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Witnesses	:	<u>Otto Nichols</u>
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PUBLIC ADVOCATES OFFICE
CALIFORNIA PUBLIC UTILITIES COMMISSION

Opening Testimony
in Response to San Diego Gas & Electric Company's
Dynamic Rate Application (A.) 26-02-001

Chapter 1
Rate Design

San Francisco, California
September 11, 2026

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CHAPTER 1 RATE DESIGN

I. SUMMARY AND RECOMMENDATIONS

This chapter provides the Public Advocates Office at the California Public Utilities Commission’s (Cal Advocates) testimony on San Diego Gas & Electric Company’s (SDG&E) proposed dynamic rate design in Application (A.) 26-02-001, which was originally filed with the California Public Utilities Commission (Commission) on February 2, 2026.¹ Specifically, this chapter responds to SDG&E’s proposals for marginal commodity, distribution, and transmission costs, as well as customer protections. SDG&E subsequently filed two revisions – on June first² and seventeenth³ of this year – to its original testimony regarding these topics, as well as implementation (discussed in Chapter 2 of Cal Advocates’ Opening Testimony).

The Commission ordered the utilities in its jurisdiction to provide dynamic rate proposals that comply with the California Energy Commission’s (CEC) Load Management Standards (LMS).⁴ SDG&E notes in its initial application:

“...[SDG&E] does not believe this proposal reflects the most cost-effective or prudent use of Commission or SDG&E resources given the current affordability challenges facing electric ratepayers in our service area and across the State.”⁵

¹ Application (A.) 26-02-001, *Application of San Diego Gas & Electric Company (U 902 E) for Approval of Demand Flexibility Rates in Compliance with [Decision (D.)] 25-08-049*, February 2, 2026.

² In this revision, SDG&E updates Chapters 2 (Commodity/Generation), 3 (Transmission and Distribution), 4 (Customer Protection), and 5 (Implementation).

³ In this revision, SDG&E updates Chapters 2, 4, and 5.

⁴ Decision (D.) 25-08-049, *Decision Adopting Guidelines for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on Demand Flexibility Rate Design Proposals*, August 29, 2025, at 137, Finding of Fact (FOF) 1, at 138, Conclusion of Law (COL) 2, at 146, COL 34(c). FOF 1: “The CEC Load Management Standards require that the Large IOUs seek Commission approval of at least one marginal cost-based dynamic rate for each customer class within twenty-one months of April 1, 2023.” COL 2: “It is reasonable to require the Large IOUs to use CAISO’s day-ahead energy market price at DLAPs as the MEC in DF Rate Proposals to comply with the CEC LMS and effectively incentivize customer load shifting.” COL 34(c): “It is reasonable to require the Large IOU’s DF Rate Proposals to include a detailed description regarding how the Large IOUs will collaborate with CCAs on various features of DF rates and DF rate programs, including but not limited to: ... [c.] ensuring that LSE DF rates conform with CEC LMS requirements.”

⁵ A.26-02-001, at 1.

1 To support its position, SDG&E points to several reasons. First, SDG&E
2 points to the fact that it has no participants enrolled in its dynamic export pilot
3 despite millions of dollars spent on the pilot.⁶ Next, SDG&E highlights that the
4 commodity cost component is the most significant portion of a customer's price
5 signal and that 80% of its customers are served by Community Choice
6 Aggregators (CCA).⁷ SDG&E states that the CCAs in its territory have indicated
7 that they will not offer dynamic rates at this time.⁸ Finally, SDG&E points to the
8 fact that the existing dynamic rate pilots in Pacific Gas and Electric Company's
9 (PG&E) and Southern California Edison's (SCE) territories have not yet been
10 fully evaluated, as they are ongoing, as a reason to not commit any additional
11 resources to dynamic rates at this time.⁹

12 Cal Advocates generally agrees with SDG&E's position that dynamic rates
13 remain unproven as a cost-effective measure for reducing grid costs. SDG&E
14 does not demonstrate that its proposal, and all associated costs, is just and
15 reasonable and the Commission should reject SDG&E's Application. However, if
16 the Commission decides to adopt a dynamic rate in this proceeding, it should:

- 17 • Adopt SDG&E's marginal commodity cost proposals;
- 18 • Adopt SDG&E's distribution pricing proposal;
- 19 • Require SDG&E to study and evaluate its locational
20 distribution pricing approach for future refinement;
- 21 • Adopt SDG&E's interim transmission cost recommendations;
- 22 • Adopt price limiters as the customer protection mechanism;
23 and
- 24 • Require that SDG&E monitor the monthly bill impacts of the
25 dynamic rate in comparison to the customer's otherwise

⁶ A.26-02-001, at 1.

⁷ A.26-02-001, at 1.

⁸ A.26-02-001, at 1.

⁹ A.26-02-001, at 2.

1 applicable tariff (OAT) and evaluate the potential for other
2 customer protections mechanisms.

3 **II. MARGINAL COMMODITY COSTS (Witness: Lauren Schenck)**

4 **A. If the Commission adopts a dynamic rate in this application, it**
5 **should adopt SDG&E's Marginal Energy Cost proposals.**

6 SDG&E's Marginal Energy Cost (MEC) proposals, as discussed below, are
7 reasonable and should be adopted by the Commission. SDG&E proposes to use the
8 California Independent System Operator's (CAISO) Day-Ahead Default Load
9 Aggregation Point (DLAP)¹⁰ prices to reflect real-time energy costs. This method is
10 consistent with the other investor-owned utility (IOU) dynamic rate proposals¹¹ and with
11 the guidance issued in Decision (D.) 25-08-049.¹² SDG&E also proposes to use a floor
12 and ceiling for its MEC,¹³ which is discussed in the Section V below.

