand load; to encourage peak demand reduction and associated environmental and system benefits; to provide options for customers to save money on their bills; and/or to promote successful and cost effective transportation electrification. With the exception of SDG&E's VGI RTP program, load management was not specifically cited as an objective of RTP programs, although the markets where almost all of these RTP rates are offered do not share the characteristics of the CAISO market that are driving the need for a comprehensive load management approach. Table 2-4 provides some examples of RTP program objectives based on PG&E's assessment of rate schedules, other secondary information, and interviews.

14 See Chapter 5 for the details of PG&E's Measurement & Evaluation plan for the proposed Pilot.

TABLE 2-4
EXAMPLES OF RTP PROGRAMS AND THEIR OBJECTIVES AND COMPARISON WITH THIS GRC PHASE II RTP PROPOSAL

Line No.	Objective	Example	Method
1	Load Management	Oklahoma Gas & Electric VPP	Hybrid between an RTP and a TOU rate for Residential and small commercial customers.
2	Transportation Electrification	PG&E's Proposed DAHRTP-CEV Pilot (CEV RTP Pilot)	A rate rider for commercial electric vehicle (CEV) customers that replaces the generation rate with a generation rate derived from CAISO's DA hourly wholesale market.
3	Transportation Electrification and Load Management	SDG&E Vehicle-Grid Integration (VGI) RTP Pilot	A pilot rate for electric vehicle (EV) customers comprising of: 1. an hourly Base Rate; 2. an hourly Commodity Base Rate with an adjustment based on the CAISO DA hourly price, an adder to reflect the system's top 150 system peak hours, and an adjustment to reflect day-of CAISO surplus energy hours; and 3. an hourly Distribution Base Rate with an adder to reflect the top 200 annual hours of peak demand for the individual circuit feeding the VGI charging station.
4	Economic Development	Georgia Power	Customers are billed a fixed (or subscription) amount for "customer baseline" (CBL) use at their standard rate and either pay or receive credits for energy used above or below their baseline each hour at the hourly price.
5	POLR	First Energy	RTP is mandatory rate for large customers that do not select a REP in the fully competitive market, in order to limit the utilities' need to enter into power contracts for these customers.
6	Load Management as well as Electrification	PG&E's C&I RTP Pilot (proposed)	A rate rider for large C&I customers that replaces the generation rate with a generation rate derived from CAISO's DA hourly wholesale market.

C. California IOU RTP Programs

Both SDG&E and SCE have RTP hourly pricing rate options for eligible customers. SCE's RTP hourly pricing program is available to most Non-Residential customers but does not pass through hourly prices from the

CAISO wholesale market. SDG&E's hourly pricing program passes through prices from the CAISO DAM, includes a distribution component that charges different prices based on geography, and also includes a CPP element that can be activated when the grid is stressed. The rest of this section describes these RTP offerings in more detail.

1. SCE RTP Schedules[15]

a. Background and Rate Design

While it is a different design, SCE's RTP program experience supports PG&E's proposal for a phased approach starting with a C&I pilot targeted to large customers. It also demonstrates a higher level of load response that can be achieved by an RTP program with large C&I customers with a very small portion of the customer base as compared to a Residential TOU program with a very large portion of the customer base. At the same time, the program highlights the risk of customer attrition and bill impact risks, inherent even for large customers, from an unusually hot summer, even with a mild RTP rate structure (i.e., SCE's RTP rates have limited and predictable price volatility since they do not pass through wholesale prices).

SCE's RTP program was introduced in 1987 and charges participants for the electricity they consume based on one of seven pre-set schedules of 24-hourly prices that vary according to season and the prior day's temperature.[16] Customers are responsible for acquiring the daily maximum temperature at the Los Angeles Downtown site, which determines which of the seven pre-set hourly pricing schedules will be in effect the next day. Since the hourly pricing schedules are set in advance and updated infrequently, customers are better able to predict the specific hourly prices that will be called on any particular day by monitoring the weather. Customers can also select a price threshold from SCE's DR Alerts app and receive a courtesy daily email. RTP is

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15 SCE, RTP Fact Sheet (2018), at <https://www.sce.com/sites/default/files/inline-files/RTP%20Fact%20Sheet%200918_WCAG_2.pdf>, accessed March 27, 2021.

16 The daily maximum temperature, as recorded by the National Weather Service, at its Downtown Los Angeles site, is used to determine the hourly rates for the following day.

available for most of SCE's bundled Non-Residential customers on the following rate schedules:

- Ag < 200 kilowatt (kW) (TOU-PA-2-RTP)
- Ag 200 kW - 500 kW (TOU-PA-3-RTP)
- C&I < 20 kW (TOU-GS-1-RTP)
- C&I 20 kW - 200 kW (TOU-GS-2-RTP)
- C&I 200 kW - 500 kW (TOU-GS-3-RTP)
- C&I and Ag > 500 kW (TOU-8-RTP)
- C&I > 500 kW Standby (TOU-8-RTP-S)

Customers participating in RTP may also be dually enrolled in the Agricultural Interruptible Program or Base Interruptible Program (BIP).

Time-Related Demand charges apply year-round in the medium and large RTP rate schedules, and during summer only in the small and medium business RTP rate schedules. The Downtown Los Angeles temperature triggers for the seven pre-set hourly pricing schedules (3 for summer, 2 for winter and 2 for weekends) are listed in Table 2-5.

TABLE 2-5
SCE RTP HOURLY PRICING SCHEDULE TEMPERATURE TRIGGER - DOWNTOWN LOS ANGELES

Line No.	Hourly Pricing Schedule	Temperature Trigger (degrees F)
1	Hot Summer Weekday	>=91
2	Moderate Summer Weekday	81 - 90
3	Mild Summer Weekday	< = 80
4	High Cost Winter Weekday	> 90
5	Low Cost Winter Weekday	<=90
6	High Cost Weekend	>=78
7	Low Cost Weekend	<78

SCE's RTP rate schedules incorporate both the time-varying components of energy costs and generation capacity costs. The peak and ramp capacity costs are allocated to the day types based on expected capacity need. The energy prices reflect SCE's marginal generation and energy cost profile. SCE's RTP is designed to be revenue neutral to the respective rate class and is designed using the same marginal energy and capacity costs embedded in the otherwise applicable tariffed rates.

PG&E also notes that because SCE's GRC Ph II proceeding had not yet been scoped at the time of this filing, it is not clear if RTP will be addressed in that proceeding. SCE states in their opening testimony, "SCE will continue to explore the opportunity to incorporate wholesale energy prices from the CAISO into the RTP rate design upon implementation of SCE's Customer Service Re-platform initiative."[17]

b. Enrollment

Load impact studies in 2016 and 2019 indicate that SCE's RTP program enrollment has declined from 150 Service Accounts in 2017[18] to 102 in 2020. This decrease in enrollment was attributed to customers opting out of the program after a summer of many hot days in 2018 and consequently higher bills.[19] Enrollment is expected to continue to decline over time, to 70 enrolled customers in 2030.[20]

Table 2-6 below summarizes 2016 Federal Energy Regulatory Commission (FERC) Form 1 data regarding the type of customers and associated load enrolled on SCE's RTP rate schedules:[21]

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17 A.20-10-012, SCE-04, p. 66, lines 13-15.

18 SCE's Compliance Filing Pursuant to Load Impact Protocol Filing Requirements, R.13-09–011 (Apr. 3, 2017), Appendix A, p. 9, Table 2-1, at <http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/ADEBF26D1832D1F3882580F70081EDAC/$FILE/R1309011-SCE%202016%20Compliance%20Filing%20Pursuant%20to%20Load%20Impact%20Protocol%20Filing%20Requirements.pdf>, accessed March 27, 2021.

19 2019 SCE Real Time Pricing Demand Response Evaluation, Final Report (Apr. 1, 2020), p. 7.

20 *Id.*, p. 3.

21 2016 FERC Form 1 data was the most recent readily available online for SCE. (FERC Financial Report, FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report, Southern California Edison, 2016/Q4). See, <https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454555>, accessed March 27, 2021.

TABLE 2-6
2016 SCE RTP PROGRAM STATS - FERC FORM 1

Line No.	By Rate Schedule / Size / Class	MWH	Percent	Customers	Percent
1	Ag < 200 kW (TOU-PA-2-RTP)	2,158	0%	15	10%
2	Ag 200 kW - 500 kW (TOU-PA-3-RTP)	7,516	1%	8	5%
3	C&I < 20 kW (TOU-GS-1-RTP)	161	0%	20	13%
4	C&I 20 kW - 200 kW (TOU-GS-2-RTP)	427	0%	2	1%
5	C&I 200 kW - 500 kW (TOU-GS-3-RTP)	10,175	1%	16	11%
6	C&I and Ag > 500 kW (TOU-8-RTP)	1,428,721	99%	89	59%
7	C&I > 500 kW Standby (TOU-8-RTP-S)	-	0%	-	0%
8	Total RTP	1,449,158		150	
9					
10	By Service Level				
11	Secondary	166,079	11%	116	77%
12	Primary	101,769	7%	23	15%
13	Transmission	1,181,310	82%	11	7%
14	Total RTP	1,449,158		150	
15					
16	BIP Dual Participants				
17	T8-RTP-BIPN-P	5,017	1%	1	3%
18	T8-RTP-BIP-P	42,869	8%	7	23%
19	T8-RTP-BIP-S	74,223	13%	18	58%
20	T8-RTP-BIP-T	436,236	78%	5	16%
21	Total BIP RTP	558,345		31	
22	% of Total RTP	39%		21%	

The 2016 FERC Form 1 data shows most of SCE's RTP customer load is concentrated with a few customer types:

- 82 percent of load was from transmission level customers
- 99 percent of load was from customers on TOU-8-RTP with maximum demand >500 kW (C&I and Ag)
- 39 percent of load was from dually enrolled BIP customers

c. Load Response

Table 2-7 shows that 102 customers enrolled in SCE's RTP program delivered load reductions of approximately 31 percent on the system peak day (September 4, 2019), and an aggregate impact of 14.31 MW, all from customers with maximum demand >200 kW.[22]

[22] 2019 SCE Real Time Pricing Demand Response Evaluation, Final Report (Apr. 1, 2020), p. 23, Table 9.

TABLE 2-7
SCE 2019 RTP EX-POST IMPACTS BY CUSTOMER SIZE

Table 11: Ex Post Impacts by Customer Size

Size	# Enrolled	Average Customer (kW)				% Impact	Agg. Impact (MW)
		Ref. Load	Obs. Load	Impact	95% CI		
20kW or Lower	16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20-200kW	13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Greater than 200kW	73	634.73	438.71	196.02	-8.94 - 400.97	30.9	14.31
All Customers	102	455.68	315.34	140.34	-25.52 - 306.19	30.8	14.31

These few large customers contribute large load impacts relative to Residential TOU programs with many customers. Table 2-8 compares the load impact of SCE's RTP vs. Residential TOU. It shows that, in 2019, SCE's RTP program provided up to ~3 times more load impact on hot summer days relative to Residential TOU, which had ~1,600 times more customers. For example, in July 2019 on a hot summer weekday, 102 RTP customers shifted or reduced 15 MW in aggregate load, 2.7 times greater load response than the 5.6 MW in aggregate load impact produced by169K (1,657 times more) Residential TOU Rate 5 customers.

TABLE 2-8
SCE 2019 NON-DISPATCHABLE PROGRAMS PEAK PERIOD LOAD IMPACTS

Table 8: Peak Period Impacts for Monthly Peak Days for Non-Dispatchable Programs

Program	Month	Detail	Ref (kW)	Obs (kW)	Imp (kW)	% Imp	Imp (MW)	Enrolled
RTP	Jan	Low Cost Winter Weekday	226.6	223.5	3.1	1.4	0.3	104
	Feb	Low Cost Winter Weekday	226.0	222.9	3.1	1.4	0.3	104
	Mar	Low Cost Winter Weekday	219.9	218.4	1.4	0.7	0.1	104
	Apr	Low Cost Winter Weekday	234.1	236.0	-1.9	-0.8	-0.2	106
	May	Low Cost Winter Weekday	527.9	518.1	9.8	1.8	1.0	98
	Jun	Hot Summer Weekday	472.0	331.4	140.7	29.8	13.8	98
	Jul	Hot Summer Weekday	476.6	328.2	148.5	31.1	15.0	101
	Aug	Moderate Summer Weekday	467.7	460.4	7.2	1.6	0.7	102
	Sep	Hot Summer Weekday	455.7	315.3	140.3	30.8	14.3	102
	Oct	High Cost Winter Weekday	530.4	520.2	10.2	1.9	1.0	100
	Nov	Low Cost Winter Weekday	244.1	242.6	1.5	0.6	0.2	109
	Dec	Low Cost Winter Weekday	221.8	218.7	3.1	1.4	0.3	105
Res TOU	Jun	Rate 4	1.56	1.55	0.00	0.3	0.8	170,321
	Jun	Rate 5	1.59	1.57	0.02	1.5	4.1	170,186
	Jul	Rate 4	1.86	1.84	0.02	1.2	3.9	168,766
	Jul	Rate 5	1.89	1.86	0.03	1.8	5.6	168,748
	Aug	Rate 4	1.70	1.69	0.02	1.0	2.9	167,382
	Aug	Rate 5	1.74	1.71	0.03	1.7	4.9	167,312
	Sep	Rate 4	1.91	1.88	0.03	1.5	4.9	166,183
	Sep	Rate 5	1.89	1.86	0.03	1.7	5.4	166,128

Note: SCE Compliance Filing Pursuant to Load Impact Protocol Filing Requirements, R.13-09-011, Appendix A, SCE 2018 Demand Response Executive Summary (Apr. 1, 2019) Table 4-1, p. A-28, at <http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/AD82A413B0BFC9E4882583D000023D36/$FILE/R1309011-SCE%20Compliance%20Filing%20Pursuant%20to%20Load%20Impact%20Protocol%20Filing%20Reqs%20PY%202018%20(Public).pdf>, accessed March 27, 2021.

2. SDG&E PYD

a. Background and Rate Design

SDG&E's PYD, established in 2016, includes RTP rate schedule VGI[23] that is mandatory for customers receiving an SDG&E owned and operated Electric Vehicle-Grid Integration Pilot Program charging station (VGI Program Facilities). PYD seeks to align with the State of California's greenhouse gas (GHG) reduction and transportation

23 SDG&E Schedule VGI, at <http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_VGI.pdf>, accessed March 27, 2021.

electrification policies by integrating EV charging with the electricity grid through an hourly rate and the installation of up to 3,500 EV charging stations at 350 apartments, condominiums, and places of work. SDG&E states that the, "Hourly charging prices will correspond with the expected changing hourly price of electricity and will be designed to encourage EV charging to occur at times of the day that will minimize incremental peak loads on the electrical distribution system, integrate high levels of renewable energy use, and avoid charging on system peaks."[24] SDG&E ownership of the infrastructure simplifies the experience for customers installing chargers and ensures the reliability of the charging network.[25]

There are two variations of the rate, one for individual EV customers (Billed to Driver), and one for Site Hosts providing charging through the VGI Program Facilities (Billed to Host). Schedule VGI reflects real time grid conditions from an energy and distribution grid perspective with adders for grid-constrained hours system-wide and distribution-wide. It incorporates DA hourly pricing based on CAISO's DA Market with a CPP signal based on distribution conditions.[26] While load impacts are not yet published, initial peak vs. off peak charging data supports PG&E's proposal to assess pilot load impacts in the context of other load management programs in case they are just as effective at meeting load shift and environmental objectives. SDG&E's VGI RTP pilot differs from PG&E's CEV and C&I RTP Pilot proposals in four key ways: First, PG&E will not be providing charging stations bundled with mandatory

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24 SDG&E, A.14-04-014, Direct Testimony, Randy Schimka, Chapter 2 (Apr. 11, 2014) p. RS-3. See, <https://www.sdge.com/sites/default/files/regulatory/Chapter_2_Schimka_Testimony_VGI.pdf>, accessed March 27, 2021.

25 EV-Grid Integration Pilot Program ("Power Your Drive") Ninth Semi-Annual Report of SDG&E, R.18-12-006 (Oct. 14, 2020) pp. 2-3. See, <https://www.sdge.com/sites/default/files/regulatory/R.18-12-006%20Ninth%20Oct%202020%20PYD%20Final%20Report%2010%2014%202020.pdf>, accessed March 27, 2021.

26 Application of SDG&E for Authority to Implement a Pilot Program for Electric Vehicle Grid Integration, A.14-04-014 (Apr. 11, 2014). See, <https://www.sdge.com/sites/default/files/regulatory/VGI%20Application_FINAL.pdf>, accessed March 27, 2021.

RTP, and, neither of PG&E's Pilot proposals includes: (1) a CPP component for the highest cost generation hours, (2) an adder based on distribution system conditions, or (3) a surplus generation credit.

SDG&E's VGI Pilot rate design incorporates the following components:[27]

1) Base rate which is the class average rate for medium, large, and industrial customers. It recovers costs related to transmission, public purpose programs, nuclear decommissioning, charges to pay the above market costs for long term power contracts, reliability services to recover the costs for services provided by generating facilities to maintain system reliability and Department of Water Resources bond charges to cover of cost of purchasing power during the 2000/2001 electricity crisis;
2) An hourly commodity component consisting of: (a) the hourly CAISO DA Market price, (b) a CPP signal applied to the top 150 system hours and provided to customers on a DA basis, and (c) a day-of pricing benefit in the event that CAISO day-of prices drop below a threshold level relative to CAISO DA prices (surplus generation credit); and
3) An hourly distribution component that incorporates a circuit level CPP signal, applied to the top 200 hours and provided to customers on a DA basis.

Hourly pricing for each day is made available on SDG&E's VGI mobile and web application on a DA basis.

b. Enrollment

As of September 2019, SDG&E had executed 254 site agreements with approximately 3,040 charging ports. In October 2019, SDG&E filed an application for a program extension including an additional 2,000 EV charging ports. The application is pending at the California Public Utilities Commission (CPUC).

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[27] SDG&E, A.14-04-014, Revised Direct Testimony, Cynthia Fang, Chapter 3 (June 3, 2014), at <https://www.sdge.com/sites/default/files/regulatory/Chapter%203%20Cynthia%20Fang%20Revised%20Testimony%2006-03-14.pdf>, accessed March 27, 2021.

c. Load Response

In the context of other load management approaches it is not yet clear that the PYD VGI RTP rate is materially better at encouraging customers to charge in off-peak rather than peak periods than standard TOU rates. For example, SDG&E's Ninth Semi-Annual Report for PYD[28] indicates pilot performance is not materially different than EV TOU performance. For example, in SDG&E's comparison of resource charging time, PYD averaged 86 percent in off peak charging and 14 percent in peak hours, whereas EV TOU averaged 84 percent in off peak and 16 percent in peak. DR trailed behind at 75 percent charging in off peak and 25 percent charging at peak.

D. Residential RTP Programs

Out of the 55 active RTP rate schedules offered by U.S. regulated utilities, only two are available to Residential customers, both in the same state—Illinois, one by ComEd and the other by Ameren. Although Illinois' Residential RTP programs have been in place since 2007 when they were ordered by their Commission, enrollment levels 14 years later are still very low.

In 1997, The Illinois Public Act 94-0977 required electric utilities serving more than 100,000 customers to provide an RTP rate option for Residential customers.[29] Then, in 2006, the Illinois Commerce Commission (ICC) Docket 06-0617 found a Residential RTP program would likely provide a net economic benefit to the Residential community as a whole and approved ComEd's Residential Real Time Pricing (RRTP) program described in more detail below.

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28 EV-Grid Integration Pilot Program ("Power Your Drive") Ninth Semi-Annual Report of SDG&E, R.18-12-006 (Oct. 14, 2020) p. 14. See, <https://www.sdge.com/sites/default/files/regulatory/R.18-12-006%20Ninth%20Oct%202020%20PYD%20Final%20Report%2010%2014%202020.pdf> accessed March 27, 2021.

29 Illinois Public Act 094-0977, 220 ILCS 5/16-107, b-5, at <https://www.ilga.gov/legislation/publicacts/fulltext.asp?Name=094-0977> accessed March 27, 2021.

1. ComEd Hourly Pricing Program

a. Background and Rate Design

ComEd's RRTP Rate, known as "Hourly Pricing," has been in place since 2008 and resulted from a four-year experimental rate, RHEP (Residential Hourly Electric Pricing). ComEd's Hourly Pricing is administered by an independent third party, Elevate Energy, which handles the program implementation from recruitment to call center management to address customer inquiries and enrollments. ComEd's Hourly Pricing rate[30] design incorporates costs from:

1) A $/kWh energy price that changes hourly based on the ComEd Zonal Locational Marginal Price from the PJM real-time hourly market. The real-time hourly market price is determined by the average of the twelve 5-minute prices from that hour, and so the averaged real-time hourly price is not known until after the hour has passed;
2) A $/kW rate that is applied to a customer's individual capacity obligation. This is calculated as the customer's coincident peak, during both PJM's five peak hours and ComEd's five peak hours from the previous year; and
3) Other miscellaneous monthly charges

Since the hourly energy price cannot be known ahead of time, DA alerts notify participants to reduce their energy usage in anticipation of high demand the following day, which could impact their capacity charge. Real-time price alerts are sent to participants when the 5-minute price is at or above 14 cents per kWh for 30 consecutive

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30 ComEd's Rider RRTP (on BESH), RRTP Program, Sheet No. 356 to Sheet No. 359. See, <https://www.comed.com/SiteCollectionDocuments/MyAccount/MyBillUsage/CurrentRates/Ratebook.pdf> and <https://www.comed.com/SiteCollectionDocuments/MyAccount/MyBillUsage/CurrentRates/05_RateBESH.pdf> accessed March 27, 2021.

minutes. In 2019, there were 12 DA alerts and three real-time high price alerts at or above 14 cents per kWh.[31]

Aligned with PG&E's recommendation for its own pilot rate, Elevate, also recommended that to improve program design is that bills change to from "based on the real-time hourly pricing markets to billing based on the DA hourly pricing markets". They noted that this could allow customers to save more money and avoid larger and more unpredictable price spikes.[32]

ComEd has enabled If This That (IFTTT) as a free, online automation platform that allows participants to connect compatible smart home devices to real-time hourly prices using simple conditional statements. An email marketing campaign in April 2019 encouraging those without smart home technology to visit ComEd Marketplace and take advantage of rebates and offers, with the theme "IFTTT keeps an eye on hourly prices so you don't have to."[33] There is no evidence of any other 3rd party support of ComEd Residential Hourly Pricing customers or 3rd party technology marketplaces that have developed to support these customers yet.

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31 Elevate Energy, ComEd's Hourly Pricing Program 2019 Annual Report. April 23, 2020, p. 21. See, <https://www.icc.illinois.gov/docket/P2015-0602/documents/299208/files/521714.pdf > accessed March 27, 2021.

32 *Id.*, p. 24. See, <https://www.icc.illinois.gov/docket/P2015-0602/documents/299208/files/521714.pdf > accessed March 27, 2021.

33 *Id.*, p. 9. See, <https://www.icc.illinois.gov/docket/P2015-0602/documents/299208/files/521714.pdf > accessed March 27, 2021.

b. Enrollment

As of 2019, 34,456 (or about 1.4 percent) of ComEd's bundled Residential customers were on the Hourly Pricing program,[34] a net increase of 17 percent in 2019. Aggressive marketing targeting customers on the ComEd's Peak Time Savings DR program resulted in a total of 10,831 new participants. However, a large number of customers (5,689) left the program, either switching to a third-party supplier (951), closing their accounts (2,510) or opting out to another rate option (2,228).[35] These statistics point to a very high customer churn level of 11 percent in 2019.[36]

In October 30, 2006 testimony regarding ComEd's proposed Hourly Pricing rate, Witness Neenan forecasted that, with enrollment of 213,000 customers in seven years, there would be potential benefits to all Residential customers of between $34.4 and $41.9 million.[37] Clearly, enrollment after 13 years is only a fraction of that projected in 2006. However, Elevate Energy estimated more than $11 million in net benefits in 2019.[38]

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34 1.4 percent of ComEd's bundled Residential customers were enrolled in the Hourly Pricing Program in 2019: There were 2.5 million bundled Residential customers and 34,465 Hourly Pricing Program customers. The Hourly Pricing Program was launched in 2007. ((1) 2019 EIA Annual Electric Power Industry Report, Form EIA-861, Supplemental Data, 1990-2019 Retail Sales of Electricity by State by Sector by Provider; (2) Elevate Energy, ComEd's Hourly Pricing Program 2019 Annual Report, April 23, 2020, p. 3; and, (3) Evaluation of the RRTP Program, 2007-2010 . NAVIGANT, June 20, 2011. p. 1).

35 Elevate Energy, ComEd's Hourly Pricing Program 2019 Annual Report. April 23, 2020, p. 16. See, <https://www.icc.illinois.gov/docket/P2015-0602/documents/299208/files/521714.pdf > accessed March 27, 2021.

36 Churn Level = customers opting out to a third-party supplier or another rate option (951+2,228) / 2018 enrollment: 29,797. 2019 Annual Report, pp. 16-17.

37 Direct Testimony of Bernard Neenan on Behalf of The Citizen's Utility Board and the City of Chicago, ICC Docket NO. 06-0617, Cub-City Exhibit 3.0, October 30, 2006. p. 9 at <https://www.icc.illinois.gov/docket/P2006-0617/documents/102743/files/184620.pdf>, accessed March 27, 2021.

38 Elevate Energy, ComEd's Hourly Pricing Program 2019 Annual Report. April 23, 2020, p. 13. See, <https://www.icc.illinois.gov/docket/P2015-0602/documents/299208/files/521714.pdf > accessed March 27, 2021.

c. Load Response

Klos Energy Consulting's (Klos) 2019 report: *Updated Net Benefits of ComEd's Hourly Pricing Program"* reported that the Hourly Pricing program generated over $11,000,000 in net benefits from a societal perspective in 2019, an increase of 19 percent over 2018, much of the increase attributed to the growth in number of participants. Bill savings were an average of $92, due to market prices being lower than the standard rate. New participants saved an additional $40 on average due to conservation efforts.[39] Hourly Pricing program participants reduced their summer peak usage by .51 kW per customer in response to high peak prices.[40]

However, although there were positive net benefits and bill savings for Hourly Pricing participants, Non-Residential customers and PJM customers outside ComEd, negative benefits continue to be shown for Residential non-participants, due to the costs of program administration allocated to them outweighing the benefits.[41] In addition, Klos explains that in 2017 the environmental benefits of load shifting became negative:

> …even though there are load shifts, the marginal fuel mix study for 2017 showed that there was very little difference in marginal emission rates for on-peak vs. off-peak periods within PJM. Switching load to the off-peak period did decrease SO2 and NOx

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39 Net benefits are calculated from an evaluation of: (1) Benefits from avoided capacity costs, consumer surplus (bill savings plus), demand response induced price effect (DRIPE), environmental benefits, avoided transmission and distribution costs, improved customer satisfaction, and improved national security; and (2) Costs: Third-Party Administrator costs, ComEd program costs, and new enrollment costs. Elevate Energy, ComEd's Hourly Pricing Program 2019 Annual Report (Apr. 23, 2020), Appendix, Updated Net Benefits of ComEd's Hourly Pricing Program: Report for Calendar Year 2019 (Mar. 24, 2020), Klos Energy Consulting, pp. 2-3. See , <https://www.icc.illinois.gov/docket/P2015-0602/documents/299208/files/521714.pdf > accessed March 27, 2021.

40 Elevate Energy, ComEd's Hourly Pricing Program 2019 Annual Report (Apr. 23, 2020), Appendix, Updated Net Benefits of ComEd's Hourly Pricing Program: Report for Calendar Year 2019 (Mar. 24, 2020), Klos Energy Consulting, pp. 9. See <https://www.icc.illinois.gov/docket/P2015-0602/documents/299208/files/521714.pdf > accessed March 27, 2021.

41 *Id.*, pp. 3. See <https://www.icc.illinois.gov/docket/P2015-0602/documents/299208/files/521714.pdf > accessed March 27, 2021.

> emissions a little in 2017, but it actually increased CO2 a little at the same time…And, for the first year since these environmental benefit studies began in 2008, the net effect of the emission changes related to load shifting was an increased cost rather than a benefit…Since the environmental benefits (or costs) of pure load shifting are so close to zero, they were not estimated in the 2018 evaluation update and it is recommended that they not be estimated as a part of the 2019 evaluation update either.[42]

2. OG&E VPP

OG&E's SmartHours Residential dynamic pricing program has been very successful relative to the Illinois Residential RTP programs, with much higher enrollment and load response. Critical success factors appear to be simplicity and the provision and installation of a free programmable thermostat that receives daily price signals from OG&E that were installed for about 60 percent customers at the time of enrollment.

a. Background and Rate Design

OG&E's Residential SmartHours program has been in operation since 2012 and is based on its VPP rate schedule.[43] As discussed in Section 1b., VPP could be considered an RTP hybrid. Although VPP applies only to peak period hours, it selects from a set of four prices (Low, Standard, High, Critical) based on a daily algorithm that evaluates the forecasted marginal prices for the next day. VPP also has an

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42 *Id.*, pp. 44-45. See <https://www.icc.illinois.gov/docket/P2015-0602/documents/299208/files/521714.pdf > accessed March 27, 2021.

43 Oklahoma Rate Tariffs. OG&E offers five flavors of VPP to different customer classes/industries: Residential; General Service; Oil and Gas Producers; Public Schools Small (Non-Demand); and, Municipal Water Pumping. For example, using their Standard Pricing Service General Service VPP, "By 5:00 PM on the day prior to each day containing on-peak hours, the Company will issue a price notification to customers containing the prices effective during the next day's on-peak period. The price will be determined based on the Company's DA price calculations as set forth in the DAP Tariff excluding the energy portion of the marginal supply cost." See R-VPP "Determination of On-Peak Hours Price," at <https://www.oge.com/wps/portal/oge/my-account/billing-payments/oklahoma-rate-tariffs/!ut/p/z1/pZHNroJADIWfxQVLaRkRyd2N4g9q1GuciN0YMDiSIGMQJb69JMYF9yLR2F2b75zTtEDgASX-NZJ-FqnEj4t-Q9bWZthD12Rje2Ux5L2BGE0XfZwLhHUZGE5YH_nEcX7bC8dwOxbQN_qu-Z4eXxTHD_P_A1RvvwYqR8wNYRQOuJohWxq4NP8CFSeqBbpPh5otxkAyVsHjYTwJWrYESsN9mIapfkmL8SHLTucfDTXM81yXSsk41HfqqGGV5KDOGXhlEk5HIYSHkduk4Jbzxh0Z64v9/dz/d5/L2dBISEvZ0FBIS9nQSEh/>, accessed March 27, 2021.

over-call provision that allows OG&E to designate a critical peak period, at any time during the year with a minimum two-hour notice, for a period lasting between 2 and 8 hours, for no more than 80 hours a year.

SmartHours was originally intended to achieve enough load reduction to delay capital investment in generation. About 60 percent of SmartHours customers use a programmable thermostat provided by OG&E at the time of enrollment. Customers could choose from one of three settings: (1) Maximum Comfort (+3 degrees), (2) Medium Setting (+6 degrees), and (3) Maximum Savings (+9 degrees). Peak hours are during the summer only, from 2 p.m. to 7 p.m. on non-holiday weekdays with all other hours charged at a static off-peak rate. Winter season prices are the same as the standard Residential OG&E R-1 tariff.[44]

b. Enrollment

As of October 2019, approximately 93,000 (~11%) of OG&E's Residential customers were enrolled in SmartHours. The current opt-out rate is only two percent.[45]

c. Load Response

Average load reduction at system peak for SmartHours customers with the free OG&E provided and installed programmable thermostat during high price is .92 kW, and during critical price is 1.31 kW, and .14 kW and .35 kW for customers without the OG&E supplied programmable thermostat, respectively.[46] Load shift from SmartHours customers with a programmable thermostat compares very favorably with ComEd's Residential RTP Hourly Pricing program per participant summer peak usage reduction of .51 kW.[47] OG&E's SmartHours program demonstrates significant aggregate load response, aligned with

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44 Multi-Year Study of the Impacts of OG&E's SmartHours Residential Electric Service. EPRI 3002006187, pp. 5-6. See <https://www.epri.com/research/products/3002006187>, accessed March 27, 2021.

45 E-mail from Bryan Scott, (OG&E) to Emily Bartman, PG&E. March 29, 2021.

46 *Id.*

47 See Section D1 for more discussion of ComEd Hourly Pricing program participant load response.

market conditions, from Residential customers with a simple dynamic rate enabled by a free installed programmable thermostat.

OG&E's experience with VPP, versus ComEd's experience with RTP, validates PG&E's proposal not to include Residential customers in the RTP pilot at this time, but rather to study Residential customer preferences for a range of dynamic pricing options. PG&E's proposed rate design research could evaluate customer preferences for RTP or other dynamic pricing structures, and the impact of enabling technologies like smart thermostats, including their costs, on those preferences.

E. Texas Market Experience in Early 2021

The Texas market is fully unbundled and open to retail competition, with the regulated LDCs providing only POLR service. Multiple REPs are licensed by the ERCOT[48] to market and supply electricity to customers.

1. Griddy

One of the REPs in Texas, Griddy, offered an RTP rate that passed ERCOT market prices through to Griddy's approximately 29,000 Residential customers.[49] In February 2021, during an unprecedented winter freeze which severely impacted both power and gas supply and increased customer demand for electricity, prices hit ERCOT's price cap of $9,000 per

48 ERCOT is akin to CAISO as the non-profit in charge of maintaining reliability, facilitating a competitive wholesale market, and managing the flow of power over the bulk electric system. Texas' electrical grid supplies power to approximately 26 million Texas customers. See <http://www.ercot.com/>, accessed March 27, 2021.

49 See, <https://www.chicagotribune.com/nation-world/ct-aud-nw-cb-texas-winter-storm-electric-bills-griddy-20210222-fbm3ge6ynnhhpm3w7pjrwuy24i-story.html>; <https://www.cnn.com/2021/02/23/us/texas-outages-electric-bills-griddy/index.html>; <https://www.cnn.com/2021/03/01/us/griddy-texas-lawsuit/index.html>; <https://www.nytimes.com/2021/02/20/us/texas-storm-electric-bills.html>; and, <https://www.texastribune.org/2021/02/26/griddy-texas-ercot-electricity-costs/>, accessed March 27, 2021.

megawatt-hour (MWh)[50] and stayed at or near there for over four days,[51] translating to $9 per kWh for Residential customers who had to use more electricity to keep themselves and their pipes from freezing. Griddy customers interviewed by news services reported seeing bills in the multiple thousands of dollars for the week of the unprecedented winter freeze. Because participating customers were required to give Griddy authorization to automatically debit their bank account (at least when their bill exceeded a certain amount), the surprisingly high February 2021 bills caused negative financial impacts for many (such as paying bills many times higher than typical for the time period and then being overdrawn). ERCOT has since revoked Griddy's REP license because it had defaulted on its February payments for generation, and numerous lawsuits have been filed against Griddy, but Griddy blames the Public Utilities Commission of Texas (PUCT) for requiring ERCOT to set an excessively high price cap that

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50 Texas Administrative Code, § 25.505(g)(6)(B). "The high system-wide offer cap (HCAP) will be $9,000 per MWh and $9,000 per MW per hour." See, <https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=2&ch=25&rl=505>, accessed March 27, 2021.

51 ERCOT, Review of February 2021 Extreme Cold Weather Event – ERCOT Presentation, (Feb. 25, 2021) Slide 22. "Real-Time and DA System-Wide Pricing." See, <http://www.ercot.com/content/wcm/lists/226521/Texas_Legislature_Hearings_2-25-2021.pdf>, accessed March 27, 2021.

"allowed" generators to charge $9,000 per MW.[52] At the time this testimony was finalized, Griddy had filed for Chapter 11 Bankruptcy.[53]

2. Significance for California Market

The very recent experience with Griddy in Texas points out the challenges for and risks to customers who take service on RTP in markets that can be volatile or risky. Although customer pricing protections may offer one possible mitigation approach, this would tend to dampen the price signal to the customer (i.e., knowing they would be protected might cause less load response). Another potential down-side is that price protection approaches like bill protection or price caps could result in cost-shifting to non-participating customers, unless fixed charges or some other mechanism are used to recover the cost of bill protection from participating customers (in which case it could be considered a form of insurance or hedging). Further, other, more complex, price protection products—like contracts for

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52 In August 2020, the highest CAISO DA hourly price at the PG&E Default Load Aggregation Point (DLAP) was $0.997/kWh on August 19th.

CAISO. DA Daily Market Watch Report. August 19, 2020. At <C>, accessed March 22, 2021.

PG&E observed that higher prices have occurred in SCE's service territory, as was the case on August 18, 2020 when SCE's DA DLAP prices were above $1.50/kWh for several hours"

CAISO. DA Daily Market Watch Report. August 18, 2020. <http://www.caiso.com/Documents/Day-AheadDailyMarketWatchAug18-2020.html> accessed March 27, 2021.

The current on-peak price (generation component) for large industrial customers is $0.12/kWh.

53 Heeb, *Texas Power Company Griddy Energy Files for Bankruptcy After Texas Storms* (Mar. 15, 2021) Forbes, at <https://www.forbes.com/sites/ginaheeb/2021/03/15/texas-power-company-griddy-energy-files-for-bankruptcy-after-texas-storms/?sh=a689b9d32c07>, accessed March 27, 2021.

differences (CFD)[54]—could be too difficult for Residential customers to understand. Typically, bill protection is only provided in the first year of a customer's enrollment on a new rate, to encourage them to try the rate risk-free. This type of bill protection will not help customers when they have been on an RTP rate for more than one year.

While the ERCOT market is significantly more volatile than CAISO,[55] the Griddy experience in February 2021 validates PG&E's proposal not to include Residential customers in the RTP pilot at this time, but rather to study Residential customer preferences for a range of dynamic pricing options. PG&E's proposed rate design research would inform any future CPUC consideration of potential RTP or other dynamic pricing options for Residential and Ag customers, to ensure whatever option(s) might be adopted would be appropriately designed to be suitable to Residential customers' needs and abilities.

F. Conclusion

This section has summarized the findings of the EPRI Benchmarking Study on RTP rate schedules offered by regulated utilities in the U.S., plus provided additional information on RTP rate schedules offered by other California IOUs, ComEd's Hourly Pricing program, OG&E's VPP program and Texas customer experience with Residential RTP offered by Griddy.

PG&E's proposed phased approach for RTP, starting with a C&I RTP Pilot, and rate design research for Residential and Ag customers is supported by the benchmarking data in this chapter, summarized as follows.

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54 CFDs are financial agreements between an electricity generator and an energy retailer where there is an agreement on a fixed rate for wholesale electricity. If the market price of electricity is higher than the contracted price, the generator pays the difference. If the market price falls below the contracted price, the marketer pays the difference. See, <https://www.e-education.psu.edu/ebf483/node/720#:~:text=In%20electricity%20markets%2C%20a%20CFD,a%20positive%20or%20negative%20number.>, accessed March 27, 2021. Georgia Power also provides Price Protection Products Schedule PPP-2, which includes price stability alternatives for RTP customers, and defines a CFD as "a fixed price guarantee for the average RTP price over a specific time period." (Georgia Power, Electric Service Tariff: Price Protection Products Schedule: "PPP-2" (January 2014), p. 6.60. See <https://www.georgiapower.com/content/dam/georgia-power/pdfs/business-pdfs/rates-schedules/PPP-2.pdf>, accessed March 27, 2021.

55 See Chapter 3.

1. RTP Offerings

There are currently very few active RTP rate schedules (55) offered by regulated U.S. utilities, and only two of them are for Residential customers. The impetus for offering RTP varies, but load management was not often cited, and load and bill impacts not often tracked. Most often, RTP was instituted, as required by regulators, as a POLR offering or was a means of economic development to attract new load. The majority of the active RTP rate schedules (35 of 55) are limited to very large customers with demand > 100 kW, although there are some more broadly available to smaller customers. Participation is relatively low, and stable, and consists of mostly very large C&I customers.

The definition of RTP varies in terms of whether prices are hourly or are in blocks, and whether a wholesale price is passed through to the rate. Most of the active RTP rate schedules (35 of 55) pass through prices from a regional wholesale market such as PJM, MISO and New York Independent System Operator (NYISO), several of the active RTP schedules are based on pre-set prices (9) and some are based on a supplier forecast (11). Almost all of the active RTP rate schedules (50 of 55) have hourly pricing, with a few comprised price blocks (3) and a couple (2) with 5-minute day of pricing. Only two of the 55 active RTP schedules do not provide some kind of advanced notice of the settlement prices, and only four have pricing elements that account for distribution costs that differ by location.

About a third of the active RTP rates schedules (18 of 55) incorporate a CBL subscription amount that incorporates a built-in hourly hedge which allows customers to avoid the wholesale market price by not exceeding their baseline. Only a few other active RTP rate schedules (6 of 55) offer other types of price protection options.

2. California IOU RTP Offerings

RTP offerings by other California IOUs are atypical. SCE’s RTP rate schedules are based on pre-set prices that provide more stability than RTP rate designs that pass through wholesale prices, yet about a third of their RTP customers have left the program in the past few years due to high bills in a hot summer. SDG&E’s RTP rate schedule is only for CEV customers who install SDG&E-owned charging equipment, and then it is mandatory. It is not clear if any other CEV customers or C&I/Ag customers would enroll if it were available to them. SCE's RTP customers have shown significant load response compared to Residential TOU, while results for SDG&E's RTP customers are pending. SDG&E's RTP rate design is fairly unique with a critical peak adder on the highest cost hours of the year, and a charge that varies by location to reflect distribution conditions.

3. Residential RTP Offerings

The two Residential RTP rate schedules offered by ComEd and Ameren as required by the Illinois regulator have very low enrollment after 13 years. ComEd's RTP offerings (both Residential and Non-residential) are the only active programs that bill based on a real-time price (average of hourly five-minute prices) and therefore cannot provide advanced notice of the settlement price. This may have been sustainable due to relatively low market volatility in the PJM.

On the other hand, 11 percent of OG&E's Residential customers are enrolled on a dynamic rate that incorporates elements of RTP, called VPP. VPP applies one of four prices during the peak period every day based on a DA wholesale market forecast.

Load shift from SmartHours customers with a programmable thermostat compares very favorably with ComEd's Residential RTP Hourly Pricing program per participant summer peak usage.

In addition, recent experience in Texas has highlighted the challenges and risks for residential customers that participate in RTP.

4. PG&E's RTP Proposal - Conclusion

OG&E's SmartHours program demonstrates significant aggregate load response, aligned with market conditions, from Residential customers with a simple dynamic rate enabled by a free installed programmable thermostat. OG&E's experience with VPP, versus ComEd's experience with RTP with lower enrollment and individual load shift, and the recent failure of RTP in Texas to mitigate Residential customer risks, validates PG&E's proposal not to include Residential customers in the RTP pilot at this time, but rather to study Residential customer preferences for a range of dynamic pricing options. PG&E's proposed rate design research could evaluate customer preferences for RTP or other dynamic pricing structures, and the impact of enabling technologies like smart thermostats, including their costs, on those preferences.

In addition, the CEC Load Management Rulemaking, CalFlexHub, and Flexible Demand Appliance Standards activities described in Chapter 1 highlight that necessary technology, communication, and standards that underpin the success of RTP for Residential customers are nascent and still undergoing piloting and testing and need further time to be ready to be deployed with a Residential customer RTP pilot.

On the other hand, there is ample evidence from the 53 active RTP rate schedules offered by regulated U.S. utilities that large C&I customers will enroll in and can benefit from RTP, which supports PG&E's proposal to conduct a C&I RTP Pilot.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

ANALYSIS OF WHOLESALE MARKETS

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A. Introduction

This chapter considers which combination of energy and capacity prices should be used in the Commercial and Industrial (C&I) Real Time Pricing Pilot rate, both in terms of potential benefit to Pacific Gas and Electric Company (PG&E) ratepayers and the potential cost savings to enrolled customers. Section B addresses, first, which formulation comes closest to matching PG&E's actual marginal costs for energy and capacity; and second, which formulation is likely to provide the greatest customer value (or risk/reward ratio) for different types of customers under real-world conditions. Section C evaluates the similarities and differences between prices in the California Independent System Operator (CAISO) market and those in the Pennsylvania-New Jersey-Maryland Interconnection (PJM) and Electric Reliability Council of Texas (ERCOT) markets.

Based on the analyses described in this chapter, PG&E recommends that the C&I Real Time Pricing (RTP) Pilot generation rate be based on hourly marginal energy prices from the day-ahead (DA) CAISO wholesale market, and include a marginal capacity cost adder calculated from DA forecasts of Adjusted Net Load (ANL).[1]

PG&E finds that, while prices in the PJM market offer both less reward (potential for customer savings) and less risk (average errors in forecasted prices) under either a DA or fifteen-minute RTP rate, the risk/reward ratio for engaged and sophisticated customers is approximately equal in PJM and CAISO, and the greater price volatility in CAISO might prove attractive for such customers, as long as they are prepared to weather price extremes right when

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1 Adjusted Net Load is equal to gross load (i.e., load at the customer meter), less utility-scale wind and solar generation, less other renewables and non-emitting resources (geothermal, biomass and biogas, hydro, and nuclear generation). Essentially, ANL is the amount of load that must be met by in-state thermal generation (chiefly gas-fired), unspecified imports, and energy storage.

they need power the most.[2] For less-engaged or less-sophisticated customers, that increased volatility would likely make RTP recruitment and retention more challenging here than it has been in PJM. In contrast, the risk/reward ratio for *all* customers is significantly worse in ERCOT than in CAISO.

Using energy prices from the CAISO's Day-Ahead Market (DAM) is superior to using prices from CAISO's Day-Of Fifteen Minute Market (FMM) or Real-Time Market (RTM), because (1) prices from the DAM are a more accurate proxy for the actual marginal cost to PG&E of providing energy due to changes in customer load than are prices from the FMM or RTM, and (2) while a generation rate based on FMM or RTM prices would have moderately greater within-day variation (and thus, *potentially* greater savings to customers on the RTP Pilot rate), FMM and RTM prices are much harder to forecast than DAM prices even one hour ahead, and therefore would likely provide much less opportunity for *actual* customer savings under real-world conditions.

Including an hourly marginal capacity cost adder, rather than basing the capacity portion of the generation rate on block Time-of-Use (TOU) averages and/or generation-related demand charges, provides the following benefits: (1) the hourly generation capacity cost adder is a better proxy for the actual marginal cost to PG&E of providing capacity due to changes in customer load than are TOU averages or generation-related demand charges; and (2) the additional variability in an energy plus capacity RTP rate improves the economics of behind-the-meter energy storage and other load-shifting technologies.

As for the exact formulation of the capacity cost adder, a capacity adder calculated from DA forecasts of load and non-dispatchable renewable generation (i.e., wind and solar) is superior to a capacity cost adder calculated from real-time forecasts of load and non-dispatchable renewable generation, because (1) a DA forecast would likely provide a more accurate proxy for the actual marginal cost to PG&E of providing capacity in the most extreme conditions, when load must be shed due to insufficient generation resources

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[2] As described in section C, extreme high prices will tend to occur at the same time as electricity needs are the greatest, so even if a customer acts to reduce their load during a heat wave or deep freeze, it would likely be greater than average exactly when prices are the highest.

(as occurred on August 14-15, 2020), and (2) overall generation prices (i.e., energy plus capacity) are significantly easier to forecast when the capacity prices are determined DA rather than Day-Of, while within-day variation is almost identical whether capacity prices are determined DA or Day-Of.

The analysis in section C shows that CAISO's prices lie somewhere between those of PJM and ERCOT, both in terms of volatility and average forecast errors. Specifically, prices for both DAM and FMM are significantly less volatile in the PJM than in our CAISO market, while the relative errors of "naïve" or persistence forecasts (error divided by within-day variation) are approximately equal in PJM and CAISO. Thus, the risk/reward ratio for sophisticated customers that can respond reliably to forecasts is approximately equal in PJM and CAISO. On the other hand, ERCOT's DAM and FMM prices are significantly more volatile than prices in our CAISO market, and relative errors in ERCOT are significantly greater than in CAISO. Thus, the risk/reward ratio for customers is significantly worse in ERCOT than in CAISO.