13 SDG&E further proposes to account for energy losses related to Transmission and
14 Distribution (T&D) by using its Electric Energy Commodity Cost – Transition Bundled
15 Service (EECC-TBS) tariff Distribution Loss Factor (DLF) calculation.¹⁴ Since SDG&E
16 proposes to use CAISO energy costs for its MEC, the value reflects transmission-level
17 costs and therefore must include a loss factor to account for the energy losses that result
18 from the transition of energy from the transmission level to meter level. This is because
19 the utility must procure more than the final amount of energy served to the customer.
20 Therefore, not accounting for the losses associated with the step-down from transmission-
21 level voltage to the meter-level, where customers are served, risks undervaluing the cost
22 of serving the customer. The EECC-TBS is a direct access (transmission level) interim-

¹⁰ *Second Revised Prepared Testimony of Jeff DeTuri on Behalf of San Diego Gas & Electric Company Chapter 2 – Commodity/Generation* (SDGE-02-2R), June 17, 2026, at 2, lines 4-5.

¹¹ See A.24-06-014, et al., for SCE's Dynamic Rate Application, and A.24-09-014 for PG&E's dynamic rate proposals in its Test Year 2023 General Rate Case, Phase 2 (GRC2), Application.

¹² *Prepared Testimony of Jeff DeTuri on Behalf of San Diego Gas & Electric Company Chapter 1 - Policy* (SDGE-01), at 5, lines 3-5.

¹³ SDGE-02-2R, at 2, lines 6-7.

¹⁴ SDGE-02-2R, at 2, lines 16-18.

1 service tariff that accounts for losses when direct access customers need to take interim
2 service from SDG&E. Thus, using the EECC-TBS is appropriate since it accounts for the
3 energy losses between the transmission level and meter level.¹⁵

4 Finally, to account for non-marginal commodity costs, SDG&E proposes to apply
5 an Equal Percent of Marginal Cost (EPMC) scalar to its MEC.¹⁶ SDG&E’s workpapers
6 confirm that it does not apply the EPMC scalar to its proposed Marginal Generation
7 Capacity Cost (MGCC) value since that is calculated using the capacity share of
8 generation revenue.¹⁷ This approach is appropriate since scaling peak capacity costs risks
9 sending distorted price signals that might discourage optimal grid utilization. Therefore,
10 SDG&E’s proposal to only scale its MEC using an EMPC scalar is also reasonable and
11 should be adopted by the Commission.

12 **B. If the Commission adopts a dynamic rate in this application, it**
13 **should adopt SDG&E’s Marginal Generation Capacity Cost**
14 **Proposals.**

15 SDG&E’s MGCC proposals, as discussed below, are reasonable and should be
16 adopted by the Commission. SDG&E proposes to use a net cost of new entry (Net-
17 CONE) approach based on battery storage costs¹⁸ of \$142.10/kW-yr,¹⁹ from the 2026
18 inputs and assumptions (I&A)²⁰ for the mid-cost scenario of the Integrated Resource Plan
19 (IRP), to establish its MGCC value. The Net-CONE approach is industry standard for
20 setting MGCC and represents the most recently approved method employed by SDG&E

¹⁵ SDGE-02-2R, at 2, lines 18-21.

¹⁶ SDGE-02-2R, at 11, lines 4-5.

¹⁷ SDGE-02-2R, at 11, lines 5-6.

¹⁸ SDGE-02-2R, at 3, lines 8-13.

¹⁹ SDGE-02-2R, at 4, line 6.

²⁰ SDGE-02-2R, at 4, lines 2-5, and footnote 6. *See also* CPUC, *2024-2027 IRP Cycle Events and Materials: IRP Filing Requirements, Filing Requirements Analysis Materials, “RESOLVE Workbooks and Public Case Results Viewers,”* CPUC Pro Forma Data Viewer – 2025 FR workbook, Resource Comparison tab, cell S54 (with cell K54 set to “LFC, \$/kW-yr”), uploaded January 16, 2026, accessed August 4, 2026, available at:

<https://files.cpuc.ca.gov/energy/modeling/LTPP/RESOLVE%20Workbooks%20and%20Public%20Case%20Results%20Viewers.zip>.

1 for setting its MGCC,²¹ so it is therefore reasonable. Furthermore, the mid-cost scenario
2 of the 2026 IRP I&A is reasonable in that it relies on the most recent available data.²²
3 SDG&E also considered the 2024 Avoided Cost Calculator (ACC) value of \$176/kW-yr
4 but selected the 2026 IRP I&A value because it reflects more recent information.²³ Using
5 the ACC to set the MGCC is not appropriate since MGCCs are input to the ACC.²⁴
6 Additionally, the ACC is designed as an input to cost-effectiveness calculations, therefore
7 using the ACC to set the MGCC would not align with the purpose that the ACC was
8 designed for.²⁵ SDG&E's use of the 2026 IRP I&A battery storage costs is reasonable.

9 SDG&E further proposes a marginal flexible capacity cost of \$0²⁶ to reflect the
10 fact that its 2026 load forecast of its 3-hour ramp period shows adequate supply.²⁷ This
11 approach is reasonable because it reflects the current value of marginal flexible capacity.

12 Finally, SDG&E proposes to use a Top 150-hour approach²⁸ as the function for
13 applying MGCC to its proposed rate. This approach is based on deriving the average of
14 the CAISO system load top 150th hour over the prior three years. This value is used to set
15 the threshold for when the proposed MGCC adder will apply.²⁹ Additionally, the
16 proposed Top 150-hour approach is similar to the one that SDG&E uses in its Vehicle-
17 Grid Integration (VGI) and Public Grid Integration Rate (GIR) rate schedules.³⁰

18 Given that SDG&E's proposal results in a simple threshold-based adder instead of
19 a variable probability-based adder, it is clear that SDG&E's proposed method would be

²¹ SDGE-02-2R, at 3, lines 19-22.

²² SDGE-02-2R, at 4, lines 3-5.

²³ SDGE-02-2R, at 4, lines 8-11.

²⁴ A.23-01-008, *Administrative Law Judge's Ruling Requesting Comments on Staff Proposal Marginal Commodity Costs* (A. 23-01-008 ALJ Ruling), November 19, 2024, at 2.

²⁵ A.23-01-008 ALJ Ruling, at 2.

²⁶ SDGE-02-2R, at 4, line 14.

²⁷ SDGE-02-2R, at 5, lines 13-15.

²⁸ SDGE-02-2R, at 6, lines 2-3.

²⁹ SDGE-02-2R, at 6, lines 3-5.

³⁰ SDGE-02-2R, at 6, line 5.

1 both easier to implement and easier to explain to customers than either of the Loss of
2 Load Probability (LOLP) methods that SDG&E also explored.³¹ SDG&E's proposal to
3 use a similar approach to the one that it currently uses to allocate MGCC across hours in
4 its VGI and GIR rate schedules is also efficient for implementation and customer
5 outreach and engagement. The Commission should approve SDG&E's commodity cost
6 proposals if it chooses to approve a new dynamic rate in this proceeding.

7 **III. DISTRIBUTION (Witness: Otto Nichols)**

8 **A. If the Commission adopts a dynamic rate in this application,** 9 **SDG&E's location-based distribution pricing proposal is** 10 **reasonable.**

11 SDG&E's location-based distribution pricing proposal, which uses a circuit
12 clustering approach that differentiates pricing by shared load characteristics, is consistent
13 with the Guidance Decision (D.25-08-049).³² The Decision states that although circuits
14 have differing loads or locations, clustered circuits have similar load characteristics
15 (i.e., timing of high-load versus low-load hours, ramp periods, etc.) which in turn reduce
16 the complexity associated with determining circuit-specific distribution pricing.³³
17 SDG&E's approach is reasonable for implementation, but SDG&E should further
18 scrutinize these circuit clusters after implementation, as discussed further below, to verify
19 that they continue to share similar load characteristics over time.

20 SDG&E proposes that the distribution capacity component for demand flexibility
21 (DF) customers is a circuit-based distribution capacity hourly adder designed to recover
22 peak related distribution demand costs.³⁴ This distribution capacity hourly adder would
23 be based on the top 200 hours of circuit load in a year, on a day-ahead basis, when the

³¹ SDGE-02-2R, at 8, lines 13-14, and 9, lines 3-5. SDG&E also considered using two different applications of the Loss of Load Probability (LOLP) function for applying its MGCC – one where the LOLP is applied across summer on-peak hours (Summer On-Peak) and one where it is applied across all hours (All-Hours) of the year.

³² D.25-08-049, at 60.

³³ D.25-08-049, at 54.

³⁴ *Prepared Revised Direct Testimony of William G. Saxe on Behalf of San Diego Gas & Electric Company Chapter 3 – Distribution & Transmission* (SDG&E-03-R), at 4, lines 4-6.

1 forecasted load exceeds a threshold level established based on historic circuit load.³⁵
2 This threshold also acts as an inherent price limiter and beneficial for customer
3 protections, see Section V on Customer Protections below for additional information.³⁶
4 SDG&E proposes to cluster its 1,030 circuits into 10 circuit groups based on the
5 percentage of residential and non-residential kWh load on the circuits, broken out by 10%
6 increments.³⁷ SDG&E will notify customers on what circuit cluster they will be billed
7 under.³⁸ Since it is unclear whether a more granular and complex location-specific
8 distribution pricing design would be beneficial to ratepayers, SDG&E's approach to
9 group circuits in 10% increments is a reasonable initial approach to implementation.
10 SDG&E notes in a data request response that it believes that by basing the circuit clusters
11 on consistent percentages of residential and non-residential kWh loads, the circuits in
12 each cluster should have similar timing of high-load versus low-load hours associated
13 with residential and non-residential customer kWh loads.³⁹ SDG&E's initial proposal is
14 reasonable, but SDG&E should further scrutinize these circuit clusters after
15 implementation to verify that they continue to share similar load characteristics over
16 time.

17 **C. The Commission should require SDG&E to implement a**
18 **measurement and evaluation plan to monitor its location-based**
19 **distribution pricing approach.**

20 SDG&E should implement a measurement and evaluation (M&E) plan to monitor
21 its location-based distribution pricing approach, similar to the one PG&E proposes to use
22 in its Real-Time Pricing (RTP) Stop Gap Proposal Testimony to closely monitor PG&E's

³⁵ SDG&E-03-R, at 4, lines 6-8.

³⁶ SDG&E-03-R, at 4, lines 8-11. SDG&E's forecasted load is based upon historical hourly load at the circuit level, the local weather (both dry-bulb temperature and humidity taken into account), and calendar-based variables (weekends, holidays, day of week, month, etc.).

³⁷ SDG&E-03-R, at 5, lines 6-8.

³⁸ SDG&E-03-R, at 5, lines 13-17.

³⁹ See Appendix B, Attachment 1, SDG&E response to DR07, question 1, part a, sent on April 3, 2026.

1 own location-based distribution pricing approach.⁴⁰ PG&E plans to explore rate design at
2 higher load aggregation (such as substation or system-level), blending historical rate
3 signals with dynamic forecast-based signals, or designing rates that follow smoother
4 trend-based signals.⁴¹ A M&E plan for SDG&E’s location-based distribution pricing
5 would help parties better understand how well SDG&E’s proposed method provides
6 differentiated price signals to customers and whether customer responses to SDG&E’s
7 dynamic rates lead to measurable decreases in the need for distribution system
8 investments and/or improved utilization of the current infrastructure.

9 SDG&E should also investigate the potential issues with a circuit cluster approach
10 that PG&E describes in its application. It should conduct its investigation through a
11 periodic review to ensure that SDG&E sends appropriate price signals during
12 implementation and can be reported on in the M&E plan. PG&E notes that the
13 complexity of the distribution system and sensitivity of circuit-level load profiles to
14 changes in coincident and noncoincident demand patterns makes load forecasting and
15 price modeling challenging.⁴² Further, in the Mid-Term Evaluation of PG&E’s Hourly
16 Flex Pricing (HFP) Pilot, consultants highlight that customers were on track to be paid
17 nearly \$8 million in HFP Pilot credit but that this was largely attributable to two factors.⁴³
18 One of those factors was that customers on two circuits had persistently high midday
19 prices due to a pricing methodology that was changed in early 2026 (i.e., due to two
20 “mispriced” circuits”) and could sell excess subscription load back at the high Pilot
21 hourly prices during those hours.⁴⁴ The evaluation goes on to note that “the two
22 ‘mispriced’” circuits displayed a significantly different price pattern than the others until

⁴⁰ See Appendix B, Attachment 2, excerpt of A.24-09-014, *Pacific Gas and Electric Company 2023 General Rate Case Phase II Prepared Testimony Exhibit* (PG&E-6) *PG&E’s Testimony Supporting Stop-Gap Interim RTP Pilots Extension Proposal*, June 8, 2026, at 3-7, lines 20-32 to 3-8, lines 1-4.