The low price volatility in PJM may explain why Commonwealth Edison has been able to keep a small number of residential customers on Day-Of pricing, while the fact that CAISO prices are both less volatile and easier to forecast than ERCOT's may give some solace to potential customers who have heard the horror stories of recent events in the ERCOT market. Since the volatility of the CAISO market falls somewhere in between, one might expect RTP to be more attractive for large C&I customers but less attractive for residential customers here than it has been in PJM (but that is something this Pilot and the concurrent research project will allow to be tested).

B. Analysis of Wholesale Markets Supports DA Pricing Rather Than FMM or RTM

This section considers two complex and related high-level issues:

1) What is PG&E's actual marginal cost when a customer's load increases or decreases in response to a price signal, and
2) What pricing interval and market timeframe (DA hourly (DAM), Day-Of 15-minute (FMM), or 15-minute averaged Day-of 5-minute (RTM)) would likely provide the greatest potential cost savings to PG&E and the best risk/reward ratio for customers.

Based on the analysis described below, PG&E concludes that, when a customer's load increases or decreases, the energy-related cost is some weighted combination of prices in the DAM, FMM and RTM markets, with the heaviest weight on the DAM; and that the capacity-related cost incurred when a customer's load increases or decreases, while not incurred immediately, can reasonably be estimated using the methodology proposed in the Day-Ahead Hourly Real-Time Pricing (DAHRTP) Commercial Electric Vehicle (CEV) Pilot Application.[3] PG&E also concludes that the DAM provides the best combination of Utility cost-effectiveness and customer risk/reward ratio out of the three markets, and is preferred. This is because, while the FMM and RTM prices show moderately greater within-day variation (and thus, *potentially* greater customer savings), they are much harder to forecast even one hour ahead, and therefore would likely provide much less opportunity for *actual* customer savings under real-world conditions.

These issues are complex because they are multi-faceted, with many factors pointing in different directions from one another. These issues are also related because one of the RTP rate's objectives is to reduce PG&E's energy and capacity costs sufficiently so that participating customers do not benefit at the expense of non-participants.

The first issue – what are PG&E's actual marginal costs - is important not only because one of the objectives of RTP is to reduce utility and environmental costs (so the RTP prices should reflect those costs to PG&E), but also to determine whether and to what extent RTP creates cost shifts—costs must first be defined before cost shifting is evaluated.

The second issue – which market interval and timeframe works best for customers - is important because the beneficial impacts of establishing an RTP rate can be thought of as the product of multiple variable factors, all of which will likely be affected by which market price is used to bill customers—DAM, FMM or RTM. These variable factors include: (a) how many customers will join the rate (or more precisely, the total annual load of those customers); (b) what proportion of load those customers will shift and/or curtail in response to RTP compared to

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3 The DAHRTP CEV Pilot calculates the generation capacity-related cost based on a Peak Capacity Allocation (PCAF) calculation, which assigns capacity cost to the amount the ANL exceeds a high-load threshold.

their previous behavior on their otherwise applicable tariff; (c) the exact timing of those load shifts (i.e., customers could respond in hourly blocks following a DAM signal, 15-minute blocks under FMM, or 5-minute blocks under RTM);[4] and finally, (d) the marginal cost to PG&E for any load shifts and/or customer curtailments (i.e., the first issue discussed above).

1. What is the Actual Marginal Cost to PG&E When Load Changes?

The generation-related marginal cost to load comprises Marginal Energy Cost (MEC) and Marginal Generation Capacity Cost (MGCC). This section discusses MEC and MGCC, in that order.

a. The Marginal Cost to Load Due to Energy

The MEC, which represents the marginal cost to load due to energy, is generally taken to be the DA hourly price in the DAM at the Default Load Aggregation Point (DLAP). That is how MEC is defined in PG&E's current and previous GRC Phase II proceedings. The main reason this is appropriate is because the vast majority of PG&E's load is settled at the DAM DLAP price.[5] However, there is another reason for using the DAM price to develop MECs: traditional rates are not dynamic, and therefore, any load shifting analyses assume that customers are aware of their costs well in advance, and that their behavior can be modeled

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4 Other parties have proposed billing customers based on either FMM prices, or alternatively, on 15-minute averages of the RTM price, since PG&E's finest metering interval is 15-minute. However, in the latter case customers could still respond to individual prices from the RTM, since the 15-minute averaged price would not be available until approximately the middle of the second 5-minute RTP intervals in each 15-minute block. (RTM prices are only published 2.5 minutes prior to the start of each 5-minute interval.)

5 According to the CAISO Department of Market Monitoring (DMM), $38.12 of total energy costs in 2019 were due to Day-Ahead energy costs, with only $1.01 due to Real-Time energy costs (FMM and RTM, plus flexible ramping costs). For the third quarter of 2020 (including the August 2020 heat waves), $55.05 of total energy costs were due to Day-Ahead, and $2.61 were due to Real-Time plus flexible ramping. However, PG&E cautions that the Real-Time energy costs net out "sales" and "purchases"; PG&E estimates that the total *volume* transacted in Real-Time is approximately 10 percent of the total volume over all markets. See, CAISO DMM, *2019 Annual Report on Market Issues and Performance* (June 2020), p. 85, Table 2.1, at <http://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf>. See *also*, CAISO DMM, *Q3 2020 Report on Market Issues and Performance* (Feb. 4, 2021), p. 32, Table 1.1, at <http://www.caiso.com/Documents/2020ThirdQuarterReportonMarketIssuesandPerformance-Feb4-2021.pdf>. (Both accessed March 18, 2021.)

and forecasted relatively easily. The way the CAISO market currently works is that Scheduling Coordinators (e.g., PG&E) typically place the vast majority of their forecasted load into the DAM,[6] and only the "residual load" (i.e., deviations from the DA load forecast) typically goes into the FMM and RTM markets. Thus, if PG&E could forecast load perfectly then 100 percent of its load would currently settle at the DAM price; the FMM and RTM markets would not clear any load, and would only serve to shuffle generation around between the various generators as a result of changes in renewable generation. In that case the MEC would clearly be equal to the DA price, plus adjustments to account for line losses and the marginal cost of procuring (or not selling) RECs to meet the Senate Bill 100 Renewable Portfolio Standard mandate.[7]

However, in the real world, because load (including load-shifting behavior) can never be forecasted perfectly, a small amount of load effectively ends up settling at some combination of the FMM and RTM prices, with the proportions depending on how far off the load forecasts were in the relevant markets.[8] This complex process is explained below.

As noted above, the vast majority of load settles at the DAM price. Any change in the load forecast between the CAISO's DAM run and the FMM run goes into the FMM market (with no price-responsive bids allowed under CAISO rules), while any change in the load forecast between the FMM and the RTM goes into the RTM market, again as a price-taker.

As for the price paid by a load serving entity (LSE), the CAISO tariff specifies that it is calculated at an *hourly timestep* as a weighted average of the prices in the four FMM intervals and the twelve RTM

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6 A small amount of PG&E load is bid into the DAM using price-responsive bids, so when DAM prices get very high some of the price-responsive bids may not clear, in which case that un-cleared load would go into the FMM market. However, this is a relatively rare occurrence.

7 Exhibit (PG&E-7), pp. 2-8 to 2-11.

8 The load forecast in the DAM (and any price-responsive bids) is provided by the Scheduling Coordinator (e.g., PG&E); CAISO develops load forecasts for the FMM and RTM market runs.

intervals, with the weights given by the difference in load forecasts from each market to the next (see, e.g., Table 3-1). This (Day-Of) hourly price is called the Default LAP Hourly Real-Time Price (HRTP).[9]

TABLE 3-1
EXAMPLE CALCULATION OF DEFAULT LAP HOURLY REAL TIME PRICE
FOR HOUR ENDING 15 ON DECEMBER 6, 2020

Line No.	CAISO Market	Interval*	Load Forecast (MW)	Change from Prior Market (MW)	Market Price ($/MWh)	Weight in HRTP
1	**DAM**	**HE 15**	**9123**	**N/A**	**28.15**	**N/A**
2	*FMM*	*1*	*8973*	*-150*	*23.70*	*1.99%*
3	RTM	1	8564	-408	30.11	5.39%
4	RTM	2	8410	-562	23.76	7.43%
5	RTM	3	8442	-530	25.53	7.00%
6	*FMM*	*2*	*9098*	*-25*	*25.23*	*0.33%*
7	RTM	4	8473	-625	23.58	8.25%
8	RTM	5	8443	-654	25.49	8.64%
9	RTM	6	8464	-634	26.36	8.37%
10	*FMM*	*3*	*9215*	*92*	*32.94*	*-1.21%*
11	RTM	7	8381	-834	26.90	11.01%
12	RTM	8	8453	-762	27.24	10.06%
13	RTM	9	8474	-741	27.10	9.78%
14	*FMM*	*4*	*9105*	*-17*	*34.54*	*0.23%*
15	RTM	10	8495	-610	33.85	8.06%
16	RTM	11	8519	-586	30.97	7.74%
17	RTM	12	8580	-525	24.24	6.94%
18			Sum of values	-7574		100.00%
19			Sum of absolute values	7757		
20			**Weighted average HRTP price**	**26.92**		

Note: *There are four fifteen-minute intervals per hour in the FMM, and twelve five-minute intervals per hour in the RTM.

The catch is that CAISO's HRTP is not calculated ahead of time, or even immediately after the hour in question; it is generally published by CAISO soon after midnight on the *following* day. Thus, the HRTP cannot be used as a "price" for purposes of an RTP rate, because customers would have literally no way of knowing the price that they must respond to ahead of time (which is necessary so that they can

[9] CAISO Fifth Replacement Tariff, Section 11 CAISO Settlements and Billing, February 15, 2021, at Section 11.5, p. 21. (*See* http://www.caiso.com/Documents/Section11-CaliforniaISOSettlements-and-Billing-asof-Feb15-2021.pdf. Accessed March 18, 2021)

change their electric usage behavior accordingly, in response to that prior price signal). Moreover, while IOU load is charged the HRTP for load that ends up in the FMM and/or RTM, it is not a good proxy for (even part of the) MEC either.

To illustrate, we consider the following scenario (Scenario 1), in which the DAM load forecast is 100 megawatt (MW) *lower* than the forecast in the FMM for the first two FMM (15-minute) intervals in an hour, but 200 MW *higher* than the FMM forecast for the last two intervals; and the RTM forecasts are all exactly equal to the corresponding FMM forecasts (so the RTM's weight is zero). Then the HRTP will be equal to

$$(100*FMM_1+100*FMM_2-200*FMM_3-200*FMM_4)/(100+100-200-200),$$

where FMM_1 is the price in the FMM market for the first 15-minute interval in the hour, and so on. Then the cost to load for the portion of load that did not clear in the DAM would be that HRTP times the denominator (i.e., it would be exactly the numerator of the above expression).

But suppose that the DA forecast was 100 MW too low for interval 1 because a 100 MW customer-sited battery charged in interval 1 and the DA load forecast did not pick this up but the FMM forecast did. Then the "marginal cost to load" based on that customer's actions would be equal to the cost under Scenario 1 less the cost under a Scenario 2, in which the FMM load forecast was 100 MW less in interval 1 (i.e., equal to the DAM forecast), divided by the change in load between the two scenarios. That marginal cost to load works out to exactly the FMM price in the first interval, FMM_1. And despite the negative signs for FMM_3 and FMM_4, the marginal cost to (residual) load for intervals three and four in this example is just (positive) FMM_3 and FMM_4.

So, does that mean that the FMM price in a particular interval is the marginal cost to load after all? Unfortunately, not—it is even more complicated than that. First, if this battery's operation were accurately forecasted by PG&E in the DAM (with only *other* customers' loads being less accurately forecasted), then the marginal cost to load for that

100MW charge in the first interval would not be FMM_1, but the DAM price for that hour (because the DAM load forecast picked it up, under this illustrative scenario).

If *neither* the DAM nor the FMM forecast picked up that the customer was going to charge its battery, then the marginal cost to load *from that customer's actions* turns out to be the average of the RTM prices (assuming constant charging for the entire fifteen minutes).

Finally, this entire thought experiment using scenarios is a simplification of the true situation because none of the forecasts (for any of the markets, whether DAM, FMM or RTM) are actually developed based on *individual* customer demands. Instead, they are based on an *aggregate* of all customer loads from millions of PG&E customers, most of whom are on TOU or other non-RTP rates, not an RTP rate. So the best that can be said is that the elusive "marginal cost to load due to energy," which would ideally be signaled to customers to minimize a utility's costs, is some combination of the prices from the DAM, FMM and RTM, with the weighting dependent on how well *all* customers' load had been forecasted as of the running of each of these three markets. And the precision of load forecasts is constantly changing and will continue to change even more once the RTP Pilot is underway, as RTP customers' response to RTP prices begins to be tracked and eventually incorporated into the various load forecasts of PG&E and the CAISO.

In summary—it's complicated. But because the vast majority of load actually pays the DAM price, while the proportions of load that pay the FMM and RTM price will remain small, PG&E considers that the DAM price represents the most accurate measure of its MEC.

b. The Marginal Cost to Load Due to Generation Capacity

The marginal cost to load due to generation capacity is also a complex issue. In terms of annual Resource Adequacy (RA) costs—which represent the short-run cost of capacity—the MGCC can be considered as the system RA cost (since the local RA cost is almost exactly equal to the system RA cost, but does not apply over the entire service territory). RA costs vary by month, so the marginal cost could be considered the monthly RA price times a time-dependent factor which estimates the probability of the load setting the monthly RA obligation in a particular hour. However, the prices for monthly (or annual) RA contracts are market sensitive, and therefore not publicly available; average RA prices are available only many months (up to a year) after the fact, in an RA Report[10] or a Power Charge Indifference Adjustment (PCIA) Market Price Benchmark (MPB).[11] Therefore, this price cannot be used to develop a real-time capacity cost.

Moreover, as discussed in PG&E's GRC Phase II Rebuttal Testimony,[12] load that coincides with the system (net) peak may result in greater costs than shown in the RA Report or MPB, in that new "steel in the ground" (mostly four-hour Lithium-Ion batteries in steel containers) is currently being procured to resolve deficiencies recognized during the 2019 IRP Procurement Track,[13] the need for which became even more obvious during the rolling outages during the heat storm of August 2020. In other words, unlike the situation for MECs, a very high load this year is essentially creating a capacity cost in a future year (or years)—either by increasing the future short-term RA requirement, or by creating an obligation to put steel in the ground (as is being discussed by the CPUC

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10 For the California Public Utilities Commission (CPUC) 2019 RA Report, see <https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442468127>, accessed March 18, 2021.

11 Calculation of the Market Price Benchmarks for the Power Charge Indifference Adjustment Forecast and True Up (Nov. 2, 2020) R.17-06-026 (MPB Forecast).

12 A.19-11-019, Exhibit (PG&E-7), Ch. 2, p. 2-18, line 12 to p. 2-25, line 21.

13 The 2019 IRP Procurement Track was ordered in D.19-04-040, p. 179, Ordering Paragraph 11. Also see the CPUC website page, "IRP Procurement Track," at <https://www.cpuc.ca.gov/General.aspx?id=6442463413#:~:text=The%20IRP%20%22Procurement%20Track%22%20was,20%20IRP%20cycle%20is%20underway.>, accessed March 18, 2021.

in its ongoing Emergency Reliability Order Instituting Rulemaking [14] and its Mid-Term/Diablo Replacement procurement proceeding).[15]

PG&E considers that the most realistic marginal cost to load of capacity corresponds to the MGCC calculation in PG&E's GRC Phase II (A.19-11-019). That calculation sets an annual MGCC that considers both short-run and long-run capacity costs, and then apportions the annual cost to individual hours based on the amount that hourly load exceeds a threshold, using a PCAF calculation. PG&E proposes to set the annual PCAF threshold based on the most recent forecasts of 80 percent of annual peak load contained in proceedings like the GRC Phase II. Both the annual capacity cost and the PCAF threshold would change every year, as forecasted in the most recent GRC, but would not be updated mid-year based on recent loads.

Some might be concerned that, because the threshold would not be updated mid-year, the total capacity-related costs borne by an RTP customer would be greater than that borne by an otherwise-identical non-RTP customer in a particularly hot year (and lower in a particularly cool year). This is because the *total load* above the threshold would be greater in the hot year (and lower in a cool year) even if the customer's individual load did not change from year to year. The same applies to the energy portion as well—in a hot summer (or an extremely cold winter, as recent experience demonstrates), CAISO energy prices would tend to rise and RTP customers would likely pay more than otherwise-identical non-RTP customers. However, PG&E considers this to be "a feature, not a bug." As explained further in Chapter 4, the costs to customers on RTP rates will likely track utility costs *better* than is the case for customers on TOU rates, even those rates that include Peak

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14 The CPUC opened an Emergency Reliability Rulemaking (R.20-11-003) in response to the rotating blackouts that occurred during the August 2020 heat storm. See the CPUC website page, "Summer 2021 Reliability," at <https://www.cpuc.ca.gov/summerreadiness/>, accessed March 18, 2021.

15 Administrative Law Judge's Ruling Seeking Feedback on Mid-Term Reliability Analysis and Proposed Procurement Requirements (Feb. 22, 2021) R.20-05-003. See <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M367/K037/367037415.PDF>, accessed March 18, 2021.

Day Pricing (PDP).[16] Therefore, PG&E expects any over- or under-collections will likely be reduced under an optional RTP rate, relative to what happens currently where C&I customers are on TOU rates without RTP.

As with MECs, PG&E's capacity prices could be calculated based on DA or Day-Of data. As described in PG&E's CEV Opening Testimony, the DA MGCCs use DA forecasts of load, and wind and solar generation, with two-day-old actual generation for the other components of ANL (nuclear, hydro, geothermal, biomass and biogas). A Day-Of MGCC would use CAISO forecasts of load, wind and solar from the FMM or RTM market runs, and one-day-old actual generation for the other components. However, to estimate the behavior of the various combinations of MEC and MGCC in the next section, PG&E derived a "back-cast Real-Time" MGCC based on after-the-fact actual load, wind and solar in place of the FMM or RTM forecasted values, for simplicity. PG&E believes that the behavior of an operational Day-Of MGCC (whether based on load and renewables forecasts in the FMM or RTM) would lie closer to the back-cast RT MGCC than to the DA MGCC.

2. Which CAISO Market Provides the Greatest Risk-Reward Ratio for the Customer?

In terms of the ability of customers to actually respond to an RTP rate, a DA price is expected to be more attractive to customers as it gives their business lead-time for advance planning, including adjusting operational plans for the next day prior to closing time on the day they receive the DA price signal. This lead-time would be especially important for Commercial & Industrial customers that rely on shifting native load rather than using batteries to enable load shift. In addition, for both native-load and battery-enabled customers, it turns out that once capacity costs are included in the prices, DA hourly prices have on average 82-89 percent of the

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16 The PDP adder increases prices during a three-to five-hour block and is called on a Day-Ahead basis. While PDP is more cost-based than regular TOU, it does not differentiate between hours, nor among the nine to fifteen days on which the adder is applied; and has no market-based variation on non-event days.

within-day variation[17] compared to FMM-based prices, but as described below, the accuracy of forecasts of FMM prices is significantly less. While this would not be an issue if a customer has a very long-duration battery or effective thermal storage (e.g., an extremely large water heater tank), it is problematic if they only have a normal two-hour battery[18] or are adjusting an HVAC system, which needs to stay within thermal limits for employee comfort or other reasons.

For a customer to benefit from switching to any optional RTP rate, they must either be a “structural winner” (i.e., their load shape is such that they will reduce their costs without changing their prior-established usage behavior), or be able to change their usage by reducing load at high-priced times and possibly increasing load at low-priced times more effectively than under their otherwise-applicable tariff (which for most C&I customers is a TOU rate). Structural winners aside, the amount that a customer can save depends on two factors which are in tension:

1) The amount of variability in the energy rate over a day (because the greater the variability, the greater the savings from shifting a given amount of energy from a high-priced to a low-priced hour, and also the greater the savings from curtailing load during a high-priced hour), and
2) The customer’s ability to react to that variability by using accurate forecasts to plan its activity (because if the customer cannot rely on forecasts of when high and low prices will occur, they will likely end up with a sub-optimal load shifting strategy).

The reason that the most customer-beneficial CAISO market is not obvious is that factors (1) and (2) are in opposition—prices based on the DAM have the least variability of the three, but are easiest to forecast (and have a perfect forecast one day ahead, by definition); whereas prices based on the RTM have the most variability but are the hardest to forecast; and

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17 PG&E calculates within-day variation based on both the standard deviation of prices over each day, and the average *absolute* deviation from the mean. Both metrics are proxies for potential customer cost savings assuming perfect foresight.

18 As of March 25, 2021, of non-residential batteries installed under the Self Generation Incentive Program (SGIP), approximately 130 Megawatts (MW) have a two-hour duration, 20 MW have less than two hour duration, and 100 MW have greater than two hour duration. (SGIP database, available at https://www.selfgenca.com/)

prices based on the FMM lie in between these two extremes in both measures (see Table 3-2, below).

TABLE 3-2
STATISTICS ON HISTORICAL SIMULATIONS OF DA AND DAY-OF RTP PRICES IN $/MWH, JANUARY 1, 2017 TO SEPTEMBER 30, 2020

Line Number		DA Energy + DA MGCC*	DA Energy + RT MGCC	FMM Energy + DA MGCC	FMM Energy + RT MGCC	RTM Energy + DA MGCC	RTM Energy + RT MGCC
1	**Overall Average Price**	48.07	48.07	47.19	47.19	45.20	45.20
2	**Overall Standard Deviation**	141.23	149.07	149.98	160.50	143.90	154.50
3	**Mean Absolute Deviation**	29.27	29.27	32.48	32.51	34.46	34.49
4	**Average within-day std. dev.**	**35.95**	**36.64**	**43.73**	**44.41**	**56.61**	**57.23**
5	Std. error of naïve DA fcast	93.02	112.81	113.74	134.66	121.06	140.63
6	Std. error of naïve HA fcast	Not useful	Not useful	86.88	94.79	100.88	107.16
7	**Std. error of less naïve DA fcast**	**79.66**	**96.56**	**97.72**	**114.97**	**103.91**	**120.17**
8	**Std. error of less naïve HA fcast**	Not useful	Not useful	**62.64**	**67.55**	**83.64**	**87.51**
9	**Average absolute within-day deviation**	**26.47**	**26.65**	**29.71**	**29.92**	**31.42**	**31.60**
10	MAE of naïve DA forecast	13.68	15.04	21.54	23.05	26.57	28.07
11	MAE of naïve HA forecast	Not useful	Not useful	17.01	17.36	21.85	22.15
12	**MAE of less naïve DA forecast**	**14.20**	**15.32**	**20.38**	**21.78**	**24.65**	**26.29**
13	**MAE of less naïve HA forecast**	Not useful	Not useful	**14.98**	**15.30**	**20.24**	**20.47**

* PG&E's original DAHRTP Proposal. Note that "DA forecast" of DA Energy + DA MGCC is actually 2-day-ahead

Because Table 3-2 contains a great deal of complex information, PG&E provides an explanation of the data on each line as well as the implications for choosing one of the six listed price variations and developing the rate based on that choice.

First, Line 1 shows the average price over the historical dataset of January 1, 2017 through September 30, 2020 (i.e., including the August 2020 rolling blackouts). Because the FMM and especially RTM prices are on average lower than DAM prices, the flat adder would be adjusted upward from the value shown in Chapter 4 (which was calculated based on the ten DA MEC scenarios for 2021 developed for PG&E's 2020 GRC Phase II). In the absence of other information, PG&E assumes that the slight differentials between prices in the DAM, FMM and RTM markets would persist going forward, so the flat adder for an RTP using FMM or RTM prices would be adjusted upward by the loss-adjusted historical difference between the average DAM price and the average FMM or RTM price, respectively.

Line 2 shows the standard deviation of prices over the historical dataset. Because these include variation between seasons and years (let alone days) the statistic does not appear to have much relevance in estimating customer benefits, but it is provided to give a sense of the overall variability of prices over the 3¾ year historical period.

Line 3 shows the average absolute deviation from the mean in the historical dataset. Because the capacity costs especially add a lot of "spiky-ness," these statistics are much smaller than the standard deviations (which give more weight to outliers).

Line 4 shows the average *within-day* standard deviation of prices for each variant. This is a proxy for the potential customer benefit due to load shifting (or battery operation), *given perfect information* (assuming that customers would generally operate a battery or shift their load within a calendar day, rather than between days). The highlighting color coding on this line uses **green** for high values, to indicate that higher within-day variability likely would allow for greater (better) customer savings with perfect forecasts and customer response. Note that while the prices that use FMM and RTM MECs have higher within-day variation than those that use DAM MECs, the prices that use RT MGCC have only slightly more within-day variation than those that use DA MGCC (less than $1/MWh difference).

Line 5 shows the standard error of a "naïve DA forecast" or "persistence forecast," which is just equal to the actual price 24 hours earlier. In other words, if customers assumed that today's prices will be equal to yesterday's, this is the average standard error that the forecast would have. However, as described in the notation at the bottom of the table, in the case of PG&E's original DAHRTP proposal (the first column), the prices are actually known perfectly one day ahead of what CAISO calls the "operating day;" for this variant the standard error is actually for a *two-DA* forecast. Note that the standard error of naïve DA forecasts of FMM and especially RTM variants are higher than the standard errors of the *two-DA* forecasts of the DAM variants. As for the DA vs. RT MGCCs, standard errors of naïve forecasts are notably higher for the RT MGCC variants than for the DA MGCC variants, no matter which energy market is used for MECs.

Line 6 shows the standard error of a naïve Hour-Ahead forecast (equal to the previous hour's price rather than the price 24 hours ago). Because the DA market prices are published simultaneously on the day before operating day, an Hour-Ahead forecast of that price doesn't make sense, so the statistic is not calculated for the DAM variants. As for the Day-Of market variants, the standard errors for the RTM-based prices are greater than those for the FMM market-based prices. RT MGCC variants again show greater standard errors than DA MGCC variants, for all MEC choices.

Lines 7 and 8 show the same statistics as the previous two lines, but using a "less naïve forecast" that takes into account days of the week and hours of the day. For example, prices on Saturdays are generally lower than on Fridays, so the less naïve forecast adjusts for the mean price by hour for each day type, and also multiplies the deviation from the mean by a factor between zero and two (again, depending on the day and hour) rather than a factor of one as with the true persistence forecast. These "less naïve" forecasts show notably lower standard errors than the naïve forecasts, but the same patterns noted above for lines 4 and 5 apply here. The highlighting color coding on these lines uses **red** for high values, to indicate that higher average forecast errors likely would allow for *lower* (worse) customer savings under real conditions.

Finally, line 9 shows the mean absolute within-day deviation, and lines 10 through 13 show mean absolute errors of the various forecasts. In this section of data, extremes are weighted less than in lines 4 through 8.

PG&E makes the following observations regarding the statistics shown in Table 3-2:

- The DA version of MGCC should provide greater customer value under real conditions and thus is preferred. For every choice of MEC (DAM, FMM or RTM), the RT MGCC adds very little within-day variability compared to the DA MGCC—and it reduces the accuracy of (naïve and less naïve) forecasts to a much greater extent. This applies whether extreme values are weighted heavily (standard deviations and standard errors) or not (absolute deviations and absolute errors).[19]

- Similarly, the DA version of MEC should provide greater customer value under real conditions and thus is preferred. Day-Of prices (FMM + DA MGCC, or RTM + DA MGCC) show greater within-day variability, thus may in theory translate to greater *potential* customer savings, especially considering the standard deviation metrics. However, forecasts of Day-Of prices are much less accurate than forecasts of the DAM + DA MGCC prices, so it is *much less likely that this potential customer value could actually be realized*. In particular, focusing on the less-naïve forecasts, the standard errors of the *Hour-Ahead* forecasts of the FMM+DA MGCC price are only 22 percent lower than the *two-DA* forecasts of DAM+DA MGCC prices (62.64 compared to 79.66), while standard errors of Hour-Ahead forecasts of RTM + DA MGCC prices are actually greater than those of the two-DA forecasts of DAM+DA MGCC prices (83.64 compared to 79.66). In terms of Mean Absolute Errors, the Hour-Ahead forecasts of FMM and RTM prices *both* show greater errors (14.98 and 20.24, respectively) than the MAE of two-DA DAM-based prices (14.20).

Price forecasts that account for weather conditions would likely result in lower levels of forecasting errors than those described above. However, statistics from two operational forecast providers—WattTime and Myst AI—show a similar pattern to those described above.

The first example is WattTime, an entity that has been providing forecasts of 5-minute marginal greenhouse gas (GHG) emissions since January 2020. While it is not the primary goal of the WattTime model to predict RTM prices, it can provide some context. This is because for prices above and below certain cutoffs, these emissions rates are calculated as a multiple of the RTM price. WattTime reports[20] that the standard error of

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19 Also, because rotating outages or other load drop occurs in real time and is not incorporated in DA forecasts, a capacity price calculated based on RT load could underestimate the severity of grid stress compared to a capacity price calculated based on DA load, exactly when the grid is most stressed.

20 Email from Gavin McCormick, WattTime Co-founder and Executive Director, February 4, 2021.

their two-hour forecasts is approximately the same as those of their 72-hour forecast. In fact, on these time horizons the simple "less naïve" forecast above might well be able to provide comparable standard errors. For the second example, Myst AI provides DA price forecasts (as well as load forecasts) every day at 6 a.m. to a number of Community Choice Aggregators (CCAs) in California. Myst AI forecasts the DAM price (i.e., seven hours ahead of the CAISO's 1 p.m. run) and the next day's hourly average FMM price (which is easier to predict than the interval prices themselves). Myst AI reports that the standard error of their DA hourly-average FMM price forecasts is approximately double the standard error of their DAM forecasts.[21]

In summary, neither the FMM nor RTM-based prices appear to provide sufficient additional potential value to overcome their difficulty to forecast. For a customer with long-duration energy storage (e.g., an eight-hour battery or a very large water heater tank), the difficulty in forecasting may not be a problem, as the customer could "ride through" a period of unexpected high prices without running out of storage capacity. But for the standard situation of a two-hour battery, not being able to forecast accurately two hours ahead is a real problem—if prices were to spike at 4 p.m., the customer would be faced with a dilemma as to whether to discharge now or wait for potentially higher prices later. Customers that want to change operations apart from battery control face the same situation—employees (and electronic equipment) can withstand temperature excursions for perhaps two hours, but not much longer. For workplace EV charging the situation is even worse—a DA signal known the previous afternoon allows the building manager to alert employees to charge their vehicles in the morning (or not at all); telling them at 3:05 p.m. to stop charging at 3:15 p.m. when they may want to leave at 4:30 p.m. would be an inconvenience to say the least.

C. Review of PJM and ERCOT Markets in Comparison to CAISO

The previous analysis considered historical prices (and price forecasting scenarios) in the CAISO, and concluded that a DA price (composed of DAM

21 Email from Titiaan Palazzi, Myst AI Co-founder, February 19, 2021.

energy prices and the DA MGCC) would likely provide the greatest opportunity for customer benefits due to its significantly lower risk (improved ability to plan operations) and similar reward (potential for customer savings due to load shift) compared to the Day-Of price options. In this section, PG&E discusses how recent CAISO prices compare to DAM and FMM prices in two other markets: the East-coast PJM and the Texas ERCOT markets. The analysis in this section, as summarized in Table 3-3 below, shows that CAISO's prices lie somewhere between those of PJM and ERCOT, both in terms of volatility and average (naïve) forecast errors. Specifically, prices for both DAM and FMM are significantly less volatile in the PJM than in our CAISO market, while the *relative* errors of naïve forecasts (error divided by within-day variation) are approximately equal in PJM and CAISO. Thus, the risk/reward ratio for a sophisticated customer would be approximately equal in PJM and CAISO. On the other hand, ERCOT's DAM and FMM prices are significantly more volatile than prices in our CAISO market, and *relative* errors in ERCOT are significantly greater than in CAISO. Thus, the risk/reward ratio for customers is significantly worse in ERCOT than in CAISO.

The low volatility, with a similar risk/reward ratio to a CAISO-based RTP, may explain why PJM's Commonwealth Edison has been able to keep a small number of residential customers on Day-Of pricing, while the second observation may give some solace to potential customers who have heard the horror stories of recent events in the ERCOT market. Since the volatility of the CAISO market falls somewhere in between, one might expect RTP to be less attractive to residential customers than it has been in PJM, but (with the right communications) more attractive than it will be going forward in ERCOT (assuming the risk-aversion and price-responsiveness of eligible customers is similar in all places). The more-volatile CAISO prices might be more attractive to a potential C&I RTP customer than the less volatile prices in PJM (but that is something this Pilot will allow to be tested).

TABLE 3-3
STATISTICS ON HISTORICAL DAM AND FMM PRICES IN $/MWH AT PG&E DLAP, PJM DOM LAP, AND ERCOT HUB AVERAGE, JANUARY 1, 2017 TO SEPTEMBER 30, 2020

Line No.		PG&E DLAP DAM	PJM DOM DAM	ERCOT HubAvg DAM	PG&E DLAP FMM	[PJM Not Available]	ERCOT HubAvg FMM	PG&E DLAP Avg FMM*	PJM DOM Avg FMM*	ERCOT HubAvg Avg
1	**Overall Average Price**	38.25	30.51	29.74	37.37		27.98	37.37	30.26	27.98
2	**Overall Standard Deviation**	31.66	19.05	95.43	55.18		131.75	47.38	27.50	125.15
3	**Mean Absolute Deviation**	15.18	10.38	16.01	17.89		16.69	16.84	12.01	16.50
4	**Average within-day std. dev.**	15.61	7.97	21.49	24.60		28.75	19.79	12.42	24.30
5	Std. error of naïve DA fcast	21.30	11.10	85.51	59.75		166.98	48.55	27.87	157.21
6	Std. error of naïve HA fcast				54.08		108.95	37.81	21.49	93.69
7	**Avg. abs. within-day deviation**	15.18	10.38	16.01	17.89		16.69	16.84	12.01	16.50
8	MAE of naïve DA forecast	6.39	4.84	9.36	14.33		17.11	13.39	9.54	16.75
9	MAE of naïve HA forecast				11.51		10.60	9.36	6.78	9.47

* Hourly average FMM prices. Interval FMM prices were not available for the PJM Market.

Taking Table 3-3 line by line, the average prices shown on Line 1 indicate that average prices during the record period were higher at the PG&E DLAP than in either PJM or ERCOT, for both the DAM and FMM markets. This is mostly due to the GHG Cap and Trade adders that apply in CAISO.[22] From Line 2, the standard deviations of prices were significantly lower at the PJM DOM LAP[23] and higher at the ERCOT Hub Average than at the PG&E DLAP, for both markets. But from Line 3, the mean *absolute* deviations at the ERCOT hub were approximately equal to the mean absolute deviations at the PG&E DLAP, while mean absolute deviations at the PJM hub were again lower, for both markets. This indicates that much of the variability in ERCOT was driven by extremes. (The statistics would have been even more extreme if Texas' February market anomaly had been included in the dataset.)[24]

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22 Gas-fired generators in the CAISO (which set the marginal energy price most of the time) must purchase California Carbon Allowances (Allowances) to cover their emissions. For a moderately efficient combined-cycle generator (with a "heat rate" of 7000 British thermal units per kilowatt-hour (BTU/kWh)), the most recent Allowance auction price of $17.87/metric ton translates into an additional cost of $6.63 per Megawatt-hour.

23 This corresponds to the Dominion Energy LAP.

24 For example, the DAM price at the PG&E DLAP during the August 2020 heat wave reached approximately $1.00/kWh for two hours on August 19th, while the DAM price at the Southern California Edison DLAP reached approximately $1.50/kWh for four hours on August 18th. See the Day-Ahead Daily Market Watch Reports at http://www.caiso.com/Documents/Day-AheadDailyMarketWatchAug18-2020.html and http://www.caiso.com/Documents/Day-AheadDailyMarketWatchAug19-2020.html.
In contrast, DAM prices in ERCOT stayed at or near the ERCOT price cap of $9.00/kWh for *over four days* in February 2021.

Now to consider the potential for customer benefits, the PJM hub prices had lower within-day standard deviations (Line 4) and also lower within-day absolute deviations (Line 7) than PG&E DLAP prices, for both DAM and hourly-averaged FMM prices. Thus the *potential* customer savings due to load shifting on an RTP rate would have been lower in PJM than at the PG&E DLAP (assuming perfect foresight). For both DAM and FMM markets, ERCOT prices had higher average within-day standard deviations than PG&E DLAP prices, but the average within-day deviations were approximately equal between PG&E and ERCOT. This indicates that the *potential* customer savings due to load shifting would have been greater in ERCOT, particularly for short-duration batteries (which would capture the extreme high and low prices given more weight by the standard deviation metric than the average absolute deviation metric).

Finally, the standard error and MAE of forecasts indicate that RTP using PJM prices would have imposed less risk on customers than RTP using PG&E DLAP prices, with the reduced risk comparable to the reduced potential reward described above. For example, from Line 5, the standard error of naïve two-DA forecasts of DA prices at the PJM hub is approximately half the standard error at the PG&E DLAP, and the standard error of naïve DA forecasts of hourly-average FMM prices (and from Line 6, also the standard error of naïve hour-ahead forecasts) is slightly more than half the CAISO value in PJM. In terms of MAE, the statistics show a similar, though less extreme, pattern.

Turning to the ERCOT prices, the standard error of naïve two-DA forecasts of DAM prices was *four times* the standard error for the PG&E DLAP, while DA standard errors for interval FMM prices and hourly-average FMM prices were approximately three times higher in ERCOT. In terms of MAE, the ratios were approximately 1.5 and 1.2. Turning to the naïve hour-ahead forecasts, the standard error of HA interval prices in ERCOT was twice the standard error at the PG&E DLAP, while the standard error of hourly-averaged FMM prices was 2.5 times greater in ERCOT. But in terms of MAE, the standard errors were approximately equal between ERCOT and the PG&E DLAP. The ratios of standard errors between CAISO and ERCOT (between 2:1 and 4:1, depending on the temporal granularity) was much greater than the ratios of within-day standard deviations (between 1.1:1 and 1.4:1), indicating that the ERCOT market had much greater forecasting risk than at the PG&E DLAP, but only modestly greater potential reward.

The California experience in August 2020 and the ERCOT experience in February 2021 illustrate a downside to high-volatility prices that applies to both sophisticated and less-sophisticated customers alike: high prices are generally correlated with high customer demands, so even if customers have perfect price forecasts available and take advantage of them, their load is likely to be higher during a heat storm or extreme freeze due to the significantly greater cooling or heating needs, respectively. Those greater electricity needs will occur exactly when prices are at their extreme peaks. The “risk/reward ratios” used here do not incorporate this effect, and therefore could underestimate the risk portion, especially where price volatility is high.

To summarize, one reason that a residential RTP rate has been relatively successful in PJM is that PJM prices are less volatile than those in the CAISO (and especially in ERCOT). While customers would have relatively less to gain from an RTP rate in PJM than in PG&E’s territory, they also have less to lose, especially during extreme conditions. In ERCOT, on the other hand (as Griddy customers are now only too painfully aware), the risks are much higher and the potential rewards only modestly greater for customers on RTP.

PG&E therefore concludes that an RTP rate for sophisticated large C&I customers based on DA CAISO prices could find similar customer acceptance to PJM’s RTP rates, while avoiding the extreme risks (and now, customer reluctance) based on ERCOT’s more volatile prices. PG&E also concludes that an RTP based on DAM energy prices and DA capacity prices is preferred because it is more aligned with PG&E’s energy costs (because almost all energy is transacted at the DAM price) and has less customer risk (because forecasts of DA prices are significantly more accurate than forecasts of FMM and RTM prices), while providing almost the same potential customer savings as RTP rates based on FMM or RTM prices (based on within-day variability of prices).

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

COMMERCIAL AND INDUSTRIAL,

REAL-TIME PRICING PILOT RATE DESIGN

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CHAPTER 4
COMMERCIAL AND INDUSTRIAL, REAL-TIME PRICING PILOT RATE DESIGN

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COMMERCIAL AND INDUSTRIAL, REAL-TIME PRICING PILOT RATE DESIGN

A. Rate Design

1. Rate Design

The rate design for Pacific Gas and Electric Company's (PG&E) proposed Commercial and Industrial (C&I) Real-Time Pricing (RTP) Pilot (C&I RTP Pilot) uses the same design as PG&E proposed in Chapter 2 of Application 20-10-011, for PG&E's Day-Ahead Hourly Real-Time Pricing Commercial Electric Vehicle (DAHRTP-CEV) Pilot, updated on March 12, 2021, which is attached hereto as Attachment A. The DAHRTP-CEV Pilot rate is a "rate rider," designed intentionally to be easily extended to other rate classes. PG&E's proposal extends the DAHRTP-CEV Pilot rate generation component design, without modification, to the pilot rates DAHRTP-B19 and DAHRTP-B20. Moreover, should the California Public Utilities Commission (Commission) desire in the future to expand the customer classes or segments to which this RTP rider would apply, PG&E does not anticipate that many, if any, changes to the rate design would be required. PG&E is not proposing any price protection or incentives for this pilot.

Like the DAHRTP-CEV rate, the rate proposed for this C&I RTP Pilot replaces the current time of use (TOU) generation rates on the customer's base schedule with a formula for determining hourly rates on the basis of the California Independent System Operator's (CAISO) Day-Ahead Market (DAM). Rates related to distribution, transmission, and non-bypassable charges would continue to be assessed as specified in the base schedule. Each day, PG&E will determine the generation prices for each of the 24 hours of the following day, based on these three parts: (1) CAISO's DAM energy price (times a line loss factor), (2) a capacity adder based on forecasted adjusted net load in each hour, and (3) a non-time-differentiated adder.

This generation rate structure works even for schedules that have a generation demand charge because the proposed RTP rate design would fully replace all generation charges on the base schedule, including demand charges. As capacity charges are built into the RTP volumetric rate in the hours that they are needed, there is no need for a separate peak demand charge that is typically used to estimate the generation capacity requirements imposed by the customer. The capacity adder is a critical part of the design as it provides a more cost-based signal at the times when the grid is stressed because energy prices by themselves do not provide enough price variance to capture the diversity of costs experienced by PG&E. The Joint Advanced Rate Parties (JARP) agree with this method of capacity pricing, saying "PG&E's proposed methodology for capturing generation capacity costs is excellent."[1]

Including an hourly marginal capacity cost adder, rather than basing the capacity portion of the generation rate on block TOU averages and/or generation-related demand charges, provides the following benefits: (1) the hourly generation capacity cost adder is a better proxy for the actual marginal cost to PG&E of providing capacity due to changes in customer load than are TOU averages or generation-related demand charges, and (2) the additional variability in an energy plus capacity RTP rate improves the economics of behind-the-meter energy storage and other load-shifting technologies. This structure should both be simple for customers to understand and provide hourly price variance that can be taken advantage of by flexible customers by managing their loads in response to these DA price signals.

2. Bill Impacts

For most rate design proposals, typical bill impact evaluations assume no change in customer load. However, RTP rates are specifically designed to influence customer behavior, making this comparison unhelpful. Thus, a key factor necessary to estimate participating customers' likely bill results under RTP is what assumptions to use for price elasticity of demand. This

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1 JARP Direct Testimony, p. 21, Lines 10-11.

factor cannot be developed without studying actual customer response to CAISO DAM prices.

PG&E proposes to study price elasticity of demand in the RTP Pilot. As discussed in Chapter 1, the EPRI Benchmarking Study includes a review of RTP price elasticity of demand that shows some indication of load response, but these results are inconclusive and could not be extrapolated to the CAISO market. For example, as discussed in Chapter 3, the PJM market has less volatility than the CAISO market, with similar ability to forecast, so it provides both less risk and less reward than an RTP based on CAISO prices. On the other hand, Texas' Electric Reliability Council of Texas (ERCOT) market has significantly greater volatility and is also harder to forecast than CAISO's market, so that market provides much greater risk along with somewhat greater potential reward than PG&E's CAISO based RTP.

3. Cost Tracking

PG&E recognizes that the potential for RTP over/under-collections is a concern for many interested parties as well as the Commission itself. However, it is not known at this time what might be the likely magnitude of any such over/under-collections, nor is there sufficient data to justify a proposal for what to do if they occur.

It is important to recognize that over/under-collections can be caused by two different possible sources of variance: (1) a difference between forecasted revenue and collected revenue and (2) a difference between collected revenue and utility cost. Only the second of these represents a true cost-shift (the first should be classified as a forecasting error). An RTP rate, by its very nature, should track more closely to utility costs than standard TOU rates. Standard TOU rates will have much higher cost variances, so customers on RTP rates should actually be reducing existing cost-shifts, rather than increasing them or creating new ones. For example, if a heat wave occurs and market prices are high for an extended period, customers on RTP rates will have increased costs compared to what was originally forecasted in the revenue requirement. TOU customers are also likely to have increased costs (due to higher air conditioning needs), but not as dramatically. However, utility costs will also be much higher, so it is probably a more accurate statement to say that TOU customers would be causing an under-collection rather than RTP customers causing an over-collection. This is why PG&E characterizes the more variable cost collection under RTP as "not a bug, but a feature". As described in Chapter 3, the same over/under collection behavior occurs for the capacity part of the rate—RTP would collect revenue that more closely tracks PG&E's marginal capacity costs than do TOU-based or demand-charge-based rates.

Because PG&E's C&I RTP Pilot proposal is a limited-time and limited enrollment pilot, the size of any potential over/under collections will be constrained. PG&E believes a rate design proposal for what to do about any potential over/under collections is premature. Instead, PG&E proposes that data be collected and analyzed during the RTP Pilot so that the magnitude and direction of any potential cost-shifts can be understood. Only after the data is collected can there be efforts to forecast whether the magnitude of future over/under collections might be material enough to affect future design—and how that might be affected should eligibility for the future RTP rate program be expanded to a larger scale. PG&E believes that only then could the subject of the appropriate approach to cost recovery be meaningfully discussed. Post-Pilot workshops to present its findings could be an appropriate forum in which to begin such discussions. The relevant data includes, but is not limited to:

- Customer load profiles before and after going on the RTP rate;
- RTP prices compared to TOU prices; and
- Aggregate load of non-participating customers.

If the magnitude of cost-shift due to RTP appears to be material, part of the workshop's discussion needs to consider the timing of cost recovery. This is because, as illustrated below, utility costs are passed on to RTP customers immediately, rather than the following year after balancing accounts settle for TOU customers. For example, if there were a very hot summer and PG&E faced an under-collection in its Energy Resource Recovery Account (ERRA) balancing accounts, all bundled customers' generation rates would be increased the following year to make up for that under-collection. However, RTP customers would have already paid for this under-collection through higher rates during the hot summer. Tracking these differentials would be quite complicated, especially for customers that may enroll or leave the program partway through the year. The correct method for adjusting RTP and TOU rates in ERRA proceedings would need further discussion once data on RTP customer behavior becomes available after the Pilot. As an initial step, PG&E can present high-level drivers (price variances, sales volume variances, etc.) of ERRA over/under-collections and potential remedies during post-Pilot workshops.

PG&E notes that for its Residential TOU Default Pilot, the Commission concluded in Resolution E-4846 that:

> "[T]he default pilot may result in revenue shortfalls due to selection of customers who are structural benefiters on TOU rates, and these shortfalls may occur in both the generation and distribution rate components."[2]

The Resolution went on to direct PG&E to recover these self-selection revenue shortfalls in the general, preestablished balancing accounts, effectively meaning non-Residential customers also funded them:

> "Any generation revenue shortfall should be recorded in PG&E's Utility Generation Balancing Account (UGBA) and any distribution revenue shortfalls should be recorded in PG&E's DRAM."[3]

PG&E also notes that these directives only applied to the pilot; shortfalls experienced during the full rollout of Default TOU will be paid by the entire Residential class, not just Residential customers that moved to TOU.[4]

Similarly, with Peak Day Pricing (PDP) programs, if a program is called more (or fewer) times than expected there can be over (or under)-collections. The differences in revenue between the actual event hours and expected event hours is returned to all customers in the classes where PDP participation occurs, not just PDP participants.[5]

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[2] Resolution E-4846, p. 20.

[3] *Ibid*.

[4] D.15-07-001, Conclusion of Law 47.