⁴¹ See Appendix B, Attachment 2, excerpts of PG&E-6, at 3-7, lines 20-27.

⁴² See Appendix B, Attachment 2, excerpts of PG&E-6, at 2-25, lines 24-27.

⁴³ Mid-Term Evaluation of PG&E’s Hourly Flex Pricing and Vehicle Grid Integration Pilots (PG&E HFP Evaluation), August 3, 2026, available at: <https://pgera.azurewebsites.net/Regulation/search>.

⁴⁴ See Appendix B, Attachment 3, excerpt of A.24-09-14, PG&E HFP Evaluation, August 3, 2026, at 4.

1 the Marginal Distribution Capacity Cost (MDCC) pricing algorithm was modified in
2 February 2026 and that this price pattern had a significant effect on customer outcomes.⁴⁵
3 SDG&E should heed this cautionary tale from PG&E’s HFP Pilot and continue to
4 investigate its own algorithm to help ensure this problem is not replicated in SDG&E’s
5 territory.

6 **IV. TRANSMISSION (Witness: Nathan Chau)**

7 **A. If the Commission adopts a dynamic rate in this proceeding, it**
8 **should adopt SDG&E’s proposal for transmission costs.**

9 The Commission should adopt SDG&E’s interim TOU-based approach as it
10 meaningfully improves the flat status quo rate by charging customers higher peak period
11 prices for transmission costs incurred to meet peak demand. The Guidance Decision
12 requires the IOUs to propose hourly transmission rates and describe their plan for
13 implementing time-varying transmission rates in their respective applications.⁴⁶ SDG&E
14 declines to develop dynamic transmission components as it claims the company does not
15 have the billing system capability to fully implement dynamic rates.⁴⁷ Consequently,
16 SDG&E proposes the TOU-based approach as an interim solution for residential, small
17 commercial and agricultural DF customers with the plan to implement base transmission
18 hourly energy rates for these customers at a later date.⁴⁸ SDG&E’s TOU design
19 approach, which is informed by the company’s 2025 Transmission Cost Study, assigns
20 peak-related transmission costs to the peak period. SDG&E then spreads the remaining
21 transmission costs across all hours of the day.⁴⁹ Given SDG&E’s billing system
22 limitations, this approach is reasonable in the event that the Commission approves a
23 dynamic rate in this proceeding.

⁴⁵ See Appendix B, Attachment 3, excerpt of A.24-09-14, PG&E HFP Evaluation, August 3, 2026, at 15.

⁴⁶ D.25-08-049, at 66-67.

⁴⁷ SDG&E-03-R, Chapter 3, at 8, lines 6-8.

⁴⁸ SDG&E-03-R, Chapter 3, at 8. Medium Commercial and Large C&I DF customers will continue to pay the base transmission non-coincident and on-peak demand charges.

⁴⁹ SDG&E-03-R, Chapter 3, at 8.

D. SDG&E's TOU-based approach is a reasonable interim approach.

Given its billing system limitations, SDG&E's TOU-based approach is a reasonable interim approach as it is grounded in actual cost data and transmission project characteristics. SDG&E proposes assigning 10.7% of its annual transmission revenue requirement to the peak period with the remaining 89.3% collected at an equal cent per kWh rate across all hours.⁵⁰ Accordingly, the peak period \$/kWh transmission rate is equal⁵¹ to;

$$Rate_{Peak} = Rev_{transmission} * 0.893 * \frac{1}{\sum_i^n kWh} + Rev_{transmission} * 0.107 * \frac{1}{kWh_{peak}}$$

Where:

1. $Rev_{transmission} = \text{transmission revenue}$
2. " $Rev_{transmission} * 0.893 * \frac{1}{\sum_i^n kWh}$ " is equal to the flat equal cents per kWh rate in all periods
3. " $\sum_i^n kWh$ " is equal to the total sales in all⁵² periods
4. " $Rev_{transmission} * 0.107 * \frac{1}{kWh_{peak}}$ " is the peak period adder

SDG&E derives these peak and non-peak percentages from its 2025 Transmission Cost Study of its approved transmission projects.⁵³ Of these approved transmission projects, SDG&E determines which projects are designed with the purpose of accommodating peak demand and which are not designed with this purpose. To determine the percentage share of total costs related to peak demand for each year, SDG&E compares the aggregate capital expenditures of the transmission projects

⁵⁰ SDG&E-03-R, Chapter 3, at 9.

⁵¹ "Base Trans TOU Energy Rates and Demand Charges WP Revised" Workpapers, submitted by SDG&E on June 18, 2026, to support its revised testimony submitted June 1, 2026. SDG&E's workpapers are served concurrently with this testimony.

⁵² I.e., from the first (aka "i") period to the last (aka "nth") period.

⁵³ SDG&E-03-R, Chapter 3, at 8, lines 12-15, and 9, lines 4-6.

designed to meet peak demand to the combined capital expenditures of all transmission projects for each year in the study. The average of these annual percentages produces the 10.7% peak percentage of transmission costs SDG&E proposes to use for its TOU-based approach. The other 89.3% of transmission costs in this study are associated with projects serving non-peak related functions.⁵⁴

E. SDG&E’s criteria for determining the proportion of costs that are peak-related are reasonable.

The Commission should adopt SDG&E’s partition of costs between peak and non-peak because it is grounded in empirical project costs and characteristics. SDG&E identified three categories of transmission projects based on function developed from the CAISO Transmission Planning Process (TPP). These categories include economic, reliability, and policy-related motivations: “Economic” projects that reduce market congestion if implemented; “Policy” projects that enable the interconnection and delivery of energy resources; and “Reliability” projects that ensure the overall grid can serve load according to current North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council, and the CAISO reliability standards.⁵⁵ Of these categories, SDG&E determined reliability projects as the best representation of peak-related costs⁵⁶ because they are the subset of projects that are directly approved by the CAISO to address year-to-year increases in system load. Additionally, SDG&E reaffirmed its assignment of 10.7% transmission costs to peak periods when applying the deferability criteria.⁵⁷ Under the deferability criteria, projects that would be delayed and/or cancelled due to large drops in load would be considered deferrable and therefore excluded from collection in peak transmission rates. SDG&E determined that projects

⁵⁴ “Base Trans TOU Energy Rates and Demand Charges WP Revised” Workpapers, submitted by SDG&E on June 18, 2026, to support its revised testimony submitted June 1, 2026.

⁵⁵ See Appendix B, Attachment 4, SDG&E response to DR04, question 1, part b.

⁵⁶ See Appendix B, Attachment 4, SDG&E response to DR04, question 1, part b; see also Appendix B, Attachment 5, SDGE response to DR20, questions 1 and 2 (SDG&E’s response reaffirms its response to DR04).

⁵⁷ See Appendix B, Attachment 5, SDG&E response to DR20.

1 the company had identified as peak-related are also deferrable pursuant to this
2 definition.⁵⁸

3 **V. CUSTOMER PROTECTIONS (Witness: Otto Nichols)**

4 **A. If the Commission adopts a dynamic rate in this application, it**
5 **should adopt price limiters as the method of customer**
6 **protection.**

7 SDG&E proposes to use price limiters as its sole form of customer protection for
8 its proposed DF rate, utilizing both inherent price limits and self-imposing one onto its
9 pricing function for marginal energy costs (MEC).⁵⁹ This approach is reasonable as it is
10 the least costly option compared to other forms of customers protections (such as
11 subscription or bill limiters) yet still holds safeguards in place to shield customers from
12 extreme bill volatility. Price limiters place a floor and ceiling on the pricing function for
13 a cost component of the rate. SDG&E's MGCC and MDCC include inherent price
14 limiters in the proposed pricing functions because they both utilize a "Top Hours"
15 approach (Top 150 priced hours for MGCC and Top 200 hours for MDCC).⁶⁰ The Top
16 Hours approach acts as a threshold metric that is either met and the cost is applied, or is
17 not met and the cost component is \$0 in that hour.⁶¹ SDG&E proposes to include
18 additional protection by adding a floor and ceiling price to its MECs because its pricing
19 function does not inherently produce bounded values.⁶²

20 Subscriptions, on the other hand, consider historical usage and determine a set
21 amount of electricity that the customer subscribes to, limiting exposure to the dynamic
22 rate. Bill limiters would compare the customer's bill on the OAT rate to the dynamic rate
23 and cap any difference the customer must pay in relation to the OAT bill (for example +/-

⁵⁸ See Appendix B, Attachment 5, SDG&E response to DR10; see also Appendix B, Attachment 6, SDG&E response to DR 20, question 2 (SDG&E's response reaffirms its response to DR 10).

⁵⁹ SDG&E-04-2R, at 1, lines 12-14, and at 3, lines 19-23.

⁶⁰ SDG&E-04-2R, at 5, lines 1-20.

⁶¹ SDG&E-04-2R, at 5, lines 1-20.

⁶² SDG&E-04-2R, at 4, lines 1-19.

1 50% of the OAT bill). Both subscriptions and bill limiters require added complexity and
2 cost without providing enough additional protections beyond what price limiters provide.
3 As described below, both PG&E and SCE provide supporting viewpoints for adopting
4 price limiters in their respective and ongoing dynamic rate applications.

5 For example, SCE describes in supplemental testimony that the other potential
6 customer protections are costly and difficult to understand with uncertain benefits.
7 Specifically, SCE notes that subscriptions are a relatively complex customer protection
8 mechanism and that bill limiters would add significant complexity compared with
9 subscriptions.⁶³ SCE further describes the added billing logic and processes that would
10 be required for each approach, such as calculating two bills if applying subscriptions (one
11 for the subscribed kWh and one for the remaining kWh billed on the dynamic rate) or a
12 third bill if applying a bill limiter (since the limiter would produce a bill entirely separate
13 from the OAT and dynamic rate bills).⁶⁴ SCE also provides a cost breakdown of the
14 three options for its proposed rate showing the relative cost-effectiveness of price
15 limiters.⁶⁵ The issue of additional complexity leading to additional costs without clear
16 benefits would also apply to SDG&E.⁶⁶

17 Additionally, PG&E notes in its own dynamic rate application (RTP Stop Gap
18 Testimony) that it has received considerable feedback from customers that they find
19 subscriptions challenging to understand and manage to ensure they are achieving bill

⁶³ See Appendix B, Attachment 7, excerpt of A.24-06-014, et al., *Testimony of Southern California Edison Company (U-338-E) in Support of (1) Application for Approval of Large Power Dynamic Pricing Rate and (2) Application for Approval of Marginal Cost-Based Dynamic Pricing Rates in Compliance with Decision 22-10-022 and Load Management Standards* (SCE-06-A; A.24-12-008), May 12, 2026, at 5, line 16, and at 6, lines 18-19.

⁶⁴ See Appendix B, Attachment 7, excerpt of SCE-06-A, at 5, lines 18-20, and at 6, lines 18-23.

⁶⁵ See Appendix B, Attachment 8, excerpt of SCE-06-A, at 25, Table 4: Summary Table of Customer Protection & Locational Price Options, Costs, and Timing.

⁶⁶ SDG&E-04-2R, at 3, lines 14-15.

savings.⁶⁷ Further, PG&E shares SCE and SDG&E's concerns about the implementation complexity and costs of the bill limiter approach.⁶⁸

Finally, analysis of SDG&E's dynamic rate bill impact workpapers - with SDG&E's proposed price limiters applied and assuming no load shifting - shows reasonable results, which are reflected in the tables below.⁶⁹

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⁶⁷ See Appendix B, Attachment 9, excerpt of PG&E-6, at 2-20, lines 22-24.

⁶⁸ See Appendix B, Attachment 10, excerpt of PG&E-6, at 2-34, lines 14-15.

⁶⁹ Data pulled from SDG&E's bill impact tables for non-solar exporting customers received in DR Response "CALPA-DR-18_SDGE Supplemental Response_6-26-26." SDG&E's workpapers are served concurrently with this testimony.