[5] D.10-02-032, Ordering Paragraph 7.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

ATTACHMENT A

COMMERCIAL ELECTRIC-VEHICLE DAY-AHEAD HOURLY REAL TIME PRICING PILOT CHAPTER 2 - RATE DESIGN UPDATED TESTIMONY, UPDATES TO MARGINAL COSTS – UPDATED MARCH 12, 2021, SERVED IN A.20-10-011 ON MARCH 12, 2021

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2 – RATE DESIGN

UPDATED TESTIMONY

UPDATES TO MARGINAL COSTS – UPDATED MARCH 12, 2021

A. Overview of Changes in Updated Testimony

Attached is an updated version of Chapter 2 for Pacific Gas and Electric Company's (PG&E) Day Ahead Hourly Real Time Pricing for Commercial Electric Vehicles (DAHRTP-CEV) Pilot Rate A.20-10-011, with updates to marginal generation costs (MGC), which were presented in PG&E's 2020 General Rate Case (GRC) Phase II Rebuttal Testimony. Both the Marginal Energy Cost (MEC) and Marginal Generation Capacity Cost (MGCC) were updated, and reflect the following changes:

<u>Changes to Marginal Energy Costs</u>

Updated MECs include a flat RPS/REC adder of $0.00519/kWh based on the fact that an incremental increase in load results in an increased incremental need to purchase Renewable Energy Certificates (RECs) or the reduced ability to sell RECs per Senate Bill (SB) 350. The addition of the RPS/REC adder is backed out for the calculation of the revenue neutral adder, so the actual impact on customer costs and rates from this change is nil.

<u>Changes to Marginal Capacity Costs (MGCC)</u>

MGCCs have been updated to more closely conform financial and other assumptions for new-build Lithium-Ion batteries to those used in the 2019-2020 Integrated Resources Plan (IRP), and to correct an error in extrapolating Energy Gross Margin revenues for those batteries (which act as a subtractor to MGCCs). The impact of these changes is to reduce the MGCC as of 2021 from $102.66/kilowatt-year (kW-year) to $68.56/kW-year, with proportional reductions in the hourly capacity prices used in the DHARTP-CEV Pilot Rate. This reduction in MGCC necessitates an increase in the revenue-neutral adder to compensate; the overall impact is to reduce the variation in the DHARTP rate (measured as overall standard deviation of 2021 modeled prices) by approximately 30 percent, from $0.1525/kW-hour to $0.1052/kW-hour.

PG&E is not proposing any overall structural changes to the rate; only marginal cost values are being updated. The overall generation revenue requirement is also unchanged to remain consistent with the revenue requirement used for the GRC Phase II. While the MEC value has been updated, the only change is the addition of the flat REC adder, which does not appear in the CAISO prices. Because the CAISO energy price part of the rate is unchanged (due to the reduction in the revenue neutral adder canceling out the

REC adder), the only updates to the DAHRTP-CEV Pilot rate are in the capacity adder and the flat revenue neutral adder. The *calculation* of the revenue neutral adder needs to change slightly because the REC adder needs to be removed from the MEC when calculating the total Marginal Cost Revenue (MCR).

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CHAPTER 2 – UPDATED TESTIMONY MARCH 12, 2021
RATE DESIGN

A. Introduction

The purpose of this chapter of Pacific Gas and Electric Company (PG&E) testimony is to describe the rate design proposal for a dynamic rate option for Commercial Electric Vehicle (CEV) customers. PG&E's dynamic rate proposal for CEV customers is a Day-Ahead Hourly Real-Time Pricing (DAHRTP-CEV) Pilot rate, consistent with Decision (D.) 19-10-055. The DAHRTP-CEV Pilot rate has been designed to be cost-based and provide customers with a more accurate price signal than the standard CEV schedules. It provides customers with a price that can be different in each hour of each day—indicating to customers the most beneficial times to charge their vehicles. It also helps customers reduce overall greenhouse gas (GHG) emissions by avoiding the hours in which the system is most stressed and increases the utilization of renewables by charging when renewable generation is being curtailed due to oversupply. In this chapter, PG&E explains its proposed rate option, how rate values are derived, and calculations for operating the rate on a daily basis.

Section B describes how the proposed rate is structured and its marginal and fixed cost components. Section C replies to certain questions posed in D.19-10-055. Section D addresses considerations related to Real-Time (RT) distribution rates, net energy metering (NEM) customers, and other demand response programs.

B. PG&E's Dynamic Rate Option for CEV Proposal

1. Summary

PG&E's proposal for the DAHRTP-CEV Pilot rate is a rate rider that would replace the current time-of-use (TOU) generation rates on Schedules BEV-1 and BEV-2 with a formula for determining hourly rates on a day-ahead (DA) basis. Rates related to distribution, transmission, and non-bypassable charges would continue to be assessed as specified in the original BEV schedule. Each day, PG&E will determine the generation prices for each of the 24 hours in the following day based on DA market prices and forecasted load and generation for each hour.

The proposed prices in each hour will be composed of three parts: (1) the DA market energy price from California Independent System Operator (CAISO), (2) a capacity adder based on forecasted adjusted net load (ANL) in each hour, and (3) a non-time-differentiated adder.

2. Total Generation Costs

PG&E's generation rates include three broad cost categories: (1) energy-related marginal costs; (2) capacity-related marginal costs; and (3) other costs including above-market, Power Charge Indifference Adjustment (PCIA) costs. Ignoring cost differences at different voltage levels due to line loss for the moment, the costs for the two marginal cost categories vary by hour but do not vary by end-use schedule. Generation marginal costs only vary between schedules when averaged over TOU periods because the load patterns vary between customer classes, creating different weighted averages of cost in both energy and capacity. However, when generation is priced at an hourly level (and not averaged over TOU periods) and includes hourly capacity costs, there is no longer a need to vary generation marginal costs between schedules, and a system average can be used.

a. Calculating Marginal Generation Costs (MGC)

The time-varying generation costs that inform PG&E's proposed DAHRTP-CEV Pilot rate were developed from scenarios of time-varying MGCs forecasted for 2021. These MGCs consist of marginal energy costs (MEC), plus marginal generation capacity costs (MGCC). Forecast scenarios of MEC and MGCC for 2021 were developed in PG&E's 2020 General Rate Case (GRC) Phase 2 Rebuttal testimony.[1] The DAHRTP-CEV Pilot rate would use actual market prices from the CAISO and forecasts of capacity costs created daily. The MGCs developed in PG&E's 2020 GRC 2 are used to calculate the rate adder described in Section 2(c) of this Chapter. PG&E's 2020 GRC 2 MGC can also be used to develop distributions of expected prices and 24-hour price shapes, as described in Section 2(d) below.

[1] Application 19-11-019, Exhibit (PG&E-7), Chapter 2, February 2021.

PG&E developed hourly MEC and MGCC forecasts using 10 “weather years” (2005-2014). These contain 3,650 days of 24-hour MEC and MGCC marginal costs. The MECs are forecasts of DA energy prices in dollars per megawatt-hour ($/MWh) or cents per kilowatt-hour (cents/kWh) at the PG&E Default Load Aggregation Point (DLAP), adjusted to account for losses. The MGCC are forecasts of the hourly value of capacity, converted into the same units and adjusted for losses and the 15 percent planning reserve margin. MGCCs are calculated using a peak capacity allocation factor (PCAF) methodology, which assigns capacity costs only to hours in which the ANL[2] exceeds a threshold equal to 80 percent of the average of annual peak ANLs over the 10 weather scenarios.[3] Hourly MGCC is then allocated proportionally to the amount each hour’s ANL exceeds the threshold.

b. Developing Operational Generation Cost Forecasts

This section describes at a high level how the generation costs will be developed day by day after the rate has been implemented. Generation costs are equal to the sum of megawatt-hour, MGCC, and a revenue-neutral rate adder discussed below.

1) MEC

The MECs are the loss-adjusted DA prices at the PG&E DLAP. These prices are available on the CAISO’s Open Access Same-time Information System (OASIS) web site at 1 p.m. on the day before “Operating Day.” The CAISO DA prices are multiplied by a loss factor of 1.069 to represent costs at the secondary distribution level.

2) Marginal Generation Capacity Costs

As described above, MGCCs are calculated from ANL, which, in turn, is calculated from load and GHG-free generation. While

[2] The Net Load referred to in descriptions of the CAISO’s famous Duck Curve is equal to gross, or metered load (i.e., load supplied to customers net of grid exports from customers), less utility-scale wind and solar production. ANL also subtracts other GHG-free resources: nuclear, hydro (both small and large hydro), and other renewables such as geothermal, biomass, and biogas. ANL is essentially the amount of load that must be met by thermal generators, imports and energy storage.

[3] Application 19 11 019, Exhibit (PG&E 2A) Updated Testimony, January 15, 2021, footnote 29 on p. 2-14 and p. 3-3.

CAISO publishes DA forecasts of load and wind and solar generation on OASIS, they do not publish forecasts of nuclear, hydro or other renewable generation. Thus, PG&E proposes a DA forecast of ANL that uses DA forecasts of load and wind and solar generation with 2-day prior actuals from OASIS for the other components of ANL (nuclear, hydro, and other renewable generation).

Of the three additional components listed above, hydro and other renewable generation have little variation from day-to-day because: (1) hydro generation input to the ANL calculation is actually the lagged 25-day average;[4] (2) geothermal, biomass and biogas generation have little variability day to day;[5] and (3) nuclear generation is almost constant except for outages. The error in the forecast of ANL could be reduced by using the nuclear generation at 1 p.m. on the day before operating day, rather than 2-day prior data as with the other components. However, this would introduce another step in generating the forecast with relatively little improvement, so PG&E recommends using 2-day prior actual data for all three components discussed in this paragraph.

The last step in calculating MGCCs is to compare the forecasted ANL_h in each hour h with the annual threshold, with hourly MGCC given by the formula:

$$MGCC_h = \frac{MGCC * (ANL_h - Thresh) * CapLoss * PRM}{Sum\ (ANL\ above\ Threshold)}$$

Where:

- MGCC = Annual MGCC from 2020 GRC Phase II Rebuttal Testimony ($68.56/kW-year);

[4] *Ibid.*, footnote 37 on p. 2-22.

[5] The standard error for a “forecast” of geothermal plus biogas plus biomass generation equal to its 2-day prior value (which reproduces the proposed input to the ANL forecast calculation) is only 68 megawatt (MW), approximately 4.8 percent of its average generation over January 2017-September 2020, and 0.3 percent of average CAISO load.

- Thresh = 80 percent of average annual peak ANL over all 2021 scenarios (25,313 MW CAISO-wide);
- CapLoss = Loss factor for capacity (1.091);
- PRM = Factor for planning reserve margin (1.15); and
- Sum (ANL above Threshold) = Average annual sum of ANL above Thresh over all 2021 scenarios.

3) Revenue Neutral Rate Adder

The third component of the DAHRTP-CEV Pilot rate is a rate adder that would collect other non-marginal costs collected in generation (including the portion included in bundled generation rates for the PCIA) as necessary to ensure that the rate is revenue neutral.[6] The proposed revenue neutral rate adder would not vary by time of day.

PG&E proposes to base all of its generation revenue neutral calculations on the bundled average generation rate. The CEV class has only been in service since May 2020, and there is not yet sufficient data to create a robust set of billing determinants for this class. Creating a proposed rate rider that is revenue-neutral to the system average simplifies implementation. It does so by requiring only one set of RT rates each day instead of requiring a set for each rate schedule. This methodology also makes it easier to apply these rates to other classes if RT rates are used with non-CEV classes at a later date.

Using the calculation of system MGC from PG&E's 2020 GRC Phase 2 Rebuttal,[7] the total generation marginal cost revenue is

[6] Ordering Paragraph 2 of D.20-03-019 required PG&E, Southern California Edison Company, and San Diego Gas & Electric Company to collaborate and submit a joint proposal for bill and tariff changes to show a PCIA line item in their tariffs and bill summary tables on all customer bills. On August 31, 2020, PG&E submitted Advice Letter (AL)-5932-E to implement the joint proposal by the last business day of 2021. If the joint proposal is implemented, PCIA will no longer be part of bundled generation revenue and the adder will be reduced accordingly. PG&E's proposal is to not have the adder vary by rate schedule even when it includes PCIA. Once PCIA is removed from generation, it will be a separate rate component that can vary by schedule and will no longer be affected by this rate rider.

[7] Rebuttal Revenue Allocation and Rate Design workpapers "MCRev_GRC.xlsx".

about $2.1 billion. However, this includes about $187 million from the flat Renewable Energy Credits (REC) adder in the MEC which does not appear in the CAISO rate. This makes the adjusted system MGC about $1.9 billion. The total generation Revenue Requirement under May 1, 2020, rates is about $4.0 billion. The difference between these is divided by forecasted bundled sales to give a revenue neutral adder of $0.05999/kWh.

Since customers on this option will be receiving hourly DA RT rate signals that include an accurate capacity component based on the CAISO market, they would not be eligible for critical peak pricing options such as Peak Day Pricing. They would also be ineligible for demand response programs and the Demand Response Auction Mechanism (DRAM).

c. Total Generation Cost Examples

The table below gives some information about the expected distribution of the generation rate. Table 2-1 lists the percentiles of total generation price (including the flat adder) for each hour in PG&E's forecasted 2021 prices. For convenience, the table lists different values by season[8] even though the DAHRTP-CEV Pilot rate will not need any defined seasons.

8 The standard 2020 GRC seasons are used: Summer is June through September, Winter is October through February, and Spring is March through May.

TABLE 2-1
FORECASTED 2021 GENERATION PRICES BY PERCENTILE RANK
(CENTS/kWh)

	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Summer Percentiles																								
5th	9.2	8.8	8.5	8.4	8.5	8.7	7.9	6.0	6.0	5.8	5.6	5.6	5.8	5.9	6.0	6.0	7.2	8.4	9.8	11.0	12.0	11.4	10.6	9.9
10th	9.4	9.1	8.8	8.7	8.7	9.0	8.5	6.9	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.8	8.1	9.2	10.5	11.4	12.3	11.6	10.8	10.1
25th	9.8	9.4	9.2	9.1	9.2	9.4	9.2	8.0	6.8	6.3	6.1	6.2	6.4	6.7	7.3	8.5	9.4	10.4	11.2	12.2	12.8	12.0	11.1	10.4
50th	10.1	9.8	9.6	9.5	9.6	9.8	9.9	9.1	8.3	7.8	7.7	7.7	8.0	8.3	8.9	9.7	10.5	11.1	12.0	13.1	13.5	12.4	11.4	10.6
75th	10.3	10.0	9.9	9.8	9.9	10.2	10.4	9.9	9.3	8.8	8.7	8.9	9.2	9.4	9.9	10.7	11.3	11.8	12.7	19.1	46.7	13.0	11.6	10.8
90th	10.5	10.2	10.1	10.0	10.1	10.4	10.7	10.3	9.7	9.4	9.4	9.6	9.8	10.1	10.8	11.4	12.0	12.6	13.7	103.3	109.8	44.4	11.9	11.0
95th	10.6	10.3	10.2	10.1	10.2	10.5	10.9	10.4	10.0	9.7	9.7	9.9	10.1	10.5	11.1	11.8	12.5	13.0	36.3	145.6	143.0	76.0	12.1	11.1
Winter Percentiles																								
5th	9.6	9.3	9.2	9.2	9.2	9.3	9.5	8.5	6.3	6.0	5.7	5.8	5.6	5.6	6.0	6.0	7.9	10.1	12.1	11.5	11.1	11.0	10.5	10.0
10th	9.7	9.5	9.4	9.3	9.3	9.5	9.8	9.0	7.0	6.0	6.0	6.0	6.0	6.0	6.0	6.6	8.5	10.6	12.3	11.7	11.2	11.2	10.7	10.2
25th	9.9	9.7	9.6	9.6	9.6	9.8	10.2	9.7	8.1	6.8	6.4	6.4	6.3	6.4	6.7	7.7	9.3	11.5	12.7	12.0	11.6	11.4	10.9	10.4
50th	10.2	10.0	9.9	9.9	9.9	10.2	10.6	10.3	9.0	8.1	7.7	7.7	7.7	7.7	8.0	8.8	10.5	12.4	13.1	12.4	11.9	11.7	11.2	10.6
75th	10.5	10.3	10.2	10.2	10.3	10.6	11.1	10.9	9.8	9.1	8.8	8.7	8.7	8.8	9.0	9.6	11.1	13.0	13.7	12.9	12.2	12.0	11.4	10.9
90th	10.7	10.6	10.5	10.5	10.6	11.0	11.5	11.4	10.4	9.9	9.8	9.7	9.7	9.8	9.9	10.2	11.4	13.4	20.5	13.3	12.5	12.4	11.7	11.1
95th	10.9	10.8	10.7	10.7	10.8	11.2	11.8	11.6	10.7	10.3	10.2	10.1	10.1	10.1	10.3	10.5	11.5	13.7	49.2	36.9	12.8	12.6	11.8	11.2
Spring Percentiles																								
5th	9.1	8.6	8.3	8.2	8.2	8.5	8.0	6.0	4.9	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.8	6.0	8.2	10.6	11.5	10.9	10.2	9.7
10th	9.3	8.8	8.5	8.5	8.5	8.8	8.6	6.6	5.7	4.4	4.4	4.4	4.4	4.4	4.4	4.4	5.5	6.0	8.6	11.0	11.7	11.1	10.4	9.8
25th	9.6	9.1	8.9	8.9	8.9	9.2	9.2	7.7	6.0	5.7	5.0	4.8	4.9	4.9	5.0	5.5	6.0	7.0	9.3	11.5	12.0	11.4	10.7	10.2
50th	9.9	9.5	9.3	9.2	9.3	9.6	9.8	8.7	6.8	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.5	8.1	10.1	12.0	12.4	11.7	11.0	10.5
75th	10.2	9.8	9.7	9.6	9.7	10.0	10.3	9.5	8.1	6.8	6.1	6.0	6.0	6.0	6.2	6.7	7.8	9.2	10.8	12.4	12.8	12.0	11.2	10.7
90th	10.4	10.1	9.9	9.9	10.0	10.3	10.7	10.3	9.0	7.9	7.4	7.2	7.1	7.1	7.3	7.9	9.0	10.6	12.2	12.8	13.0	12.3	11.4	10.9
95th	10.6	10.2	10.1	10.1	10.2	10.5	10.8	10.6	9.5	8.5	8.0	7.9	7.8	8.1	8.0	8.7	9.4	11.1	12.7	13.0	13.2	12.5	11.6	11.1

There can be a great deal of volatility in the summer evening prices during extreme events. PG&E expects prices above $2.00/kWh to occur approximately 10 hours per year and above $2.50 about 2 hours per year.[9] In terms of timing of the highest and lowest cost hours, Table 2-1 indicates that the *expected*, or *average* peak hour is always Hour Ending (HE) 21 in the summer (except HE20 for very high percentiles), HE19 in the winter; and HE21 in the spring. Likewise, the expected lowest-priced hour is HE11 in summer, and HE12 or HE13 in winter and spring. However, the peak hour and the hour with the lowest price can shift depending on weather and date within a season. Table 2-2 shows the expected percentage of days within each season in which prices are the greatest and the least for each hour.

9 Using May 1, 2020, Revenue Requirements.

TABLE 2-2
PERCENTAGE OF FORECASTED HIGHEST AND LOWEST PRICES
BY HOUR AND SEASON

	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
SUMMER EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	32.7	66.6	0.2	0.0	0.0
Percent Low Hrs	0.0	0.2	0.2	0.7	0.4	0.2	0.0	0.8	7.0	25.7	44.1	16.3	3.7	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WINTER EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.1	71.8	9.3	0.2	0.5	0.0	0.0
Percent Low Hrs	0.0	0.0	0.9	1.0	0.1	0.1	0.0	0.0	0.5	8.8	20.8	20.8	26.2	16.8	3.1	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
SPRING EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.5	22.4	67.4	0.8	0.0	0.0
Percent Low Hrs	0.0	0.2	0.1	0.3	0.0	0.0	0.0	0.1	5.5	21.6	19.5	16.5	12.9	11.3	10.3	1.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0

As an additional reference, Tables 2-3 and 2-4 below show the distribution of simulated historical values from January 2017 through September 2020.[10]

TABLE 2-3
SIMULATED HISTORICAL PRICES FROM JANUARY 2017 TO SEPTEMBER 2020
BY PERCENTILE RANK
(CENTS/kWh)

	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
Summer Percentiles																								
5th	8.2	8.1	8.0	7.9	8.1	8.3	8.1	7.0	6.5	6.5	6.6	6.7	7.0	7.3	7.5	7.9	8.0	8.5	9.1	10.3	10.0	9.4	8.7	8.5
10th	8.3	8.2	8.2	8.1	8.2	8.5	8.5	7.7	7.1	7.2	7.3	7.5	7.7	7.9	8.2	8.3	8.5	8.7	9.5	10.6	10.2	9.5	8.8	8.6
25th	8.8	8.6	8.5	8.5	8.6	8.9	9.0	8.4	7.8	7.8	7.9	8.2	8.5	8.7	8.9	9.0	9.2	9.6	10.5	11.5	10.7	10.0	9.3	9.0
50th	9.3	9.1	9.0	8.9	9.0	9.2	9.5	9.2	8.7	8.5	8.6	8.8	9.0	9.3	9.5	9.6	9.9	10.5	11.7	12.7	11.4	10.3	9.7	9.4
75th	9.6	9.4	9.2	9.2	9.3	9.6	10.1	9.8	9.2	9.1	9.3	9.5	9.7	10.0	10.3	10.7	11.1	11.7	13.7	15.0	12.2	10.9	10.1	9.8
90th	10.1	9.9	9.6	9.6	9.6	9.9	10.6	10.2	9.7	9.7	10.0	10.3	10.7	11.0	11.4	11.9	12.8	15.2	71.2	99.0	58.2	12.8	11.2	10.5
95th	10.8	10.3	10.2	9.9	10.1	10.3	11.0	10.6	10.0	10.0	10.4	10.9	11.3	11.9	12.8	14.4	21.8	74.6	157.7	177.1	119.1	37.1	12.2	11.2
Winter Percentiles																								
5th	8.5	8.4	8.3	8.3	8.5	9.0	9.5	9.2	8.6	7.9	7.3	7.3	7.1	7.2	7.4	8.1	9.0	10.2	10.4	10.1	9.9	9.5	9.2	8.8
10th	8.8	8.7	8.6	8.6	8.7	9.2	9.8	9.5	8.9	8.3	8.0	7.9	7.6	7.6	7.8	8.5	9.3	10.4	10.7	10.3	10.1	9.7	9.3	9.0
25th	9.2	9.1	9.0	9.0	9.1	9.5	10.2	10.0	9.3	8.8	8.6	8.4	8.2	8.2	8.5	9.2	9.8	11.0	11.4	10.9	10.6	10.1	9.7	9.4
50th	9.6	9.4	9.3	9.3	9.4	9.9	10.8	10.8	9.9	9.4	9.1	9.0	8.9	9.0	9.1	9.7	10.5	11.9	12.2	11.5	11.1	10.5	10.1	9.8
75th	10.2	10.0	9.8	9.9	10.0	10.6	11.7	11.5	10.4	10.0	9.8	9.6	9.5	9.7	9.9	10.4	11.5	13.6	13.7	12.8	11.8	11.3	10.8	10.3
90th	11.1	10.8	10.7	10.7	11.1	12.1	12.9	12.9	11.3	10.9	10.7	10.5	10.4	10.5	10.7	11.4	13.5	16.4	16.2	14.6	13.5	12.8	12.0	11.5
95th	12.6	12.1	11.7	11.9	12.4	13.7	15.0	14.0	12.7	12.4	11.9	11.5	11.3	11.5	11.7	13.0	15.0	18.4	19.7	17.0	15.4	14.4	13.5	12.9
Spring Percentiles																								
5th	7.3	7.1	6.8	6.8	7.0	7.8	7.6	6.5	6.0	6.0	5.9	5.6	5.4	5.6	5.6	5.8	6.0	6.6	8.5	9.5	9.5	9.0	8.5	8.0
10th	7.7	7.3	7.1	7.1	7.5	8.2	8.2	6.9	6.3	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	7.2	8.8	9.8	9.7	9.2	8.6	8.2
25th	8.1	7.9	7.7	7.7	8.0	8.7	9.0	8.3	7.5	6.8	6.5	6.3	6.3	6.2	6.3	6.6	6.9	8.0	9.4	10.5	10.6	9.8	9.0	8.5
50th	8.5	8.3	8.2	8.2	8.5	9.3	10.0	9.3	8.4	7.8	7.5	7.4	7.2	7.2	7.4	7.6	7.9	8.7	10.1	11.6	11.6	10.4	9.3	8.8
75th	8.9	8.8	8.6	8.6	8.8	9.7	10.9	10.4	9.1	8.6	8.3	8.1	8.1	8.0	8.2	8.4	8.7	9.4	10.9	12.6	12.1	10.8	9.7	9.1
90th	9.4	9.2	9.0	9.0	9.2	10.1	11.6	11.3	9.9	9.3	9.1	8.8	8.7	8.8	9.0	9.1	9.4	10.6	12.1	13.8	12.7	11.3	10.2	9.6
95th	9.9	9.6	9.4	9.5	9.7	10.6	12.0	11.6	10.3	9.7	9.5	9.3	9.1	9.1	9.3	9.6	10.1	11.6	13.7	14.8	13.6	11.6	10.7	10.1

10 MEC in the simulation are equal to DLAP prices times the loss factor. Marginal Capacity Costs are calculated according to the formulae in Section 2.B.2.b.2, using CAISO's DA forecasts of load and utility-scale wind and solar generation, and 2-day-lagged values for nuclear, biomass, biogas, and geothermal generation to calculate ANL. The revenue neutral adder was not changed for this historical presentation.

TABLE 2-4
PERCENTAGE OF SIMULATED HISTORICAL JANUARY 2017 TO SEPTEMBER 2020 HIGHEST AND LOWEST PRICES BY HOUR AND SEASON

	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
SUMMER EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.5	77.0	8.4	0.0	0.0	0.0
Percent Low Hrs	0.2	0.2	1.0	21.3	2.3	0.2	0.0	1.4	28.7	26.0	10.5	3.9	3.1	1.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WINTER EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	2.8	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0	48.5	5.0	0.2	0.0	0.0	0.0
Percent Low Hrs	0.0	0.0	10.3	7.9	0.2	0.0	0.0	0.0	0.2	1.8	8.5	10.1	33.5	24.6	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SPRING EXTREME HOURS																								
Percent High Hrs	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.3	52.7	36.1	0.0	0.0	0.0
Percent Low Hrs	0.0	0.3	4.9	5.4	0.0	0.0	0.0	0.8	2.7	3.5	6.8	9.0	20.4	20.9	15.5	5.2	4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Note that the forecasted prices peak up to an hour later than the historical simulated ones, while the lowest forecasted prices are both lower and more concentrated in the middle of the day than the lowest historical simulated prices. This is to be expected because both utility-scale and distributed (rooftop) solar generation are greater in the forecasted dataset compared to the historical simulations, while load, wind, and other generation sources are relatively similar between forecasted and historical data.

d. Primary and Transmission Customers

For Primary and Transmission voltage customers, PG&E proposes to use the same marginal cost drivers, but with smaller gross-ups for line losses. Instead of using a 6.9 percent energy loss factor for Secondary customers, Primary customers would have a 1.9 percent loss factor, as shown in PG&E's 2020 GRC Phase 2 Updated testimony.[11] For capacity, the loss factor is 9.1 percent for Secondary and 2.9 percent for Primary. Transmission customers would not have any loss factor. These loss factor changes would apply to the energy and capacity cost calculations but would not apply to the revenue neutral adder.

3. Updating Rate Values With Revenue Requirement and Sales Changes

The flat adder rate is based on Revenue Requirements from May 1, 2020, effective rates and a 2020 sales forecast to have easy alignment with the 2020 GRC Phase II marginal cost revenue calculations. If adopted, PG&E will adjust the rates to new Revenue Requirement and sales levels that are in effect at the time of implementation.

[11] Exhibit (PG&E-2A), served January 15, 2021, Chapter 2

PG&E proposes that the MGC for evaluating capacity should remain constant until reevaluated in the 2023 GRC. Therefore, any changes to Revenue Requirement or sales forecasts would only affect the flat revenue neutral adder portion of the rate. The calculation of the other portions would remain the same until updated in the 2023 GRC. As the flat adder was determined with system generation information, updates to the adder rate should be in line with average bundled rates. For May 1, 2020, rates, the bundled average generation rate was $0.11224/kWh.[12] Therefore, to keep this rate revenue neutral with average generation, PG&E proposes to keep the delta between the bundled average rate and the revenue neutral flat rate adder constant at $0.05225 ($0.11224 minus $0.05999). Therefore, increases in Revenue Requirement would be captured in the flat adder while retaining the same difference between the adder and the bundled average generation rate.

C. Answers to Commission's Questions in D.19-10-055

In D.19-10-055, the California Public Utilities Commission (Commission) posed a set of questions "that should be addressed before the Commission orders PG&E to implement such a rate for its customers."[13] In this section, PG&E addresses those questions that pertain to the structure and implementation of the proposed rate as described above. Other questions posed in the decision are addressed in later chapters.

1) *Assuming that any dynamic rate must utilize CAISO wholesale market price data, how will the dynamic rate utilize such data? Will the rate use DA prices only, or will it use day-of and RT CAISO prices as well?*

As described in Section B, the proposed DAHRTP-CEV Pilot rate uses DA prices only, adjusted to account for losses to primary or secondary distribution voltage where appropriate. While day-of RT CAISO prices (from either the 15-minute or 5-minute markets) do represent the most up-to-date MEC, implementing rates with such fine granularity and frequent updates would be a very significant undertaking with little added benefit, even in a pilot. PG&E prefers to "walk before we run" by instituting a DA pilot rate.

12 AL 5661-E-A, Attachment 1.

13 D.19-10-055, p. 29.

2) *Are there data other than CAISO data, such as a GHG signal data, that should be used as the basis for a dynamic rate instead?*

A GHG signal forecasting and broadcasting system was established by D.19-08-001 for the Self-Generation Incentive Program (SGIP) and has been implemented by WattTime and the SGIP Program Administrators.[14] This signal is essentially equal to a multiple of the 5-minute RT price, with a floor of zero and a cap corresponding to a heat rate of 12,500 British thermal units/kWh.[15] While PG&E considers that a parallel signal corresponding to actual RT prices could be developed and broadcast similarly to the GHG signal, billing and other Information Technology issues would be significantly greater than for a DA, hourly rate such as that proposed here. In addition, the fact that RT prices are not published until less than an hour prior to the operating interval would make it significantly harder for customers to plan when best to charge under a rate that uses RT CAISO prices.

3) *What time interval should be utilized for the rate? If a longer interval is utilized (e.g., a one-hour retail rate price) than the wholesale price data used to inform the retail rate (e.g., 15-minute or five-minute CAISO RT market data), how will the differences in temporal granularity be reconciled?*

As discussed above, PG&E is proposing that the rate use hourly intervals, which corresponds to the granularity provided in CAISO's generation data used to develop the rate. While a 15-minute granularity DA market has been proposed by CAISO, such a market does not yet exist and its implementation has been postponed by CAISO.[16] Therefore, any finer granularity prices would require using the day-of CAISO RT market price with corresponding higher implementation costs and challenges on both the

[14] Historical GHG emission rates and the Application Programming Interface for the SGIP signal available at: www.SGIPsignal.com.

[15] The formula comes from the Avoided Cost Calculator (ACC), which per D.16-06-007 is to be used to value Distributed Energy Resources such as the Energy Storage incented by the SGIP program. Heat rate is a measure of the [in]efficiency of the marginal gas generator; the ACC considers that when the RT price is equal to or below zero, renewable generation is on the margin, while a heat rate of 12,500 is considered to represent a reasonable maximum actual gas throughput per kWh of output, with higher prices representing additional generator costs such as those due to fast ramping, or prices in excess of costs required to cover fixed costs and those from startup and/or running units for a loss in the middle of the day.

[16] See Day-Ahead Market Enhancements – Straw Proposal, February 3, 2020, p. 6.

Load Serving Entities (LSE) and customer side. In particular, the fact that RT prices are not published until less than an hour prior to the operating interval would make it significantly harder for customers to plan when best to charge under a rate that uses RT CAISO prices.

4) *Will the dynamic rate focus solely on periods of overgeneration where CAISO wholesale prices are negative, or will dynamic rates seek to send critical peak price signals as well?*

The proposed DAHRTP-CEV Pilot rate focuses on periods of oversupply[17] where CAISO prices are zero or negative. It also seeks to send “critical peak price signals” through the capacity portion of the rate, while sending more muted price signals corresponding to actual generation marginal costs at other times. PG&E notes that the proposed capacity portion of the DAHRTP-CEV Pilot rate would include a non-zero amount on approximately 3 hours per day for approximately 68 days of the year on average.[18] For comparison, PG&E’s new Critical Peak Pricing (CPP) adder to be implemented in March 2021 includes a non-zero amount on approximately 3 hours per day on 9-15 days per year. Also, the capacity component of PG&E’s proposed DAHRTP-CEV Pilot rate varies depending on the severity of the capacity tightness, whereas traditional CPP rates just have a single adder that applies uniformly across all peak hours, and for each day in which an event is called. This makes CPP rates simpler to understand but less cost-based and unable to have a tailored response depending on the severity of grid stress.

5) *Given that overgeneration events may be either system-wide or limited to a transmission constrained area, should a dynamic rate available to all customers only signal system-wide events?*

[17] CAISO defines overgeneration as “a condition that occurs when total Supply exceeds total Demand in the ISO Balancing Authority Area.” This can lead to over-frequency and in extreme conditions, manual intervention. The CAISO uses “oversupply” to describe the situation when *potential* supply exceeds demand; in those (much more frequent) conditions the RT and/or DA price can drop to zero or below, and renewable generation is curtailed economically. PG&E uses the term oversupply in this document as being synonymous with renewable curtailment.

[18] Calculation in workpapers.

The price at the PG&E DLAP, which includes areas in the major transmission zones North of Path 15 (NP15) and ZP26 (in between NP 15 and South of Path 15 (SP 15)), incorporates both system-wide over-supply events and also those that are local to its service territory.[19] While some oversupply is local to a sub-Load Aggregation Point (LAP), PG&E's analysis indicates that zero or negative CAISO DA prices generally appear in almost all sub-LAPs at the same time. Thus PG&E's proposed DAHRTP-CEV Pilot rate generally accounts for most DA forecasted over-supply events within its service territory, whether CAISO system, PG&E system, or local.

6) *At what level of spatial granularity should wholesale prices be sourced? Should it be the DLAP, the sub-LAP, price node, or circuit substation-level? What challenges would the use of any sub-system level of granularity present? For example, if 16 sub-LAPs exist in PG&E's territory, and if a dynamic rate is designed to reflect a particular sub-LAP's wholesale prices, then how will the rate be communicated to customers in 16 different sub-LAPs simultaneously?*

PG&E believes that its proposed DAHRTP-CEV Pilot rate appropriately uses DLAP prices for the generation energy and capacity components. First, as intimated in the last part of the question, communicating that the rate is different depending on location would be confusing for many customers, who are not used to energy prices that vary depending on the customer's location. A rate that differs based on the sub-LAP would also cause problems for PG&E's billing system, which does not currently track the sub-LAP designation, let alone the more geographically granular p-node.

Second, PG&E does not consider that generation capacity costs vary within its service territory (in particular, by sub-LAP),[20] so the capacity portion of the generation adder should be the same across PG&E service

[19] The CAISO tracks oversupply in terms of various "buckets," including local vs. system economic curtailment, local vs. system self-schedule cuts, and local vs. system exceptional dispatch. In both 2019 and 2020 (through August 26), oversupply was composed of approximately 2/3 local economic curtailment, 1/3 system curtailment, and less than 2 percent local self-schedule cuts. However, most of the "local" curtailment appears to be local only in terms of being exclusively in NP15, SP15, or ZP26. See http://www.caiso.com/informed/Pages/ManagingOversupply.aspx and daily curtailment reports linked therefrom.

[20] Exhibit (PG&E-02A), Updated Testimony served January 15, 2021, p. 2-5.

territory. As for finer granularities, while p-node energy prices do vary geographically, they correspond to prices paid to *generators*, not prices paid by *load*, so they may be inappropriate from a regulatory standpoint. Generation energy costs do not vary by circuit.

Third, as described in the answer to Question 5, over-supply events generally occur simultaneously in most of PG&E's sub-LAPs. Analysis using data from January 1, 2017, through August 27, 2020, indicates that negative or zero sub-LAP prices occurred in approximately 400 hours for 11 of the 15 PG&E sub-LAPs, and approximately 700 hours for the remaining four sub-LAPs. Of the outliers, Fresno, Kern, and "Other ZP26" all have significant utility-scale solar generation, but all have sub-LAP prices whose correlations with average DLAP prices are over 98 percent, indicating that their prices move almost in lockstep with the other sub-LAPs. Only the North Coast sub-LAP has both a high number of hours with zero or negative prices (680) and a lower correlation with DLAP prices (approximately 92 percent).

At the other end of the scale, only the Humboldt sub-LAP has both higher-than-average DA prices ($1.50/MWh greater than average) and a relatively low correlation with DLAP prices (88 percent). Humboldt has been a transmission-constrained area for a long time and is therefore served by PG&E's Humboldt Power Plant, so it is not surprising that its energy prices often diverge from others in PG&E's service territory. The other sub-LAPs that are not called out above all have correlations with DLAP prices greater than 98 percent, and in some cases greater than 99 percent.

In conclusion, PG&E considers that while sub-LAP level energy prices could potentially provide a more accurate price signal in some areas, using the DLAP prices as PG&E proposes would capture the vast majority of price variance, and thus benefit from a DA rate. Differentiating by sub-LAP would increase customer confusion and increase implementation costs significantly without a corresponding decrease in generation costs.

7) *How should distribution rates be treated in a dynamic rate scheme? Should distribution capacity costs be included in a dynamic rate?*

As described in more detail in Section D below, PG&E is not proposing to include distribution rates for its DAHRTP-CEV Pilot rate.

D. Other Considerations

1. RT Distribution Rates

PG&E's proposal does not include a RT component for distribution rates.[21] The underlying base CEV rate includes standard TOU differentials in distribution and these would remain in effect for customers taking the DAHRTP-CEV Pilot rate. PG&E believes that there would be load-management advantages to dynamic distribution prices, but it is not as straightforward as generation pricing that can be implemented based on system average conditions. More research and analysis need to be conducted before distribution is added as a RT component.

One of the main obstacles in creating a cost-based RT distribution rate is that distribution capacity constraints are much more localized. The Distribution Planning Areas (DPA) do not experience peak loads at the same times, and some areas have more reserve capacity than others. A single system-level price with significant volatility can create incorrect incentives for some circuits/DPAs. PG&E does not believe that a RT distribution rate would be beneficial without area differentiated pricing. Additionally, localized distribution pricing can often be temporary in nature—lasting only for the period where pricing can defer additional investment. This temporal aspect of any localized RT rate makes the pricing for such a program highly variable year to year, contributing to the uncertainty for customers and any investments they may make. Regulatory lag and the timing of distribution project approvals exacerbates the situation. Finally, as with varying generation prices by geographic area, incorporating area-based distribution rates would add substantial complexity to the information and billing systems and potentially cause confusion for customers with accounts in multiple areas.

2. NEM Customers

PG&E's intends to offer the DAHRTP-CEV Pilot rate to NEM customers that qualify for the base CEV rate. As the rate rider substitutes one set of

[21] Community Choice Aggregators (CCA) and Direct Access LSEs would be able to establish their own generation rate components for each 24 hours in day. The hourly CCA or Direct Access generation rate could be billed using PG&E's bill-ready billing under Electric Tariffs E-CCA and E-ESP.

generation rates for another, exports to the grid will need to be tracked by hour and will be given generation compensation equal to that hourly price. PG&E does not propose any special rules for NEM customers on the DAHRTP-CEV Pilot rate.

3. Other Demand Response Programs

As PG&E's proposed DAHRTP-CEV Pilot rate already incorporates the full market price for both energy and capacity, customers on the pilot rate should not be eligible to enroll in other demand response programs, or for DRAM where third parties use retail customer demand response to participate in the CAISO market. Such dual enrollment would represent "double dipping," not provide accurate costs signals to customers, and potentially lead to assuming duplicative grid benefits, i.e., in the demand response-related program and also under the DAHRTP-CEV Pilot rate.

E. Conclusion

In conclusion, PG&E respectfully requests approval of its rate design for the DAHRTP-CEV Pilot rate. Specifically, PG&E requests:

1) Approval of the rate rider format which substitutes one generation rate for another;
2) Approval of the use of CAISO's DA hourly price for the generation energy marginal cost;
3) Approval of PG&E's generation capacity costs for the purpose of determining the capacity adder, as well as PG&E's proposed methodology for calculating the DA PCAF component;
4) Approval of the revenue neutral rate adder and approval to use the same rate adder for all schedules; and
5) Approval of PG&E's proposed method for adjusting the revenue neutral adder with sales and Revenue Requirement changes.

PG&E's rate proposal provides customers with a more cost-based rate option, allowing them to respond more appropriately to grid needs. Customers that can shift their charging times will be able to use electricity at times beneficial to the grid and reduce overall GHG emissions and their charging costs.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

PILOT STRUCTURE FOR COMMERCIAL AND INDUSTRIAL REAL TIME PRICING PILOT

PACIFIC GAS AND ELECTRIC COMPANY
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
PILOT STRUCTURE FOR COMMERCIAL AND INDUSTRIAL REAL TIME PRICING PILOT

A. Introduction

In this Chapter, Pacific Gas and Electric Company (PG&E) proposes a Real Time Pricing (RTP) pilot specifically for Commercial and Industrial (C&I) customers (C&I RTP Pilot). As explained in Chapter 1, PG&E is proposing to focus PG&E's initial RTP pilot (for non-Commercial Electric Vehicle (CEV) customers) on large C&I customers, because benchmarking results, summarized in Chapter 2, revealed that large C&I customers are most likely to enroll in an RTP rate. All C&I customers would be eligible to enroll in PG&E's C&I RTP Pilot, but PG&E's recruitment efforts will be focused on its large C&I customers.

PG&E is proposing to conduct a C&I RTP pilot in order to evaluate the ability of an RTP rate to achieve load management objectives. The objectives of this pilot are:

- To 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; and
- Test the complex operational systems needed to offer a new RTP, including involvement of Community Choice Aggregators (CCA).

PG&E proposes to leverage aspects of the CEV RTP Pilot proposed in Application (A.) 20-10-011,[1] (including the rate design, RTP pricing communication platform, and billing system) to implement this C&I RTP Pilot. The remainder of this chapter details PG&E's recommended structure for an RTP pilot, including:

- Positioning the RTP value proposition as compared to existing load management options;
- Pilot structure and customer eligibility;
- Customer research, Marketing, Education and Outreach (ME&O);
- Program operations and support;
- Pilot evaluation; and
- Pilot costs and duration.

B. Positioning the RTP Value Proposition Compared to Existing Load Management Programs

As discussed in Chapter 2, PG&E enlisted the Electric Power Research Institute to perform a Benchmarking Study of other utilities' RTP programs; this study found that, by far, the predominant participants in RTP programs currently run by other utilities are large C&I customers. Large C&I customers tend to have (1) more sophisticated knowledge about their energy usage, (2) energy managers, and (3) energy management systems that automatically control their facilities' electricity use,[2] enabling them to be successful on a dynamic rate like RTP.

PG&E's proposed C&I RTP Pilot would be open to all C&I customers. In PG&E's service territory, there are approximately 250,000 bundled C&I customers. Of those, the C&I RTP pilot proposes to target the 4,000 bundled customers who have peak demands >200 kilowatts (kW), as well as the approximately 5,000 with peak demands between 100 to 200 kW. These

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[1] PG&E's Application for Approval of Its Proposal for a CEV DA Hourly RTP Pilot, A.20-10-011 (October 23, 2020).

[2] Customers may program their energy management system to reduce usage when prices exceed a certain threshold. Customers may also program their system to respond to the duration as well as the price signal itself. Similarly, customers with batteries may program their system to not charge when prices exceed a certain price threshold, or charge when the price is low.

approximately 9,000 customers represent the customers who would be most suitable for this RTP Pilot, if adopted as proposed by PG&E.

The ideal candidates for the C&I RTP Pilot may already be enrolled in other load management programs.[3] One purpose of PG&E's proposed RTP Pilot is to evaluate how to position/market the RTP pilot rate against other load management programs, and whether (and if so by how much) the RTP rate results in a greater load management response by certain types of customers than can be achieved through other load management programs.[4] PG&E currently has several load management programs, including pricing programs, DR programs, and incentives available to these customers. Table 5-1 below provides a summary of such programs along with their 2020 *ex-post* load results.

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3 As discussed in Chapter 4, dual enrollment is not allowed. Therefore, customers currently enrolled in other load management programs would need to unenroll for the other load management program before enrolling in one of the RTP rate plan.

4 It may not be appropriate to attribute to RTP the full value of the gross load response that may result during this pilot, because the RTP customers could have instead taken service on another available load management program. The load response customers achieve under those programs could be seen as being duplicated by RTP, making the question whether the *incremental* load response caused by RTP is significant and cost-effective. The first step in evaluating RTP, therefore, is to determine whether the customer participated in another load management program before enrolling in RTP. The second step is to determine the incremental level of load response caused by RTP relative to the load response from existing load management programs.

TABLE 5-1
SUMMARY OF LOAD MANAGEMENT PROGRAMS AND INCENTIVES FOR NON-RESIDENTIAL CUSTOMERS

Line No.	Program	Description	Program Year 2020 DR Ex-Post Load Results: Load Reduction by Participating Customers (megawatt (MW))	Program Year 2020 DR Ex-Post Load Results: Dispatched Number of Service Agreements
1	Pricing Programs			
2	Time of Use (TOU) rates	A rate plan in which rates vary according to the time of day, season, and day type. TOU is mandatory for all Non-Residential customers. Peak Pricing period is 4 p.m. - 9 p.m. (for C&I) Super-Off Peak Winter pricing period is 9 a.m. – 2 p.m. (for C&I)	Because most non-residential customers are on a TOU rate plan, there is no recent load reduction study.	There are 436,000 C&I customers on PG&E's system receiving mandatory TOU price signals
3	CPP, known as PDP for PG&E's Non-Residential customers	PDP is an optional (annual default with ability to opt-out) rate that offers businesses a discount on regular summer electricity rates in exchange for higher prices from 5 p.m. to 8 p.m., on 9 to 15 peak pricing event days per year (typically occurring on the hottest days of the summer, although event days can be called at any time of the year).	12.3	64,752
4	DR Programs			
5	Base Interruptible Program (BIP)	Optional program intended to provide load reduction on PG&E's system on a Day-Of basis when the CAISO issues a curtailment notice to BIP-enrolled customers who are then required to reduce their load down to or below their Firm Service Level.	174	467

TABLE 5-1
SUMMARY OF LOAD MANAGEMENT PROGRAMS AND INCENTIVES FOR NON-RESIDENTIAL CUSTOMERS (CONTINUED)

Line No.	Program	Description	Program Year 2020 DR Ex-Post Load Results	
			Load Reduction by Participating Customers (megawatt (MW))	Dispatched Number of Service Agreements
6	Capacity Bidding Program	An aggregator-managed program that operates with a Day-Ahead (DA) option and runs each year, from May 1 - October 31.	11.76	500
7	Demand Response Auction Mechanism (DRAM) pilot	The DRAM pilot is a pay-as-bid solicitation where PG&E seeks monthly Resource Adequacy (RA) capacity from DR providers. Sellers bid aggregated DR directly into the CAISO DA energy market and can choose to also participate in real-time; all energy revenues from CAISO go directly to the Seller	99	
8	Other Programs (not including solar with battery storage, which can also be considered a load management tool a customer can use to manage bills under TOU, and not including other available DR offerings)			
9	Self-Generation Incentive Program (SGIP)	SGIP is a rebate program that provides incentives to support existing, new, and emerging distributed energy resources.[a]	Not available at this time. Data will be available after April 1, 2021.	8,300 customers representing 104 MW

(a) Qualifying technologies include wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells, and advanced energy storage systems, but most recent SGIP incentives have been for batteries. SGIP can be considered a load management tool because the incentive provided for C&I battery systems depends partially on meeting a GHG reduction standard.