SDG&E Table 5-1: Monthly Bill Changes (\$) by Usage Profile for Non Solar⁷⁰
Exporting Customers

Change			
Month	Total Bill Low Usage	Total Bill Average Usage	Total Bill High Usage
January	\$5	\$13	\$26
February	-\$8	-\$24	-\$46
March	-\$12	-\$35	-\$70
April	-\$12	-\$34	-\$68
May	-\$14	-\$41	-\$83
June	-\$6	-\$19	-\$39
July	\$7	\$24	\$49
August	\$16	\$59	\$121
September	\$32	\$116	\$235
October	\$0	-\$1	\$0
November	-\$8	-\$22	-\$43
December	-\$6	-\$17	-\$34
Total Annual Change	-\$7	\$18	\$50

⁷⁰ SDG&E-05-2R, at 3, lines 7-9. SDG&E's bill impact workpapers with customer protections showing only for non-NEM customers since NEM/NBT are proposed to be excluded from participation on this rate.

SDG&E Table 5-2: Monthly Bill Changes (%) by Usage Profile for Non Solar Exporting Customers

Percent Change			
Month	Total Bill Low Usage	Total Bill Average Usage	Total Bill High Usage
January	5%	6%	6%
February	-10%	-12%	-12%
March	-14%	-17%	-18%
April	-14%	-18%	-19%
May	-17%	-22%	-23%
June	-8%	-9%	-10%
July	7%	9%	10%
August	16%	21%	22%
September	34%	47%	49%
October	-1%	0%	0%
November	-9%	-11%	-11%
December	-6%	-8%	-8%
Total Annual Change	-1%	1%	1%

SDG&E's Tables 5-1 and 5-2 reveal that, with its proposed price limiters applied, customers switching to the dynamic pricing rate should not experience a significant change in their bills without intentionally shifting any load. Further, these tables illustrate that this rate should avoid the "free riding" problem since most average and high usage customers should not automatically experience significant bill savings without shifting any load. Therefore, it is reasonable to adopt SDG&E's proposed price limiters as its form of customer protection for initial implementation of its proposed DR rates.

F. The Commission should require SDG&E to monitor monthly bill impacts of the dynamic rate in comparison to a customer's OAT and make ongoing assessments and changes to its customer protections, as necessary.

If the Commission adopts a dynamic rate in this Application, it should require SDG&E to closely monitor bill impacts of its participants and make changes to the

1 customer protections as necessary. For example, SDG&E could compare the monthly
2 bill impacts of DF participants to the customer's bill on the OAT rate to assess the
3 volatility, or difference in bills, to determine if changes to the customer protections are
4 necessary. If SDG&E determines that changes to the customer protections are necessary
5 after implementation, the Commission should require it to file a Tier 2 Advice Letter to
6 make this change while continuing to use the rate formulae approved by the
7 Commission.⁷¹

8 **VI. CONCLUSION**

9 The Commission should exercise caution as it adopts dynamic rates to ensure that
10 ratepayers are not subjected to undue cost burdens. As SDG&E also states in its
11 testimony, implementing dynamic rates in SDG&E's territory at this time is not prudent
12 given the time and expense it would require to do so.⁷² Furthermore, SDG&E correctly
13 points out the demonstrated lack of interest in participating in dynamic rate options
14 within its territory.⁷³ Nonetheless, if the Commission decides to adopt a dynamic rate in
15 this proceeding, then it should adopt SDG&E's marginal commodity, distribution, and
16 transmission cost proposals. Furthermore, the Commission should require SDG&E to
17 study its locational distribution pricing method for further refinement. The Commission
18 should also adopt price limiters to protect ratepayers from price volatility and continue to
19 consider customer protection options by requiring SDG&E to study them periodically in
20 the future.

⁷¹ If SDG&E proposes to use different formulas, it should be required to propose changes to the customer protections through a Tier 3 Advice Letter.

⁷² A.26-02-001, at 1.

⁷³ A.26-02-001, at 1.

APPENDIX A

Qualifications of Witnesses

QUALIFICATIONS AND PREPARED TESTIMONY
OF
NATHAN CHAU

Q.1 Please state your name and address.

A.1 My name is Nathan Chau, and my business address is 505 Van Ness Avenue,
San Francisco, California, 94102.

Q.2 By whom are you employed and what is your job title?

A.2 I am employed by the Public Advocates Office at the California Public Utilities
Commission and my job title is Public Utilities Regulatory Analyst.

Q.3 Please describe your educational and professional experience.

A.3 I hold a Bachelor of Science degree in Applied Economics from the University of
the Pacific. My degree included coursework in finance, economics, and
econometrics. Since joining the Commission in April 2015, I have actively
participated in a number of rate cases such as SDG&E's General Rate Case Phase
II (A.23-01-008), PG&E's General Rate Case Phase II (A.16-06-013), the Time-
of-Use Order Instituting Rulemaking (R.15-12-012), the Application on SB 350
Transportation Electrification Proposals (A.17-01-021) and the Order Instituting
Rulemaking to Revisit Net Energy Metering Tariffs (R.20-08-020). I also worked
as project coordinator and witness in PG&E's General Rate Case Phase II
(A.24-09-014).

Q.4 What is your area of responsibility in this proceeding?

A.4 My area of responsibility in this proceeding is focused on the transmission costs.

Q.5 Does that complete your prepared testimony?

A.5 Yes.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
LAUREN SCHENCK

Q.1 Please state your name and address.

A.1 My name is Lauren K. Schenck, and my business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2 By whom are you employed and what is your job title?

A.2 I am employed by the Public Advocates Office at the California Public Utilities Commission and my job title is Public Utilities Regulatory Analyst.

Q.3 Please describe your educational and professional experience.

A.3 I have a Bachelor of Science in Earth Sciences from the University of California, Santa Cruz, and a Master of Science in Law from Northwestern University Pritzker School of Law. I have been employed by the Public Advocates Office, in the Electricity Pricing and Consumer Programs Branch since September of 2022, and have worked on utility General Rate Cases, the Demand Flexibility Order Instituting Rulemaking, and proceedings related to behind-the-meter solar. I have experience conducting complex analyses related to rate design, sales forecasting, and affordability issues.

Q.4 What is your area of responsibility in this proceeding?

A.4 My area of responsibility in this proceeding is focused on Marginal Energy Costs and Marginal Generation Capacity Costs, Budget, Cost Recovery, Implementation, and Evaluation Issues.

Q.5 Does that complete your prepared testimony?

A.5 Yes.

**QUALIFICATIONS AND PREPARED TESTIMONY
OF
OTTO NICHOLS**

Q.1 Please state your name and address.

A.1 My name is Otto Nichols, and my business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2 By whom are you employed and what is your job title?

A.2 I work in the Electricity Pricing and Customer Programs Branch of Cal Advocates as a Regulatory Analyst.

Q.3 Please describe your educational and professional experience.

A.3 I graduated from the University of San Francisco with a Master of Science degree in Energy Systems Management and hold a Bachelor of Science degree in Business Management and Economics from DePaul University in Chicago, Illinois. I joined the Electricity Pricing section of Cal Advocates in October 2021 as a Public Utilities Regulatory Analyst and my work is focused on utility electric rate design. I have experience conducting analyses related to rate design, sales forecasting, and affordability issues. My previous professional experience includes a decarbonization analyst position for the renewable energy consulting firm, Apala Group.

Q.4 What is your area of responsibility in this proceeding?

A.4 My area of responsibility is focused on Distribution and Customer Protections in Cal Advocates' Prepared Testimony in this proceeding.

Q.5 Does that complete your prepared testimony?

A.5 Yes, it does.

APPENDIX B

Supporting Materials

ATTACHMENT 1: SDG&E's responses to Q1a and Q1ai in CALPA-DR-07_SDGE Response.pdf.

SDG&E RESPONSE
DATE RECEIVED: MARCH 20, 2026
DATE RESPONDED: APRIL 3, 2026

PRICING

QUESTION 1a(i)

1. SDG&E's location-based distribution pricing proposal consists of implementing circuit-based distribution capacity adders for each customer class across 10 clusters of circuits.¹ SDG&E is proposing to cluster the distribution circuits into 10 circuit groups based on the percentage of residential and non-residential kWh load on the circuits to reduce the number of distribution circuit rates needed from 1,030 to 10.²
 - a. Please provide a detailed narrative explaining SDG&E's reasoning for selecting the circuit clusters based solely on the percentage of residential and non-residential kWh load on the individual circuits.
 - i. Do these circuits in each cluster share similar load characteristics? For example, do these circuit clusters share similar timing of high-load versus low-load hours or ramp periods? If so, please provide data and analysis showing the load characteristics for circuits in each cluster and explain the similarities.

SDG&E RESPONSE 1a(i)

- a) Because the loads of residential and non-residential customers peak at different times in the day, SDG&E believes that basing the circuit clusters on the percentage of residential and non-residential load on the individual circuits in a particular cluster, broken out into separate clusters by 10% increments, groups the circuit clusters by load characteristics and reflects marginal distribution capacity costs/marginal distribution demand costs.
 - i. Yes, as mentioned in response to Question 1a above, residential and non-residential customers generally peak at different times in the day, which is why SDG&E clustered the circuits to achieve a grouping on circuits with consistent percentages of residential and non-residential kWh loads. By basing the circuit clusters on consistent percentages of residential and non-residential kWh loads, the circuits in each cluster should have similar timing of high-load versus low-load hours associated with residential and non-residential customer kWh loads. Please see workpaper "Demand Flexibility (DF) – Distribution Capacity Hourly Adder & Distribution Base Rate Workpaper" and the percentage of residential and non-residential load by cluster.

QUESTION 1a(ii)

- ii. Do circuits in each cluster share characteristics that reflect differences in operations from circuits in other clusters? If so, please provide data and analysis showing how circuits in each cluster are operationally similar and also how they are operationally different from circuits in other clusters.

Attachment 2: Excerpts for Pacific Gas and Electric Company 2023 General Rate Case Phase II Prepared Testimony Exhibit (PG&E-6) PG&E’s Testimony Supporting Stop-Gap Interim RTP Pilots Extension Proposal in A.24-09-014.

20 experience which may encourage wider customer participation. Thus, PG&E
21 plans to research alternate rate design structures with that process in mind.
22 Such refinements may include but are not limited to exploring rate design at
23 higher load aggregation (such as substation or system-level), blending historical
24 rate signals with dynamic forecast-based signals, or designing rates that follow
25 smoother trend-based signals. PG&E will also investigate the potential to
26 increase fixed charges for HFP participants in order to reduce non-coincident
27 demand and energy charges.

28 The primary challenge preventing PG&E from proposing more fundamental
29 changes to rate design in this application is the uncertainty around the general
30 implications of such modifications. A key element of that uncertainty is that it is
31 still unclear how customer responses to RTP rates translate into material,
32 quantifiable reductions in distribution investment needs and/or better utilization

⁷ Exhibit (PG&E-5), pp. 2-15 to 2-18, Section H-2.

(PG&E-6)

1 of the existing system without incurring new costs. The planned measurement
2 and evaluation studies described in Chapter 7 of this exhibit will provide
3 important data points for continued learnings, which may help inform if moving
4 away from the current pricing model is warranted.

16 **3. Distribution Pricing**

17 **a. Learning: PG&E's RTP Distribution Pricing Approach May Need**
18 **Further Evolution**

19 In PG&E's HFP and Phase 2 of the VGI pilots, the distribution
20 component of the HFP rate is being determined at a distribution circuit
21 level.³² PG&E's over 3,000 distribution circuits are grouped into 59
22 clusters with similar load profiles and each circuit's pricing is based on
23 the day-ahead forecasted load on one of those 59 representative
24 circuits. The complexity of the distribution system and sensitivity of
25 circuit-level load profiles to changes in coincident and noncoincident
26 demand patterns makes load forecasting and price modeling
27 challenging.³³ Consequently, while PG&E has made refinements to the
28 distribution component of the HFP pilots to address such challenges,

³² A set of conductors of the electric primary distribution system originating at a substation and delivering power to a defined set of downstream customers and equipment, with load, topology, and operating characteristics that can be analyzed and managed as a unit