Large C&I customers who are eligible for RTP will need to carefully consider how they would manage being on an RTP rate, because RTP exposes customers to unpredictable (in the long term) and potentially more volatile marginal prices, which, if not properly managed, could pose a risk of higher bills than on other rate plans.[5] Because marginal prices are volatile and uncertain and a customer's response to stronger price signals is also uncertain, it is impossible to exactly calculate the impact the RTP rate will have for that customer, and even estimating a reasonably expected range of results will be difficult. Thus, the value proposition of this program for a given eligible customer is hard to quantify in advance. PG&E expects to work with targeted eligible customers to assess the financial risks and benefits for that potential customer using historical prices and customer load, with the caution that future prices are unknown and may not necessarily follow historical prices. The inherent uncertainty in such risk/benefit evaluation estimates may make it more difficult for eligible customers to choose RTP based on economics alone as compared with other load management programs. Finally, there is no guarantee that a given RTP customer will have a load response when the grid is most strained. For example, price reductions or increases alone may not be desirable enough to incentivize a change in usage at a time that is otherwise important not to be curtailed for a business' operations.

PG&E's proposed C&I RTP Pilot aims to evaluate eligible customers' receptivity to an RTP rate, given the potential challenges described above, and to better understand RTP's load reduction compared to that of other load management and incentive programs.

C. Pilot Structure and Customer Eligibility

As discussed in Chapter 4 (C&I Pilot Rate Design), PG&E's proposed C&I RTP Pilot rate will replace the applicable generation component for PG&E's large C&I rate plans (i.e., Schedules B-19 and B-20)[6] with a DA Market price for participating RTP customers, just as the Day-Ahead Hourly Real Time Pricing (DAHRTP) CEV DA rate plan replaces its applicable generation

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5 For example, during the February 2021 severe weather event in Texas, prices for some customers on an RTP rate reached $9/kilowatt-hour (kWh) and remained there for four days. While CAISO's energy price cap is lower at $2,000/MWh ($2/kWh) and has never even been approached for more than a few hours at a time, these prices can still pose risks to customers over a sustained period, especially when capacity prices are added in. By comparison, the system average generation charge is approximately $0.11/kWh.

6 Rate Schedule B-20 is mandatory for customers with demands >1 MW. Schedule B-19 is mandatory for customers with demands >500 kW, but is also available on an optional basis to all commercial customers with demands <500 kW. Therefore, all C&I customers would be eligible to participate in the proposed C&I RTP Pilot.

component for the CEV rate plan. Table 5-2 summarizes the similarities and differences between the CEV and the C&I RTP Pilot.

TABLE 5-2
COMPARISON OF THE CEV AND C&I RTP PILOTS

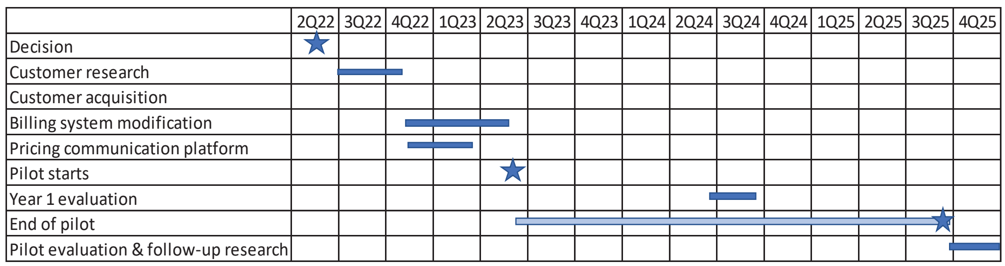
Line No.		CEV RTP	C&I RTP
1	Eligible Customers Characteristics/Rate Plans	Business Electric Vehicle (BEV) Bundled customers Unbundled customers of participating load serving entities	Medium General Demand-Metered TOU Service (B-19) Service to Customers with Maximum Demands of 1000 kWs or More (B-20) Bundled customers Unbundled customers of participating load serving entities
2	Rate Design	CAISO DA hourly prices, plus capacity adder and flat adder In addition to the BEV underlying rate design (e.g., subscription charges, etc.)	CAISO DA hourly prices, plus capacity adder and flat adder In addition to the B-19 and B-20 underlying rate design (demand charges, etc.)
3	Dual Program Participation	No dual enrollment with PDP or other DR programs	Same
4	Solar and Battery Participation?	Yes	Yes Net Generation Output Meter (NGOM) will be required for customers with both solar and storage[(a)]
5	Technology Incentive	Total technology incentive of $365,000 for no more than three sites Driver incentive	None. Incentives available through Energy Efficiency and possibly Demand Response (DR)[(b)]
6	Participation Cap	50 account holders for the incentives	No cap
7	Pricing Engine and Pricing Dissemination	Afternoon the day before Daily calculation based on CAISO prices Available via Application Programming Interface (API) and flat web site	Same

(a) Per Section Special Condition 9(c)(4) of PG&E's Net Energy Metering (NEM) 2.0 Tariff, the cost for NEM Paired Storage requiring complex metering varies and is based on actual costs which will be described in the customer's invoice. See, <https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_NEM2.pdf>, accessed March 22, 2021.

(b) There are existing DR incentives. However, because dual enrollment is not allowed, if the C&I RTP pilot is adopted as PG&E proposes, PG&E will be amending the current DR incentive to include the C&I RTP pilot.

PG&E proposes to conduct the proposed DA C&I RTP Pilot alongside the CEV RTP Pilot over the course of three years, as illustrated in Figure 5-1. The proposed timetable is believed to include sufficient time to complete sequential tasks across vendor assessments, technology development, CCA coordination, customer outreach and recruitment, customer baselining, data collection, and evaluation. Each of these tasks is discussed in detail in the subsequent sections of this chapter.

FIGURE 5-1
C&I RTP PILOT ILLUSTRATIVE SCHEDULE



PG&E proposes to make the proposed C&I RTP rates available for participation by interested eligible customers for two years, encompassing two summers. A two-year pilot period will allow adequate time to collect data on such matters as: (1) customer load behavior and bill impacts, (2) customer retention and load response, especially in the second year, and (3) whether customers need additional time to learn and/or optimize their operations and technologies to be successful on RTP. PG&E proposes to issue an interim evaluation report shortly after the end of the Pilot's first year, and a final Pilot report at the conclusion of the entire two-year period. At the end of this RTP pilot, PG&E proposes to automatically transition all participants back to their Otherwise Applicable Tariff (OAT). This pilot rate treatment—i.e., moving customers back to the OAT—has been used in other PG&E pilots, such as the opt-in residential TOU pilot, where PG&E and the parties need time to evaluate the feasibility of the rate plan, and, perhaps, change the rate design.

PG&E aims to be ready to open the C&I RTP Pilot rate plans to enrollment by interested eligible customers in summer 2023.[7] Pilot participants will be able

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7 This schedule is based on information available at the time of this supplemental testimony and may change as the Complex Billing System replacement project timeline is finalized (expected by July 2021). A delay in the start of the Billing System programming may cascade through the rest of the Pilot timeline. In addition, the Billing System programming timeline may also be impacted by billing change requirements resulting from outcomes in other pending proceedings, such as (but not limited to) the NEM Successor Tariff proceeding currently underway in Rulemaking 20-08-020, with opening testimony scheduled for April 23, 2021.

to unenroll at any time, just like any other rate plan, but their unenrollment would not become effective until the beginning of their next 30-day billing period, per Rule 12. Other Rule 12 provisions, such as limiting the number of times a customer can enroll/unenroll from the rate plan (to prevent customers from attempting to "game" the RTP rate by unenrolling before each summer and re-enrolling after each summer to avoid the riskiest season with the highest rate levels), will also apply to the RTP pilot participants.

1. Eligibility

PG&E will enable RTP for its Schedule B-19 and B-20 rate plans. Schedule B-20 is mandatory for customers with demand >1 MW. Schedule B-19 is mandatory for customers with demand >500 kW, but is also available on an optional basis for all C&I customers with demand <500 kW. Therefore, all C&I customers would be eligible to participate in the proposed C&I RTP Pilot. As discussed in Chapter 4, customers who enroll in the RTP pilot are not eligible to also participate in the PDP CPP program or other DR programs.[8] Participation in this Pilot would require customers currently participating in these programs to unenroll.

Any RTP Pilot participant that has both on-site solar generation and battery storage greater than 10 kW (i.e., enrolled on the NEM Paired Storage/NEM Multiple Tariff program) will also be required to purchase and install NGOM for each of their participating NEM-eligible generators.[9] The NEM2-MT metering requirements are such that two different technologies need to be metered separately to ensure the integrity of NEM credits. A separate NGOM enables accurate measurement of export and consumption

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8 As discussed in Chapter 4, Section 1 and the accompanying attachments, this RTP Pilot is <u>not</u> being designed to allow an eligible customer to have dual enrollment in both RTP and other load management programs because this rate already incorporates the full market price for both energy and capacity. Such dual enrollment would represent "double dipping," not provide accurate costs signals to customers, and potentially lead to assuming duplicative grid benefits, i.e., in the DR-related program and also under the C&I Pilot rate.

9 Per Section Special Condition 9(e) of PG&E's NEM 2.0 Tariff, Requirements for Large NEM Paired Storage >10 kW. See, <https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_NEM2.pdf>, accessed March 22, 2021.

intervals for each technology, which are necessary for accurate compensation calculations, given the volatile nature of RTP pricing.

2. CCA Participation

As shown in Table 5-3 below, over 50 percent of PG&E's C&I customers are currently served by a CCA or are a Direct Access customer. Given the large number of CCAs in PG&E's service territory area[10] and the complexity of coordinating RTP with each of them, PG&E proposes to limit the number of CCAs and other Energy Service Providers (ESP) that would participate in the C&I RTP Pilot to no more than two total CCA/ESPs. But because PG&E does not have experience with this type of pilot, it will need to develop and test a framework for collaborating with the CCAs and ESPs, from both a technical and a customer service perspective. It is critically important that PG&E's pilot include participation by some eligible C&I customers served by CCAs and/or other ESPs[11] in order to support greater customer participation for a more meaningful pool of pilot participants.

The CCAs who participate in the RTP Pilot would need to mirror PG&E's proposed RTP pilot rate structure (i.e., replacing the customer's otherwise-applicable generation prices on their underlying rate with CAISO DA hourly prices, including a capacity adder). Mirroring the CAISO prices is necessary to minimize customer confusion and eliminate the need to develop a customized pricing (and billing approach) for each participating CCA.[12] The C&I RTP Pilot is designed so that CCAs can easily implement it using the same infrastructure PG&E is developing for bundled customers, at minimal incremental cost to the CCA.[13] For example, the pricing platform (described in Section E.1 below) is designed to allow CCAs/ESPs to provide

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[10] As of March 17, 2021, there were 12 CCAs operating in PG&E's service territory. See, <www.pge.com/cca>, accessed March 20, 2021.

[11] Other ESPs include generation supply providers for Direct Access (DA) customers. There are approximately 2,600 Direct Access C&I customers.

[12] For example, significant additional customization would be required if a participating ESP wants to use 15-minute Day-Of CAISO data instead of the hourly DA CAISO data. Similarly, additional customization would be required if the ESP would like to make prices available at a different time than PG&E proposes.

[13] It is unknown how much it would cost the CCA and/or ESP to provide adders to the pricing engine, and to bill for RTP.

their own capacity and any other adders to calculate the CCA/ESP-specific hourly prices. Similarly, the C&I RTP Pilot marketing material will be developed so that ESPs can also use them with their customers.

TABLE 5-3
NUMBER OF PG&E LARGE C&I CUSTOMERS BY ESP[14]

Line No.		Number of RTP-Eligible Large (>100 kW) C&I Customers (Service Agreements)	Percent of Total RTP Pilot-Eligible Customers
1	Total Large C&I Customers	20,388	
2	Bundled (served by PG&E)	8,774	43.1%
3	Unbundled, served by a CCA	9,000	44.1%
4	Unbundled, Direct Access	2,614	12.8%
5	Subtotal of PG&E customers served by a different ESP (total of rows 3 and 4)	11,614	56.9%

D. ME&O

ME&O efforts for PG&E's proposed non-residential C&I RTP Pilot will seek to directly engage with customers to qualitatively assess level of interest and understand the customer experience. The remainder of this section details: (1) marketing objectives; (2) target audience; (3) outreach and tactics; and, (4) estimated budget and timeline.

1. Marketing Objectives

Marketing will be conducted to support the Pilot's objectives of giving customers an operational understanding of the proposed rate, testing the feasibility of the technology, and evaluating participants' experience with the rate.

PG&E's ME&O plan calls for:

- Conducting customer research to evaluate customer's interest in the proposed Pilot rate, the value proposition, and any other motivations and barriers for participation.
- Providing education materials to support enrollment.
- Enrolling customers onto the proposed rate.

[14] Data as of February 1, 2021.

- Providing participants with support to help them succeed while on the Pilot.

2. Target Audience

PG&E recommends that this Pilot's outreach focus on PG&E's large (>100 kW) Commercial & Industrial customers. Studies, including the recent RTP Benchmarking Study discussed in Chapter 2, have shown that large C&I customers are likely to be better equipped to respond to price signals and take advantage of DR programs and more dynamic rate plans.[15] Additionally, analysis of customers on PG&E's PDP program found that customers with greater demand size correspondingly had greater proportional average customer load impact on events.[16] Because these types of customers have already demonstrated an ability to be flexible and responsive in their energy usage, PG&E will focus its RTP outreach and recruitment efforts on large C&I customers. Within this large C&I segment, the initial "Prime" target audience will be those most likely to succeed on an RTP rate because they already have an energy manager on staff and/or have an automated energy management system in place. PG&E estimates that there are approximately 1,000 bundled customers that would fit this profile.

The rationale for initially focusing outreach on this Prime target audience is that, to effectively enroll participants in this C&I RTP Pilot, PG&E will need to clearly explain to targeted customers the potential benefits and risks for them of an RTP rate and what they would need to be able to do to succeed on it. Any attempt to use analytics based on past load response performance to explain and assess whether a customer could likely benefit on RTP is challenging because assumptions need to be made about how the customer might respond to the new RTP price signal. This is why the Prime target audience for focused initial outreach is customers who already have an energy manager and/or equipment that automates a business's ability to respond. Outreach also needs to help the potential RTP candidate

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15 Market Decisions Corporation, PG&E DR High Performer and Under Performer Study (April 2010).

16 Nexant Inc, 2015 Load Impact Evaluation of California's Statewide Nonresidential CPP Program (April 1, 2016).

assess their business' willingness to take action (such as set up new devices and maintain connectivity), including understanding the ratio of flexible load to non-automated load (to project likely outcomes more accurately). In a study among participants in PG&E's DR program(s), customers cited energy management systems/controls as the primary reasons they were able to successfully respond through load shifting and/or reduction during DR events.[17] Therefore, PG&E believes the best way to gain initial enrollments in this Pilot is to focus on customers who are believed to have the automated technology (including but not restricted to automated energy management systems and/or battery storage) and/or staffing resources to successfully participate in the C&I RTP pilot, such as is typically found in the manufacturing segment, in order to reduce the risk due to price fluctuations.

3. Outreach and Tactics

PG&E expects to use a multi-channel, segmented approach to enroll participants into the proposed C&I RTP Pilot rate plans (Pilot acquisition) and provide ongoing support throughout the duration of the Pilot (Pilot retention). PG&E plans to use targeted outreach tactics and also support technology providers with their own enrollment efforts.

PG&E's planned outreach tactics are described in greater detail below.

a. Acquisition

PG&E proposes taking a tiered approach to RTP Pilot acquisition outreach. Figure 5-2 illustrates a sample tactical calendar for the first year in-market.

[17] Market Decisions Corporation, PG&E DR High Performer and Under Performer Study (April 2010).

FIGURE 5-2
SAMPLE YEAR ONE TACTICAL CALENDAR

	Jan	Feb	March	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Tier 1 All Business Customers: 500K SAs				Newsletter (2 versions)			Newsletter (2 versions)					
Tier 2 Bundled Large C&I customers: 9K SAs				Newsletter (2 versions)			Newsletter (2 versions)					
				Direct Outreach (DM/EM)			Direct Outreach (DM/EM)			Direct Outreach (DM/EM)		
Tier 3 Manufacturing: 1K SAs				Newsletter (2 versions)			Newsletter (2 versions)					
				Direct Outreach (DM/EM)			Direct Outreach (DM/EM)			Direct Outreach (DM/EM)		
					Telemarketing							
				Always-on tactics: pge.com, collateral materials, dedicated support inbox								

All non-residential customers could be made aware of the opportunity to participate via cost-effective PG&E channels, with communication emphasis on attributes and actions that correlate with program success. Within that group, bundled large (>100 kW) C&I customers who are more likely to respond to hourly price signals and provide load would receive more targeted direct outreach. Finally, customers within that segment who have a battery, an energy manager, or an energy management system (and therefore are most likely to be able to succeed on this type of program), would receive direct one-to-one outreach. Specifically, PG&E may use the following tactics to enroll[18] customers onto the program:

- **Owned Channels:** The RTP Pilot rate will be cross-promoted as appropriate throughout PG&E channels to reach the broadest possible potential audience (such as leveraging existing digital newsletters sent to business customer segments). PG&E would also make information readily available about the C&I RTP Pilot on pge.com, including program details and benefits, how to enroll, and links to any relevant collateral and tools.

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18 Bundled customers will enroll in PG&E's proposed RTP rate plan through existing rate change channels, while participating CCA customers will need to enroll in that CCA's RTP rate plan(s) through their respective CCA. Because of the anticipated limited size of the Large Commercial, Industrial, and Agriculture (LCIA) RTP Pilot, customer enrollment and disenrollment will be done manually.

- **Direct Outreach:** PG&E will likely utilize email and/or direct mail to reach the broad population of C&I customers, including those who might still be interested but may not have been included in the initially targeted sub-group, who will also be receiving one-to-one outreach. Such direct outreach will provide an overview of the program and inform eligible customers of the opportunity to participate. Offering this rate to a broad range of customers supports the "test and learn" program objective, to see which customer types are interested in participating and how they ultimately perform.
- **One-to-One Outreach:** Direct-to-customer outreach to enroll the subset of eligible customers identified most likely to be able to successfully engage with the proposed DA RTP rate is expected to center on one-to-one conference call meetings to inform customers about the program, encourage enrollment and promote program benefits. One-to-one outreach would be conducted by a specialized team of phone-based representatives who have been educated on this rate offering and may also include the customer's PG&E account representative.
- **Collateral/Tools:** PG&E will develop collateral and tools (i.e., e-mail templates, fact sheets, sales toolkits, etc.) that showcase the opportunity of the RTP Pilot rate. These materials would be available to share directly with customers, ESPs, and/or technology providers, for both acquisition and retention purposes.

b. Retention

To encourage retention and engagement throughout the duration of the RTP Pilot, PG&E proposes to provide additional ongoing support for enrolled participants, which may include:

- **Welcome:** A welcome communication to confirm enrollment and provide tips on how to succeed with the RTP Pilot rate.
- **In-Season Support:** Ongoing communications throughout the duration of the Pilot, providing content such as seasonal tips and a first-year wrap-up.

- **Pilot Conclusion Prep:** About two months before the conclusion of the RTP Pilot program, a communication thanking customers for their participation and informing them of any next steps and upcoming rate plan proposals or approved changes.
- **Call Center Education**: PG&E will provide education/resources to enable our call center to support participants who do not have a PG&E assigned account representative.
- **Dedicated Support E-mail Inbox:** PG&E will provide this dedicated resource to facilitate RTP Pilot participants asking and getting answers to questions about the program, or their performance on the program.
- **Website:** PG&E will include RTP Pilot-specific information in appropriate places on pge.com (such as a C&I landing page or FAQ page) throughout the duration of the RTP Pilot.

4. Estimated ME&O Budget and Timeline

PG&E estimates it will cost about $550,000 to implement the ME&O plan for the C&I RTP Pilot if adopted as proposed. Of this total cost, it is estimated that $272,000 would be dedicated to customer acquisition, while $278,000 would be dedicated to customer retention and support. The timeline for these ME&O efforts will align with the overall proposed RTP Pilot implementation schedule.

E. Program Operations and Support

PG&E will need to make certain technology changes to implement the C&I RTP Pilot. The core of the RTP rate rider is the dynamic price signal itself, which enables PG&E to calculate and send DA price signals to a variety of endpoints, including Web portals and energy management systems. In addition, PG&E will need to modify its billing system to support the RTP prices. Assuming one or two CCAs choose to participate (as PG&E hopes they will), PG&E will also need to coordinate with them on data exchanges, outreach and customer support. Lastly, PG&E will need to develop ongoing support for program management, administration and customer support. Each component is discussed in detail below.

1. RTP Calculation Tool and Pricing Dissemination

The purpose of the pricing calculation tool is to consistently and reliably communicate CAISO's DA hourly prices to participating customers. As such, the pricing calculation tool will apply the methodology detailed in Chapter 4 and abbreviated here:

a) Intake the CAISO DA hourly Default Load Aggregation Point (DLAP) prices;

b) Use the DA CAISO hourly load, wind and solar forecasts, and prior day's generation from other CAISO GHG-free resources, to calculate hourly capacity prices (as described in Chapter 4) and use any DA capacity pricing from a non-Investor-Owned Utility (IOU) service provider, such as a CCA/ESP;

c) Apply the flat revenue-neutral adders described in Chapter 4 for bundled customers, and adders for a non-IOU service provider based on that provider's specifications; and,

d) Calculate the hourly prices.

PG&E envisions providing CCA/ESPs with the option to use PG&E's hourly RTP prices or to provide raw hourly prices to the pricing tool. In the latter case, the pricing tool will be programmed with logic to add charges for each service provider to the CAISO DA prices.[19] For example, if a particular CCA/ESP provider procures its own RA capacity and wishes to price capacity as a short-run capacity cost,[20] then the pricing tool would apply a specified RA adder based on that CCA/ESP's cost.

PG&E will specify business rules for the processing of the input files and the publishing of the hourly prices. PG&E will provide this pricing file in a machine-readable format (such as the Open Automated Demand Response

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[19] PG&E assumes that the participating CCA/ESPs will be using the same CAISO market prices (i.e., DA at the PG&E DLAP), but the adders may be different than PG&E's adders.

[20] The capacity cost developed by PG&E represents a long-run capacity cost, i.e., the cost of building incremental capacity to meet peak loads. As shown in PG&E's 2020 General Rate Case (GRC) Phase II (A.19-11-019), PG&E must add new generation (specifically, battery energy storage) in the near to medium term for reliability purposes. CCA/ESPs may wish to use different assumptions about their own need for new capacity or the levelized cost of building (or retaining) that capacity, which could result in different capacity costs than those developed in Chapter 4.

format) and a format that can be posted on a web site (e.g., daily pricing table).

The pricing communication platform will disseminate the hourly prices to all downstream systems. These systems include PG&E's billing system, a web site for customers and third parties to manually retrieve prices, and an API for machine-to-machine automation. To preserve neutrality, PG&E proposes publishing the prices on both a non-PG&E-branded web site and the PG&E web site. In addition to providing DA prices, PG&E will post historical prices.

PG&E plans to coordinate its development of the pricing communication platform with the California Energy Commission (CEC). The CEC launched its 2020 Load Management Rulemaking (Docket #19-OIR-01), and components of the Customer Enablement functions (the Market Informed Demand Automation Services (MIDAS) and dissemination of signals) are currently proposed to be in scope for the CEC to develop and operate.[21] Without coordination, duplication is likely, making it more challenging to define the requirements. Since PG&E's proposed customer enablement platform will be designed to be reusable if and when the CEC completes its Statewide MIDAS, PG&E intends to use the pricing communication platform to publish hourly pricing information to the CEC server.

PG&E proposes to expand on the CEV RTP Pilot's technology platform, allowing PG&E to use the same infrastructure for the C&I RTP Pilot, thereby reducing development time and costs. This platform intakes the CAISO DA market data, calculates the retail Pilot rate component for each hour for each applicable rate plan, and makes those rates available for Pilot participants to see on a timely basis.

PG&E's proposed pricing tool and communication platform will allow PG&E, CCAs and other ESPs[22] to compose DA hourly price forecasts and to publish and disseminate those hourly prices to participating customers and third parties via a non-PG&E website or API. The platform could also

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21 See, CEC's "Commissioner Workshop on Scope of Load Management Rulemaking (19-OIR-01)," at <https://www.energy.ca.gov/event/workshop/2020-01/commissioner-workshop-scope-load-management-rulemaking-19-oir-01>, accessed March 20, 2021.

22 Including Direct Access ESPs.

serve as the basis for future dynamic rates, including potential future RTP rates, that may be developed and piloted to these customers or other customer classes or segments.

The incremental cost estimate for expanding the CEV RTP Pilot technology platform for the C&I RTP Pilot is estimated to range from $1 million to $1.3 million. This C&I RTP Pilot incremental cost estimate includes a one-time cost (ranging from $50,000 to $100,000) to expand the CEV RTP Pilot technology platform[23] and an additional $40,000 to $50,000 per month in operations and maintenance costs. The range in costs reflects the variability of implementing technology projects as the details will not be apparent until the business rules are fully defined.

2. Billing and Ancillary System Modifications

In its CEV RTP Pilot proposal, PG&E outlined the work that would need to be done to modify its billing infrastructure to support the new RTP rate. These upgrades include the following components:

- A new automated interface to extract the Pilot rate hourly prices and apply them to the Billing System(s), including an automated tool that will confirm receipt of rate prices by a predefined daily timeframe, or signal that manual intervention is required;
- The ability to store hourly prices for billing, reporting, and archiving needs, including setting up and testing the business process and operational structure needed for hourly billing (e.g., determining the impact of hourly RTP billing for billing exceptions and data transfer);
- A modification to PG&E’s automated monthly rate interface to exclude the Pilot rate, since the generation component of rates will be derived from the price communication platform rather than the sources maintaining PG&E’s other rates;
- A modification to PG&E’s rate-framing and rate calculation engines in the Billing System to include hourly usage data to support the bill structure change;

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[23] The expected cost to build the platform for the CEV RTP Pilot was estimated as ranging from $300,000 to $550,000, in A.20-10-011.

- New interfaces to transmit billed hourly costs to the data warehouse and downstream systems;
- Testing rate calculations and other associated bill charges;
- Testing interval data Validation, Editing, and Estimation rules and algorithms;
- Testing for all price and usage data flowing between the Billing System(s) and the customer enablement platforms; and
- Moving all customers back to their respective OAT[24] at the conclusion of the pilot.

The incremental billing work required for the C&I RTP Pilot would be building and testing the Schedules B-19 and B-20 RTP rate versions. PG&E currently plans to replace its Advanced Billing System (ABS) starting in 2021, with an expected completion in 2022. Once the ABS replacement and stabilization is complete, PG&E will implement the CEV RTP pilot rate, followed by the C&I RTP pilot rates. These cost estimates assume implementation of the RTP pilot after the ABS upgrade is complete, in order to avoid costs of designing, building and testing the rate twice.

It is important to point out that these billing changes must also be completed by each CCA and ESP that wishes to participate in the C&I RTP Pilot.

The incremental cost estimate (compared to the CEV RTP Pilot) to build the RTP pilot rate is projected to range from $4.6 million to $6.9 million[25] based on the high-level rate design outlined in this testimony and on the costs of previous similar billing system implementation projects. The variance between the high and low Information Technology (IT) billing cost estimates can be attributed to unknown factors associated with the new Billing System (ABS replacement discussed above). For example, the lower end of the cost estimate assumes that the new Billing System will automatically validate the DA hourly price receipt and calculation, rather

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24 PG&E may need to program different rate plans for the RTP and the non-RTP versions of the rate plan; that is the reasoning behind moving customers back to their OAT.

25 There may be $400,000 to $500,000 in non-incremental costs for interfaces, depending on billing system architectural design, which will be determined during the plan/analyze stage of the IT billing programming.

than manual validation by a Billing Operations employee. This assumption cannot be confirmed until after the requirements of the new Billing System have been finalized and implemented. Lack of detailed options also contribute to the variance between the high and low IT billing cost estimate; detailed design options have not been finalized regarding how pricing and usage data will flow to the billing system from the customer enablement platform. These technical data flow design elements will be scoped out in further detail following the approval of the pilot.

The cost estimate includes additional key assumptions. Any changes to these assumptions would necessitate re-evaluation of the pilot design, implementation plan and cost estimates. Assumptions include that:

- The pricing is based on CAISO's hourly DA market;
- Only Schedules B-19 and B-20 will be created with an RTP component;
- Customers cannot participate in PDP or any CAISO market integrated DR programs at the same time as the RTP Pilot;
- No additional rate riders will be added to these RTP rate plans for the duration of the RTP Pilot;
- Participating ESPs will calculate the generation component of their pilot customer bills, while PG&E will continue to bill customers using the ESP-calculated bills. PG&E will need to test the data transfer process, especially with the participation of CCAs. The CCAs have historically relied on PG&E's framed usage for billing. PG&E would need to work with the CCAs to determine the level of technical support needed for a small set of customers, before scaling to a larger population; and
- Participating CCAs will be responsible for enrolling their customers in the RTP Pilot (since the CCAs calculate generation charges and the non-generation charge calculations can remain the same).

3. Ongoing Customer Support

The load performance aspect of the pilot program needs to be measured to ensure success. As a result, it is vital that customers have access to tools that monitor and ensure load and event performance. PG&E will provide all enrolled customers with usage and interval cost information.[26] PG&E will continue to support metered usage data sharing through its Your Account's Share my Data platform and procedures. Additionally, PG&E has existing processes to allow customers to access real time metering information by adding a KYZ Pulse attachment to their SmartMeter™ or MV90 meter, as governed by Electric Rule 2.

In addition to technical support, PG&E anticipates the need to track and address technical issues related to customers who do not receive pricing signals in a timely manner. PG&E will develop business processes, employee training and customer and partner communications in anticipation of these technical challenges. In addition, PG&E will need to develop business processes and gain concurrence from its participating CCA/ESP partners on how to address customer complaints about potentially high bills, due to market fluctuations.

F. Pilot Evaluation

PG&E will be conducting customer research to evaluate the effectiveness and attractiveness of RTP with a specific group of customers, as well as hone ME&O for potential full rollout. PG&E anticipates that expected cost savings and/or reduced GHG emissions are likely to be primary drivers motivating participation, as those drivers are key components of pilot design, measurement and evaluation. However, PG&E also needs to understand the customer experience in more detail to identify barriers, risks, benefits and additional motivations for participation. These results may help in understanding the potential value proposition of an RTP rate (or other dynamic rate options) for other customer groups, as well.

To evaluate the customer experience, PG&E's Customer Experience and Insights team anticipates conducting qualitative and quantitative research with PG&E customers during the C&I RTP Pilot. Pre-pilot research will explore topics such as customer barriers, motivations and overall impressions, to understand how to best message and promote the program. Although recruitment for the pilot would target a particular Prime customer profile, this aspect of research could also include a broader group of non-residential customers for potential to

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[26] Interval costing for bundled customers will be available after the bills have been calculated.

help assess future roll-out. PG&E will also survey customers who declined to enroll in the pilot, to further research customer barriers to participation. Similarly, PG&E will consult with its account representatives to inform research design, and later to debrief them on their customers' experience on this Pilot.

Over the duration of the C&I RTP Pilot, research will focus on customer satisfaction and understanding of both the rate and the supporting outreach among participants. Finally, at the conclusion of the Pilot, research will focus on overall customer experience, impressions and take-aways for future roll-out, as well as ascertain any differences among customer segments. The overall aim of the research will be to position the program to succeed by taking the learnings from the pilot research and determining customer interest and viability beyond the pilot.

Based on previous PG&E customer research, customers prefer simple messaging that is easy to understand and gets to the point quickly. For the proposed C&I RTP Pilot rate, PG&E anticipates customers will want to know who is likely to succeed on the rate, what the benefits are, and how they can take advantage of this option. This who/what/how approach will be fundamental to testing efforts, allowing PG&E to deliver clear and effective messaging to customers in the future.

Tracking metrics allows PG&E to learn and improve throughout the ME&O process. PG&E plans to track and evaluate the success of its efforts based on the following metric types, outlined in Table 5-4:

TABLE 5-4
RTP PILOT METRICS AND TRACKING OVERVIEW

Line No.	Metrics and Tracking	
1	Effort	Metrics
2	One-to-one Outreach	Number reached, Conversions
3	Direct Outreach	Number reached, Conversions, Open/Click-Through Rates for Email
4	Owned Media	Landing page visits—Overall and Campaign-level
5	Retention	Number of participants who remain for the duration of the Pilot
6	Customer Insights	Customer satisfaction, awareness and understanding

In addition to the customer evaluation, PG&E will be evaluating the cost of the RTP Pilot compared to its grid benefits. This evaluation will include:

- Benefits and trade-offs inherent to RTP pricing, including whether and to what extent it could result in revenue shortfall;
- Assessment of load response. Depending on the number of customers participating in the pilot, the load impact could potentially be compared to the impact of other load management programs. In addition, if data is available, PG&E will compare customer load for the first year against that for the second year. In addition, there may be other eligible customers who already tend to operate predominantly during the off peak periods, who would likely benefit from RTP, but may not have much if any load to drop on peak (i.e., "free riders" or structural winners on RTP that don't provide new system benefits during peak). PG&E will need to determine which customers provided load benefit compared to those who are structural winners;
- Assessment of GHG impacts. The marginal GHG emissions rate is calculated and published in five-minute intervals for SGIP participants using a methodology approved by the Commission.[27] GHG impacts can therefore be assessed by multiplying the load impact by hour (or preferably, by 15-minute interval) by the average marginal GHG emissions rate in each hour or interval and summing over appropriate periods (e.g., by month and by hour of the day).
- Customer bill analysis compared to the OAT and/or other load management programs;
- Program costs; and
- Revenue under-collection/over-collection, as discussed in Chapter 4

PG&E estimates that the cost of the above-described Evaluation is likely to range between $150,000 and $200,000. In addition, customer experience and customer insights research is forecasted to cost between $250,000 and $350,000. This research will cover qualitative and quantitative research with program participants and customers. The primary variance between the estimates in these ranges is attributed to uncertainty about the number of pilot

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27 *See* https://sgipsignal.com/. Page accessed March 23, 2021.

participants and the scope of research to be executed (resulting from discussions at the post-decision workshop).

G. Estimated C&I RTP Pilot Cost Summary

As shown in Table 5-5 below, the total estimated incremental cost for PG&E's LCIA RTP Pilot (that go beyond the costs already identified and requested in PG&E's DAHRTP-CEV Pilot proposal) is expected to range between $7.8 million and $11 million over the 2022 – 2025 period, covering Pilot preparation, operations and post-Pilot evaluation.

TABLE 5-5
COST SUMMARY
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	LCIA RTP Pilot Activities	Low Forecast	High Forecast
1	Customer Enablement (incremental to the CEV DAHRTP Pilot)	1,010	1,300
2	LCIA Pilot Design, Evaluation, and Reporting	150	200
3	Labor	1,337	1,917
4	ME&O	679	779
5	Incremental Billing System Modifications	4,600	6,900
6	Total for All LCIA Pilot Incremental Activities	7,776	11,096

PG&E requests flexibility in spending among the different activities to conduct the Pilot. PG&E is requesting authority to record those costs in a memorandum account for recovery in a future GRC Phase I proceeding or through a separate application. In addition, any changes to these key assumptions, or other assumptions outlined in this filing, will result in changes to Pilot design, implementation plans and estimated costs.

H. Conclusion

In this chapter, PG&E has described PG&E's proposed plan for the C&I RTP Pilot, including pilot objectives, pricing communication, customer enrollment, pilot phases, target customers, ME&O, billing and evaluation. PG&E proposes to conduct the RTP pilot in order to assess the value proposition of a dynamic rate for non-residential customers. PG&E proposes to discontinue the RTP rate plans after the Pilot is completed, to allow for sufficient time to rate design, analyze Pilot operations, retention rates and customer satisfaction, to help inform and refine the program before the California Public Utilities Commission considers whether it or something like it should be offered on a longer-term basis, and whether it should be more broadly available in the future.

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APPENDIX A

BENCHMARKING STUDY OF US REGULATED UTILITY REAL TIME PRICING PROGRAMS, ARCHITECTURE AND DESIGN, ELECTRIC POWER RESEARCH INSTITUTE, FINAL REPORT, MARCH 2021

ELECTRIC POWER RESEARCH INSTITUTE

Benchmarking Study of US Regulated Utility Real Time Pricing Programs, Architecture and Design

Final Report

3002021204

Benchmarking Study of US Regulated Utility Real Time Pricing Programs, Architecture and Design

Final Report

3002021204

Technical Update, March 2021

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Energy Resource Economics, LLC

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This publication is a corporate document that should be cited in the literature in the following manner:

Benchmarking Study of US Regulated Utility Real Time Pricing Programs, Architecture and Design: Final Report. EPRI, Palo Alto, CA: 2021. 3002021204.

ABSTRACT

The project sought to classify the ecosystem of time-varying pricing constructs, inclusive of dynamic pricing and time-of-use (TOU) structures and their derivatives, into a logical and applicable taxonomy. It also advanced a conceptual foundation to ascribe "building block" attributes of dynamic pricing plans. The project conducted a comprehensive review of the universe of RTP plans that have been offered by regulated utilities across the U.S. This was based on documented studies cited in the report. Due diligence was then conducted on the identified plans to (a) verify their accurate classification as RTP plans and (b) document structural attributes for sub-classification. As a further step, interviews were conducted with rate managers from selected utilities across the country with experience in RTP to better understand the motivations for developing the plans, customer uptake and persistence in the plans, customer satisfaction, and load shaping results. Finally, the project provided a conceptual illustration of designing an RTP plan to integrate into a utility pricing portfolio.

Keywords

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PRIMARY AUDIENCE: Utility professionals in rate design and pricing products

SECONDARY AUDIENCE: Utility professionals in customer programs

KEY RESEARCH QUESTION

This study captures the current landscape of real time pricing (RTP) programs offered by regulated electricity suppliers in the United States. It characterizes RTP design principles and benchmarks design choices and utility experiences with RTP offerings in terms of practice, performance and lessons learned to inform better design of RTP plans and programs. This study further provides a framework for how to design and develop RTP offerings that can promote strategic load management objectives.

RESEARCH OVERVIEW

1. Taxonomy of Pricing: The project first sought to classify the ecosystem of time-varying pricing constructs, inclusive of dynamic pricing and time-of-use (TOU) structures and their derivatives, into a logical and applicable taxonomy. It also advanced a conceptual foundation to ascribe “building block” attributes of dynamic pricing offerings, including RTP.
2. Definition of RTP: RTP is a variant of dynamic pricing in which the price for electricity fluctuates hourly, and sometimes sub-hourly, reflecting changes in the wholesale price of electricity and is typically known to customers on a day-ahead or hour-ahead basis. Despite the “real-time” naming convention, the retail rate is distinguished from wholesale prices that may be transmitted from day-ahead or hour-ahead markets, in addition to more granular sub-hourly wholesale markets such as the California Independent System Operator (CAISO) Fifteen Minute Market (FFM) or five-minute Real Time Market (RTM). The study focused exclusively on “full requirements” RTP offerings that apply to all electricity use at a customer facility’s, rather than applied to a specific end-use such as electric vehicle charging.
3. Secondary Research on RTP: The project conducted a comprehensive review of the universe of RTP plans that have been offered by regulated electricity suppliers across the U.S. This was based on documented studies cited in the report. Due diligence was then conducted to (a) verify RTP classification, and (b) document structural attributes for sub-classification.
4. Benchmarking RTP: As a further step, interviews were conducted with rate managers from selected utilities across the country with experience in RTP to better understand the motivations for developing the plans and plan attributes, customer uptake and persistence in the plans, customer satisfaction, and load shaping results. Finally, the project provided a conceptual illustration of designing an RTP plan to integrate into a utility pricing portfolio.
5. Evaluating RTP Load Response
6. Illustration of integrating RTP into an Electric Service Portfolio:

KEY FINDINGS:

- RTP Program Availability and Eligibility
    - The study verified 55 currently active RTP offerings from 41 regulated U.S. utilities.
    - 51 of these RTP offerings are open for new enrollment while enrollment for the remaining 4 is capped are therefore not available for new subscribers.
    - Only two (2) active residential RTP offerings were identified, compared to 53 RTP offerings for non-residential customer classes. The reason that RTP has been scarcely applied to residential customers owes chiefly to a lack of technology to enable households to automate responses to price signals. By contrast, non-residential customers – particularly larger commercial and industrial customers – are more likely to have control systems in place to automate responses to RTP signals. Moreover, many larger non-residential customers have dedicated energy managers and staff who actively manage energy usage.
    - Availability and eligibility for RTP among non-residential customers is weighted towards larger commercial and industrial customers based on such factors as minimum monthly peak demand. 35 RTP offerings require a peak demand greater than 100 kW, with 15 of those requiring a peak demand greater than 1 MW.
    - All RTP programs identified were opt-in, except in jurisdictions with full retail competition for which RTP is default or mandatory for large customers who do not select an alternate retail electricity provider.
- Drivers:
    - The impetus for most utilities' RTP offerings was either compliance with a regulatory order (actual or anticipated), to promote economic development, or in response to restructured markets with customer choice.
    - A few of the earliest program were launched as pilots to gain experience with dynamic pricing but most were offered as an alternative to standard services. Currently, 43 of the 55 verified RTP offerings in the U.S. are permanent services, while 12 are either in the experiment or pilot phase.
- Price Elasticity:
    - The available studies have not shown significant price elasticity/load impact from RTP, although anecdotal evidence from interviews indicates some customers can consistently shift load and save money over the long run
- Rate Experience:
    - The majority of RTP offerings identified had very low enrollment with stagnant program growth. In many cases, RTP offerings are not actively marketed and promoted by the utility. Customers subscribing to the RTP tend to have been on the plan for a long period and have adjusted their operations and energy use to take advantage of hourly price variations.
    - Often significant investment in modifying or replacing metering, billing and other systems was necessary to accommodate RTP

- Customers on RTP rates have relatively high customer satisfaction
- Customer bill savings depends on customers' ability to respond to hourly price fluctuations (e.g., "savvy" customers and/or customers with technology to closely monitor prices)
- A concerted effort is required to help customers understand why RTP is different from their current service, what is required to benefit and how to associate a cost to those actions, and the risks associated with subscription
- Generally, customers were only provided an interval meter and in some cases equipment for receiving or retrieving posted prices.

SUMMARY:

Taxonomy of Real Time Pricing

- A robust rate categorization schema includes a taxonomy for understanding the basic building blocks of rate structures, including: (a) energy flow (kWh) based on time-of-use or volume of consumption; (b) demand (kW); and (c) fixed charges.
- As a subset of time-varying or dynamic energy prices, real time pricing (RTP) can be differentiated between two sub-categories: one-part and two-part RTP
    - For one-part RTP plans, the posted energy price ($/kWh) is applied to all metered usage and with fixed costs collected either through a markup to the hourly energy price, assessing a demand charge, or both.
    - For two-part RTP plans, an access charge collects fixed supply costs while an energy charge settles hourly differences between actual metered energy use and the customer baseline load (CBL). Hourly deviations from the CBL are charged the prevailing RTP price reflecting the system marginal cost of supply for that hour.
- RTP plans can be distinguished on the basis of the following 12 key pricing design features: (1) Availability, Maturity and Eligibility; (2) Pricing Structure (including one-part or two-part construction); (3) Price Granularity – Temporal; (4) Marginal Price Granularity – Spatial; (5) Price Posting Notification; (6) Price Overcall of Posted Day-Ahead Prices; (7) Marginal Entry Price Formation; (8) Generation, Transmission and Distribution Capacity Pricing; (9) Marginal Cost Uplift; (10) Contract Term; (11) Hedging and Risk Management; and (12) Eligibility. These design features, used to categorize and characterize utility RTP plans, are defined in Section 3.

Benchmarking Results from RTP Tariff Sheet Analysis

- Verified 55 active RTP offerings from 41 regulated utilities in the U.S. out of an initial universe of 97 retail electricity providers previously documented to have implemented RTP
- The most common type of RTP program features hourly pricing with day-ahead notification targeted to commercial and industrial (C&I) customers with a specified minimum demand eligibility and no differentiation in prices within the service territory.
- Only 2 of the 55 verified active RTP offerings are available to residential customers

- 50 of the 55 verified active RTP offerings (over 90%) feature hourly pricing granularity; 3 plans assign varying rates to a block of hours, rather than hourly, while only 2 plan employs variable pricing at sub-hourly (e.g. 15-minute or 5-minute) intervals.
- 51 of the 55 verified active utility RTP offerings (93%) have no spatial price differentiation within the service territory. In other words, all eligible customers under an RTP service have the same hourly pricing levels irrespective of their spatial location on the utility system.
- 52 of the 55 verified active utility RTP offerings (82%) feature day-ahead pricing notification. One of the remaining RTP offerings features hour-ahead price notification while the remaining two post price notifications less than an hour ahead.
- 35 of the 55 verified active utility RTP offerings (64%) base hourly energy prices on regional wholesale energy market price postings (e.g. those posted by RTOs and ISOs). 11 RTP offerings base prices on the utility's own supply and demand forecasts, while the remaining 9 RTP offerings apply pre-set hourly pricing independent of any wholesale market.
- 18 of the verified active RTP offerings, representing one-third of all verified RTP offerings, employ a customer baseline load (CBL) as a basis for RTP structure, whereby participants effectively subscribe to a baseline level of usage with hourly deviations from that baseline either debited or credited at that hour's applicable price. 28 utility RTP offerings employ a pricing structure either based on marginal energy price alone (5) or marginal energy price with a charge for demand (23). The remaining 9 RTP offerings feature pre-set pricing.
- 21 of the 55 verified active RTP offerings have been confirmed to provide any sort of price protection mechanism for customers to hedge their price risk, including the 18 which feature a CBL structure.
- 51 of the 55 verified active RTP offerings are currently open for enrollment. The remaining 4 are limited to existing subscribers and not available to new subscribers.
- 41 of the 55 verified active RTP offerings do not have any enrollment cap. 10 of the RTP offerings have enrollment caps based on a maximum number of subscribers allowed, enrollment for another 3 RTP offerings is capped based on a maximum aggregate monthly demand. Reasons for enrollment caps are speculative but may include utility interest in limiting unintended or unanticipated consequences for customers who may not be adequately positioned to modify usage accordingly. The basis of the enrollment cap for the remaining RTP offering is unspecified.
- 44 of the 55 verified active RTP offerings are established tariffs while 11 are in the pilot or experimental phase. Many of the latter have been in this phase for multiple years as customer programmatic experience, bill impacts and load shaping impacts are assessed.

<u>Insights from Utility Interviews</u>

- RTP plans remain the exception rather than rule as a pricing option, even among larger commercial and industrial (C&I) customers for whom RTP has been a long-held option. Based on interviews with utility rate professionals, only 2% of customers eligible for RTP are actually enrolled in an RTP plan.
- Most (80%) of the RTP programs discussed are opt-in with a few default/opt-out for larger commercial and industrial customers who do not shop for an alternate service provider.
- Participation in RTP programs among the utilities interviewed is relatively low – anywhere from 0 to an estimated 13% of eligible customers are enrolled in RTP with an average of 4.7% and a median of 2% participation.

- No real growth nor decline in RTP subscription since programs were introduced and initially subscribed.
- The impetus for most utilities' RTP offerings was either: (a) compliance with a regulatory order (actual or anticipated), or (b) preparation for, or response to, retail competition.
- Many utilities do not regularly monitor the price responsiveness of their customers on RTP because there is negligible impact on overall load, possibly due to a lack of price volatility in recent years.
- Several utilities mentioned significant investment in modifying or replacing metering, billing and other systems was necessary to accommodate RTP.
- All but one of the RTP programs discussed with utility representatives are currently active and considered "open for enrollment", yet most RTP programs for large commercial and industrial customers do not have high market penetration.
- The majority of utilities are either indifferent to their RTP offerings or think that their program needs improvement.
- Most utilities review RTP in preparation for their regular rate cases, but few have made or plan to make any significant programmatic changes at this time and none have formal sunset dates.
- RTP is a "niche product" for large commercial and industrial customers who are able to manage their usage on a meaningful scale, according to several interviewees. High load factor was indicated as a typical attribute of customers on RTP…
- Customers on RTP generally express high satisfaction to their utility account managers.
- Only a few utilities have plans or see any likelihood to offer RTP to other customer classes in the future, e.g., in lieu of or in addition to TOU electricity pricing for residential customers.
- Marketing to residential customers requires significant investment to increase market penetration that would still be relatively low.
- A concerted effort is required to help customers understand why RTP is different from their current service, what is required to benefit and how to associate a cost to those actions, and the risks associated with subscription.

<u>RTP Price Response</u>

- Low price response was found. Of secondary research available, elasticity estimates varied from zero (RTP prices had no effect on electricity usage) to over 0.58, an outlier as no other value above .30 was reported and only two others were above 0.20.[1] Most were under 0.10 and the majority under 0.05, especially those involving residences.
- Higher elasticities were reported for some customer circumstances, for example government and educational facilities, electricity intensive facilities like arc furnaces and refineries, and when the RTP

[1] Elasticities are measured as ratios of changes which means that only the price ratio effects consumption. An elastic value of 0.20 means that a 100% change in the price ratio produces a 20% change in usage ratio.

design allows for day-ahead prices to be revised within day, particularly to post much higher prices to reflect supply conditions not anticipated the day before.

RTP Design

- Designing an RTP service involves numerous sequential, data-driven decisions. This requires acquiring, in many cases, detailed-level data about the physical nature of how the electric system is designed and dispatched. A screening process using high-level characterizations allows making some of the higher-level design decisions to reduce the analytical requirements a final design requires.
- Little research has been conducted specifically to answer the question of preferences for pricing intervals and posting. If the intent is to design an RTP service that has expansive subscription preference research maybe required to understand what design or designs to offer.
- In organized markets (ISOs/RTOs) there are still questions when prices posted are provisional or final, and what marginal energy and outage cost to use.

WHY THIS MATTERS

This study provides a comprehensive understanding of utility RTP experience, benchmarking performance and lessons learned from those implementations. It also provides a framework to inform the design of dynamic pricing and RTP plans to meet the needs of distinct customer classes. As such, it can serve as a resource reference and primer for RTP plan design.

HOW TO APPLY RESULTS

This study can help utilities determine the appropriateness of developing RTP plans and inform the design of RTP plans with attributes aligned with utility objective and suitable for particular classes of customers.

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PROGRAM: Customer Insights (Program 182)

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1 INTRODUCTION

Study Objectives

This study sought to classify the ecosystem of time-varying pricing constructs, inclusive of dynamic pricing and time-of-use (TOU) structures and their derivatives, into a logical and applicable taxonomy. It also advanced a conceptual foundation to ascribe “building block” attributes of dynamic pricing plans. The project conducted a comprehensive review of the universe of real time pricing (RTP) plans that have been offered by regulated utilities across the U.S. This was based on documented RTP studies by Lawrence Berkeley National Labs (LBNL) and annual survey data collected by the Energy Information Association (EIA). Due diligence was then conducted on identified RTP plans to (a) verify their accurate classification as RTP plans, and (b) document structural attributes for sub-classification. As a further step, interviews were conducted with rate managers from selected utilities across the country with experience in RTP to better understand the motivations for developing the plans, customer uptake and persistence in the plans, customer satisfaction, and load shaping results. A review of price elasticity studies conducted for RTP programs provide another perspective on the success of RTP programs.

Finally, the project provided a conceptual illustration of designing an RTP plan to integrate into a utility pricing portfolio.

Background

The design of electricity pricing plans, often simply referred to as “rate design”, affects how and when customers use electricity, which is inextricably linked to numerous policy goals such as:

- encouraging less consumption (i.e. conservation)
- promoting more efficient consumption (i.e. purchase and use of energy-efficient devices)
- increasing electrification to promote decarbonization (i.e. emissions reductions) and economic growth
- stimulating and sustaining local on-site generation (i.e. to promote energy diversity and sustainability)

At the same time, electricity providers and regulators recognize that customers are increasingly seeking choices among electricity pricing plans that are understandable and differentiable. Customers expect the information to select the most suitable pricing plan. Accommodating these interests makes it challenging to structure and design pricing plans.

A modernized electricity grid enables suppliers to offer dynamic pricing in ways that previously were difficult if not impossible to achieve. Advances in system dispatch, that include recognizing transmission and distribution congestion, allow electricity providers to set market-clearing prices with spatial and temporal granularity. Advanced metering technologies (AMI) enable the quick and accurate measurement of electricity consumption over very short time periods, with readings available to both customers and system operators. Finally, a considerable and growing body of experience is available from pilots and large-scale implementation of dynamic pricing services to guide utility planners and designers of pricing services. This experience can help inform an appropriate balance between highly dynamic pricing and hedging against the risks of price volatility (hedged services) to align short-term and long-term supply conditions with customers' ability and inclination to manage their electricity consumption.

These changes in how electricity is supplied and delivered, including customer-sited generation, open up the opportunity for dynamic pricing plans to become an important part of a diverse portfolio of electric service offerings. Realizing the environmental benefits attributable to many electrification opportunities, like electric vehicles and heat pumps, requires sending consumers price signals that reflect prevailing system conditions. Accordingly, it is prudent to align rate design with these needs and opportunities to best serve customers and meet both utility and societal goals going forward.

Diversifying electricity service offerings requires comparing and contrasting alternative pricing structures to ascertain how they contribute to the performance of a portfolio of electric service offerings. Portfolio optimization requires establishing strategic and tactical goals and measuring how pricing structures contribute to the portfolio, how demand elasticity is altered and impacts on electricity supply.

In addition, the industry-wide practice of adopting unique names for these pricing plans often makes it difficult to understand their structure and intended purposes. Examples of electricity pricing naming jargon include:

- Locational Marginal Pricing (LMP)
- Real-time Pricing (RTP)
- Hourly Integrated Pricing Program (HIPP)
- Contracts for Differences (CFDs)
- 2-Part Real Time Pricing (2-Part RTP)
- Voluntary Interruptible Pricing Program (VIPP)
- Peak Time Rebate (PTR)
- Critical Peak Pricing (CPP)
- Optional Binding Mandatory Curtailment (OBMC)
- Interruptible/Curtailable Pricing (I/C)
- Variable Price Interruptible (VPI)

In this report, EPRI defines a systematic process to determine tradeoffs among electricity pricing plan structural features. It includes a categorization structure with consistent semantics that can foster meaningful dialogue and debate and is intended to make the process of comparing different design attributes more transparent with respect to policy goals.

This remainder of this report is structured as follows:

Chapter 2: Anatomy of Electricity Pricing Structures

Chapter 3: Real-time Pricing Design Attributes and Review of Utility Experience

Chapter 4: Synopsis of Utility and Stakeholder Interviews on RTP Experience

Chapter 5: Estimates of Price Elasticity of Electricity Demand

Chapter 6: Illustration of Integrating RTP into an Electric Service Portfolio

2 ANATOMY OF ELECTRICITY PRICING STRUCTURES

Section Summary

Introduction

This section provides background and general context for how electricity pricing plans are structured, inclusive of dynamic and real-time pricing constructs. It describes a rate categorization schema that includes a taxonomy for understanding the basic building blocks of rate structures:

- Energy flow (kWh) based on time-of-use or volume of consumption
- Demand (kW)
- Fixed charges

Subcategories within each block are defined and described. Special attention is devoted to time-varying pricing constructs, particularly the distinction between one-part and two-part Real Time Pricing (RTP) plans.

Key Findings

While time-varying rates in general differ based on how energy flows during time of day, and usually seasonally, dynamic pricing structures reflect market conditions by introducing the element of price volatility and can also include exposure to marginal electricity costs from wholesale generation markets. Dynamic pricing differs from conventional retail time of use (TOU) tariffs which are based on prices that are fixed for months or years at a time to reflect average, embedded supply costs. Dynamic pricing rates include temperature triggered offerings such as critical peak pricing (CPP).

RTP is a variant of dynamic pricing and is a retail rate in which the price for electricity fluctuates hourly, and sometimes sub-hourly, reflecting changes in the wholesale price of electricity and is typically known to customers on a day-ahead or hour-ahead basis. Despite the “real-time” naming convention, the retail rate is distinguished from wholesale prices that may be transmitted from day-ahead (DA) or hour-ahead (HA) markets, in addition to more granular sub-hourly wholesale markets such as the California A Independent System Operator (CAISO) Fifteen Minute Market (FFM) or five-minute Real Time Market (RTM).

There are two main types of real-time pricing (RTP) constructs:

- A “one-part” RTP includes a markup to the posted hourly energy price ($/kWh) to recover fixed costs of electric service, assesses a demand charge, or both. In either case the usage price is not equal to marginal supply cost [2]
- A “two-part” RTP recovers costs for a subscription level of usage through a fixed monthly access charge separate from the hourly energy price. The customer subscribes to a fixed daily load shape called customer baseline load (CBL) which is charged at the customer’s other applicable rate to calculate the monthly access charge. Energy charges are then calculated by multiplying the difference between the CBL and the customer’s actual metered energy use for each hour by the prevailing hourly RTP price, which reflects the system’s hourly marginal cost of supply. If the actual energy use for a given hour is greater than the CBL, then the additional usage multiped by the hourly price is added to the customer bill. Conversely, if the actual energy use for a given hour is less than the CBL, then the reduced usage multiplied by the hourly price is deducted from the customer bill.

Schema for Categorizing Rate Structures

Electric rate structures are often difficult to understand because they can contain provisions that result from a complex series of design tradeoffs. As a result, public dialogues about the relative merits of alternative structures can be daunting. A system or syntax is essential to using rate structures to achieve ever more complicated resource allocation objectives.

A comprehensive system for characterizing pricing plans and services begins by constructing a framework that defines the basic building blocks that measure use of the electric system. Additional structural elements further define and refine how prices influence electricity consumption, allow for customization for particular supply situations, and adapt to customers’ willingness to accept various degrees of price variation.

What follows is an attribute-based means for characterizing and comparing different pricing structures. Such a system provides an orderly arrangement and common basis for characterizing rates by how they affect electricity demand. Moreover, it can serve as the foundation for the development of a portfolio of pricing structures that accommodates diverse consumer needs in ways that improve the utilization of available supply resources.

To help utility planners determine how to augment their electric service plan (ESP) portfolio to achieve a specific strategic goal, a pricing structure categorization schema can be employed. The schema summarized herein is intended to facilitate the development of a utility’s strategic portfolio of retail pricing offerings to fulfill service responsibilities and achieve strategic enterprise goals.

The schema illustrated in Figure 2-1 begins with three structural building blocks that sort pricing attributes into groups that have common elements that effect how prices are set and how electricity demand is influenced. The distinguishers are how the flow and stock of power is

[2] A separate demand charge may also be assessed to cover fixed costs.

measured and the assessment of fixed (i.e., usage-independent) system connection charges. Subcategories under each building block further refine the pricing structure to reflect specific spatial and temporal differences in the cost of electric supply that may influence electricity demand.

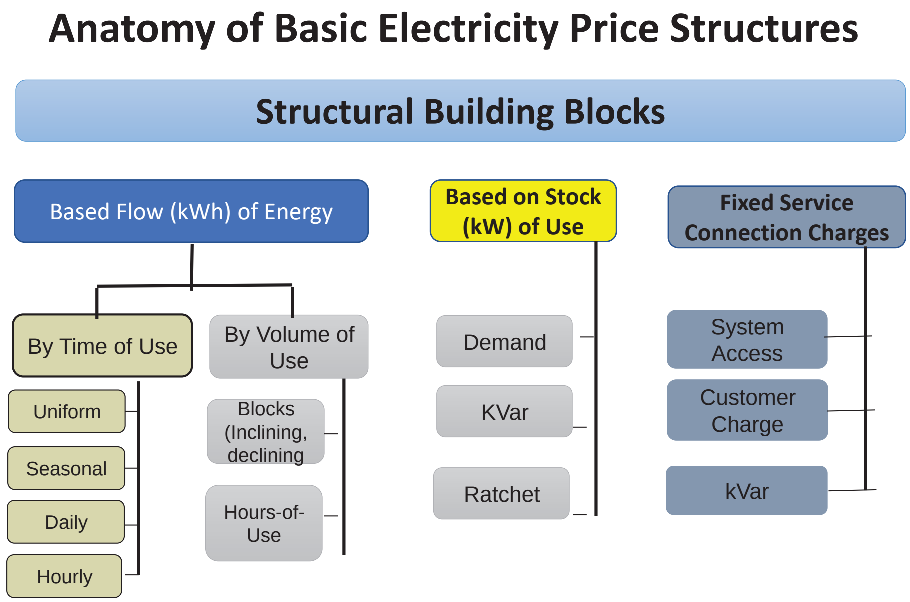

Figure 2-1
Structural Building Blocks of Electricity Pricing

This categorization schema, with sequential screening, can help system planners, customer advocates, rate designers and administrators determine how best to achieve strategic goals and fulfill service obligations. Each pricing structure is described in terms of what elements of service are measured and billed to reflect power supply costs, along with expected effect on demand. What follows are high-level descriptions of the structural building blocks of electricity pricing illustrated in Figure 2-1**Error! Reference source not found.**.

Based on Flow of Energy

By Time of Use or Time Differentiated (Time-varying)

Retail prices for metered energy usage can vary from time-insensitive to highly time-dependent.

- **Uniform**: No temporal variation in the usage price except potentially by season.
  - Time-invariant: Subset of uniform energy rate that features no temporal or spatial differentiation (e.g., $0.11/kWh). Generally, that rate is fixed for an extended period, i.e. a year or more. Adjustments in the nominal rate made be made routinely (monthly or quarterly) to account for changes in fuel supply costs.
  - Seasonal: A uniform rate that varies across months of the year, typically by season, to reflect important differences in the level of electricity usage and the associated cost of supply. For example, $0.08 in spring and fall and $0.15 in summer and winter.

- **Daily rate schedule (TOU)**: A price schedule that distinguishes the energy price among groups of hours of the day, most often between peak hours (usually afternoon hours) and off-peak hours (the rest of the day) that reflect system power demand and therefore warrant a price difference based on the cost of supply. Usually all weekend hours are designated as off-peak. Some rates employ three daily periods, adding a shoulder. peak period to reflect how supply cost ramp up and down in the morning and evening hours resulting in step-up and step-down price profile. Another design option is for the TOU prices to vary across seasons, for example between summer and winter months (including different peak definitions, different period prices, or both) and some months may be priced under a uniform rate (fall and spring, perhaps), a hybrid uniform and TOU rate.

- **Hourly price schedule**: Two basic variations of hourly pricing (i.e. real-time pricing or "RTP") can be used to vary the cost of electricity hourly to track variable supply costs. In both cases, hourly prices can be posted on a day-ahead schedule basis or in real time at hourly or sub-hourly intervals.

    - RTP – One Part: The hourly energy price ($/kWh) posted is applied to all metered usage and includes a markup to recover fixed costs of electric service, including capacity costs.

    - RTP – Two Part: Recovers fixed costs through an access charge separate from the hourly energy price. The customer essentially subscribes to a specific daily load shape called customer baseline load (CBL) for a fixed monthly charge. Energy charges are calculated by multiplying the difference between the CBL and the customer's actual metered energy use each hour by the prevailing hourly RTP price, which reflects the system's hourly marginal cost of supply. If the actual energy use for a given hour is greater than the CBL, then the additional usage is added to the customer bill. Conversely, if the actual energy use for a given hour is less than the CBL, then the reduced usage is deducted from the customer bill.

By Volume of Use

- **Blocks (inclining or declining):** The rate charged for metered usage depends on the metered volume of kWh usage. In a two-block structure, the first block used (e.g., the first 400 kWh) in the billing period is charged one rate and the subsequent block a higher (inclining block) or lower (declining block) energy rate ($/kWh). The number of blocks is a design choice.

- **Hours of Use (HOU):** A load-factor rate that employs metered demand to determine how to sort billing period metered kWh usage into blocks with different energy prices (i.e. a "block rate").

Based on Stock of Use

Customers are charged for the stock of power (i.e. capacity) they utilize, measured as maximum demand (kW).

- **Demand**: A charge for the capacity that the customer uses in the billing period, measured by the metered maximum demand (kW) as a means for collecting that cost to build and operate the system that is designed to meet maximum power demand. Demand can be measured as:

    - Coincident demand. The highest measured kW usage in hours designed as the peak period for the system (e.g. weekday noon to 9:00 pm).
    - Non-coincident demand. The highest measured kW usage in any hour of the month.

- **Reactive power**: Measures a customer's usage of power that deviates in wave form from a power quality standard (e.g., kVA lag) by separately metering and charging for reactive demand usage below that standard. Usually only deviations below the reactive power standard are charged.

Fixed Service Connection Charges

These refer to billing charges not based on measured power usage. In principle, they can be used with any of the basic structures described above, although in practice some are only used for certain rate classes.

- **Customer charge**: A monthly charge to collect some of the fixed cost of service, conventionally costs associated with connecting the customer to the grid and administrative and general costs, like billing and customer service.
- **System access (subscription) charge**: However, some argue that the proper rate design collects all fixed costs (capacity, delivery, customer and general administration) through a system access charge and energy costs through the variable energy rate (when demand is not separately metered and charged for). The energy rate structure can be any of those described previously. A variation is where a demand charge collects some fixed cost (generation capacity, for example) so the access charge collects only the other fixed costs, another Stock/Flow hybrid with many possible variations.

These charges are used to modify one or more measured billable elements to achieve specific modifications of electric demand, or to tailor a service to exact customer and supply specifications, or to collect costs that are difficult to forecast because of their inherent variability.

Finally, another subcategory includes price inducements, feedback and information to help customers alter their usage to their benefit, and system restoration information to reduce the inconvenience of power outages.

Dynamic Pricing and Real Time Pricing

While time-varying rates differ based on time of day, and usually seasonally, Dynamic Pricing structures reflect market conditions by introducing the element of price volatility and can include exposure to marginal electricity costs from wholesale generation markets. Dynamic Pricing differs from conventional retail tariffs which are based on prices that are fixed for months or years at a time to reflect average, embedded supply costs. Dynamic Pricing rates include temperature triggered offerings such as Critical Peak Pricing.

A variant of Dynamic pricing is RTP, which, stealing from the definition of the Federal Energy Regulatory Commission,[3] is a retail rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity and is typically known to customers on a day-ahead or hour-ahead basis. Despite the “real-time” naming convention, the retail rate is distinguished from wholesale prices in that wholesale prices may be forecasted and transmitted from either day-ahead (DA) or hour-ahead (HA), and can be more granular that the rate for retail customers (e.g., hourly or sub-hourly).

RTP Plans Included in this Study

RTP Plans included in this study are defined as follows:

1. A full requirements electricity service
2. Offered by a regulated utility
3. Energy usage prices ($/kWh) are set for blocks of hours, hourly or for shorter periods (e.g. 15-minute intervals)
4. Prices are posted to subscribers a day or less in advance of their effective time
5. Prices apply for every day of the week throughout the year (rather than solely during events for selected days or hours of the year, which characterize critical peak pricing or variable peak pricing)
6. Posted prices apply to metered kWh usage corresponding to the pricing interval
7. Posted prices reflect the contemporary marginal cost of electricity supply

“Full requirements” means that the RTP service plan applies to all energy usage at the customer’s facility, rather than just for selected end-uses (e.g. electric vehicle charging) that are separately metered. For the purpose of this study, benchmarking was limited to full requirements services offered to customers as an alternative to their incumbent electricity tariff. RTP services offered only to a specific individually-metered end use (e.g. electric vehicle charging) were not included.[4]

The second distinction is invoked to focus the study’s benchmarking to services whose provisions and features are readily ascertained by reviewing regulatory approved tariffs. The details of RTP services offered by competitive energy suppliers in states with customer choice are difficult to obtain and are subject to frequent change.

Establishing the frequency of pricing change eliminates from consideration dynamic pricing programs offered by RTOs such as price-cap load bidding and demand response programs

3 https://www.ferc.gov/sites/default/files/2020-06/2008-glossary.pdf

4 Full requirements might be less that the total facility usage if the customer has on-site generation, but would be considered full requirement serve for this study as would cases where the facility uses power for only one purpose, like irrigation and pipeline stations which are eligible for RTP in some utilities.

available to retail customers directly or through a utility or competitive supplier.[5] RTP services offered in vertically integrated markets are included.

The remaining characteristics distinguish RTP from other utility dynamic pricing structures like variable peak pricing, critical peak pricing, and load curtailment programs because RTP sets a price for every hour based on prevailing or expected market conditions and the corresponding marginal supply cost. The others are event driven terms of service changes where customers otherwise served on a less dynamic tariff are exposed to large price changes as penalties or incentives. The motivation for employing RTP in electricity markets is to induce customers to alter their usage based on the prevailing marginal cost and the value of electricity consumption at that time.

Chapter 3 provides further detail on RTP design and the results of EPRI's benchmarking study of U.S. regulated utility RTP offerings.

[5] Price Cap Load Bidding allows end-use customers to submit a buy price to the day ahead wholesale market (or stepped series of paired price and quantities) to the day-ahead RTP market and bid load that clears at the market hourly price it is treated as a firm purchase, deviations from which are settled in the real-time market. Demand response program are event-triggered payments for recuing load or elevated prices to purchase power that may be in the form of a non-compliance penalty.

3
REAL-TIME PRICING DESIGN ATTRIBUTES AND REVIEW OF UTILITY EXPERIENCE

Section Summary

Introduction

This section defines and describes key design features for RTP plans which determine how prices are set, what services are measured, and the corresponding range of usage levels.[6] This framework clarifies distinctions in designing an RTP program based on foundational EPRI works on the subject.[7] Chapter 6 provides more expansive distinctions between electricity pricing structures and attribute levels to help characterize RTP programs and construct and analyze alternative designs.

This section uses this framework to characterize and categorize 55 verified active real-time pricing (RTP) offerings implemented by 41 regulated U.S. electric utilities in 21 states, based on a detailed review of tariff sheets and additional information gathered through interviews discussed in more detail in Chapter 4.

Key Findings

1. EPRI identified an initial universe of 97 retail electricity providers in the U.S. that were cited in prior published sources as having RTP plans. EPRI was able to verify that 41 regulated utilities collectively have 55 active RTP offerings.

   Offerings from unregulated competitive retailers who are not required to file tariffs with state regulatory commissions could not be validated or verified through the due diligence process and were therefore excluded from further consideration. Similar exclusions applied to municipalities, cooperatives, and public power entities without verifiable tariff sheets. Among regulated utilities, the project team determined that some offerings are either misclassified as RTP or simply could not be verified as RTP based on the tariff sheets. In some cases, investigation of tariff sheets revealed that some offerings classified as RTP are actually other dynamic pricing variants, such as critical peak pricing (CPP) or peak time rebate (PTR), and therefore misclassified as RTP.

2. The most common type of RTP program features hourly pricing based on regional wholesale energy market postings (RTOs/ISOs), with day-ahead notification targeted to commercial

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[6] The attributes and levels described herein are not exhaustive; other attributes can be added, and attribute levels can have finer gradation.

[7] EPRI. Quantifying the Impacts of Time-Based Rates, Enabling Technology, and Other Treatments in Consumer Behavior Studies: Protocols and Guidelines. Palo Alto, CA. 2013.

and industrial (C&I) customers with a minimum demand eligibility and no intra-territory spatial differentiation.

- Only 2 of the 55 verified active RTP plans are available to residential customers with the remaining 53 offerings available to only to non-residential customers, typically targeted to distinct customer commercial, industrial and agricultural customer classes on the basis of such metrics such as peak demand.
- 50 of the 55 active RTP offerings (91%) feature hourly pricing granularity and 43 of those feature day-ahead notification. Only 2 RTP plans offer sub-hourly pricing; 3 plans assign varying rates to blocks of hours, rather than hourly.
- 7 plans feature pre-determined sets of prices, whether hourly or by blocks of hours, based on pre-defined day-types selected based on day-ahead temperature forecasts.
- Only 4 of the 55 verified active RTP offerings feature spatial price differentiation within the service territory, meaning pricing differs based on the customer’s spatial location on the utility system; the remaining 51 plans provide the same pricing levels irrespective of the customer’s spatial location on the utility system.
- 35 of the 55 verified active RTP offerings have hourly energy prices based on regional wholesale energy market price postings (RTOs /ISOs); 11 RTP offerings base their hourly prices on supplier forecasts, while the remaining 9 have a pre-set pricing schedule based on hours or blocks of hours.

3. Nearly one-third of the verified active RTP offerings (18 of 55) employ a customer baseline load (CBL) as a basis for RTP structure, with the time-varying pricing applying only to hourly consumption above (bill increase) or below (bill decrease) the customer’s established CBL.
4. 23 of the 55 verified active RTP offerings employ a pricing structure based on marginal energy price and metered demand; 5 RTP offerings roll all cost recovery into the energy price.
5. 21 of the 55 verified active RTP offerings explicitly have some form of price protection mechanism in the tariff to hedge customer price risk, including the 18 with a CBL structure.
6. 41 of the 55 verified active RTP offerings do not have any enrollment cap; 10 have enrollment caps based on a maximum number of subscribers while 3 are based on a maximum aggregate demand.
7. 51 of the 55 verified active RTP plans are currently open for enrollment; the remaining 4 are only open to existing subscribers and therefore closed to new subscribers.
8. 44 of the 55 verified active RTP offerings are established tariffs while 11 are in the pilot or experimental phase. Many of the latter have been in this phase for multiple years as customer programmatic experience, bill impacts and load shaping impacts are assessed.
9. The most predominant eligibility factor is customer size, as measured by either minimum monthly peak demand. 35 of the 55 verified active RTP offerings are available to non-

residential customers with a peak demand greater than 100 kW; 15 of those require a minimum demand greater than 1 MW.

RTP Pricing Design Features

The following design features have been established to characterize RTP offerings, and are described further in the remainder of this chapter:

Table 3-1
Key Design Features for RTP Plans

Key Design Features for RTP Plans	
1. Availability and Maturity	7. Price Overcall of Posted Day-Ahead Prices
2. Eligibility	8. Entry Price Formation
3. Pricing Structure	9. Capacity Pricing (Gen., Trans. & Dist.)
4. Temporal Price Granularity	10. Marginal Cost Uplift
5. Spatial Price Granularity	11. Contract Term
6. Price Posting Notification	12. Hedging and Risk Management

Review of US Utility RTP Programs[8]

EPRI conducted a comprehensive review of the universe of RTP plans that have been offered by utilities across the U.S. The project team developed an initial master list of 97 distinct retail electricity providers in the U.S. understood to either currently offer, or have once offered, an RTP plan to at least one class of customer. This list was compiled from a combination of sources, principally a 2004 study on RTP programs by Lawrence Berkeley National Laboratory (LBNL)[9] and listings of RTP plans compiled by the U.S. Energy Information Administration (EIA)[10] in 2015 and 2019 as self-identified by utility filings.

Due diligence was then conducted on this universe of identified retail electricity providers to: (a) resolving listings and track changes in utility names and ownerships through mergers, acquisitions, and consolidations; (b) verify accurate classifications of RTP offerings and (c) document structural attributes for sub-classification. This involved researching utility tariff sheets to determine whether RTP offerings were actually present. Offerings from unregulated competitive retailers who are not required to file tariffs with state regulatory commissions could not be validated or verified

[8] The focus of this review was utility RTP programs. This study did not attempt to identify or evaluate RTP offerings from suppliers in competitive electricity markets.

[9] Lawrence Berkeley National Laboratory. “Customer Response to Day-ahead Wholesale Market Electricity Prices: Case Study of RTP Program Experience in New York”, C. Goldman and B. Neenan, (July 1, 2004). Paper LBNL-54761. http://repositories.cdlib.org/lbnl/LBNL-54761

[10] Cite

through the due diligence process and were therefore excluded from further consideration. Similar exclusions applied to municipalities, cooperatives and public power entities without verifiable tariff sheets.

Among regulated U.S. utilities, the project team determined that some offerings are either misclassified as RTP or simply could not be verified as RTP based on the tariff sheets. In some cases, investigation of tariff sheets revealed that some offerings classified as RTP are actually other dynamic pricing variants, such as critical peak pricing (CPP) or peak time rebate (PTR), and therefore misclassified as RTP. Finally, the project team excluded RTP offerings that have been closed or superseding, focusing only on regulated U.S. utilities with active RTP offerings. The project team was ultimately able to verify that 41 regulated utilities in the U.S. collectively have 55 active RTP offerings. A visual summary of the screening process is illustrated in Figure 3-1

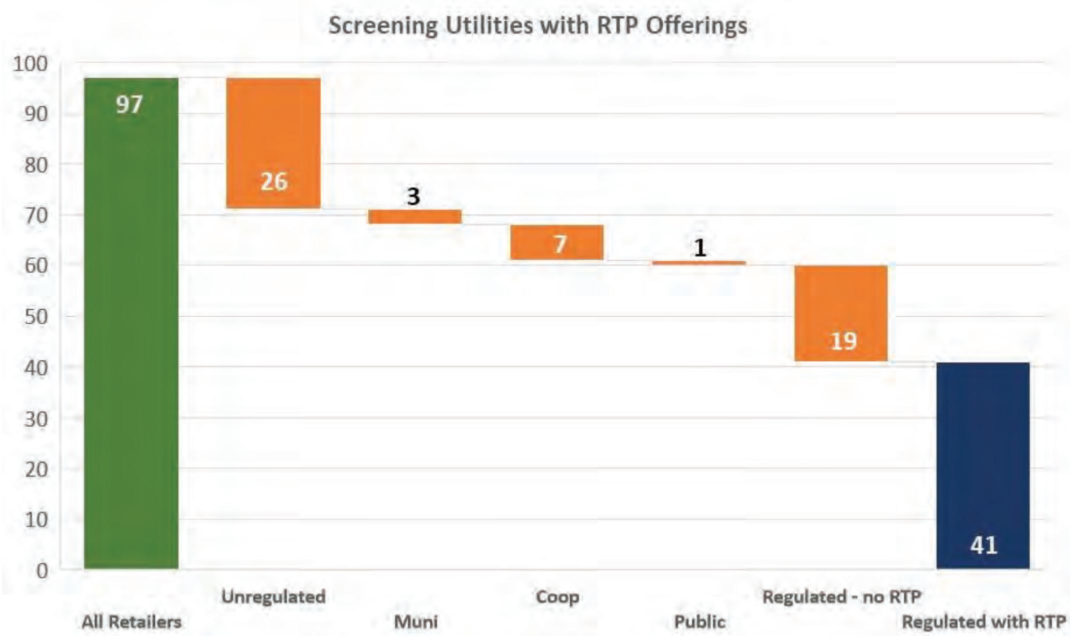

Figure 3-1
Screening of U.S. Utilities with RTP Offerings

As a further step, the team conducted 16 interviews with a total of 24 individuals collectively representing 19 distinct utility jurisdictions with a total of 24 RTP programs to better understand the motivations for developing the plans, customer uptake and persistence in the plans, customer satisfaction, and load shaping results. Participating utilities/stakeholders included current and former utility executives, program managers and consultants. These interviews are summarized in Chapter 4 - Synopsis of Utility and Stakeholder Interview on RTP Experience.

1. Availability and Maturity

A primary consideration is whether an RTP service will be available to a specific population to discover, through experience, customer subscription, persistence, and load and bill impacts. There are two basic options for making a service plan available to customers:

- Open enrollment – service is available to all eligible customers. Explanatory material should explain ways that customers could benefit from the rate so that customers can assess its potential benefits and risks.
- Capped Enrollment – service is available to all eligible customers, but enrollment is capped by either a limited number of participants or maximum amount of aggregate peak demand. This can serve the utility by keeping the participant pool manageable for an initial trial and can dually provide an incentive for customers to participate in an exclusive beneficial service before the opportunity expires.

Availability Findings

The vast majority of verified active RTP offerings (51 of 55) are currently open for enrollment, with 4 limited to existing subscribers and therefore closed to new subscribers.

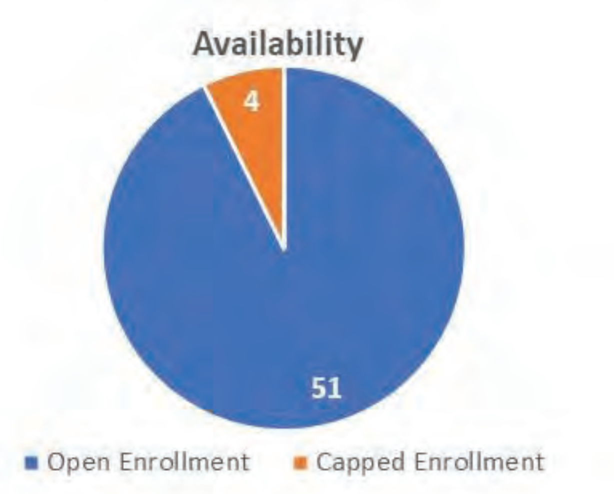

Figure 3-2
Availability of Verified Utility RTP Plans

In a similar vein, a related operational decision is whether to roll out an RTP service initially as an experiment or pilot versus a full-fledged tariff program. This can be referred to as the *maturity* of the offering.

In a pricing experiment, candidates are selected from the population of eligible customers and recruited to participate either in a controlled or self-selected manner. In a controlled experiment, selected participants are sorted randomly into control and treatment groups, with treatments required to enroll, and controls not allowed to enroll. Alternatively, in a self-selection experiment any of those customers randomly selected to participate has the freedom to enroll.

A limited or targeted pilot is similar to an experiment but at a larger scale with subscription either targeted to specific customer classes, to customers of specified circumstances or those considered to be best candidates. Pilots often employ targeted subscription to confirm expectations for those anticipated to find value in the service to verify their price responsiveness. These results are not generally attributable to the larger population of customers, but rather just to those who are similar to the pilot participants.

By contrast, a full-fledged tariffed service plan, whether RTP or otherwise, is open to all eligible customers and implies conformance with *revenue neutrality*, meaning that the subscriber would pay the same under the new plan as under the incumbent tariff if energy consumption patterns remained unchanged. This intends to prevent cross-subsidization that results from subscribers realizing reduced power costs without responding to hourly prices. As such, tariffed service plans undergo considerable scrutiny within a utility rates departments, utility executive management and regulatory commissions.

Maturity Findings

44 of the 55 verified active RTP offerings are established, permanent service tariffs while 11 are in the pilot or experimental phase. Many of the latter have been in this phase for multiple years as customer programmatic experience, bill impacts and load shaping impacts are assessed.

Figure 3-3
Maturity Status of Verified RTP Plans

Enrollment Cap Findings

The vast majority (41 of 55) of verified active RTP offerings do not have any enrollment cap. While Figure 3-2 shows that only 4 active utility RTP offerings are currently capped to new subscribers, a total of 14 RTP offerings are subject to some enrollment cap. 3 RTP offerings are capped based on a maximum aggregate demand under subscription; 9 are capped by a maximum number of customers who can be on the plan, including 1 RTP offering that exists solely for the use of an individual customer. The remaining RTP offering is capped on an unspecified basis. These findings are illustrated in Figure 3-4.

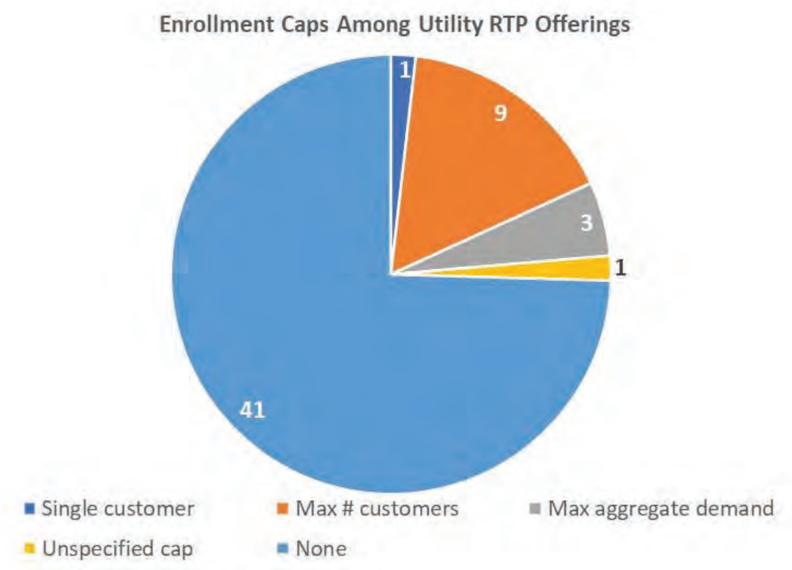

Figure 3-4
Enrollment Caps Among Verified Utility RTP Offerings

2. Eligibility

Eligibility is typically based on customer class, which is a function of customer segment and peak monthly demand. For example, a typical set of customer classes for a utility to distinguish rate option eligibility may include:

- Large Commercial & Industrial (C&I) customer (over 1 MW)
- Commercial and Light Industrial Customers (50 kW to 1 MW)
- Small Commercial Customers under 50 kW
- Residential

Eligibility Findings

Error! Reference source not found. Figure 3-5 below illustrates the distribution of verified active RTP offerings on the basis of customer eligibility criteria. They vary based on factors such as peak monthly demand, incumbent pricing plan and selected other factors.

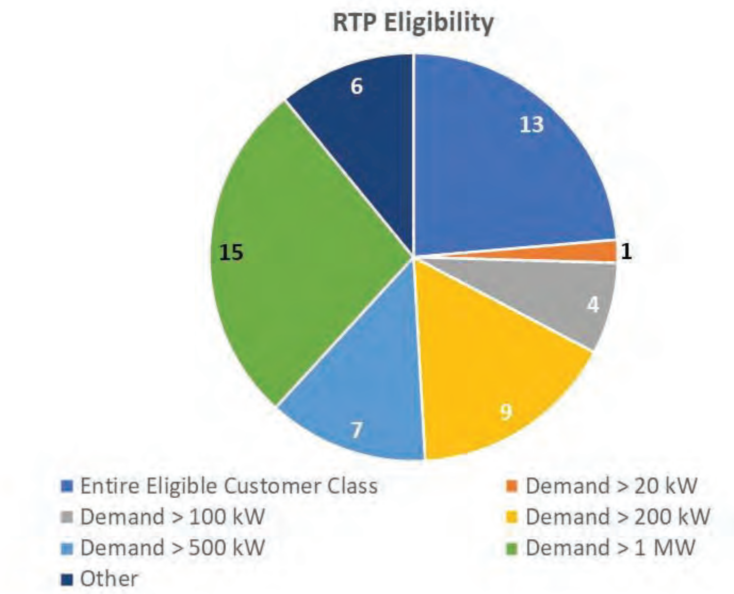

Figure 3-5
Customer Eligibility Criteria of Verified RTP Offerings

Customer eligibility for 35 RTP offerings is predicated on a minimum demand threshold of 100 kW, while 15 of those offerings have a minimum demand requirement of 1 MW. For 13 of the RTP offerings, all customers in the designated customer class are eligible. Eligibility for the remaining 13 RTP offerings is based on a variety of other factors, including medium- to high-voltage service, as defined by the utility. Only two RTP offerings are available for residential customers.

3. Pricing Structure

The most fundamental distinction in RTP design is pricing structure, which determines the extent to which prices align with forecasted marginal supply costs. It also distinguishes whether an RTP service is designed to be revenue-neutral for an individual customer or for an aggregated class or subclass of customers.

There are two main types of real-time pricing (RTP) constructs: “one-part” and “two-part”.

- A “one-part” RTP includes a markup to the posted hourly energy price ($/kWh) to recover fixed costs of electric service[11]. In other words, fixed cost recovery is bundled together with the hourly energy price.
- A “two-part” RTP recovers costs for a subscription level of usage through a fixed monthly access charge separate from the hourly energy price.

[11] A separate demand charge may also be assessed to cover fixed costs.

Customer Baseline Load (CBL)

For a two-part RTP construct, the customer subscribes to a fixed daily load shape called the customer baseline load (CBL), which is established prior to subscription based on the customer's historical usage adjusted for abnormalities to represent a customer's expected energy usage without RTP subscription. The CBL sets a baseline load for each hour of the year to which the customer commits for the duration of subscription.

Energy charges are calculated by multiplying the difference each hour between the customer's actual metered energy use and the CBL by the corresponding price for that hour, which reflects the system's hourly marginal cost of supply. If the actual energy use for a given hour is greater than the CBL, then the additional usage multiped by the hourly price is added (debited) to the customer bill. Conversely, if the actual energy use for a given hour is less than the CBL, then the reduced usage multiplied by the hourly price is deducted (credited) from the customer bill. The resulting cumulative amount for the month represents the billing energy charge.

For each billing period, the fixed access charge is calculated by pricing out the month's CBL at the customer's standard (i.e. "otherwise applicable") rate. The monthly access charge is not influenced by actual metered usage.

Because the CBL is subscriber-specific, in effect each subscriber pays its revenue requirements based on cost-of-service allocations and there is no cross-subsidization.

A CBL can be calculated in one of three basic ways: historic-based, self-selecting, and hybrid.

- Historic-based

  CBL is based on a subscriber's historic energy usage adjusted for abnormalities to represent typical load on the prior rate schedule. Some applications of this CBL configuration allow for changing the CBL over time to reflect permanent changes in usage, for example lowering the CBL to reflect energy efficiency investments that reduce the load potential or adding CBL for plant expansions or for residential electric vehicle charging.

- Self-selecting

  The subscriber selects the CBL level of energy usage for each hour, which can be less than, equal to, or greater than historic usage for any given hours. Typically historic usage is a starting point from which subscribers can adjust their CBL depending on their circumstances and expectations for RTP prices, if allowed under the tariff. Those anticipating lower prices might shed CBL and those expecting higher prices and load growth might add CBL, in effect hedging against price outcomes. The electricity provider may allow customers to adjust their CBL either at no charge or for a fee. In the latter case, the CBL might be sold or purchased at the original applicable rate or a hedging premium devised by the suppliers.

- Hybrid

  The CBL can be auctioned off in what amounts to a capacity purchase market or subscribers could be required to specify for each hour load blocks priced at declining prices. The subscriber would be informed of what was scheduled (i.e. blocks up to the market-clearing price) with the price locked in, with provision for settling overages in the next day, real-time market. This structure follows the Priority Service concept developed by Wilson and Chao (1987).

As it pertains to a two-part RTP structure, a CBL may remain unchanged throughout the term of subscription or may be renegotiated in some cases depending upon the terms and conditions of the service plan. Provisions to adjust CBL may cover such contingencies as the subscriber adopting energy efficiency measures that reduce energy usage, or undergoing a change in operations, such as an expansion of scope or shifts, that alters its energy usage profile. Some provisions allow for resetting the CBL each year by formulation, such as a prescribed percentage of the difference between the previous year's actual metered usage and the existing CBL, or seasonally adjusted based on historic load at a level selected by the subscriber.

Marginal Energy Price Only

In this structure, the energy price collects both the marginal energy cost and fixed costs, rather than the latter being collected through a demand charge or other fixed charge (although there may be a relatively small customer charge). Posted hourly energy prices apply to all hourly metered usage, with no charge assessed for metered demand. As a result, during hours when fixed costs are collected through an uplift to the $/kWh charge (which could be all hours or some hours, such as peak demand hours), the real time price exceeds the marginal supply costs and over-induces reducing electricity usage.

Marginal Energy Prices plus Demand Charge

The primary variation on the energy-only rate is the imposition of demand charge based on metered monthly demand or a ratcheted demand value. Another option is imposing a minimum bill for highly seasonal usage customers. Another variation is to charge customers for usage above the CBL but not for usage below it. This results in a subscription structure similar to telephone calling plans or internet services. It could be combined with a demand response program such as peak-time rebate, whereby payment for reduction from the CBL is only offered when an event is declared. The credit payment could post each event based on prevailing market prices (or rationing needs) or be chosen from a prearranged schedule of event prices. The result is a structure more closely related to CPP than RTP since prices for load curtailment are episodic rather that predictably systematic.

Pre-Set Prices

Some utility RTP plans establish pre-set hourly prices for specific seasonal day-types, as determined a day ahead based on weather- and/or demand- forecasts.

Pricing Structure Findings

As illustrated in Figure 3-6, 18 RTP offerings, representing nearly one-third of all verified active utility RTP offerings, employ a customer baseline load (CBL) as a basis for RTP structure. 23

utility RTP offerings employ a pricing structure based on marginal energy price plus a demand charge, while 5 RTP offerings roll all cost recovery into the hourly energy price.

Earlier utility implementations of RTP service predominantly employed two-part subscription-based CBL structures, i.e. subscription-based plans. By contrast, more recently developed RTP services tend to employ a one-part structure for dynamic energy charges with or without a separate demand charge.

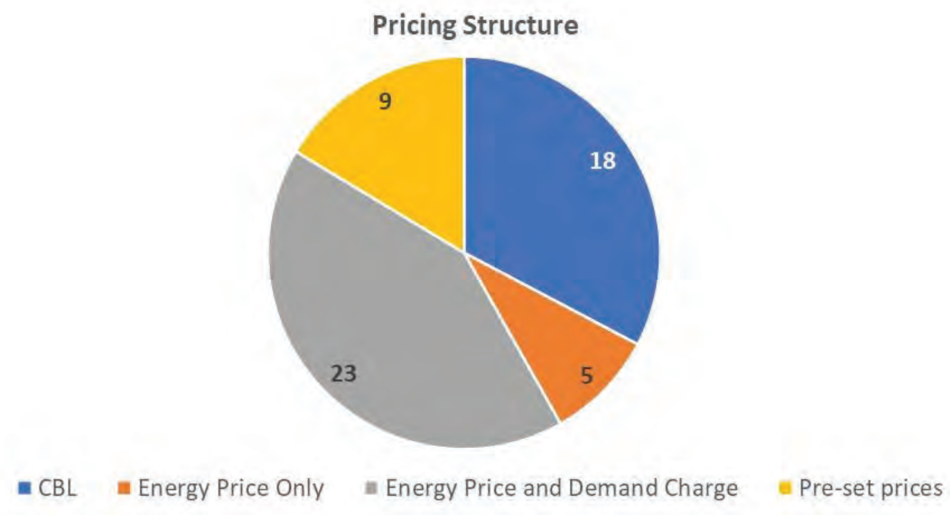

Figure 3-6
Pricing Structure of Verified RTP Offerings

Of the 18 verified utility RTP programs that utilize a CBL, i.e. two-part RTP structures, 14 of them include provisions to revise the CBL during the subscription term. 3 do not include any explicit provision, while the tariff sheet for the remaining offerings does not specify this point.

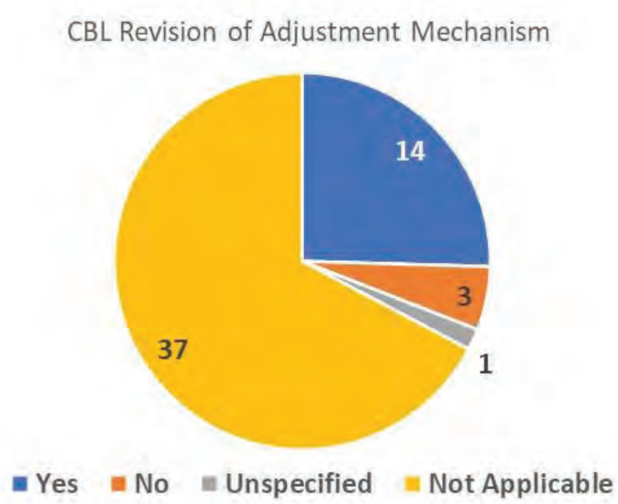

Figure 3-7
RTP Offerings by Ability to Revise CBL

4. Temporal Price Granularity

This attribute describes how often prices are reset. This not only affects how well actual supply prices are passed on to RTP subscribers but also customers' willingness to manage the resulting level of price volatility. RTP designers typically seek a balance between an efficient pricing and customer manageability and appeal.

Hourly

An energy price is set for each hour of each day. If the reference for supply prices is at a finer time granularity (for example ISO real time prices established every five minutes) then some form of averaging is required, either simple or weighted. Most retail RTP programs employ hourly prices.

Blocked Hours

To better balance design tradeoffs, hourly prices may be averaged over blocks of hours, for example creating six four-hour blocks with the price per block equal to the average of the hourly prices. Alternatively, the day could be divided between peak and non-peak hours with block prices representing the average of the constituent hours. RTP price blocking requires that the CBL in a two-part rate be correspondingly blocked. The blocks should be stipulated (like TOU distinctions) not customized or else the synchronizing of supply price and customer usage decision is undermined. Blocking could be offered as an alternative to an hourly CBL formulation

Sub-hourly

An energy price is set for each sub-hourly period of each hour of each day (e.g. 30-minute, 15-minute or even 5-minute). Very narrow pricing intervals such as 5-minute may require unconventional metering that would expand the requirement to collect and process usage data for billing.

Temporal Price Granularity Findings

50 of the 55 verified active RTP offerings (over 90%) employ hourly pricing granularity, as shown in Figure 3-8. 3 RTP offerings assign varying rates to blocks of hours, rather than hourly, while 2 RTP offering employs variable pricing at sub-hourly intervals.

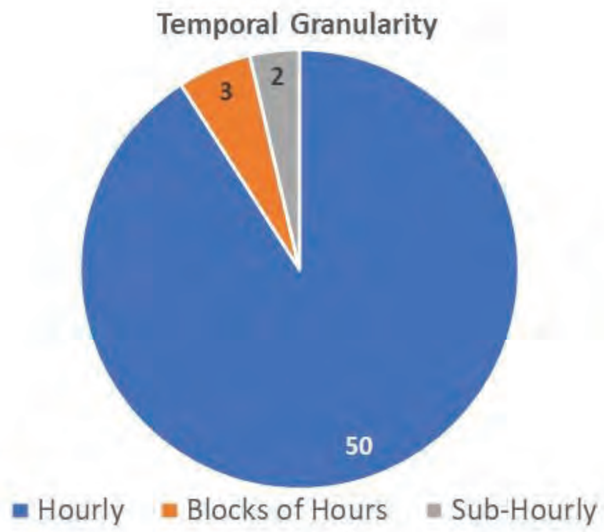

Figure 3-8
Temporal Price Granularity of Verified RTP Plans

In conjunction with the information presented in Figure 3-9 and Figure 3-10, the most common form of RTP plan is an hourly pricing structure with day-ahead pricing notification and no intra-territory spatial differentiation.

5. Spatial Pricing Granularity

Uniform and Universally Available

Prices are the same for all subscribers in the eligible customer class regardless of geographic location. However, there may be taxes or other uplift factors that are called or location-specific.

Spatially Differentiated

RTP may constructed with spatial differentiation to vary prices over defined areas to reflect differences in marginal supply cost because of local power congestion or other zonal distinctions. This differentiation may coincide with contiguous RTO pricing zones or similar distinctions made by the utility to reflect transmission congestion.

Spatial Price Granularity Findings

As show in Figure 3-9, 51 of the 55 verified active utility RTP plans have no spatial price differentiation within the service territory. In other words, all eligible customers under the RTP plan have the same hourly pricing levels irrespective of their spatial location on the utility system.

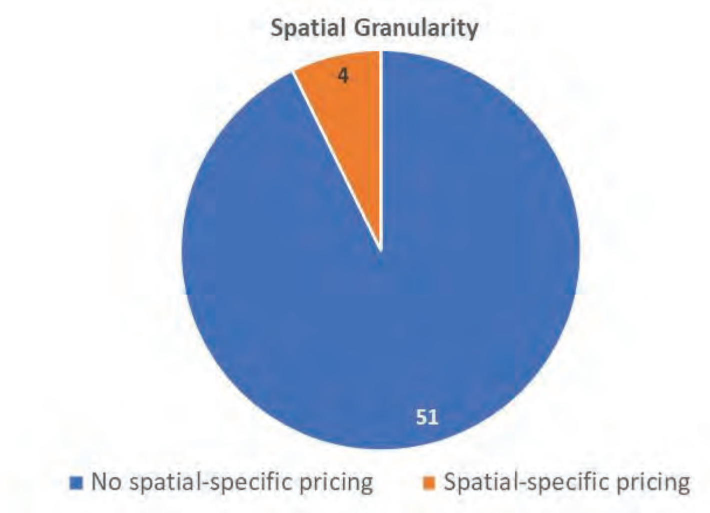

Figure 3-9
Spatial Price Granularity of Verified RTP Plans

6. Price Posting Notification

Close alignment of price formation and RTP price setting notification is required to promote efficiency. Day-ahead RTP posting of the next day's hourly prices requires forecasting the next day's supply conditions, which is standard practice among U.S. utilities, and ISO markets post wholesale closing prices for the day-ahead market. Both are available in the early afternoon and can be sent to RTP subscribers almost instantaneously so they can plan the next day's power usage accordingly.

Day-ahead

Final usage prices ($/kWh) for hours to which they apply are posted, usually for utility-based programs, sometime the afternoon before (e.g. by 4:00 pm). Services that use ISO/RTO prices may have day-ahead prices available as early as 10:00 am. For prices to be considered "posted" means that they are made available at a utility-maintained site and transmitted over one or more media (telephone, internet, fax, cell) to subscribers. Generally, receipt is deemed to have been affected unless the subscriber notifies otherwise by a stipulated time.

Hourly

The effective price for each hour is always posted an hour ahead.

Sub-Hourly

The effective price for each hour is always posted less than an hour ahead. For example, ISO/RTO real-time prices (using their definition) are formulated five-minutes ahead of each hour (or shorter) rating period, so they may be posted but not received in advance of their time of effect.

Pre-set or Other Pricing

RTP programs that feature pre-set pricing based on seasonal day-types only post notification of the day-type for the following day but do not post hourly prices per-se because 24-hour pricing for any given day-type is stipulated by contract. All of the programs that feature pre-set hourly pricing post the following day-type on a day-ahead basis.

Price Posting Notification Findings

As shown in Figure 3-10, 52 of 55 verified active RTP offerings feature day-ahead pricing notification. Of the remaining RTP offerings one features uses hour-ahead pricing and two apply sub-hourly "real-time" posting of prices.

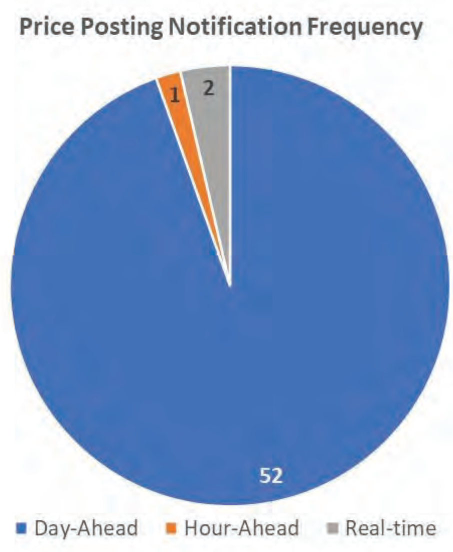

Figure 3-10
Price Posting Notification of Verified RTP Offerings

7. Price Overcall of Posted Day-Ahead Prices

Some RTP programs may have a provision for the utility to change posted day-ahead prices based on day-of changes in demand and supply conditions to better reflect prevailing conditions. With this provision, day-ahead prices are subject to retraction or "overcall" by the RTP service provider, usually for some hours (e.g. peak period) with notification sent the same morning. Overcall is usually limited to specific and verifiable circumstances such as unanticipated changes in weather or supply shortfalls (e.g. generation- or transmission- outages).

Overcall of Posted Day-Ahead Prices – Findings

Only 5 of the 55 verified active RTP offerings include some provisions for overcalling posted prices. 9 RTP offerings feature pre-set pricing for which price overcall is not applicable. Tariff sheets for another 5 RTP offerings did not specify a price overcall mechanism.

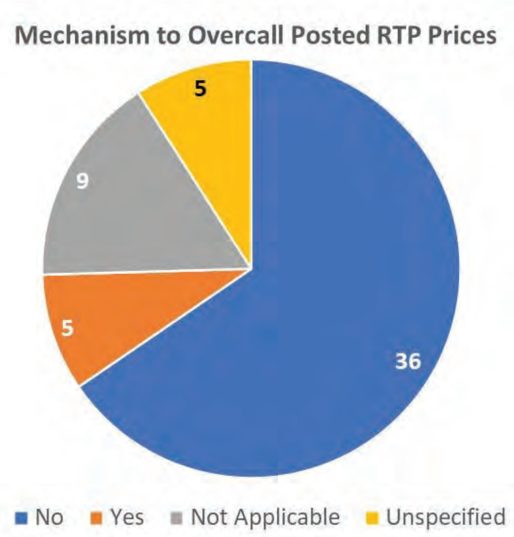

Figure 3-11
Mechanisms to Overcall Posted Prices

8. Energy Price Formation

The source of hourly prices can be the marginal cost of supply as determined by an individual utility's day-ahead (or real-time) scheduling process, prices posted by an ISO/RTO, or a confirmation of enterprise and wider market supply forecasts of supply cost.

Supplier's Forecast

The RTP supplier has a fleet of generation plants and contracts which are used to develop a day-ahead (or real time) dispatch that produces a reference internal marginal supply cost. Marginal cost for each hour, or blocks thereof, is derived directly from the enterprise supply dispatch. The hourly RTP prices can be calculated directly from the dispatch model before or after any wholesale trading.

Regional Market Energy Posting

For this, the source of hourly prices is the regional RTO/ISO hourly energy price.

Energy Price Formation Findings

As shown in Figure 3-12, 35 of the 55 verified RTP plans feature hourly energy prices based on regional wholesale energy market price postings (e.g. those posted by RTOs and ISOs). These break down as follows:

- PJM – 17
- MISO – 8
- NYISO – 7
- SPP – 2
- CAISO – 1

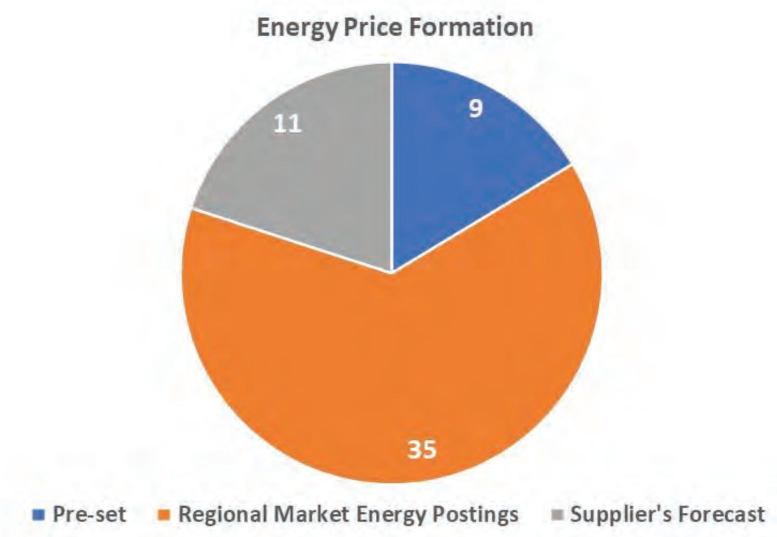

Figure 3-12
Energy Price Formation Basis of Verified RTP Plans

11 of the RTP programs apply the utility's own demand and supply forecasts as the basis for hourly energy price formation. The remaining 9 programs apply pre-set pricing as the basis for energy price formation.

9. Capacity Pricing (Generation and Transmission and Distribution)

This applies only to one-part rates that do not use an access charge to collect all fixed cost obligations through a CBL. Capacity costs would be collected though an uplift factor applied to the hourly marginal energy charge, of through another mechanism.

Energy Uplift (Collected in the Marginal Energy Price)

The marginal energy charge may be derived such that it reflects capacity costs (generation, transmission, and distribution so no separate charge is required. ISO/RTO wholesale prices are set to reflect the marginal energy generation cost of supply which include a transmission component and congestion (outage) costs. As long as the sub-elements prices are separately set and settlements distribute revenues accordingly, then the RTP supplier may or may not recover its fixed T&D costs. If high prices induce load reductions that are not consumed at another, low-cost time (usage in excess of what would be typical), then the RTP provider may experience a shortfall in T&D revenues. These could be recovered from other customers assuming that the load reduction reduced outage likelihoods and all other customers benefitted.

Demand Uplift (Collected through a Demand or other Metered Usage Charge)

A separate T&D capacity charge could be assessed, for example as a demand charge, which reduces the efficiency gains if usage decision is based not just on the prevailing marginal cost but also the potential demand charges that result.

Collected in the Access Charge – Two-part RTP

Capacity Pricing Findings

As shown in Figure 3-13, the basis for capturing non-energy charges for capacity (e.g. generation, transmission, and distribution charges) corresponds to the pricing structures detailed in Figure 3-6. As such, these charges are covered through access charges for the 18 RTP offerings that employ a CBL structure, while 5 RTP programs include all cost recovery into the energy price. The remaining two categories reflect how the 9 RTP offerings that feature pre-set pricing account for such charges, with 2 added to the count of the 23 RTP offerings that employ demand charges (for a total of 25), while the remaining 7 apply other delivery service charges.

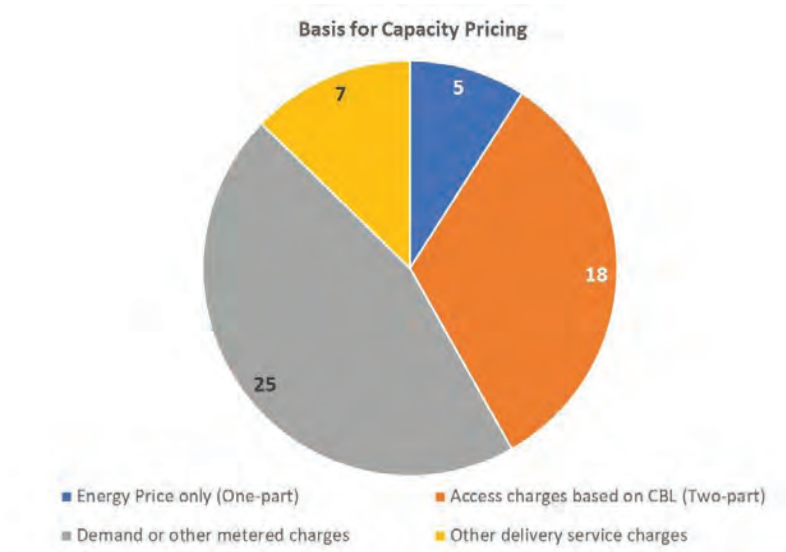

Figure 3-13
Treatment of Non-Energy Charges of Verified RTP Plans

10. Marginal Price Uplift for Administrative Costs

Uplift collects revenues by marking up the derived hourly marginal energy prices to cover RTP program development and implementation costs and may include a risk premium. A risk premium may be warranted because the utility prices usage at forecasted marginal costs but incurs cost based on real-time conditions. Underestimating RTP prices could result in no recovery of costs from RTP subscribers who consume above the CBL. The utility tariff sheets reviewed in this study did not generally specify the inclusion of this feature.

None

Provision for collecting program costs is made elsewhere in electric tariffs and risks are assumed to be inconsequential or the benefit inure to utility shareholders.

Low-priced hours

Adding uplift only to hours when RTP prices are likely lowest minimizes the efficiency loss of hourly RTP prices that are above realized marginal supply cost.

All hours

An uplift factor is added to the formulated RTP marginal cost. This spreads out the collection of the revenue targeted for collection through the RTP price, minimizing the effect on efficiency gains from prices that exceed the contemporaneous marginal supply cost.

Marginal Price Uplift Findings

Tariff sheets for 34 of the 55 verified active RTP offerings reviewed in this study do not specify the inclusion of an uplift provision to cover administrative or other costs in the energy price. 11 of the remaining RTP offerings do explicitly include some coverage of administrative and other costs through an uplift to the marginal energy price. The remaining 10 RTP offerings do not have a mechanism to cover administrative or other costs through an uplift to the marginal price.

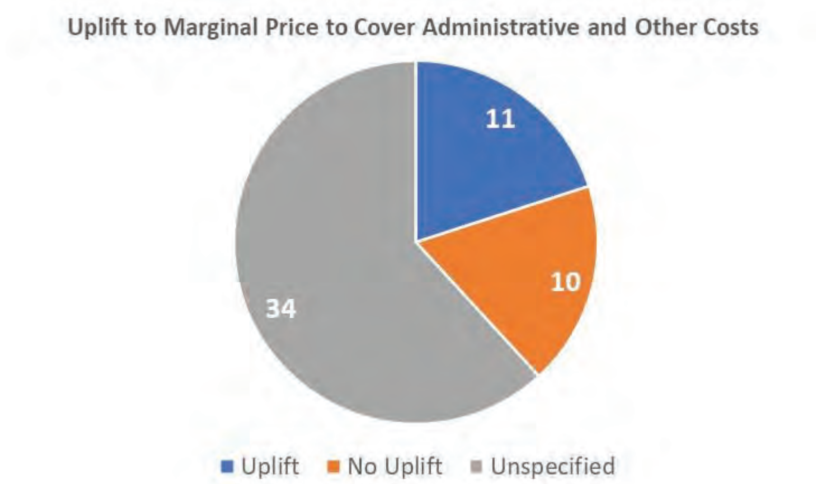

Figure 3-14
Uplift to Marginal Price to Cover Administrative and other Costs

11. Contract Term

Subscribers may be contractually obligated under a RTP service provision for a specified period. If they are unsubscribed at the end to that period, they may be assigned to a rate class to which they qualify and there may be provision for how they continue under that service. For example, if that service charged is for ratcheted demand, upon returning the ratchet provision may revert back to the conditions at the time they transferred to RTP.

Yearly

Subscriber agrees to take RTP service for one year and after that may continue with RTP or transfer to any other service to which it qualifies. A caveat may be that they must return to the original service from which they migrated to RTP.

Monthly or Seasonal

Customers may subscribe for a shorter period, for example a season or fewer consecutive months each year. Limits maybe placed on the duration and how often a customer can switch between a standard rate and RTP rate to avoid opportunistic participation that results in benefits without altering usage in response to prices.

Other

Multi-year subscriptions might be attractive under two-part pricing to a customer that wants to preserve the initial CBL because it provides opportunities for both load growth and price response. The utility gains from revenue security (based on the CBL) and benefits from price response.

Contract Term Findings

19 of the 55 verified active RTP offerings have a year-to-year contract term, as illustrated in Figure 3-15. Tariff sheets for 22 RTP offerings do not specify the contract term. The remaining RTP offerings include from five 5-year terms, two 3-year terms and seven monthly terms.

Figure 3-15
Contract Terms of Verified RTP Plans

12. Hedging and Risk Management

No Hedging

With no hedging, an RTP subscriber is fully exposed to the full range of prices. Subscribers with the ability to adjust their inter-day and intra-day power usage can take advantage of such pricing volatility. Price-inelastic subscribers with limited ability to adjust usage may be require some means to hedge against some of the adverse effects of price volatility as a condition of subscription.

CBL Hedge – Two-part RTP

A two-part RTP provides the subscriber with a hedge against price volatility because only the load variation from the hourly CBL is exposed to that hour's RTP price. When hourly prices are low, variation in usage from the CBL results in relatively small bill changes and may be attractive for expanding electricity usage in those hours. When prices are high, the CBL acts as a hedge since usage at or below the CBL reduces price exposure or produces bill reductions, respectively. On the other hand, if the subscriber's usage fluctuates considerably above the

CBL, or a change in usage has been enacted in expectation of low prices, elevated RTP prices can erode or eliminate expected savings, or raise power cost detrimentally.

Subscribers may find value in CBL hedges that allow them to either add to the CBL or reduce the CBL. The former protects against high RTP prices, since CBL is priced according to the original applicable tariff, locking in a favorable margin. For example, a CBL hedge might be considered for a month for those hours with metered usage routinely above the CBL. To be attractive, the price of a CBL hedge should be less than the expected cost of the exposure and not too far above the cost of usage under the original applicable tariff. CBL hedging involve risks for subscribers and the RTP service supplier.

Price Level Hedge

Price caps or collars are a common form of limiting exposure to price volatility. A cap establishes a price threshold such that no price higher than that level is ever posted. For example, a cap of $1.00/kWh would protect against prices might be as high a $5.00/kWh. Many early RTP programs employed algorithms that allowed a price that high, even though its occurring was highly unlikely. A common experience was that prices would rise to $1.00/kWh but only rarely and then for only a few hours. More common was episodes where prices during the afternoon and early evening hours were $0.50/kWh, several times the typical RTP prices in those hours. A price cap of $1.00 would provide protection but against unlikely adverse situations. A cap of $0.25/kWh would be triggered more often. How these are priced determines how customers value them. Price caps produce monetary savings only when prices are elevated, and usage is above the CBL.

There appears to be no case where price caps were offered by utilities as part of an RTP service. Doing so requires constructing a financial mechanism to set the cost of the cap, regulatory approval to offer the cap, and a subscription is the utility's willingness to undertake the risks.

A price collar allows for prices that vary around a specified strike price but places a floor and ceiling beyond that band. For example, the strike price might be set at $0.15/kWh and the collar +/- $0.05. These are more complex to develop because setting the strike price determines the extent and nature of price exposure, and hence the value of the collar to the utility and to subscribers. To be acceptable, collars may have to be set for relative short durations – a season or a month for example – to accommodate changing customer and market conditions.

Hedging and Risk Management Findings

As shown in Figure **Error! Reference source not found.**, 21 of the 55 verified active RTP offerings have some form of price protection or hedging, including 18 of those with a CBL structure. Tariff sheets for 13 of the RTP offerings do not include any mechanism to hedge customer price risk. The issue is unspecified on the tariff sheets for the remaining 21 RTP offerings.

Figure 3-16
Hedging Provisions Among Verified RTP Plans

While helpful to acquire basic metrics and attributes regarding RTP plans, tariff sheets are not sufficient to capture the detail necessary to acquire deeper insights into these plans. For that, interviews were conducted with utility rate experts with RTP experiences, as detailed in the next section.

4
SYNOPSIS OF UTILITY AND STAKEHOLDER INTERVIEWS ON RTP EXPERIENCE

Section Summary

This section summarizes the process by which the project team conducted interviews with utility rate design and pricing plan professionals on their RTP plans and provides insights from those sessions. The interviews provided a level of color and context for the utility programs beyond what can be ascertained through analysis of tariff sheets, particularly with respect to customer participation, i.e. uptake rates.

Key takeaways from the interviews include:

- The impetus for most utilities' RTP offerings was either: (a) compliance with a regulatory order (actual or anticipated), or (b) preparation for, or response to, retail competition.
- All but one of the RTP programs discussed with utility representatives are currently active and considered "open for enrollment", yet most RTP programs for large commercial and industrial customers do not have high market penetration.
- Most (80%) of the RTP programs discussed are opt-in with a few default/opt-out for larger commercial and industrial customers who do not shop for an alternate service provider.
- Participation in RTP programs is relatively low – anywhere from 0 to an estimated 13% of eligible customers are enrolled in RTP with an average of 4.7% and a median of 2% participation.
- Many utilities do not regularly monitor the price responsiveness of their customers on RTP because there is negligible impact on overall load, possibly due to a lack of price volatility in recent years.
- Several utilities mentioned significant investment in modifying or replacing metering, billing and other systems was necessary to accommodate RTP.
- The majority of utilities are either indifferent to their RTP offerings or think that their program needs improvement.
- Most utilities review RTP in preparation for their regular rate cases, but few have made or plan to make any significant programmatic changes at this time and none have formal sunset dates.
- No real growth nor decline in RTP subscription since programs were introduced and initially subscribed.
- RTP is a "niche product" for large commercial and industrial customers who are able to manage their usage on a meaningful scale, according to several interviewees.

- Customers on RTP generally express high satisfaction to their utility account managers.
- Only a few utilities have plans or see any likelihood to offer RTP to other customer classes in the future, e.g., in lieu of or in addition to TOU electricity pricing for residential customers.
- Marketing to residential customers requires significant investment to increase market penetration that would still be relatively low.

Introduction

Based on the definition of RTP and dynamic pricing described previously, the research team compiled a list of active and inactive, actual, and pilot RTP programs from various sources, including a 2004 LBNL report, EIA listing, previous EPRI research, internet search, and other sources. Next, the information was sorted, and rate attributes inventoried, from publicly available tariff sheets and other public sources as described in the previous chapter.

From the resulting list of verified RTP programs, the team prioritized a list of about 20 utilities from Groups A and E that they would approach within a limited three-month project timeframe to identify knowledgeable program spokespeople and schedule a qualitative discussion about RTP program implementation and lessons learned. These utilities were selected to represent a cross section of RTP program offerings in the U.S. by geographic region, utility size, customer class, various rate design attributes, etc. The interview guide was modeled after the questionnaire in the 2004 LBNL report with some modifications and additions, then applied in interviews with representatives of some recent, mature/still active, and a few inactive RTP programs.

Altogether, the team conducted 16 interviews with a total of 24 individuals representing 19 distinct utility jurisdictions with a total of 24 RTP programs in 18 states. Participating utilities/stakeholders include current and former executives, program managers and consultants with:

1. Ameren Illinois
2. Commonwealth Edison (ComEd)
3. Citizens Utility Board of Illinois
4. Duke Energy Carolinas
5. Duke Energy Midwest (includes Duke Indiana, Duke Ohio, and Duke Kentucky)
6. Duquesne Light Company
7. FirstEnergy (Ohio Edison, Toledo Edison, Illuminating Company, Jersey Central Power & Light, Penn Power, Metropolitan Edison, Penelec, West Penn Power)
8. Georgia Power
9. Oklahoma Gas & Electric (OG&E)
10. PECO
11. San Diego Gas & Electric (SDGE)

12. Upper Peninsula Power Company (UPPCO)

Considerations in Developing Interview Script

The interviews were intended to reveal aspects of utility RTP offerings beyond their structural design and other facts obtainable from tariff sheets, such as:

- Motivations for developing the service
- Regulatory approval process
- Operational protocols
- Implementation infrastructure
- Recruitment and enrollment of subscribers
- Customer satisfaction and retention
- Lessons learned

The following questions, which elaborate these aspects, were the basis for the interview guide, which is provided in its entirety in Appendix A:

Enterprise Motivation for Developing the Service

- What motivated development of the RTP service? A regulatory mandate, success with RTP elsewhere, or customer requests?
- Who was responsible for developing the program, establishing requirements, and setting resources across several departments?
- What internal buy-in (level of approval) was required and how was it accomplished?

Regulatory Approvals

- Who prepared and filed the tariff sheets for the service?
- What regulatory approval was required to implement the program, tariff, and program mechanisms?
- What program/service reporting was required on subscription, price responses, process activities, drop-outs, and new subscribers?
- How were program expenditures recovered – from RTP subscribers or all customers?

Service Availability

- When was the RTP service first offered?
- Was it offered as a pilot, experiment, or as generally available?
- To whom was it offered? For how long is continuous subscription allowed?

- If already offered, is service still available under the initial structure, closed to subscription, or discontinued?
- If the service was closed or discontinued, what were the reasons?
- Who was responsible for preparing documents and agreements to execute?
- If a CBL (customer baseline load) was required, who was responsible for its initial development and for any adjustments made during the recruitment process?

Recruitment

- How was the population frame – which determines customers eligible for immediate participation – identified?
- What research was undertaken to establish which customers to target for subscription?
- How were recruitment materials developed and implemented?
- How were customers contacted to explain and be offered subscription?
- How were the subscription agreements executing?

Hourly Price Formation

- What process, methods and models were used to set levels of each element of the hourly price, e.g. marginal energy cost, outage or congestion costs, uplift, taxes, collections, and other adders?
- How were the procedures and analytics to calculate hourly marginal prices developed?
- How were hourly price schedules for each day developed?
- How was the posting of short-notice price overcalls determined?

Price Posting and Delivery

- How were daily prices transmitted to subscribers? What alternative mechanisms were available? How was receipt of prices confirmed?
- Were daily prices made publicly available when posted? If so, when were they posted – at a later time or not at all?
- If short notice overcalls were used, when were they transmitted to subscribers? How were they confirmed?

Measuring Power Usage

- How was power usage measured?
- How was usage metered and transmitted to those responsible for billing?
- What data verification procedures were used? Were they automated?

- Was hourly usage made available immediately to subscribers? If not, when was usage information available – within a short delay, a day later or other?

Financial and Accounting Protocols

- What changes to billing procedures and practices were required?
- What changes to financial accounting procedures and practices were required?

Cost of Service Treatment

- Were RTP subscribers treated as a separate class or did they remain in their prior class?
- What changes, if any, to cost of service protocols were required?
- What changes, if any, to fuel adjustment mechanisms were required?
- How were load changes associated with price changes incorporated into the creation of class load profiles?

Performance Evaluation Considerations

- What analyses were used to quantify how RTP impacted power demand?
- What analyses were used to quantify how power supply was affected by changes in customers' consumption due to RTP and whether those changes affected the utility's aggregate load profile?
- Are the results of these analyses made public or kept proprietary to the customer and the utility? If made public, how is the data accessed?

Key Findings from Interviews

RTP program history and outlook

Most utilities interviewed indicated the impetus for their RTP program offerings was related to compliance with a regulatory order (actual or anticipated) and/or in preparation for, or response to, retail competition. A few indicated their RTP program was developed in response to customer interest. When asked to indicate the primary goal of their RTP program, the responses varied from regulatory compliance to load growth/economic development to peak demand reduction to environmental benefits and cost savings and increased satisfaction for customers.

Figure 4-1
Utility Motivation for Developing RTP Plans

Figure 4-2
Utility Goals for Developing RTP Plans

All but one of the RTP programs we discussed with utility representatives are currently active and considered "open for enrollment." However, one is fully subscribed so new enrollment would depend on a facility closure by a currently enrolled customer to make room for a new subscriber to the program. Most RTP programs for large commercial and industrial customers do not have high market penetration. Similarly, the two residential RTP programs in Illinois have a lot of room for growth in customer participation. Note that end-use rates such as hourly pricing specifically for EV charging are not considered RTP for the purposes of this study.

A few utilities indicated they had modified their RTP offerings slightly over the years since introduction (most pre-2004). Changes include the addition of pricing protection mechanisms, and the review and adjustment of original customer baseline loads (CBLs) to reflect current electricity usage more accurately. Several utilities shared that they have installed advanced metering infrastructure and upgraded other systems since their RTP programs were first introduced and have offered or are investigating opportunities to provide enabling technology to customers on RTP.

The utilities' current level of enthusiasm for their RTP programs varied widely – from "very happy with it" and "high level of enthusiasm" to "lukewarm, at best" to "indifferent," seeing it as a "just a pass through" or "requirement." However, the majority were either indifferent or thought their program needs improvement. Most utilities review RTP in preparation for their regular rate cases, but few have made or plan to make any significant programmatic changes at this time and none have formal sunset dates.

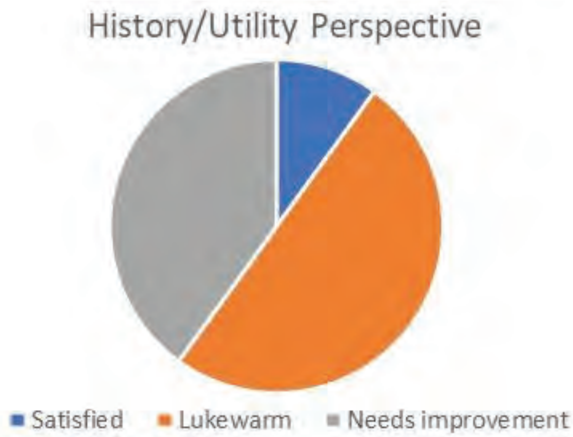

Figure 4-3
Utility Satisfaction with RTP Plans

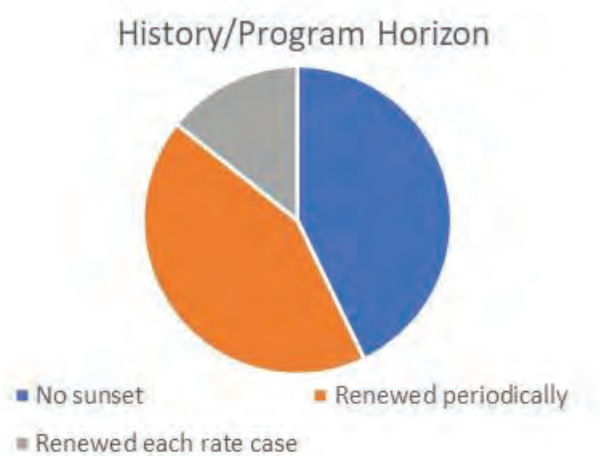

Figure 4-4
RTP Program Horizon

Marketing/customer outreach

Most (80%) of the RTP programs discussed in these interviews are opt-in with a few default/opt-out for larger commercial and industrial customers who do not shop for an alternate service provider. Most utilities said they did some outreach in the early years of their programs, e.g., account managers would meet directly with larger commercial and industrial customers about RTP programs, but marketing activity has waned since then. Notable exceptions are the residential RTP programs in Illinois, which have been marketed and evaluated by a third-party company using a variety of communication tactics and educational outreach, and for which there is interest in promoting and increasing subscription levels over the next several years.

Interviewees acknowledge that marketing to the residential customer class requires significant investment to increase market penetration that would still be relatively low, and they also are investigating pricing protection mechanisms and whether an opt-out strategy would be more cost effective while still offering customer choice.

When asked whether solar or solar and storage customers are eligible to participate in their RTP programs, two thirds of the utilities interviewed indicated yes, but that few customers in their service territories had solar resources (low solar penetration and very low storage penetration overall) and also met other eligibility criteria for the RTP programs.

Participation and Performance including price response

Among the utilities interviewed, there is relatively low participation in RTP programs – anywhere from 0 to an estimated 13% of eligible customers are enrolled in RTP with an average of 4.7% and a median of 2% participation. Some interviewees expected these relatively low participation levels since their goal was to encourage customers to shop for pricing in competitive markets. Some utilities saw initial success with customer participation and economic development with expanding and new businesses, but most utilities indicate no real growth or a decline in subscription since the program was introduced and initially subscribed. Several interviewees characterized RTP as a niche product for large commercial and industrial customers who are able to manage their usage on a meaningful scale.

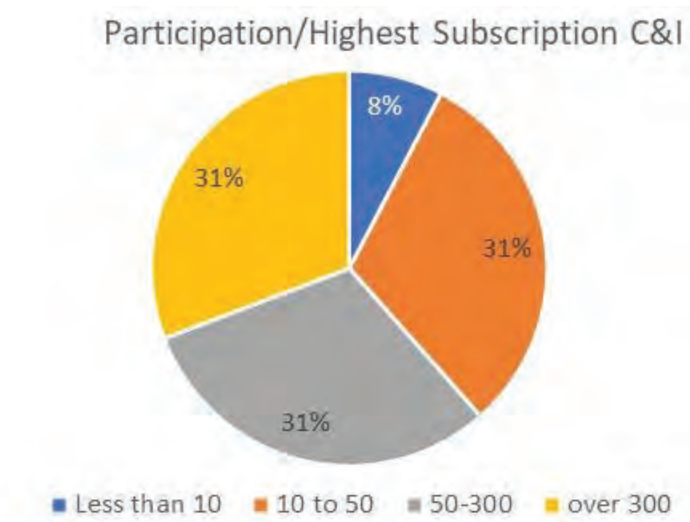

Figure 4-5
Participation – Highest C&I Customer Subscription in RTP Plans

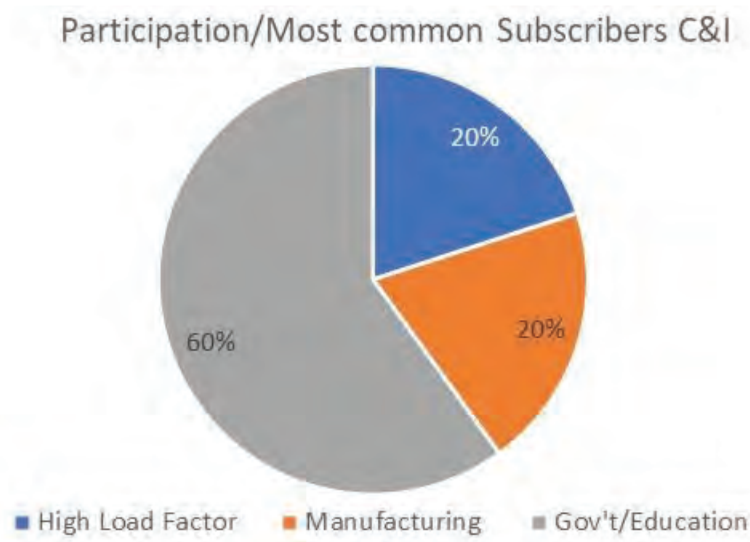

Figure 4-6
Participation – Most Common C&I Subscribers to RTP Plans

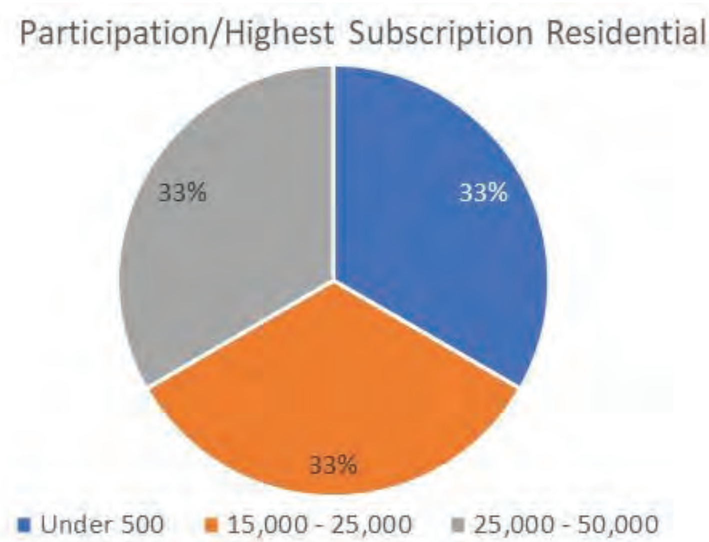

Figure 4-7
Participation – Tiers of Residential Subscribers to RTP Plans

While participation in residential programs in Illinois has been steadily increasing and may see a boost from promotion planned for the next several years, the new target of twice the current enrollment is still about two percent of all residential customers. According to Elevate Energy's 2019 Annual Report of ComEd's Hourly Pricing Program for residential customers:

In 2019, ComEd's Hourly Pricing program had 34,465 participants and generated more than $11,000,000 in net benefits from a societal perspective, a more than 18% increase from 2018. Hourly Pricing participants realized strong bill savings from favorable market conditions and by maintaining a high rate of conservation. In 2019, participants averaged annual savings of $92 when compared to ComEd's standard fixed-price rate. Participants netted an average reduction of 601 kWh from conservation efforts in 2019, adding another $40 per participant to their annual savings.

Customer feedback is not often formally solicited or reported by utilities with RTP programs for large commercial and industrial customers, but those utilities said they are in regular contact with RTP customers through their account managers who report high customer satisfaction overall.

Many utilities do not regularly monitor the price responsiveness of their customers on RTP because there is negligible impact on overall load, possibly due to a lack of price volatility in recent years. These utilities aren't sure if or why a large C&I customer may have altered operations in response to price or in spite of it – based on the economics of customer orders in production, for example. Similarly, few offered a guess at estimated bill impacts for customers on RTP compared with other pricing programs. Those few utilities that do monitor RTP program results more closely shared that while bill impacts vary by customer, most customers save money on the RTP rate. However, how much those customers save depends on their level of response and ability to respond to hourly price fluctuations (e.g., "savvy" customers and/or customers with technology to closely monitor prices).

Only a few utilities have plans or see any likelihood that RTP would be offered to other customer classes in the future, e.g., in lieu of or in addition to TOU electricity pricing for residential customers.

Implementation experience/lessons learned

When utilities were asked about their overall experience with RTP program implementation – what went well and areas for improvement – their responses ranged from tactically specific to higher level strategy, objective-setting and long-term planning. For example, one utility representative noted, "We didn't think it would last 25 years" and recommended that utilities considering RTP "think about long term success" and "figure out if there's a difference by region [in case you] might be able to have different retail prices by node or zone and have customers be comfortable with it." Other utility representatives recommended that utilities "go to opt-out to get higher subscription" from residential customers and avoid high marketing costs to meet modest market penetration with an opt-in program. A few utility representatives recommended utilities planning to offer RTP for commercial and industrial customers should consider scale to justify the expense of administering the program due to the level of personal attention required from account managers.

Several utilities mentioned significant investment in modifying or replacing metering, billing and other systems was necessary to accommodate RTP. Several utility representatives also reiterated that they view RTP as one of many tools in a pricing portfolio, characterizing it as a niche product for commercial and industrial customers with the ability to respond to pricing signals, and adding that RTP has very limited potential in their view due to low price responsiveness of customers generally. Some interviewees commented positively that RTP programs can be difficult to administer but are worth the effort for the utility and subscribers based on customer satisfaction, economic development and some load management benefits, while others offered more pessimistically that RTP programs are "a lot of effort for little benefit" unless there is capacity shortfall and demand response is needed.

5
ESTIMATES OF PRICE ELASTICITY OF ELECTRICITY DEMAND

Section Summary

Key Findings

- Review of thirty-one reported RTP elasticity[12] estimates indicated low load response, with most elasticity estimates under 0.10 and the majority under 0.05, especially those involving residences.
- Higher elasticities were reported in some circumstances, for example government and educational facilities, electricity intensive facilities like arc furnaces and refineries, and when the RTP design allows for day-ahead prices to be revised within day, particularly to post much higher prices to reflect supply conditions not anticipated the day before.

Introduction

Real-time pricing (RTP) has been as argued to be an effective way to equate variable marginal supply cost with electricity consumption decisions. It is believed that there is great potential for RTP services to improve the electricity sector operational and investment efficiency, provided that at least some customers subscribe and exhibit at least a modest level of price response to price variations. This chapter provides a way to gauge RTP potential and provide insights into which customers are the most responsive by measuring their price elasticity.

Elasticities are measured as rations of changes which means that only the price ratio effects consumption. The force of price change is diluted because customers are unable or not inclined to alter usage. An elastic value of 0.20 means that a 100% change in the price ratio produces a 20% change in usage ratio.

Findings

EPRI identified studies that reported price responsiveness, or price elasticity of electric utility customers on a retail RTP service. The intent was to comparably measure the effectiveness of RTP at inducing changes in electricity usage. EPRI's review summarizes how price affects participants' electricity usage, across RTP designs.

We identified eight utility-offered RTP programs that met those criteria: five for large commercial and industrial customers and three for residential customers. Four of the eight RTP

[12] Elasticities are measured as ratios of changes which means that only the price ratio effects consumption. An elastic value of 0.20 means that a 100% change in the price ratio produces a 20% change in usage ratio.

programs are two-part, such that participants pay a non-bypassable monthly subscription fee based on an hourly baseline usage profile (CBL),with the difference from actual metered energy usage (kWh) settled at each hour's RTP price ($/kWh). The other four RTP programs employed a one-part approach utilizing either a demand charge or an RTP price adder to collect capacity costs not covered by hourly RTP prices.

Studies varied in how they characterized the causal link between hourly RTP price changes and customer usage of electricity. Some studies aggregated hours to reflect substitution possibilities. Other studies of RTP targeted to C&I customers extended the substitution possibilities to other days of the month. Some studies estimated own- and cross- price elasticities of demand, quantifying how hourly usage changes with hourly price changes and during other hours. One residential RTP program reported only estimated substitution elasticities, either between intra-day or inter-day hours, which simplifies the estimation of elasticities by assuming that RTP only shifts when electricity is used but that aggregate electricity usage remains constant. Two other RTP programs reported own-price elasticities, but their estimation methodologies lack sufficient rigor for comparison.

Comparisons of nominal elasticity estimates among the studies are instructive, e despite the fact they may not be measuring the same behaviors. However, all elasticities are relative measures of how changes in RTP prices invoke changes in electricity usage, so comparing their absolute values can provide insights into the RTP experience.

Thirty-one reported RTP elasticity estimates are summarized in Table 5-1. An elasticity of zero means that RTP price changes had no effect on electricity usage. .

Table 5-1
Distribution of Elasticity Estimates Among Studies

Distribution of Elasticity Estimates (Absolute Values)	
0.00 to 0.05	12
0.06 to 0.10	9
0.11 to 0.20	6
0.20 to 0.30	2
Over 0.30	2

Most elasticities were under 0.10, meaning that a 10% change in price resulted in less than a 1% change in electricity usage.

While the results generally indicate low degree price responsiveness, higher elasticities were reported for government and educational facilities, and electricity-intensive facilities like arc furnaces and refineries. In addition, higher elasticities were reported where RTP design allowed intra-day revisions of day-ahead prices. This allowed the posting of higher prices to reflect supply conditions not anticipated on the prior day. This variation allows customers to take advantage of day-ahead hourly price postings for the vast majority of hours each year when marginal supply costs are low. RTP enables utilities to match prices with prevailing supply conditions, benefitting those customers who respond.

Table 5-2 lists the 31 price elasticities of utility RTP programs that were studied.

Table 5-2
Estimated Price Elasticities for RTP – Absolute Values

Study	Subjects	Column Reference	Type of Elasticity Estimated	Figure 1 Reference	Absolute Value
HP&L	C&I	A	Own-price L	OP-Low	0.03
HP&L	C&I	A	Own-price H	OP-High	0.22
HP&L	C&I	A	Cross-price L	CP-Low	0.04
HP&L	C&I	A	Cross Price H	CP-High	0.06
NMPC	C&I	B	Within day L	WD Low	0.042
NMPC	C&I	B	Within day mean	WD Mean	0.093
NMPC	C&I	B	Within day H	WD High	0.136
NMCP	C&I	B	Between day L	BD-Low	0.01
NMPC	C&I	B	Between day mean	BD-Mean	0.163
NMPC	C&I	B	Between day H	BD-High	0.56
Duke	C&I	C	Own-price L	OP-Low	0.09
Duke	C&I	C	Own-price H	OP-High	0.26
Duke	C&I	C	Cross-price L	CP-Low	0.001
Duke	C&I	C	Cross Price H	CP-High	0.02
CSW	C&I	D	RTP-HA Within day L	WD-HA Low	0.238
CSW	C&I	D	RTP-HA Within day mean	WD-HA Mean	0.249
CSW	C&I	D	RTP-HA Within day HL	WD-HA High	0.304
CSW	C&I	D	RTP-HA Within day L	WD-DA Low	0.161
CSW	C&I	D	RTP-HA Within day mean	WD-DA Mean	0.169
CSW	C&I	D	RTP-HA Within day high	WD-DA High	0.198
NMPC/DS	C&I	E	Govt/Education Within day	WD-DS Gov	0.31
NMPC/DS	C&I	E	Mean Within day	WD-DS Mean	0.14
NMPC/DS	C&I	E	Indusrtial Within day	WD-DS Indust	0.11
NMPC/DS	C&I	E	Commercial Within day	WD-DS Com	0
ComEd	R	F	One-Price	R OP	0.042
Ameren	R	G	One-Price 2008	R OP-2008	0.043
Ameren	R	G	One-Price 2009	R OP-2009	0.023
ComEd	R	H	CPP Event day within	R WD CPP Event	0.127
ComEd	R	H	PTR event day within	R WD PTR Event	0.062
ComEd	R	H	CP non-event day within	R WD CPP no event	0.015
ComEd	R	H	CP non-event day within	R WD PTR no event	0.055

HP&L: Houston Power & Light

NMPC: Niagara Mohawk Power Company

CSW: Central and Southwest

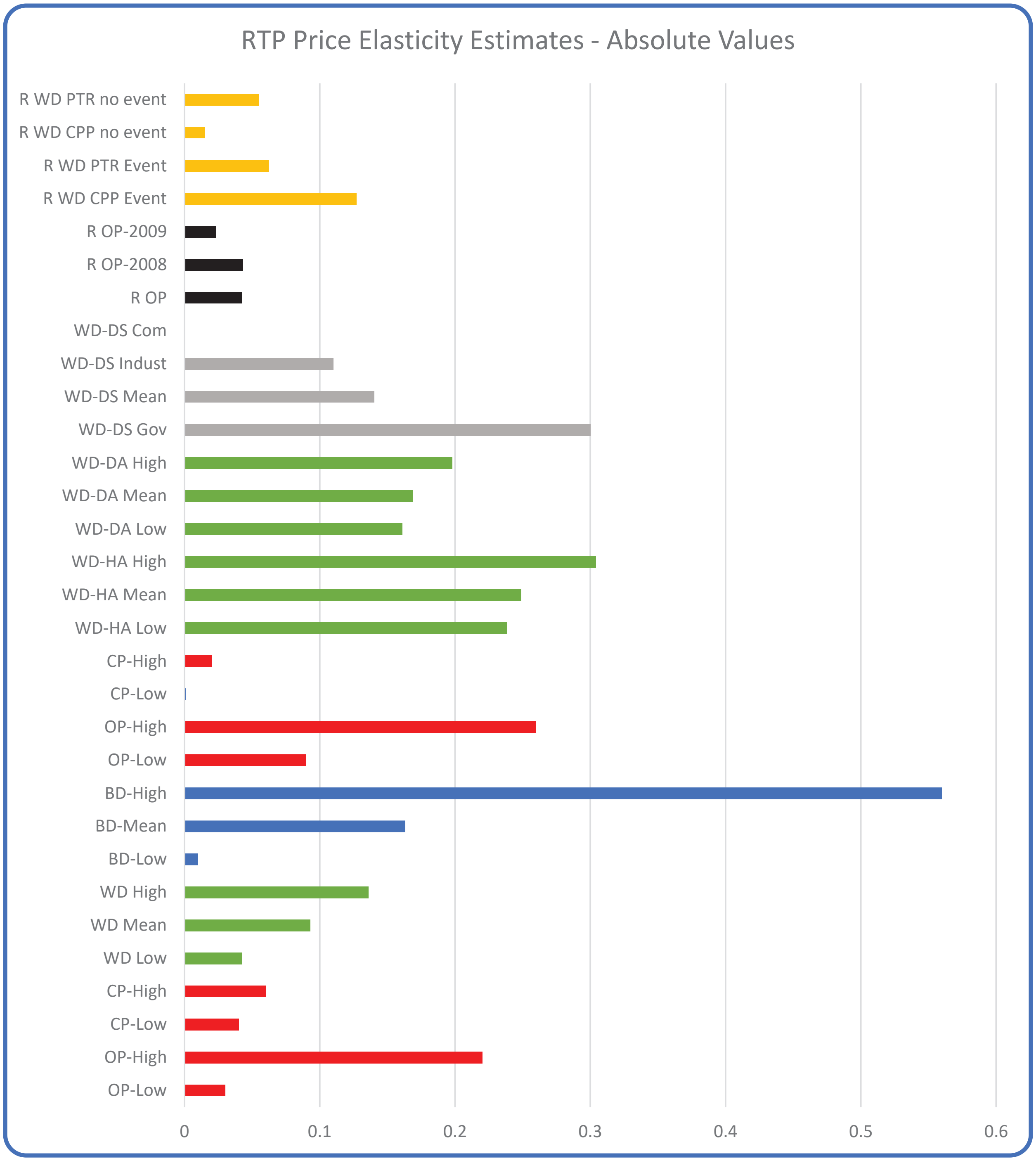

Figure 5-1
RTP Price Elasticity Estimates

6

ILLUSTRATION OF INTEGRATING RTP INTO AN ELECTRIC SERVICE PORTFOLIO

Section Summary

This section illustrates (a) a process to developing an RTP design that fulfils overarching objectives and (b) practical considerations to accommodate market circumstances.

Key Findings:

- Constructing and evaluating an RTP service requires accounting for a wide array of interests, including system and market characteristics.
- Little research has been conducted to understand customer preferences for real-time pricing intervals and advance posting periods.
- Customer preference research is critically important to inform the design of RTP services intended for expansive subscription.
- Constructing and evaluating an RTP service requires accounting for a wide array of interests, including system and market characteristics.
- Even in organized markets (i.e. ISOs/RTOs), determining whether posted prices are provisional or final can be ambiguous. A utility could develop a mechanism to forecast marginal energy and outage costs or elect to set up a state-driven schedule.
- A concerted effort is needed to help customers understand: (a) why RTP is different from their current service; (b) what actions are required to benefit from RTP; (c) what costs are associated with those actions; and (d) what risks are associated with RTP subscription.
- Pilots can play a pivotal role in providing insights into customer acceptance of various RTP design options to inform final design for broad roll-out.
- Deriving prices from utility system dispatch operations may require investments in those systems to extract the marginal operating prices and if employed, generate marginal outage costs.

Introduction

Previous sections have discussed the variety of ways real time pricing is defined and how services implemented by utilities have taken different forms. This chapter provides a strategic decision-making framework for stakeholders to design an RTP offering. Figure 6-1 illustrates a sequential decision framework to guide RTP design, with associated data requirements.

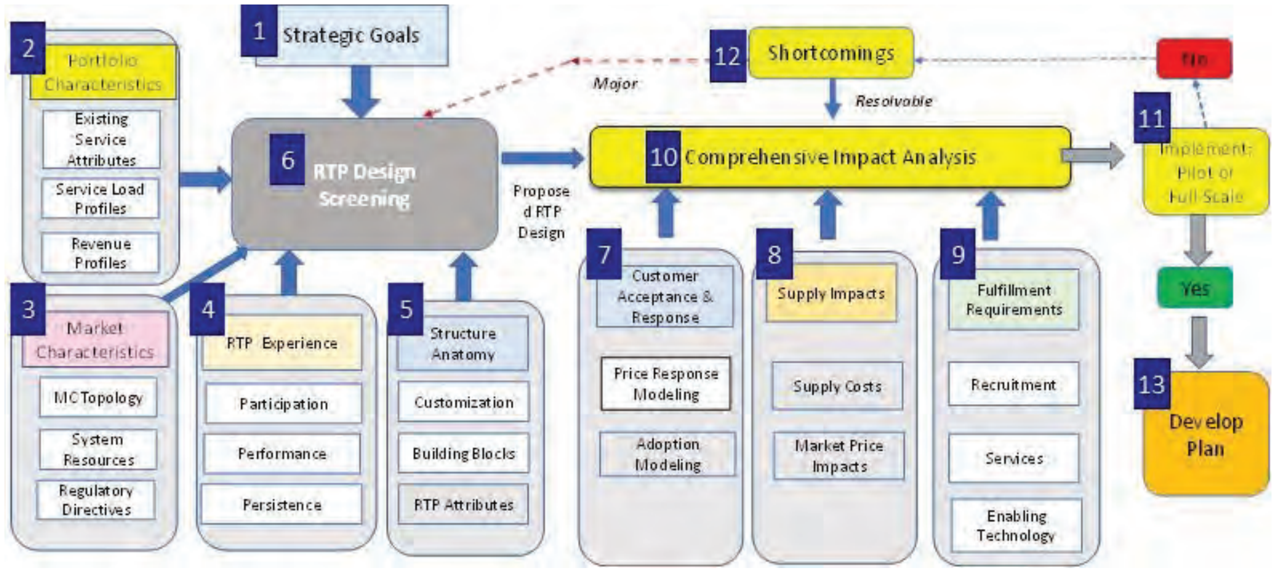

Figure 6-1
Flow Diagram Illustrating Decision Sequence for RTP Design

The remainder of this chapter provides further details on each component of the RTP decision sequence:

1. Strategic Goals
2. Portfolio Characteristics
3. Market Characteristics
4. RTP Experience
5. Structure Anatomy
6. RTP Design Screening Requirements
7. Customer Acceptance & Response
8. Supply Impacts
9. Fulfillment Requirements
10. Comprehensive Impact Analysis
11. Implementation: Pilot or Full Scale
12. Shortcomings: Redesign
13. Develop Plan

[1] Strategic Goals

Strategic goals for RTP may include any combination of the following load-shaping objectives based on the circumstances of the particular utility the wholesale market in which it operates:

- Reduce consumption and demand during peak periods
- Shift usage from peak hours to off-peak hours
- Reduce congestion of power delivery at the transmission level
- Reduce congestion of power delivery at the distribution level
- Encourage flexible consumption to maximize utilization of zero- or low- carbon renewable generation sources
- Promoting more efficient consumption (i.e. purchase and use of energy-efficient devices)
- Promote electrification to advance decarbonization and economic growth
- Stimulate and sustain customer-sited generation to promote energy diversity and sustainability

A utility considering design of RTP plans for customers should begin with the first-principles of which strategic goals to advance.

[2] Portfolio Characteristics

Whether RTP would be added or be a revision to the retail service portfolio – the criterion should be how RTP would benefit the portfolio. This starts by characterizing how it could contribute to the goals for portfolio performance. The overall effectiveness of a design must consider the impact of migration from existing services (both physical and financial) so they can be compared to the benefits that could be realized from an RTP subscription.

Existing Service Attributes

The RTP attribute template described earlier in the report serves as a starting point. To that add categorically the attributes of the existing services to highlight differences and tradeoffs to consider. As an example, is to what extent are usage prices linked to wholesale, market-clearing prices or by utility-equivalent dispatch. Establishing the spatial and temporal characteristics of existing prices provides the basis for comparing them to the marginal cost topology developed in the market characteristics sections. Prices that change regularly and are highly variable must be contrasted to price schedules like TOU or uniform energy and demand charges in terms of how electricity usage is affected and the implications for the financial efficacy and customer acceptance of RTP.

Service-level Load Profiles

Load profiles for each service class are required for initial screening and the subsequent detailed analyses. They must be constructed at the level of usage measurement consistent with RTP designs, some of which measure and price usage hourly, but others utilize shorter time intervals to price energy usage, for example every five minutes. Classes that have been metered and billed hourly for several years are compatible with an hourly RTP service. If hourly data is available but not used for billing, then a judgement must made about what would be required to develop a class hourly profile and can it be broken down into customer-specific profiles. This characterization should include what would be required produce these profiles; what new metering and data management capacities would be required so that the screenings can be balanced with other considerations.

Revenue Profiles

Construct a multi-year synopsis of the revenues associated with each class/pricing structures distinguishing them by what measures of service are priced. This provides insights into the importance of cost recovery from measured energy usage (the flow of energy) compared to collections from use of the stock of system supply and delivery assets. RTP can be constructed to isolate the recovery of fixed and variable costs to variable degrees and the extent to which a specific design does. This revenue topology provides a perspective on the risks associated with the migration of customer from existing services to an RTP services that likely requires additional and detailed analysis of any service proposal that emerges from the screenings process.

[3] Market Characteristics

RTP services take advantage of existing and future market conditions and circumstance can may be limited or mandated by them.

Marginal Cost Derivation and Topology

RTP prices energy usage at marginal costs. A primary RTP design building block is to determine how those prices are generated each hour for each day, using posted wholesale market prices, prices derived from internal system dispatch operations, or specified by an established schedule that associates the level and profile of daily marginal cost with observable conditions (e.g., weather, scheduling a peaking unit, or the likelihood of an abundance or shortfall of intermittent resources). Screening RTP alternatives requires a characterization of the current availability of prices form each source and an assessment of how that might change over time. If the utility is part of an RTO that produces hourly market-clearing prices and day-ahead prices and has done so for years, for example, the a price topology can be constructed that provides annual overviews such as: average price by hour and the mean and variance, a price distribution that shows the frequency of prices (how often a price occurs at or above price tranches), the pattern and sequencing of high and low prices (how often to prices sustain for a specified period (six hour), and other temporal and if applicable, temporal price regimes. These can be compared to the price variation developed in the portfolio characteristics to link existing service prices to marginal costs that reflect prevailing market prices.

If RTO or equivalent prices are not available, the suitability of systems available to provide hourly or shorten interval prices, and if not available, what is required to develop and implement them. Most utilities operate system dispatch algorithms that indicate the unit at the margin each hour that when associated with the unit's heat rate and accounting cost provides an estimate of marginal energy supply cost. Using historical data or simulating dispatch over forecast scenarios provides hourly data to develop price topologies as discussed above. An additional consideration is how to establish congestion or shortage cost. A review of mechanisms that have been developed and used for RTP services by others provides alternatives that can be evaluated in terms of applicability and requirements to develop that are passed on to the screening process.

If neither of these is available currently, then this characterization requires as assessment of when either (or both) price-determining mechanism will be available to set prices for an RTP service.

System Resources

A general assessment of what resources are available to serve electricity supply and delivery and the potential shortcomings provides insight into capacity needs which informs valuing an RTP service; could it forestall or even eliminate a future investment requirement, provide better information as to what capacity will be needed, or would a RTP service speed up, increase, or both, capacity addition. The latter might be the result of an RTP design that results in customers served on interruptible service to migrating to RTP because it offers firm service at an acceptable premium.

Regulatory Directives and Stakeholder Interests

A mandate to consider RTP by regulators may be a driving force to design and evaluate service alternatives. The directive may be general but characterizing the reasons for the directive will ensure that those considerations are employed in the screenings and resulting proposals responsive. A customer or group of customers may request that RTP be given consideration as an addition to the portfolio. It is essential to work with such entities so that they articulate their expected benefits. They may have in mind a specific formulation; they may be relying on substantiated or unsubstantiated estimates of the benefits they might realize or using the term RTP very generally and have in mind a different form of dynamic pricing. The results more likely to be accepted if these interests and concerns are properly formulated, considered, and addressed explicitly justifying a proposed design.

[4] RTP Experience

When designing an RTP program it is useful to learn from utility experience with implementing RTP. This can be done through reviewing published studies on the subject. For example, Chapters 3 and 4 of this report summarize the collective experience of US regulated electric utilities that have implemented RTP, through reviews of RTP tariff sheets and interviews of utility rate managers, respectively. These chapters describe utility experiences to-date with RTP, including a comparison of programs by their choice of building blocks, attributes included, and customizations to adapt designs to customer- and market- circumstances. While the analysis of tariff sheets in Chapter 3 provided structural details, the interviews with utility professionals provided valuable additional insights and perspectives on how customers were recruited, what motivated subscription, what support services were offered, observed and measured price response, and other programmatic features.

Figure 6-2 illustrates three dimensions of customer response: participation, performance and persistence.

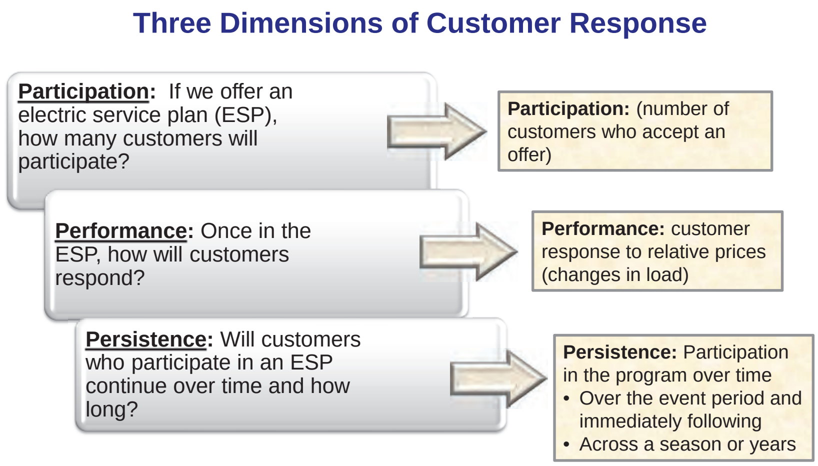

Figure 6-2
Three Dimensions of Customer Response

Participation

Participation describes the motivation for participation in an RTP service, including factors that the RTP design team proposes are important and what is gleaned for the experience of others. They include measurements such as the percent of customers invited to join who subscribed, broken down into distinguishing factors that support segmentation like business activity (primary metals fabrication and refining, manufacturing, retail, government and education), previous experience with a dynamic pricing service (CPP, PTR), an on-site generation facility, etc. These provide a first approximation of how design features affect subscription.

Performance

Performance measures gleaned from the experience catalogue, distinguishing the RTP design that are accounted with the design, provide the means for estimating the degree of price response expected from those hypothesized to subscribe. When available, estimated price elasticities combined with RTP price topologies developed under market characteristics produce estimates of RTP price-induced changes that can be transformed into utility and market supply impacts, utility financial impacts, and subscriber benefits that to be used in the screening process.

Persistence

Persistence measures how long RTP subscribers remain on the service, assuming that they have the option to return to a more conventional service plan. Our review of utility RTP experience shows that programs allow migration after an initial contract period, and most programs allowed subscribers to renew the contract for additional years; notable exceptions were RTP pilots or fixed-term experiments. Subscription persistence information allows for more realistic forecasting of RTP impacts by considering the possibility that some subscribers will drop out.

[5] Structure Anatomy

Section 2 described a structural characterization of RTP as utilizing a set of descriptive attributes, basic structural building blocks, and customization. These are functional elements of screenings process used to construct designs that are assessed according to strategic goals.

[6] RTP Design Screening

Constructing and evaluating an RTP service requires accounting and screening for all of the preceding considerations – [1] through [5].

- Strategic goals
- Portfolio characteristics
- Market characteristics
- RTP experience
- Structure anatomy

The screening process filters the possible RTP designs to a select few that pass an initial test of suitability, achievability, and responsibility.

A planner can construct an evaluation template to sort these inputs into categories amenable to rating, rankings, or some criteria for quantitative scoring for the screenings process.

The goal of the screening exercise is proposing an RTP design for further, more in-depth analysis. The information gathered, interpreted, and synthesized in this process provides a basis for evaluation. Because subsequent design analyses are resource-intensive and time consuming, it is imperative to select a basic design or identify a key decision factor to focus the additional analyses.

Ideally, a cross-functional team with expertise in RTP design and in the constituent technical, portfolio and market areas will collaborate on the RTP design screening process. Diverse expertise is needed because many of the customer, market, and supply considerations defy definitive weighed scoring.

A fundamental screening decision is what degree of customer RTP subscription is required. This drives all subsequent building block decisions and customizations.

A second decision for the screening team is whether the advantages of the historic customer baseline load (HCBL) or nominated customer baseline load (NCBL) design merit the added complexity of developing and managing baseline loads. Related questions to consider include:

- *Is linking RTP price to market or system marginal supply cost to achieve the greatest efficiency benefit a preemptive priority*? If so, then HCBL is the better design choice.
    - Usage price always reflects marginal supply cost, and since it applies to changes in usage from the HCBL, subscribers make efficient decisions about energy use.
    - Collection of fixed cost is achieved by a non-bypassable access charge so there are no structural winners who benefit from cross subsidization or structural losers who pay a premium just to participate.
    - Several implemented HCBL programs provide insights into how to administer the HCBL, gauge its effectiveness in inducing price response, and reveal any shortcomings that caused program to wane or close.

- *Would allowing customers to nominate the CBL periodically improve customer acceptance at the expense of lower efficiency gain, greater complexity in administering the program, and the need to add a way to collect each customer's fixed cost obligation?*
  - Potential subscribers are skeptical of a fixed HCBL over several years
  - Potential subscribers' power demands fluctuate seasonally or monthly, or even daily
  - Potential subscribers want to be able to expose more load to or hedge load against RTP price volatility
- *Is either subscription model deemed beyond the utility's' capability to administer, or is efficiency is a lower priority than realizing some improvement over conventional rates?*
  - Utility rates staff are experienced in setting charge specifically to collect fixed costs that are not recovered without the rate charged for energy.
  - RTP subscribers migrate from existing services which provides a base for establish a cost recovery factor that is aligned with the cost-of-service foundation for the service portfolio.
  - Potential subscribers are averse to the concept of a HCBL or NCBL and are willing to forego the potential benefits of a HCBL or NCBL

A third screening decision is RTP pricing and price posting interval. This may be determined by prevailing market conditions. A utility operating in an RTO market (for example, CAIOS, PJM, NYISO) that posts market-clearing prices would argue strongly for using those prices, but still leaves open the question of the measurement and pricing interval, when prices are posted and if they are provisional or final. Otherwise, the utility develops a marginal energy and outage costs forecast mechanism or elects to set up a state driven schedule.

Given what can be provided, the determining factor in choosing the pricing interval is what will be acceptable to RTP service providers. For organized markets, the choice of the pricing interval is restricted to what the ISO/RTO provides (i.e., day-ahead and real-time). Utility-dispatch pricing will be determined by the capability of existing systems or what can be developed and implemented.

The experience of others provides no definitive conclusion since most use hourly day-ahead prices, but others post prices on very short notice, some of which are provisional. Little research has been conducted specifically to answer the question of preferences for pricing intervals and posting. The limited subscription in many programs may be because customer preferences are diverse but only a single interval is offered. If the intent is to design an RTP service that has expansive subscription preference research maybe required to understand what design or designs to offer.

The NCBL and no subscriptions obligation designs required collecting some or all of subscribers' fixed cost obligation through a demand charge or as an uplift to RTP usage prices.

Customizations to a basic RTP design provide a means for adapting the design to local market and customer circumstances. For the initial screening, these are less important considerations because their efficacy and effectiveness require more in-depth analyses that are undertaken subsequently in the comprehensive impact analysis applied to the design or designs screenings recommends moving forward on.

The primary purpose of screening is to establish the functional and process requirements for implementing and RTP service and select the one that best fulfills the established goals and comports with what is technically feasible and acceptable to customers, using high-level characterizations. Before a final decision is made, a comprehensive analyst is required that raises the bar in term of the analyses required and their scale and scope that vary among RTP designs. Screening should be focused on making a preliminary design recommendation of which one to move forward on, or if that cannot be determined because of uncertainties, indicate what additional information so required to do so and provide direction as to what additional research is required.

[7] Customer Acceptance and Response

A more detailed characterization of RTP effects involves modeling subscription and price response in greater detail, which may require undertaking field research to establish value for the behavioral characterization these platforms utilize.

Price Response Modeling

Price response simulations are helpful when deciding whether or not to implement an RTP if they are conducted only for likely subscribers. Price elasticity summarizes how electricity usage changes as price changes, providing a metric that can be used to evaluate a prospective RTP design. For RTP, a convenient characterization is to divide days into peak and off-peak periods that correspond to time when RTP prices are likely to be much higher than the overall average price (price peak hours) and to when they vary only occasionally and modestly from the average price. Since high prices are most likely to induce usage changes by subscribers, and because studies suggest that most load shifting induced by RTP pricing is within day, this structure provides a way to estimate how an RTP structure affects the diurnal load profile.[13]

Estimating hourly (or shorter interval) impacts requires constructing an analytical framework that uses as inputs a baseline load profile and corresponding price changes. In this structure, the relative change in both load and price is defined by the difference in the peak and off-peak values which determines the load change. The price elasticity model produces a simulated load change for every day modeled that in turn produces a stream of benefits to the estimated subscribe. The simulation can be performed using a class load profile, the load profile for selected customers, or for each customer. The second option is more useful when likely

[13] As the forementioned review discussed, more complex characterizations of price response can be used to reflect hourly shifting among adjacent or distant hours of the day or even a subsequent day. They require many more elasticity estimates for which there are few reliable sources that makes simulating price effects more speculative with little additional insight. Hence a relatively simple platform is recommended.

subscribers have been identified. Modeling individual customers is a more daunting undertaking because elasticities have to be assigned to each.[14]

Adoption Modeling

Before a utility offers a new service, it should ideally know how many customers are likely to elect it over other available options. Load profiles will not be enough. A utility should also seek to segment customers for direct engagement and implementation campaigns. Customer preferences must be distinguished by observable demographics and premise characteristics so that outreach and marketing efforts can be conducted effectively. [15] Pilots can play a pivotal role in providing insights into customer acceptance of various RTP design options to inform final design for broad roll-out. Targeting an effective value proposition to those customers cost-effectively is paramount for success.

Discrete choice experiments (DCE) are well suited for estimating preferences for ESP.[16] A DCE is a structured way to elicit from customers detailed information about how the features (attributes) of a product or service contribute to the overall utility or value they assign to it. Its application to ESP involves breaking services down into their constituent parts, attributes, and measuring how those attributes contribute to consumer preferences for the services. Demographic and premise correlations facilitate associating preferences with observable customer characteristics, to develop segments that can be mapped to an electric service territory.

[14] A large number of customers modelled individually is tedious but in this simplified response structure the analytical mechanics of the simulation can be done in Excel quickly; the tedium is organizing and assessing the outputs.

[15] Estimating the level of Participation in a service when it is offered is only part the story. A utility needs to be able to estimate how participants alter electricity demand (Performance), and how long that participation and performance will be sustained (Persistence). EPRI is developing methods and models to address all of three elements, referred to as The Three Ps. Additional research is underway to round out the suite of methods and practices needed to provide customer with choices in a financially and socially responsible way. It begins by developing a strategic vision to align supply cost and considerations with services that comport with them, and effectively managing the portfolio of services that result.

16Methods for Characterizing Customer Preferences for Electric Service Plans. EPRI. 2012. 1024401.

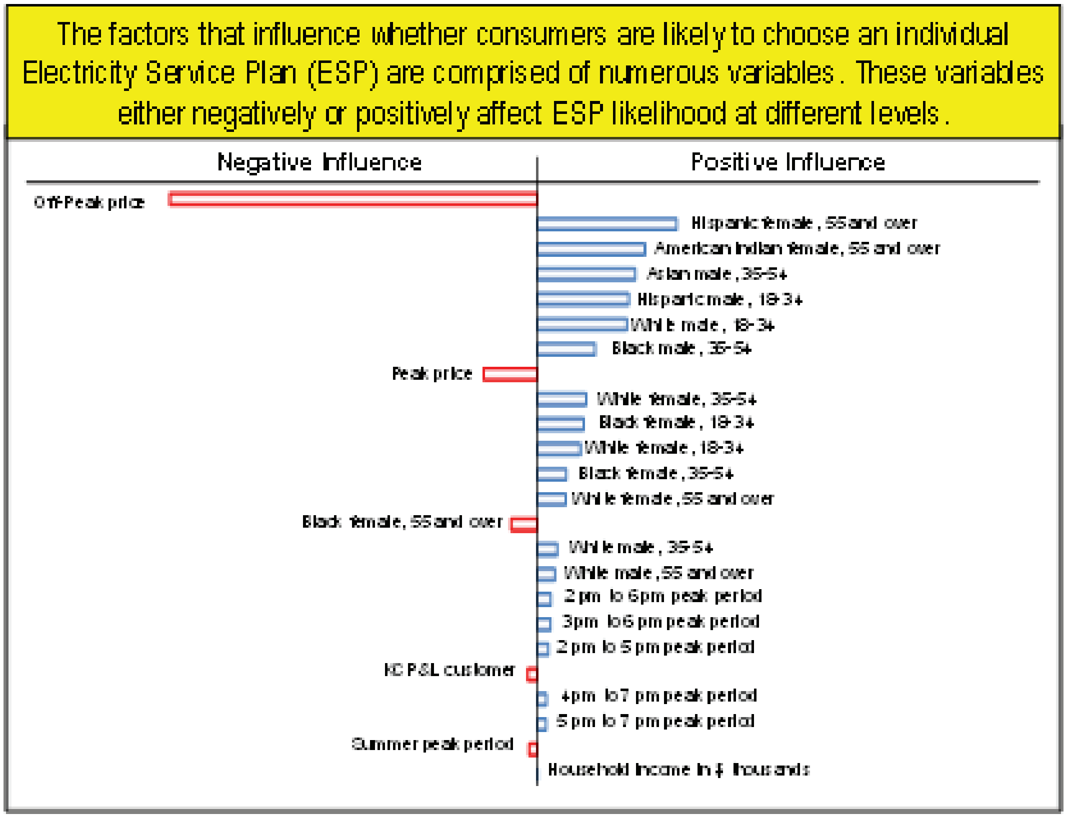

Figure 6-3
Factors Influencing Consumer Choice of Electricity Service Plan

DCE was developed to elicit preferences for new and novel products and services. It is well suited to elicit customer (residential customer) preferences for RTP. An example of its application to residential choices among TOU and uniform rates (Electric Service Plans) revealed the extent to which service design feature and demographics influence the likelihood of adoption, as illustrated in Figure 6-3.[17] A study undertaken by Oklahoma Gas and Electric reported preferences for alternative pricing designs from its study and a prior study by Public Service Oklahoma (PSO), including RTP as illustrated in Figure 6-4; 7 to 10% preferred RTP to alternatives involve less dynamic pricing like TOU, and about 25% indicated a preference for a full hedged service (fixed bill) where the subscriber agrees to pay an annual subscription fee ($/years) that does not change as a result of its usage during that period.

[17] Neenan, B., Bingham, M., Kinnell, J. Hickman, S. May 2016. Consumer Preferences for Electric Service Alternatives. Electricity Journal Vol. 29 Issue 5, pp. 62-71.

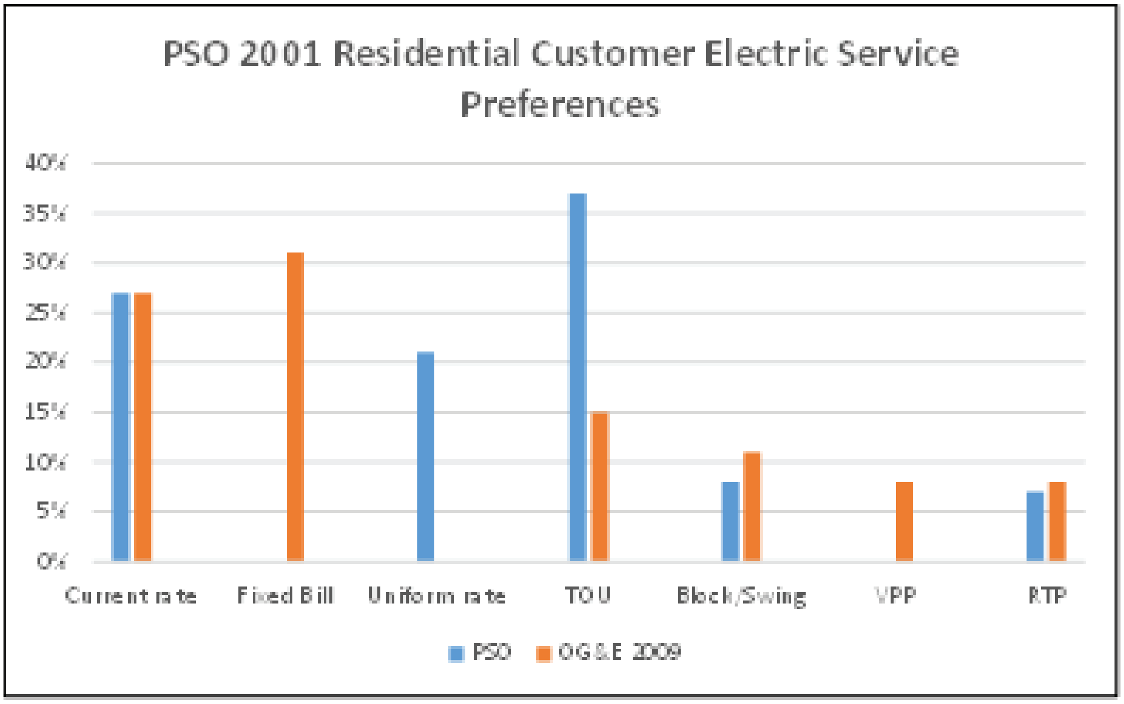

Figure 6-4
PSO 2001 Residential Customer Electric Service Preferences

Only a few such studies are available to provide this detailed characterization. A utility may conclude that those findings are inadequate to represent their customer circumstances, or that they are informative but not conclusive enough to support the RTP implementation decision. A field study may be required to collect date to construct an adoption platform.

Such studies require extensive time and resources to undertake, delaying RTP implementation. A key decision for a full impact analysis and using the results to decide on RTP implementation hinges on the degree to which the characterization of adoption is deemed adequate. If implementation depends on the realization of a specified threshold level of participation eventually, then an in-depth RTP adoption study may be required as part of the full impact analysis. Alternatively, the initial RTP implementation may be seen as the means for resolving uncertainties about the rate of adoption, and price response and persistence, and provisions are made as part of the launch to conduct research specifically to resolve uncertainties by limiting or targeting the subscription drive or implementing a pilot or experiment.

[8] Supply Impacts

Supply Costs

A measure of the benefit of RTP is how supply costs are affected. In the short run those benefits are captured though a welfare analysis as described above as the improved utilization of existing resources. The long-term implication is that RTP prices better equate consumption to the cost of supply, revealing the nature of electricity demand so that investment decisions in capital assets to supply power are more effectively used; the choice of generation assets to build and delivery improvements to serve demand. The need for peaking units that are seldom is reduced. Base load unit additions benefit from the more precise knowledge of demand and its time topology resulting in less surplus capacity that raises average costs. Establishing the change in investments in physical assets requires employing capacity planning models that forecast system asset investment needs over several years. These models are an integral component of utilities' system planning tools, and those of RTOs, that can trace out the implications of changes in electricity demand attributed to RTP.

Market Price Impacts

RTP is promoted as improving the efficiency of utilization of electricity sector assets. That comes from reduced usage when prices are high by shifting load to another, lower priced period. Expanded electricity consumption (the result of RTP average prices being lower than what would be charged under the OAT) also contributes to efficiency as available resources are utilized that otherwise would not. Measuring how RTP price response behaviors affect electricity supply captures these benefits.

One way to do so is to calculate the impact on the overall cost of supplying all customers' usage by comparing the change in the average cost of supply. Load shifting from high to low priced periods contributes to reducing the average supply cost. The benefit of increased usage during lower priced periods is more difficult to measure as there is no basis for equivalency. RTP price above the standard rate may provide incentive to expand usage because of the value realized by the subscribers from greater services powered by electricity. Using the difference between the RTP price and the OAT price would result in an increase in the average cost under RTP and could be sufficiently large to substantially reduce the load shifting benefits.

Alternatively, the benefits associated with RTP can be measured as the change in net welfare that results, where welfare is measured assessing the value of changes in electricity demand and the cost to do so. This involves constructing market supply and demand curves, imposing changes in supply over time to determine the resulting price change, and then interpreting. Ruff describes the foundation for such a measure of price changes and Boisvert and Neenan provide a way to employ this concept to measure the market benefits of dynamic pricing.[18] An example of its application to wholesale is provided in Boisvert et al. [19]

[9] Fulfillment Requirements

Implementing an RTP service requires recruiting customers to participate and constructing and operating systems to manage the processes.

Recruitment

The experience of utilities that have implemented RTP is that customer recruitment requires a concerted effort. Customers need to understand why RTP is different from their current service,

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[18] Ruff, L. October 2002. Economic Principles of Demand Response. Prepared for the Edison Electric Institute. Boisvert, R. Neenan. B. 2002. Establishing the Social Welfare Implications of Price Responsive Load (PRL) Programs in Competitive Electricity Markets.

[19] UtiliPoint International, Inc. May 29, 2007. The Benefits of Linking Massachusetts Retail Basic Service Prices to Wholesale LMPs. Prepared for: Massachusetts Division of Energy Resources: Boisvert, R., Neenan, B. August 2003. [8]Social Welfare Implications of Demand Response Programs in Competitive Electricity Markets. Lawrence Berkeley National Laboratory Report No. LBNL-52530. Available at http://www.lbl.gov/.

what actions are required to benefit from RTP, what costs are associated with those actions, and what the risks associated with RTP. Subscription campaigns generally prepare materials to introduce the concept and highlight the potential benefits to identify candidates. Subsequently, customers are typically provided detailed contractual descriptions of the RTP service and more detailed analyses of both the risks and benefits they can expect. The benefits can be illustrated by simulating example load changes using the customer offers as a possible response the customers' load profile using a representative (forecast of historic) RTP hourly price profile. Augmenting this with the experience of other customers that have benefited from RTP subscription reinforces the potential for benefits. These are time-consuming activities the cost of which in time and resources is an important input to the decision to proceed with implementation.

Services

Several new services are required to implement RTP that vary according to the design selected. Using RTP day-ahead prices as posted requires only establishing the means for retrieving them and sending them to subscribers. If the RTP prices are adjusted to create the RTPs prices, then processes and models are required that operate daily with a high degree of reliability. Deriving prices from utility system dispatch operations may require investments in those systems to extract the marginal operating prices and if employed, generate marginal outage costs. Setting prices for a state-driven schedule is relatively easy but setting up the schedule may require an investment in models to develop the marginal cost and observed conditions (state) relationships. Estimating the requirement for all these regimes is daunting, which emphasizes why the screening process is important so that all primary design decisions have bene made and only a single structural design proceeds to full analysis.

Enabling Technology

The review of RTP experience reveals that generally customers that subscribed were provided only the necessities; an interval meter to measure usage and in some cases equipment for receiving or retrieving posted prices. Most provided customer with hourly data to support response planning, in almost all cases in the form of monthly data sets. Some made the reading available regularly (daily) or directly from meter on demand. A few provided subscribers with software tools to help them develop scripts for how to reopen when prices hit a level where response might be beneficial.

The rudimental nature of these support technologies reflects time when many RTP programs were launched, the late 1980 and 1990 when technologies to implement load changes automatically, or at least assist accomplishing load changes, were limited to expensive controls intended for large business operations. Today, a wide variety of electricity device control technologies are available to control many aspects of a business (production processes and support services) and individual electric services at residences (like an HVCA systems, pool pumps, water heaters). These make carrying out price response actions easier and more effective, which makes subscription more attractive if the benefits realized exceed the costs to acquire and operate them. Regardless of which RTP basic structure is considered, the decision to implement should be informed by identifying which technologies are most likely to enhance RTP responsiveness and the ownership costs. A deciding factor maybe whether RTP produces sufficient benefit to warrant providing subscribers with enabling technology at reduced or no cost.

Consolidated Results – Benefit/Cost Analysis

Benefit/Cost Analysis (BCA) is an additional activity under Fulfillment Requirements, which provides a means for consolidating and synthetizing the impact, cost, and benefits, associated with a policy that effects an enterprise, a public or private entity. The difference is that a public policy BCA considers the impacts on all element of society while a BCA for a private firm generally limit the scope to factors that directly affect enterprise costs and benefits. Because the decision to implement RTP is strategic in nature, a BCA is warranted. Because it involves RTP subscribers and all other utility customers, and though the price impacts that effect regional markets and those that supply power to them, some societal impacts may warrant inclusion. EPRI developed a BCA framework for evaluating smart grid investments and provide a framework and template for identifying which cost and benefits to include in the RTP BCA, and how portray to inform the policy decision: should RTP be added to the service portfolio. [20]

EPRI has also investigated how a service portfolio can be optimized, which goes beyond a BCA by directly characterizing risks and incorporated risk preferences into portfolio addition decisions. [21] With further development utility ratemaking will progress from cost-based accounting decisions to consideration of how to optimize the service portfolio to maximize the use of societal and private resources.

[10] Comprehensive Impact Assessment

Design screening used available data that summarizes the experience of others with RTP, which might include that of a utility considering a redesign or extension of its RTP service. Screening alternatives may be sufficient to identify a single design for more in-depth analyses or propose several designs to evaluate because the screening distinguishers were insufficient to select on or rule out RTP launching an RTP service altogether. A full impact analysis extends the scope and scale of the impact analyses to provide more detailed estimate for load, financial and market impacts This requires developing behavioral analysis platforms that involve more extensive characterization of what factors (and their relative importance) influence subscription (participation), how subscriber respond to RTP prices and other influences that affect electricity demand. Original field research maybe required to construct these models.

An additional consideration is how wholesale electricity markets are affected, which in turn influences the topology of RTP prices. An equivalent analysis is appropriate when RTP prices are generated from utility dispatch operations or set using a state-variable schedule; how subscribers respond to posted prices affects how these pricing mechanisms evolve over time.

Finally, fulfilment costs are incurred to launch and support an RTP service. They must be identified and quantified as originating and ongoing costs which will vary in nature and level depending on the design chosen.

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[20] The basic of BCA as applied to utility decisions, which can be adapted to service portfolio changes, are laid out in: The Integrated Grid: A Benefit/Cost Framework. EPRI 3002004878.

[21] Specifications for and Design of an Electric Service Plan Portfolio Management System. EPRI 3002001266

The estimated costs and benefits measure what to expect from implementing an RTP service, summarized as net benefits over the study period.

[11] Implement: Pilot or Full-Scale

The comprehensive impact assessment informs whether to implement the RTP as a full-scale rate offering or a pilot. A pilot can help establish a platform to learn about customer uptake for various design options and resultant bill and load impacts. As one of the considerations, the BCA can help stakeholders understand the cost that would be incurred to implement a specific RTP design, the benefits that are expected to accrue for that program, and the fulfillment requirements, all portrayed over an extended time period (for example 5 years). It also indicates constraints that effect the timing for implementation, and an overall assessment of the certainty associated with this characterization. In particular, it identifies elements whose outcome are uncertain and the consequences for the net benefits estimate.=[12] Shortcomings: Redesign

If the proposed and full configured and evaluated design is deemed not sufficient for testing or full adoption, stakeholders should determine if shortcomings are resolvable. Risks may be not resolvable though a pilot and may require additional analyses, including customer acceptance and response, supply impacts, fulfillment requirements. It may require re-piloting or it may mean RTP does not provide sufficient benefit to warrant the articulated risks, and consideration is shelved. As a result, the portfolio stands as is unless in the process of considering RTP shortcomings in existing dynamic service are revealed that warrant attention. The process described herein can be used to consider ways to improve their contribution to strategic goals.

[13] Develop Plan

A directive to move forward requires additional planning to accomplish. An experiment or pilot must be designed to address specific hypotheses about outcomes (acceptance, response, and persistence, market price impacts, etc.). A full-scale implementation may require a staged implementation that sets priorities for what customers to offer service to and how to prepare the fulfillment requirements, which may involve substantial development of analytical and software tools and technologies to support RTP-interval measurement, pricing, and accounting, and acquiring and installing enabling technologies at subscriber’s premises. The schedule created for the impact analysis must identify and arrange all of the technology, systems, process, and staff requirements sequentially to define the workflow over time. Refinement of resource requirements is also necessary and regulatory filings must be identified and undertaken.

A

Utility Interview Guide

Section Summary

What follows is the interview guide used to structure the telephone interviews with utility rates professionals, the results of which are summarized in Section 4. Rather than serving as strict interview script, this document provided parameters to guide the discussions to ensure coverage of fundamental points while allowing flexible narrative pathways as the conversations unfolded.

Introduction

Hello and thank you again for agreeing to participate in EPRI's Real Time Pricing research. As a token of our appreciation for your time, you'll receive a complimentary summary of study findings, available in the first quarter of 2021.

Today's discussion is anticipated to take approximately 45 minutes to one hour. We understand your time is valuable and will respect it. If there are any questions, you're unable to answer today and would like to get back to us later with more information, we'd be happy to schedule a follow-up conversation with you or another member of your staff or collect additional information via email.

<u>Privacy</u>

Your responses and comments today will not be attributed to you by name in our report; rather, information gathered in these utility interviews will be used in aggregate to inform our findings and only publicly available tariff filings and other public information will be attributed to your utility, if appropriate. Just a reminder: I'll be taking notes and recording our conversation for reference and accuracy, but the recording will not be distributed externally.

Do I have your permission to record this call? [yes/no - if yes, start recording; if no, discuss options, reschedule, or terminate.]

RTP Tariff History

(1) What was the initial motivation for the tariff?
   a. Compliance with regulatory order and reasoning for regulatory order (please describe requirements or name order for further review)
   b. Preparation for, or response to, retail competition
   c. Response to customer interest
   d. Replace conventional interruptible rates
   e. Other:

(2) What was the <u>primary</u> program goal?
   a. To encourage peak demand reductions
   b. To encourage load growth
   c. Other load management objectives
   d. To retain existing and/or attract new customers

e. Whatever results from efficient pricing
f. To measure customers' price elasticity
g. To gain experience with market-based pricing
h. To recover revenue requirements more equitably
i. To reduce costs for utility, customer, system
j. Other:

(3) Is the program still active? Available to new subscribers? If so...

(4) What is your company's current attitude and level of enthusiasm for the program? Any plans to modify the program?

(5) When is the program set to expire? Will it be renewed?

(6) If the program has closed, when? Briefly describe the primary reason(s) why.
a. Tariff term expired
b. No subscribers or too few to warrant continuation
c. Replaced with another dynamic pricing service. What was it (tariff name and type, like CPP/PRT/TOU)?
d. Other

Marketing Strategy

(7) Is this a default pricing program for some customers, e.g., mandatory or opt-out? Or is this a choice in a portfolio of pricing plans, i.e., opt-in?

(8) Has the tariff been or was it pro-actively marketed (for example, by identifying likely participants and arranging meetings)?

(9) To which customer classes was the program marketed? What criteria are used to identify prospective participants? Are solar customers able to participate in the RTP program? Do you think RTP will be attractive for customers with solar + storage, or storage only? How theoretical is this idea?

(10) How were customers informed of the tariff offering (check all that apply)?
a. Email marketing
b. Brochures/bill inserts
c. website content
d. Workshops
e. Customer Meetings organized by account representatives
f. Meetings sponsored by Public Service Commission or other entity
g. Other? Please specify.

Participation

(11) How many customers are currently enrolled? And how do you define customers? (e.g. one meter = one customer? other?)
a. If the program is closed, how many customers were enrolled when it closed?

b. What was the highest level of subscription in any year – and for the year it ended?
c. And what is (or was) the program's total summer peak demand (MW) at the apex of the program, i.e. at the time of highest subscription? What percentage of total load did that represent?
d. If the program is closed, what was the total peak demand (MW) at closure?
e. What types of customers are enrolled? Any concentration by industry, size, etc.?

(12) Approximately how many customers are/were eligible for the tariff within your service territory (based on minimum size restrictions, etc.)? What is their combined summer peak demand?

(13) If eligible customers are able to take service from a competitive service provider, what portion chose to do so?

(14) Do any of the competitive service providers have an RTP rate?

(15) What is the utility's summer peak demand?

(16) Over the past several years of the program, how would you characterize the level of program subscription?
a. Enrollment has been increasing (absolute or percentage terms)
    i. Number of new enrollments?
b. Enrollment has been about the same with few new subscriptions or retirements
    i. Why have customers dropped out?

(17) What customer feedback have you received or gathered about the pricing program, e.g., anecdotal, survey or other? Was it generally positive, negative, or mixed? Please summarize the customer questions, concerns and/or feedback you've received about starting on and participating in the program.

Performance

(18) Are any published materials or regulatory proceedings available that report how RTP prices altered subscribers' electricity usage?

(19) What percent of enrolled customers appear to alter their usage based on posted RTP prices? How have marginal prices varied over the past several years (e.g., maximum price, frequency of price spikes, etc.)? Do you have a report or dataset with posted RTP prices for some or all of the years that services have been offered? If so, can you provide it?

(20) Is there some threshold marginal price above which customers that actively participate in the tariff begin to alter their electricity usage?

(21) What is the maximum load reduction due to high prices that the program has induced? At what posted RTP price did this occur?

(22) What level of load reduction would likely occur at prices of [insert range of prices appropriate for the interviewee's utility based on prevailing rates in the state or region, e.g.]?
   a. 10 ¢
   b. 20 ¢
   c. 50 ¢

(23) Are customers provided with access (e.g. via the internet) to their hourly electricity consumption? If so, when to they have access or receive notification?
   a. Real-time or near-real-time
   b. Day-after
   c. End of month

(24) What are typical bill impacts on the program?

(25) Have customers been provided with technical assistance to help identify strategies for responding to prices?

(26) How do customers take in the pricing signals? Do they have energy management systems that have been programmed to respond hourly? Is this generally a manual process (view the day ahead prices online and manually adjust operations the next day)?

(27) If only large customers are enrolled, what is the likelihood that this program would be extended to smaller customers and/or residential customers?

(28) Is price response from customers on the tariff incorporated into:
   a. Daily system scheduling/dispatch?
   b. The creation of RTP prices?
   c. Long-term planning (e.g., IRP), or other resource decisions?

(29) How were/are daily prices transmitted to subscribers; what alternative mechanisms were/are available? How was/is receipt of prices confirmed?

(30) Were/are daily prices made publicly available? If so, when were/are they posted?
   a. At a later time or not at all?
   b. RTP prices are not made publicly available

Implementation Experience/Lessons Learned

(31) Overall, what was the utility's experience in implementing this program? What went well? What were some areas for improvement?

(32) What changes were required to usage metering equipment, procedures, and practices?

(33) What changes were required to billing procedures and practices?

(34) What changes were required to financial, accounting procedures and practices?

(35) What were the main lessons learned from this program implementation?

Conclusion

(36) Is there anything else you'd like to add that we haven't already discussed?

This concludes today's interview. As we discussed at the beginning, if there is any additional information, you'd like some time to gather and share with us, please let me know. We can set another time to talk or we can exchange information by email, if that's easier for you.

Thank you very much for your time and insights today.

Goodbye.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

ATTACHMENT A

ELECTRIC POWER RESEARCH INSTITUTE REAL TIME PRICING BENCHMARKING STUDY, PROGRAM ATTRIBUTES, MARCH 2021

Benchmarking Study of US Regulated Utility Real Time Pricing Programs, Architecture and Design, Techncial Update, March 2021
Active RTP Program Attribute Detail

					RTP Structural Attributes															
					1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Holding Company	**State**	**Status of Retail Competition**	**Utility Jurisdictions**	**RTP Program Name**	**Availability**	**Eligibility**	**Mandatory?**	**Maturity (Permanent vs. Experimental)**	**Enrollment cap**	**Pricing Structure**	**CBL Revision or Adjustment (Two-part)**	**Price Granularity - Temporal [d]**	**Price Granularity-Spatial**	**Daily Price Posting Frequency**	**Overcall of Posted Day-Ahead Prices**	**Energy Price Formation**	**Generation, Transmission, Distribution Capacity Pricing**	**Marginal Uplift in Hourly Energy Price to cover Admin and Implementation costs**	**Contract Term**	**Mechansim to Hedge Customer Price Risk**
Southern Company	**Alabama**	**No Retail Choice**	**Alabama Power**	XRTPD (Real Time Pricing - Day Ahead) Effective July 9, 2019	Capped (No longer available to new accounts)	Industrial customers: >= 500 kW Commercial customers: >= 850 kW	No	Permanent	None	CBL	Yes; only in the event the customer's connected capacity increases requiring additional investment by the Company	Hourly	None	Day-ahead	Yes; may increase hourly price 30 min ahead	Supplier's forecast MC	Collected in access charge (Two-Part RTP)	Yes Energy Cost Recovery (ECR) factor applied to hourly rates	5 years for new customers; 1 year for existing customers	Yes; Rate Stabilization and Equalization Factor (RSE) applied into hourly rate to increase or decrease kWh charges
Southern Company	**Alabama**	**No Retail Choice**	**Alabama Power**	RTP (Real Time Pring Industrial Power) Effective Jan 2006	Open enrollment	44kV or higher ; < 20 MW	No	Permanent	None	Energy and Demand	N/A	Hourly	None	Day-ahead	Yes; may increase hourly price as 30 min ahead	Supplier's forecast MC	Collected through demand or other metered charges	Yes Energy Cost Recovery (ECR) factor applied to hourly rates	5 years for new customers; 1 year for existing customers	Yes; Rate Stabilization and Equalization Factor (RSE) applied into hourly rate to increase or decrease kWh charges
Ameren Corporation	**Illinois**	**Full Retail Choice**	**Ameren (IL)**	Rider RTP-1 Residenal Real-Time Pricing Effective April 12 2017	Open enrollment	Entire eligible class; Customers served under DS-1 (residential)	No	Permanent	None	Energy Only	N/A	Hourly	Spatially differentiated (locational marginal prices as a subset of energy charges)	Day-ahead	No	MISO	Collected in energy price (One-Part RTP)	unspecified	Month	unspecified
Ameren Corporation	**Illinois**	**Full Retail Choice**	**Ameren (IL)**	RTP-2 Small General Real-Time Pricing	Open enrollment	Entire eligible class; Customers served under DS-2 (non-residential general service)	No	Permanent	None	Energy Only	N/A	Hourly	Spatially differentiated (locational marginal prices as a subset of energy charges)	Day-ahead	No	MISO	Collected in energy price (One-Part RTP)	unspecified	Month	unspecified
CH Energy Group	**New York**	**Full Retail Choice**	**Central Hudson**	Hourly Pricing Provision in Service Classification No.2 (General Service)	Open enrollment	General Service Non-Residential, demand > 300 kW and < 1 MW	Yes Effective 10/1/11: default for customers > 500 kW in any 2 of 12 previous months who elect to purchase energy from CenHud. Effective 10/1/12 default for all customers > 300 kW in 2 of 12 previous months who elect to purchase energy from CenHud. Opt-in for all other eligible customers who elect to purchase 100% of their energy from CenHud	Permanent	None	Energy and Demand	N/A	Hourly	None	Day-Ahead	No	NYISO Day-Ahead LBMP	Collected through demand or other metered charges	unspecified	None (month to month)	unspecified
CH Energy Group	**New York**	**Full Retail Choice**	**Central Hudson**	Hourly Pricing Provision in Service Classification No.3 (Large Power Primary Service)	Open enrollment	Large Power Primary Service, demand >= 1 MW	Yes Default for eligible customers who elect to purchase their energy from CenHud	Permanent	None	Energy and Demand	N/A	Hourly	None	Day-Ahead	No	NYISO Day-Ahead LBMP	Collected through demand or other metered charges (e.g. Demand)	unspecified	None (month to month)	unspecified
Exelon Corporation	**Illinois**	**Full Retail Choice**	**Commonwealth Energy (ComEd)**	Rate BESH Basic Electric Service Hourly Pricing (Non-Res)	Open enrollment	Entire eligible class; Retail customers under bundled electric service	No	Permanent	None	Energy and Demand	N/A	Sub-Hour	None	Real-time (avg of twelve 5 minute real-time PJM prices for that hour; price is not fully known until after the hour)	No	PJM Zonal Wholesale Hourly Pricing	Collected through demand or other metered charges	unspecified	Year to Year	No: Not included for non-res BESH while explicitly included in res BESH
Exelon Corporation	**Illinois**	**Full Retail Choice**	**Commonwealth Energy (ComEd)**	Rate BESH Basic Electric Service Hourly Pricing (Res)	Open enrollment	Entire eligible residential class; Retail customers under bundled electric service	No	Permanent	None	Energy and Demand	N/A	Sub-Hour	None	Real-time (avg of twelve 5 minute real-time PJM prices for that hour; price is not fully known until after the hour)	No	PJM Zonal Wholesale Hourly Pricing	Collected through demand or other metered charges	unspecified	Year to Year	Yes: Rider RRTP serves as Bill Protection Experiment; applicable only to maximum of 20,700 residential customers
Duke Energy Corporation	**North Carolina**	**No Retail Choice**	**Duke Energy Carolinas (North Carolina)**	HP (NC) Hourly Pricing for Incremental Load	Open enrollment	>= 1 MW under LGS, I, OPT-V or PG	No	Permanent	Maximum 150 customers on the system	CBL	Yes; Every four years	Hourly	None	Day-Ahead	No	Supplier's forecast MC	Collected in access charge (Two-Part RTP)	unspecified	Year to Year	Yes
Duke Energy Corporation	**South Carolina**	**No Retail Choice**	**Duke Energy Carolinas (South Carolina)**	HP (SC) Hourly Pricing for Incremental Load	Open enrollment	>= 1 MW under LGS, I, OPT or PG	No	Permanent	Maximum 150 customers on the system	CBL	Yes; Every four years	Hourly	None	Day-Ahead	No	Supplier's forecast MC	Collected in access charge (Two-Part RTP)	unspecified	Year to Year	Yes
Duke Energy Corporation	**Indiana**	**No Retail Choice**	**Duke Energy Indiana**	Experiment Rate - Market Pricing Program	Open enrollment	Customers served under LLF, HLF; minimum monthly peak load >= 1 MW	No	Experiment	None	CBL	No	Hourly	None	Day-Ahead	No	MISO LMP	Collected in access charge (Two-Part RTP)	unspecified	Year to Year	Yes
Duke Energy Corporation	**Kentucky**	**No Retail Choice**	**Duke Energy Kentucky**	RTP Experimental Real Time Pricing	Open enrollment	Entire eligible non residential customer class	No	Experiment	None	CBL	Yes; if customer consumption differs significantly	Hourly	None	Day-Ahead	No	PJM Day-Ahead Total Locational Marginal Price for power at the DEK Aggregate price node	Collected in access charge (Two-Part RTP)	unspecified	Year to Year	Yes

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Active RTP Program Attribute Detail

					RTP Structural Attributes															
					1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Holding Company	**State**	**Status of Retail Competition**	**Utility Jurisdictions**	**RTP Program Name**	**Availability**	**Eligibility**	**Mandatory?**	**Maturity (Permanent vs. Experimental)**	**Enrollment cap**	**Pricing Structure**	**CBL Revision or Adjustment (Two-part)**	**Price Granularity - Temporal [d]**	**Price Granularity-Spatial**	**Daily Price Posting Frequency**	**Overcall of Posted Day-Ahead Prices**	**Energy Price Formation**	**Generation, Transmission, Distribution Capacity Pricing**	**Marginal Uplift in Hourly Energy Price to cover Admin and Implementation costs**	**Contract Term**	**Mechansim to Hedge Customer Price Risk**
Duke Energy Corporation	**Ohio**	**Full Retail Choice**	**Duke Energy Ohio**	RTP Real Time Pricing Program	Open enrollment	Entire eligible non residential customer class	No	Permanent	None	CBL	No	Hourly	None	Day-Ahead	No	PJM Balancing Market (Real-Time) Locational Marginal Price (LMP) at the DEOK Zone inclusive of the energy, congestion, and losses charges, for each hour	Collected in access charge (Two-Part RTP)	unspecified	Year to Year	Yes
Duke Energy Corporation	**North Carolina**	**No Retail Choice**	**Duke Energy Progress (North Carolina)**	LGS-RTP-62 Large General Service Real Time Pricing	Open enrollment	Nonresidential customers with a Contract Demand >= 1 MW	No	Permanent	Maximum of 85	CBL	Yes; customer request (30-day advance written)	Hourly	None	Day-Ahead	No	Supplier's forecast MC	Collected in access charge (Two-Part RTP)	unspecified	Month	Yes
Duke Energy Corporation	**South Carolina**	**No Retail Choice**	**Duke Energy Progress (South Carolina)**	LGS-RTP-61	Open enrollment	Nonresidential customers with a Contract Demand >= 1 MW	No	Permanent	Maximum of 20	CBL	Yes; only downward adjustment at customer's request (30 days advance) due to energy efficiency measures	Hourly	None	Day-Ahead	No	Supplier's forecast MC	Collected in access charge (Two-Part RTP)	unspecified	Year to Year	Yes
Southern Company	**Georgia**	**Partial Retail Choice**	**Georgia Power**	RTP-HA-5 Real Time Pricing - Hour Ahead	Open enrollment	Peak 30-minute demand >= 5 MW each month	No	Permanent	None	CBL	Yes; Within 2 years after event causing the revision	Hourly	None	Hour-Ahead	Yes; continue to receive prices on an hour-by-hour basis if on price protection	Supplier's forecast MC	Collected in access charge (Two-Part RTP)	No; Fixed monthly admin charge	5 years	Yes; Schedule of options offered in the tariff (Price Protection Products)
Southern Company	**Georgia**	**Partial Retail Choice**	**Georgia Power**	RTP-DA-5 Real Time Pricing - Day Ahead	Open enrollment	Peak 30-minute demand >= 250 kW each month	No	Permanent	None	CBL	Yes; Within 2 years after event causing the revision	Hourly	None	Day-Ahead	Yes; continue to receive prices on an hour-by-hour basis if on price protection	Supplier's forecast MC	Collected in access charge (Two-Part RTP)	No; Fixed monthly admin charge	5 years	Yes; Schedule of options offered in the tariff (Price Protection Products)
Southern Company	**Florida**	**Retail Choice Under Consideration**	**Gulf Power**	RTP Limited Available Rate Real Time Pricing	Open enrollment	Customers under LP, LPT, PX, PXT with an annual peak load >= 500 kW for previous 12 months	No	Permanent	None	Energy Only	N/A	Hourly	None	Day-Ahead	No	Supplier's forecast MC	Collected in energy price (One-Part RTP)	unspecified	Year to Year	unspecified
National Grid plc	**New York**	**Full Retail Choice**	**Niagara Mohawk Power**	Hourly Electric Supply Charge in Schedule SC-3A	Open enrollment	Monthly demand > 2 MW in any two consecutive months for the previous 12 months	No	Permanent	None	Energy and Demand	N/A	Hourly	Load Zone specific	Day-Ahead	No	NYISO Day-Ahead LBMP	Collected through demand or other metered charges	unspecified	Year to Year	No
OGE Energy Corp.	**Oklahoma**	**No Retail Choice**	**OG&E**	Day Ahead Pricing (DAP)	Open enrollment	Entire eligible customer class (non residential)	No	Permanent	None	CBL	Yes; if permanent operational changes	Hourly	None	Day-Ahead	No	Based on SPP hourly Day-Ahead LMP for OGE, OGE's hourly Marginal Outage Costs, adjustments for service-level loss and Risk and Recovery Factor	Collected in access charge (Two-Part RTP)	unspecified	Month to month	Yes
OGE Energy Corp.	**Oklahoma**	**No Retail Choice**	**OG&E**	Flex Price FP 2018	Open enrollment	Entire eligible customer class (non residential)	No	Experiment	None	CBL	Yes; if permanent operational changes	Blocked hours	None	Day-Ahead	No	Based on SPP hourly Day-Ahead LMP for OGE; convert DAP daily prices into 6 average TOU period prices daily	Collected in access charge (Two-Part RTP)	unspecified	Month to month	Yes
WEC Energy Group	**Wisconsin**	**No Retail Choice**	**Wisconsin Electric Power**	RTMP Real-Time Market Pricing Rider	Open enrollment	C&I Customers served under Cp1 (>= 300 kW); Cp3 (>= 500 kW), Cp3S (>=100 kW - closed); CpFN (>=1,000 kW - closed)	No	Permanent	Maximum of 300 MW of Billed Demand at presubscription demand levels	CBL	Yes; if data issues or result of energy efficiency, up to once per year	Hourly	None	Day-Ahead	No	Locational Marginal Prices by MISO	Collected in access charge (Two-Part RTP)	unspecified	Year to Year	Yes
WEC Energy Group	**Wisconsin**	**No Retail Choice**	**Wisconsin Electric Power**	RTP Real-Time Pricing Rider	Open enrollment	C&I Customers served under Cp1 (>= 300 kW) and at voltage >= 138 kvolts	No	Permanent	Maximum of 200 MW of total nominated RTP load	Energy and Demand	N/A	Hourly	None	Day-Ahead	No	Locational Marginal Prices by MISO	Collected through demand or other metered charges	unspecified	Intial term of 3 years and 2 year cancellation notice	unspecified
Consolidated Edison, Inc.	**New York**	**Full Retail Choice**	**ConEd**	NY Mandatory Hourly Pricing	Open enrollment	Monthly peak demand >500 kW	Yes	Permanent	None	Energy and Demand	N/A	Hourly	None	day-ahead	No	NYISO posted zonal day-ahead wholesale hourly price	Collected through monthly demand charge	unspecified	unspecified	unspecified

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Active RTP Program Attribute Detail

Holding Company	State	Status of Retail Competition	Utility Jurisdictions	RTP Program Name
Evergy	Missouri	No Retail Choice	Kansas City Power & Light	Real Time Pricing Program
MidAmerican Energy Company	Iowa	No Retail Choice	MidAmerican Energy	Rate DAP
Avangrid	New York	Full Retail Choice	New York State Electric & Gas (NYSEG)	NY Mandatory Hourly Pricing
Consolidated Edison, Inc.	New York	Full Retail Choice	Orange & Rockland	NY Mandatory Hourly Pricing
Rochester Gas & Electric	New York	Full Retail Choice	Rochester Gas & Electric	NY Mandatory Hourly Pricing
Otter Tail Corporation	Minnesota	No Retail Choice	Otter Tail Power Company	Real Time Pricing Rider
Sempra Energy	California	Partial Retail Choice	San Diego Gas & Electric (SDG&E)	Commodity Rate as a component in Schedule VGI - Electric Vehicle Grid Integration Pilot Program
Xcel Energy Inc.	Wisconsin	No Retail Choice	Xcel Energy WI	RTP-1 Experimental Real Time Pricing Service
FirstEnergy Corporation	Ohio	Full Retail Choice	OhioEdison	Rider RTP Experimental Real Time Pricing Rider
FirstEnergy Corporation	New Jersey	Full Retail Choice	Jersey Central Power & Light	Rider BGS-CIEP
Exelon Corporation	Delaware	Full Retail Choice	Delmarva Power (Delaware)	Hourly Priced Service Rider (HPS)
Dominion Energy, Inc.	North Carolina	Partial Retail Choice	Dominion North Carolina Power	Schedule LGS-RTP

RTP Structural Attributes

Holding Company	1 Availability	2 Eligibility	3 Mandatory?	4 Maturity (Permanent vs. Experimental)	5 Enrollment cap	6 Pricing Structure	7 CBL Revision or Adjustment (Two-part)	8 Price Granularity - Temporal [d]
Evergy	Capped Frozen - not available to new customers after Feb 22, 2017	Entire eligible customer class (non residential)	No	Permanent	Unspecified	CBL	unspecified	Hourly
MidAmerican Energy Company	Capped (tariff since 2015	Available only to University of Iowa	No	Pilot	Single customer only (University of Iowa)	CBL	Yes; up to 2 changes per month as mutially agreed by MidAm and customer	Hourly
Avangrid	Open enrollment	>300 kW	Yes	Permanent	None	Energy and Demand	N/A	Hourly
Consolidated Edison, Inc.	Open enrollment	>500 kW	Yes	Permanent	None	Energy and Demand	N/A	Hourly
Rochester Gas & Electric	Open enrollment	>300 kW	Yes	Permanent	None	Energy and Demand	N/A	Hourly
Otter Tail Corporation	Open enrollment (Effective with bills rendered on or after Feb 1,2019)	Demand >= 200kW during historical period used for CBL development	No	Permanent	Limited to 20 Customers	CBL	Yes; if change of equipment or at time of re-subscription	Hourly
Sempra Energy	Open enrollment (Effective 2017-2020)	currently registered BEV or PHEV charged through SDG&E owned facilities	No	Pilot	None	Energy and Demand	N/A	Hourly
Xcel Energy Inc.	Capped; No new customers (effective 2018, Experiment period to end 12/31/21)	Monthly peak demand >= 1 MW	No	Experiment	Limited to 60 MW	Pre-set block prices for energy (based on 8 day types); plus demand charges	N/A	Blocked hours
FirstEnergy Corporation	Open enrollment (Effective 2016 on experimental basis through 05/31/24)	Entire eligible customer class (non residential); exclusions for customers served under Rider ELR, HLF, CPP, GEN	No	Experiment	None	Energy Only	N/A	Hourly
FirstEnergy Corporation	Open enrollment	Customers served under Schedules GP and GT; peak load >= 500 kW	No	Permanent	None	Energy and Demand	N/A	Hourly
Exelon Corporation	Open enrollment (Effective 2015, current tariff)	Entire eligible customer class (non-residential)	Yes Mandatory for Cusstomers in GS-T, Customers with Capacity PLC >= 1000 in GS-P and LGS-S	Permanent	None	Energy and Demand	N/A	Hourly
Dominion Energy, Inc.	Open enrollment (Effective 2019, current tariff)	Non-residential customer with peak demand > 3 MW but < 50 MW in past 12 months (in conjunction with Schedule 6L)	No	Experiment	Limitation of 15 nonresidential customers where 5 spaces shall be reserved for new customers	CBL	Yes Can adjust up or down based on change in customer's max monthly peak demand; at next contract anniversary.	Hourly

Holding Company	9 Price Granularity-Spatial	10 Daily Price Posting Frequency	11 Overcall of Posted Day-Ahead Prices	12 Energy Price Formation	13 Generation, Transmission, Distribution Capacity Pricing	14 Marginal Uplift in Hourly Energy Price to cover Admin and Implementation costs	15 Contract Term	16 Mechansim to Hedge Customer Price Risk
Evergy	None	day-ahead	No	Suppliers Forecast; Utility-generated day-ahead forecast of hourly short-run marginal cost of generation and transmission of energy to Missouri retail customers	Collected in access charge (Two-Part RTP)	unspecified	unspecified	Yes
MidAmerican Energy Company	None	day-ahead	No	MISO MEC.MECB DA Load Zone price	Collected in access charge (Two-Part RTP)	unspecified	unspecified	Yes
Avangrid	None	day-ahead	unspecified	NYISO posted zonal day-ahead wholesale hourly price	Capacity costs recovered based on customer's co-incident peak demand for the previous year (capacity tag)	unspecified	unspecified	unspecified
Consolidated Edison, Inc.	None	day-ahead	unspecified	NYISO posted zonal day-ahead wholesale hourly price	Collected through demand or other metered charges	unspecified	unspecified	unspecified
Rochester Gas & Electric	None	day-ahead	unspecified	NYISO posted zonal day-ahead wholesale hourly price	Capacity costs recovered based on customer's co-incident peak demand for the previous year (capacity tag)	unspecified	unspecified	Yes
Otter Tail Corporation	None	day-ahead	None	Supplier's forecast MC plus outage cost	Collected in access charge (Two-Part RTP)	No (flat monthly admin charge)	Year to Year	None
Sempra Energy	Yes	day-ahead	Yes; day-of hourly adjustment for surplus energy is applied when day-of prices lower than day-ahead prices >= 1 cent	CAISO day-ahead hourly price	Collected through demand or other metered charges	unspecified	Year to Year	None
Xcel Energy Inc.	None	day-ahead (notification of next day type)	N/A	Pre-set prices	Collected through demand charges tiered based on service voltage	unspecified	Year to Year	None
FirstEnergy Corporation	None	day-ahead	No	PJM day-ahead LMP	Collected in energy price (One-Part RTP)	No (flat monthly admin charge)	unspecified	None
FirstEnergy Corporation	None	day-ahead	No	Real-time PJM load weighted average residential metered load aggregate LMP	Collected through demand or other metered charges	No	Year to Year	None
Exelon Corporation	None	day-ahead	No	real time PJM load weighted average residential metered load aggregate LMP	Collected through demand or other metered charges	No	unspecified	None
Dominion Energy, Inc.	None	day-ahead	No	PJM day-ahead LMP	Collected in access charge (Two-Part RTP)	No	Year to Year	Yes

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Holding Company	**State**	**Status of Retail Competition**	**Utility Jurisdications**	**RTP Program Name**	**Availability**	**Eligibility**	**Mandatory?**	**Maturity (Permanent vs. Experimental)**	**Enrollment cap**	**Pricing Structure**	**CBL Revision or Adjustment (Two-part)**	**Price Granularity - Temporal [d]**	**Price Granularity- Spatial**	**Daily Price Posting Frequency**	**Overcall of Posted Day-Ahead Prices**	**Energy Price Formation**	**Generation, Transmission, Distribution Capacity Pricing**	**Marginal Uplift in Hourly Energy Price to cover Admin and Implementation costs**	**Contract Term**	**Mechansim to Hedge Customer Price Risk**
Dominion Energy, Inc.	**North Carolina**	**Partial Retail Choice**	**Dominion North Carolina Power**	Schedule LGS-RTP Economic development Day-Ahead Hourly Pricing	Open enrollment (Effective 2019, current tariff)	customer has added at least 10 MW of new load at one delivery point, but not exceed 50 MW	No	Experiment	Limitation of 6 nonresidential customers where 3 spaces shall be reserved for new customers	Energy and Demand	N/A	Hourly	None	day-ahead	No	PJM day-ahead LMP	Collected through demand or other metered charges	No	Year to Year	None
Dominion Energy, Inc.	**Virginia**	**Partial Retail Choice**	**Dominion Energy Virginia**	Schedule MBR - Market Base Rate	Open enrollment (Effective 2020; will be withdrawn 12/31/2022)	In conjunction with GS-3; peak demand >= 5 MW at least 3 months within current and previous 11 months; monthly load factor >= 85%	No	Experiment	None	Energy and Demand	N/A	Hourly	None	day-ahead	No	PJM day-ahead LMP	Collected through demand or other metered charges	Yes (to Cover Utility and PJM Admin costs)	3 Year minimum	None
FirstEnergy Corporation	**Pennsylvania**	**Full Retail Choice**	**Penn Power**	Rider I - Hourly Pricing Default Service Rider	Open enrollment (Effective June 2019; current tariff)	Customers on GM (> 100 kW), GS-Large (>= 400 kW and < 2.500 kVa); GP, GGT, GS; must have smart meter	Yes Default Service for customers > 500 kW under GS-Large, GP, GT (elected customers); Voluntary for GS, GM	Permanent	None	Energy and Demand	N/A	Hourly	None	day-ahead	unspecified	PJM "Real Time" load-weighted average LMP	Collected through demand or other metered charges	Yes	unspecified	None
PPL Corporation	**Pennsylvania**	**Full Retail Choice**	**PPL Electric Utilities**	GSC - Generation Supply Charge-2 (Energy component)	Open enrollment (Effective June 2020; current tariff)	C&I customers with peak demand >= 100 kW who take Basic Utility Supply Service under GS-3, LP-4, LP-5; peak demand >= 100 kW	Yes Default service to eligible large C&I customers who have not selected an alternative generation supplier	Permanent	None	Energy and Demand	N/A	Hourly	None	Day-ahead	unspecified	PJM real-time LMP at PPL Residual Aggregate Node	Collected through demand or other metered charges	Yes	unspecified	None
Xcel Energy Inc.	**Minnesota**	**No Retail Choice**	**Northen States Power**	MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2REAL TIME PRICING SERVICE: RATE CODE: A62 (FIRM), A63 (CONTROLLABLE)	Open enrollment	Available to customers with peak demand >= 1 MW and < 150 MW. The controllable service option requires a minimum controllable load of 500 kW.	No	Permanent (since 2019)	Maximum total customer peak demand 150 MW.	Pre-set; 48 distinct rate units for energy charges (6 hour blocks x 8 day types)	N/A	Blocks: 48 distinct rate blocks for energy charges (six 3- to 6- hour blocks x 8 day types)	None	Day-ahead. Separate energy charges defined for each of eight day-types. Company will designate applicable day-type by 4:00 pm of preceding day. If no day type designtated by 4:00 pm, the current day-type will be repeated unless later designated.	N/A	pre-set; 48 designtated rate blocks for energy charges (6 blocks of 3 to 6 hours x 8 distinct day types)	Collected through demand or other metered charges	No	year to year	None
Alliant Energy Corporation	**Wisconsin**	**No Retail Choice**	**Wisconsin Power & Light**	DAY AHEAD MARKET PRICING RIDER (Experimental)	Open enrollment	>=5 MW (industrial customers served at transmission voltage; under Rate Schedule CP-2)	No	Experimental pilot program	Participation limit is 50 MW maximum total load	CBL	No CBL based on firm amount nominated by Customer for the term of the contract. Energy and Demand Baseline Levels contracted prior to beginning service under this Rider and will apply through the duration of Contract Period	Hourly	None	Day-Ahead	No	MISO hourly Day-Ahead LMP for ALTE.ALTE pricing load zone; applies to energy and demand consumption in excess of CBL. (Plus other components, including margin)	Collected in access charge (Two-Part RTP)	No (Flat daily admin charge)	Subscriber must enter into 5-year contract term; Subscriber may terminate service with not less than two years' written notice	Yes
Duquesne Light Holdings, Inc.	**Pennsylvania**	**Full Retail Choice**	**Duquesne Light Company**	Rider Day-Ahead Hourly Price Service	Open enrollment	Medium/large C&I (>=200kW)Applicable to Rates GS/GM, GMH, GL, GLH, HVPS and Generating Station Service	No	Permanent	None	Energy and Demand	N/A	Hourly	None	Day-Ahead	No	PJM day-ahead nodal locational marginal price	Collected through demand or other metered charges	Yes Collected through Fixed Retail Administrative Charge in $ per MWH	unspecified	unspecified
FirstEnergy Corporation	**Pennsylvania**	**Full Retail Choice**	**Met-Ed**	Hourly Pricing Default Service Rider	Open enrollment	Entire eligible customer class (non-residential) who meet metering requirements	No	Permanent	None	Energy and Demand	N/A	Hourly	None	Day-Ahead	No	Locational Marginal Price for the PJM Met-Ed Transmission Zone	Collected through demand or other metered charges	Yes	unspecified	unspecified
Exelon Corporation	**Pennsylvania**	**Full Retail Choice**	**Philadelphia Electric Conmpany (PECO)**	Hourly Pricing Service	Open enrollment	Demand > 100 kW	No	Permanent	None	Energy and Demand	N/A	Hourly	None	Day-Ahead	No	PJM on day ahead hourly price	Collected through demand or other metered charges	Yes	unspecified	unspecified
FirstEnergy Corporation	**Pennsylvania**	**Full Retail Choice**	**Penelec**	Hourly Pricing Default Service Rider	Open enrollment	Customers on GM (> 100 kW), GS-Large (>= 400 kW and < 2.500 kVa); GP, GGT, GS; must have smart meter	Yes	Permanent	None	Energy and Demand	N/A	Hourly	None	Day-Ahead	No	PJM load-weighted average Locational Marginal Price (LMP) for PN Transmission Zone	Collected through demand or other metered charges	Yes	unspecified	unspecified

Benchmarking Study of US Regulated Utility Real Time Pricing Programs, Architecture and Design, Techncial Update, March 2021
Active RTP Program Attribute Detail

					RTP Structural Attributes															
					1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Holding Company	**State**	**Status of Retail Competition**	**Utility Jurisdictions**	**RTP Program Name**	**Availability**	**Eligibility**	**Mandatory?**	**Maturity (Permanent vs. Experimental)**	**Enrollment cap**	**Pricing Structure**	**CBL Revision or Adjustment (Two-part)**	**Price Granularity - Temporal [d]**	**Price Granularity- Spatial**	**Daily Price Posting Frequency**	**Overcall of Posted Day-Ahead Prices**	**Energy Price Formation**	**Generation, Transmission, Distribution Capacity Pricing**	**Marginal Uplift in Hourly Energy Price to cover Admin and Implementation costs**	**Contract Term**	**Mechansim to Hedge Customer Price Risk**
Edison International	**California**	**Partial Retail Choice**	**Southern California Edison (SCE)**	TOU-8-RTP General Service Large Real Time Pricing	Open enrollment	> 500 kw maximum monthly demand for at least one of past 12 months	No	Permanent	None	Pre-set Hourly generation component for 7 day types	N/A	Hourly (generation component);	None	Day-ahead (temperature forecast to determine day-type for next day)	N/A	Pre-set; Hourly generation component of energy charge	Delivery service charges fixed (transmission and distribution). Generation charge varies hourly according to pre-set 24 hourly blocks x 7 day types	unspecified	unspecified	unspecified
Edison International	**California**	**Partial Retail Choice**	**Southern California Edison (SCE)**	TOU-8-RTP-S General Service Large Real Time Pricing - Standby	Open enrollment	> 500 kw maximum monthly demand for at least one of past 12 months AND with self-generation	No	Permanent	None	Pre-set Hourly generation component for 7 day types	N/A	Hourly (generation component);	None	Day-ahead (temperature forecast to determine day-type for next day)	N/A	Pre-set; Hourly generation component of energy charge	Delivery service charges fixed (transmission and distribution). Generation charge varies hourly according to pre-set 24 hourly blocks x 7 day types	unspecified	unspecified	unspecified
Edison International	**California**	**Partial Retail Choice**	**Southern California Edison (SCE)**	TOU-GS-1-RTP GENERAL SERVICE - SMALL REAL TIME PRICING	Open enrollment	< 20 kW	No	Permanent	None	Pre-set Hourly generation component for 7 day types	N/A	Hourly (generation component);	None	Day-ahead (temperature forecast to determine day-type for next day)	N/A	Pre-set; Hourly generation component of energy charge	Delivery service charges fixed (transmission and distribution). Generation charge varies hourly according to pre-set 24 hourly blocks x 7 day types	unspecified	unspecified	unspecified
Edison International	**California**	**Partial Retail Choice**	**Southern California Edison (SCE)**	TOU-GS-2-RTP GENERAL SERVICE - MEDIUM REAL TIME PRICING	Open enrollment	> 20 kW and < 200 kW	No	Permanent	None	Pre-set Hourly generation component for 7 day types	N/A	Hourly (generation component);	None	Day-ahead (temperature forecast to determine day-type for next day)	N/A	Pre-set; Hourly generation component of energy charge	Delivery service charges fixed (transmission and distribution). Generation charge varies hourly according to pre-set 24 hourly blocks x 7 day types	unspecified	unspecified	unspecified
Edison International	**California**	**Partial Retail Choice**	**Southern California Edison (SCE)**	TOU-GS-3-RTP GENERAL SERVICE - LARGE REAL TIME PRICING	Open enrollment	> 200 kW and < 500 kW	No	Permanent	None	Pre-set Hourly generation component for 7 day types	N/A	Hourly (generation component);	None	Day-ahead (temperature forecast to determine day-type for next day)	N/A	Pre-set; Hourly generation component of energy charge	Delivery service charges fixed (transmission and distribution). Generation charge varies hourly according to pre-set 24 hourly blocks x 7 day types	unspecified	unspecified	unspecified
Edison International	**California**	**Partial Retail Choice**	**Southern California Edison (SCE)**	TOU-PA-2-RTP S-M AG & PUMPING TOU - RTP	Open enrollment	Customers with >= 70% electrical usage for agricultural power, general water or sewerage pumping, or oil pumping for SIC 1311; Monthly actual or expected demand below 200 kW	No	Permanent	None	Pre-set Hourly generation component for 7 day types	N/A	Hourly (generation component);	None	Day-ahead (temperature forecast to determine day-type for next day)	N/A	Pre-set; Hourly generation component of energy charge	Delivery service charges fixed (transmission and distribution). Generation charge varies hourly according to pre-set 24 hourly blocks x 7 day types	unspecified	unspecified	unspecified
Edison International	**California**	**Partial Retail Choice**	**Southern California Edison (SCE)**	TOU-PA-3-RTP Lg AG & PUMPING TOU - RTP	Open enrollment	Customers with >= 70% electrical usage for agricultural power, general water or sewerage pumping, or oil pumping for SIC 1311; Monthly actual or expected demand > 200 kW but less than 500 kW	No	Permanent	None	Pre-set Hourly generation component for 7 day types	N/A	Hourly (generation component);	None	Day-ahead (temperature forecast to determine day-type for next day)	N/A	Pre-set; Hourly generation component of energy charge	Delivery service charges fixed (transmission and distribution). Generation charge varies hourly according to pre-set 24 hourly blocks x 7 day types	unspecified	unspecified	unspecified
Upper Penninsula Power Company	**Michigan**	**Partial Retail Choice**	**Upper Penninsula Power Company (UPPCO)**	Real-time Market Pricing	Open enrollment	Any customer interconnected directly with American Transmission Company (ATC) with demand > 1 MW	No	Permanent	None	Energy Only	N/A	Hourly	None	Day-Ahead	No	MISO LMP at UPPC pricing node for hourly energy charges charges and credits; plus $1/MWh (margin)	Collected in energy price (One-Part RTP)	Yes (plus $1/mWh)	year to year; Minimum 1-year contract with 90 day cancellation notification	Yes (customer has option to pay premium for greater price certainty while on tariff)
FirstEnergy Corporation	**Pennsylvania**	**Full Retail Choice**	**WestPenn Power**	HOURLY PRICING DEFAULT SERVICE RIDER	Open enrollment	Entire eligible customer class (non residential) on any eligible prior rate based on kW and voltage	Yes For C&I customers on Rate Schedules 30 (HP), 35, 40, 44 and 46 who elect to take Default Service from West Penn Power.	Permanent	None	Energy and Demand	N/A	Hourly	None	Day-Ahead	No	PJM load-weighted average LMP for APS Transmission Zone - basis for energy charge	Collected through demand or other metered charges	Yes	unspecified	unspecified

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX B

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF EMILY BARTMAN

Q 1 Please state your name and business address.

A 1 My name is Emily Bartman, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Chief Product Manager in the Pricing Products Department. My responsibilities include representing customer needs while identifying, addressing, and communicating potential business and operational impacts from new rate proposals including billing system, metering and customer outreach. In addition, I serve as the witness for Pricing Products' General Rate Case Phase I and Rate Reform Cost Recovery proceedings.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Mathematical Economics from Pomona College in 1986, and a Master's degree in Business Administration from the University of California at Berkeley in 1992. I have worked at PG&E since 2011, as a Principal Product Manager for pricing products before I was promoted to my current position in July 2020. Prior to that, I worked as an independent consultant for nine years including four years at Southern California Edison Company (SCE), analyzing and synthesizing existing customer research to help drive strategic planning efforts, leading the development of a product portfolio management structure and developing the business case for a new credit/debit card payment option. Between 1994-1999, I worked for Edison International, first building a customer-focused market analysis and strategy organization at SCE, and later helping launch the unregulated affiliate Edison Enterprises from the corporate center, and then building a direct marketing organization at Edison Source, which brought EarthSource green power to the California market and discounted electricity to Philadelphia customers. From 1988-1990 and 1999-2002, I worked for PA Consulting Group (also PHB Hagler Bailly and Theodore Barry and Associates) in the retail strategy group, helping energy service providers launch new businesses in newly open retail markets across the country.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's GRC Ph. II Commercial & Industrial Real Time Pricing Pilot and Research for other Customer Classes:

- Exhibit (PG&E-RTP-1), "Supplemental Testimony":
  - Chapter 1, "Background and Policy"; and
  - Chapter 2, "Real Time Pricing Benchmarking."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ANH D. DONG

Q 1 Please state your name and business address.

A 1 My name is Anh D. Dong, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Senior Manager in the Pricing Products Department. My responsibilities include defining and implementing Information Technology (IT) solutions to help customers better understand and manage their energy use and bills.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Chemical Engineering from the University of California at Berkeley in 1987, and a Master's degree in Business Administration from the University of California at Berkeley in 1992. I have worked at PG&E since 2010, in multiple roles mostly related to implementing IT system changes for complex Customer Care projects, such as web presentment, bill redesign, residential Time-of-Use transition, and new rate programs. For these implementations, my team worked with internal and external stakeholders, and internal IT teams and vendors to enhance or develop billing and payment products for residential and non-residential customers. Prior to that, I worked as an IT Project Director for the San Francisco Public Utilities Commission, where I managed a team of business analysts to implement IT projects, ranging from Learning Management System to the Customer Care and Billing System.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's GRC Ph. II Commercial & Industrial Real Time Pricing Pilot and Research for other Customer Classes:

- Exhibit (PG&E-RTP-1), "Supplemental Testimony":
  - Chapter 5, "Pilot Structure for Commercial and Industrial Real Time Pricing Pilot."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ANJA GILBERT

Q 1 Please state your name and business address.

A 1 My name is Anja Gilbert, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Principal Product Manager in the Integrated Grid Planning and Innovation Group within the Energy Policy and Procurement organization, and I am responsible for PG&E's load management strategy and policy as well as the policy and market design for distributed energy resource (DER) participation in the California Independent System Operator's (CAISO) wholesale market.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Political Science from University of California, Davis in 2007, and a Master's degree in Public Administration with a focus on Sustainable Energy Policy from Columbia University in 2013. From 2008 to 2011, and again in 2013, I held various roles at The Climate Registry, supporting entities report and third-party verify their emissions inventories. I joined PG&E in December of 2013, in the Gas Operations organization and moved to Energy Policy and Procurement organization in January of 2015. I have focused on the policies and market rules for DERs participating in the CAISO market since 2015. I also served as the IOU-lead for the California Public Utilities Commission's Load Shift Working Group.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's GRC Ph. II Commercial & Industrial Real Time Pricing Pilot and Research for other Customer Classes:

- Exhibit (PG&E-RTP-1), "Supplemental Testimony":
  - Chapter 1, Attachment A, "Commercial Electric-Vehicle Day Ahead Hourly Real Time Pricing Pilot Supplemental Testimony Chapter 1 Dual Participation, Served March 29, 2021."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JAN C. GRYGIER

Q 1 Please state your name and business address.

A 1 My name is Jan C. Grygier, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Chief Rates Analyst in the Rates Department within Regulatory Affairs. I provide quantitative modeling and analysis on Marginal Generation Costs and act as an advisor on other analytical and policy issues within the Rates Department.

Q 3 Please summarize your educational and professional background.

A 3 I graduated from the University of Toronto with a Bachelor of Science degree in 1978. I received a Doctorate degree in Environmental Systems Engineering from Cornell University, in Ithaca, New York, in 1983.

From 1987 to 1990, after a 3-year post-doctoral fellowship at Cornell University, I worked on operations research, modeling, analysis and environmental impacts for URS Consultants in Sacramento, California and at Synergo consulting in Ottawa, Ontario.

In 1990, I started work at PG&E in San Francisco as an independent contractor, and was in charge of hydrologic applications and modeling of the physical hydropower system in the stochastic SOCRATES hydro scheduling model. I was also Lead Developer of the Swift rainfall/runoff model.

I joined PG&E as an employee in 1997, initially as a Senior Operations Research Analyst in the Systems Engineering group. I maintained responsibility for all flow forecasting and hydro scheduling models at PG&E, and later matrixed in to the Power Generation organization as Hydro Scheduling Consultant for the Mokelumne and Kings watersheds, where I participated in negotiations with downstream water rights holders and provided strategic advice on operations and energy pricing of the Helms Pump Storage Plant (PSP). The experience with Helms PSP led to developing an operations and benefits model for PG&E's pilot sodium-sulphur battery in 2008.

In 2006-2010, I prepared analysis for Energy Resource Recovery Account filings, and presented tutorials on hydro forecasting and scheduling to California Public Utilities Commission's Public Advocates Office.

After a 9-month sabbatical, I joined the Energy Policy Planning and Analysis Department as a Principal in Greenhouse Gas (GHG) Market Readiness. I was responsible for assessing the design of California's GHG Cap and Trade market under Assembly Bill 32, and the readiness of the Air Resources Board and other compliance entities prior to and immediately following the launch of the market. As part of this effort, I led PG&E's analytical team and recruited multiple co-funding stakeholders for an experimental economics study of the GHG market.

With the GHG Cap and Trade market successfully launched in 2013, I provided support and modeling to PG&E's 2014 Energy Storage Request for Information, and became a prime architect of a new stochastic model of Renewables Portfolio Standard procurement.

I joined the Strategic Quantitative Analysis and Modeling group in December 2013, where I worked on energy storage evaluation, drought-related hydro analysis, energy price scenarios and marginal generation costs, and new mid-term hydro scheduling models being developed by Short-Term Electric Supply and Value Based Reliability. I sponsored Chapter 2, "Hourly Marginal Generation Costs" in PG&E's 2015 Rate Design Window application, and Chapter 2, "Marginal Generation Costs" in PG&E's 2017 General Rate Case (GRC) Ph. II application.

In 2018 I joined the Rates Department as Principal Data Scientist, and was promoted to Chief Rates Analyst in 2019. Since joining the Rates Department, I have sponsored parts of Chapter 2, "Residential Rate Proposals and Estimated Reductions in Greenhouse Gas Emissions and Costs" in PG&E's 2018 Rate Design Window, Ph. IIB. I am currently sponsoring Chapter 2, "Marginal Generation Costs" and Chapter 11, "Time-of-Use Period Assessment and Analysis" in PG&E's 2020 GRC Ph. II application.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's GRC Ph. II Commercial & Industrial Real Time Pricing Pilot and Research for other Customer Classes:

- Exhibit (PG&E-RTP-1), "Supplemental Testimony":
  - Chapter 3, "Analysis of Wholesale Markets."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF TYSEN F. STREIB

Q 1 Please state your name and business address.

A 1 My name is Tysen F. Streib, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Principal Data Scientist in the Rates and Regulatory Analytics Department within the Regulatory Affairs organization, and I am responsible for the design and operation of PG&E's filing-quality electric ratemaking models.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Chemical Engineering from University of California, Berkeley in 1998, and a Master's degree in Business Administration from Santa Clara University in 2006.

From 1998 to 2006, I held various quantitative analysis and product management positions in the chemical analysis and semiconductor industries. From 2006 to 2007, I was a Product Manager for a small software company that designed stock market analysis tools. I joined PG&E in 2007 in the Finance organization, and then moved to Regulatory Affairs in 2012.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's GRC Ph. II Commercial & Industrial Real Time Pricing Pilot and Research for other Customer Classes:

- Exhibit (PG&E-RTP-1), "Supplemental Testimony":
  - Chapter 1, Attachment B, "Data Responses to Joint Parties-001 Data Request";
  - Chapter 4, "Commercial and Industrial, Real-Time Pricing Pilot Rate Design":
    - Attachment A, "Commercial Electric-Vehicle Day-Ahead Hourly Real Time Pricing Pilot Chapter 2 - Rate Design Updated

Testimony, Updates to Marginal Costs – Updated March 12, 2021, Served in A.20-10-011 on March 12, 2021."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX C

ACRONYM AND ABBREVIATION LIST

APPENDIX C
ACRONYM AND ABBREVIATION LIST

$/kWh	dollars-per kilowatt hour
AB	Assembly Bill
ABS	Advanced Billing System
AECA	Agricultural Energy Consumers Association
Ag	Agricultural
ALJ	Administrative Law Judge
ANL	Adjusted Net Load
API	Application Programming Interface
BESH	Basic Electric Service Hourly Pricing
BEV	Business Electric Vehicle
BIP	Base Interruptible Program
BTM	behind the meter
C&I	Commercial & Industrial
CAISO	California Independent System Operator
Cal Advocates	Public Advocates Office at the Public Utilities Commission
CalFlexHub	California Flexible Load Research and Deployment Hub
CARB	California Air Resources Board
CBL	Customer Baseline Load
CCA	Community Choice Aggregators
CEC	California Energy Commission
CEV	Commercial Electric Vehicle
CFBF	California Farm Bureau Federation
CFD	contracts for differences
CforAT	Center for Accessible Technology
CLECA	California Large Energy Consumers Association
ComEd	Commonwealth Edison Company
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission or Commission
CSRP	Customer Service Re-Platform
D.	Decision
DA	day-ahead
DA	Direct Access
DAHRTP-CEV	Commercial Electric Vehicle Day-Ahead Hourly Real Time Pricing
DAM	Day-Ahead Market
DLAP	Default Load Aggregation Point
DMM	Department of Market Monitoring
DR	Demand Response
DRAM	Demand Response Auction Mechanism
DRIPE	demand response induced price effect
DRTPMA	Dynamic and Real-Time Pricing Memorandum Account
EIA	Energy Information Administration

APPENDIX C
ACRONYM AND ABBREVIATION LIST

Enel X	Enel X North America
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERRA	Energy Resource Recovery Account
ESP	Energy Service Provider
EUF	Energy Users Forum
EV	electric vehicle
FEA	Federal Executive Agencies
FERC	Federal Energy Regulatory Commission
FMM	Fifteen Minute Market
GHG	greenhouse gas
GRC	General Rate Case
Griddy	Griddy Energy LLC
HRTP	Hourly Real Time Pricing
HVAC	heating, ventilation, and air conditioning
ICC	Illinois Commerce Commission
IFTTT	If This Then That
IOU	Invester Owned Utility
IT	Information Technology
JARP	Joint Advanced Rate Parties
JCCA	Joint Community Choice Aggregators
Klos	Klos Energy Consulting
kW	kilowatt
kWh	kilowatt hour
LBNL	Lawrence Berkeley National Laboratory
LCIA	Large Commercial, Industrial, and Agriculture
LDC	Local Distribution Company
LSE	Load Serving Entity
MCE	Marin Clean Energy
ME&O	marketing education & outreach
MEC	Marginal Energy Cost
MGCC	Marginal Generation Capacity Cost
MIDAS	Market Informed Demand Automation Services
MISO	Midcontinent Independent System Operator
MPB	Market Price Benchmark
MW	megawatt
MWh	megawatt hour
NEM	Net Energy Metering
NYISO	New York Independent System Operator
OAT	Otherwise Applicable Tariff
OG&E	Oklahoma Gas & Electric

APPENDIX C
ACRONYM AND ABBREVIATION LIST

OIR	Order Instituting Rulemaking
OP	ordering paragraph
PCAF	Peak Capacity Allocation Factor
PCIA	Power Charge Indifference Adjustment
PDP	Peak Day Pricing
PECO	Philadelphia Electric Company
PG&E	Pacific Gas & Electric Company
PJM	Pennsylvania-New Jersey-Maryland Interconnection
POLR	Provider of Last Resort
PTR	Peak Time Rebate
PUCT	Public Utilities Commission of Texas
PYD	Power Your Drive
R.	Rulemaking
RA	resource adequacy
RDW	Rate Design Window
REP	Retail Energy Provider
RRTP	Residential Real Time Pricing
RSE	Rate Stabilization and Equalization Factor
RTM	Real-Time Market
RTO/ISO	Regional Transmission Operator/ Independent System Operator
RTP	Real Time Pricing
SB	Senate Bill
SBUA	Small Business Utility Advocates
SCE	Southern California Edison
SCP	Sonoma Clean Power
SDG&E	San Diego Gas & Electric
SGIP	Self Generation Incentive Program
SVCP	Silicon Valley Clean Power
TOU	Time-of-Use
U.S.	United States
UGBA	Utility Generation Balancing Account
UPPCO	Upper Peninsula Power Company
VGI	Vehicle Grid Integration
VGI Program Facilities	Electric Vehicle-Grid Integration Pilot Program charging station
VPP	Variable Peak Pricing