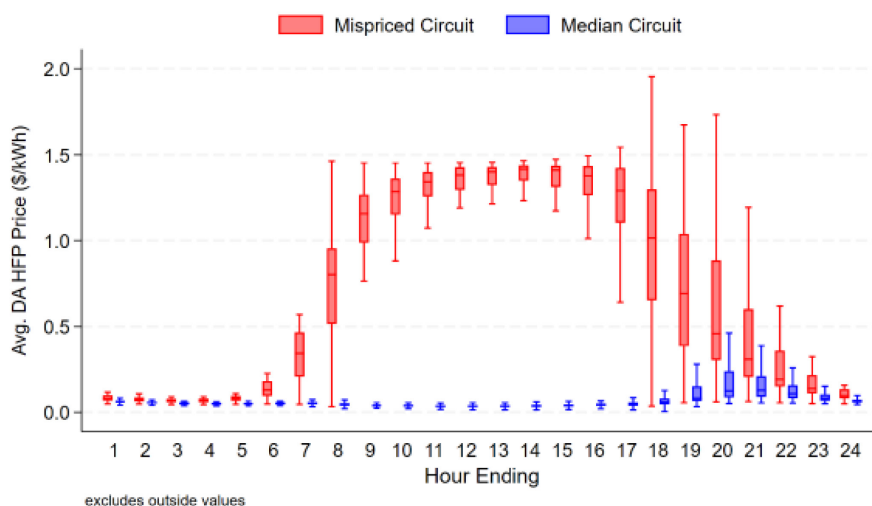
³³ PG&E 2023 GRC II Supplemental Testimony, Exhibit (PG&E-5) Real-Time Pricing Proposal (Oct. 29, 2025), pp. 2-15 to 2-18.

Attachment 3: Excerpts for Mid-Term Evaluation of PG&E's Hourly Flex Pricing Pilot.

- Customers were on track to be paid nearly \$8 million in Pilot credits. These are largely attributable to two factors:
 - Prior to a change in billing that took effect in November 2025, subscriptions were priced using a billing demand value derived from averaged hourly loads rather than the OAT methodology, resulting in a "demand discount" that ranged from approximately 8% to 25% of the OAT bill.
 - Customers on two circuits that had persistently high midday prices (due to a pricing methodology that was changed in early 2026) were able to generate credits if they could consistently sell excess subscription load back at the high Pilot hourly prices during those hours.

Two of the circuits (which we refer to as the “mispriced” circuits) displayed a significantly different price pattern than the others until the MDCC pricing algorithm was modified in February 2026. Until that time, the price profile appeared as a “plateau”, with high prices from roughly HE 8 to 18. Figure 2.6 shows the difference between prices for one of these circuits relative to those of the median circuit illustrated above. In Figure 2.6, the blue data corresponds to the top panel of Figure 2.4, with the scale modified to accommodate the high prices from the mispriced circuit. Notice that during the middle of the day (HE 11 to 15), the prices were both high and displayed comparatively little variability (relative to other hours of the day for that circuit), indicating that prices were consistently high during those hours. As our results will show, this price pattern had a significant effect on customer outcomes.

Figure 2.6: Summer Weekday HFP Prices by Circuit Type



Attachment 4: SDG&E Response to CALPA-DR-04 with Tables Reproduced from Workpapers

**CAL ADVOCATES DATA REQUEST 04
DEMAND FLEXIBLE RATE APPLICATION – A.26-02-001
SDG&E RESPONSE
DATE RECEIVED: MARCH 5, 2026
DATE RESPONDED: MARCH 26, 2026**

QUESTION 1

1. SDG&E states it conducted a 2025 Transmission Cost Study using data from 2023 through 2025. The study identifies only transmission peak-related and non-peak related costs, and does not identify transmission hourly capacity costs because the transmission costs are not hourly based. This study shows that approximately 8.1% of SDG&E's 2023-2025 total transmission capacity costs are peak-related.¹
 - a. Please describe in detail what SDG&E means in the phrase "because the transmission costs are not hourly based."²

SDG&E RESPONSE 1a:

SDG&E states that its study identifies only peak on non-peak costs and not hourly costs because transmission costs are not hourly based because it was not able to identify hourly data to use for purposes of its transmission cost study. SDG&E performed a 2025 transmission cost study where it was able to pull peak-related costs to develop TOU transmission pricing. SDG&E points this out because although Conclusions of Law (COL) 16 of Decision (D.) 25-08-049 states "It is reasonable to require the Large IOUs to include an hourly transmission capacity price component in DF Rate Proposals[.]" D.25-08-049 also acknowledges "that additional studies are needed to determine appropriate hourly and TOU transmission capacity price signals and therefore encourage the IOUs to undertake the necessary studies to propose rate designs for time-varying transmission capacity prices." D.25-08-049 at 66-67. SDG&E performed a 2025 transmission cost study where it was able to pull peak-related costs to develop TOU transmission pricing.

SDG&E's 2025 transmission cost study uses data from the California Independent System Operator (CAISO) Transmission Planning Process (TPP), which does not include hourly data because transmission infrastructure projects are not planned for each hour and cannot be removed in non-stressed conditions for hourly cost savings.³ Per CAISO's Business Practices Manual for Transmission Planning, which is used by SDG&E for transmission planning CAISO proposes mitigation to address transmission needs where system performance criteria are not met under certain stress conditions (such as summer peak or off-peak scenarios).⁴

¹ Prepared Direct Testimony of William G. Saxe on Behalf of San Diego Gas & Electric Company Chapter 3 – Distribution & Transmission (SDG&E Chapter 3), February 2, 2026, at 8

² SDG&E Chapter 3, at 8.

³ See California, ISO 2024-2025 Transmission Plan (Board Approved May 30, 2025), available at [iso-board-approved-2024-2025-transmission-plan.pdf](https://www.iso-board-approved-2024-2025-transmission-plan.pdf)

⁴ [https://bpmmc.caiso.com/BPM%20Document%20Library/Transmission%20Planning%20Process/BPM for Transmission Planning Process v28 CLEAN.docx](https://bpmmc.caiso.com/BPM%20Document%20Library/Transmission%20Planning%20Process/BPM%20for%20Transmission%20Planning%20Process%20v28%20CLEAN.docx), at page 28.

CAL ADVOCATES DATA REQUEST 04
DEMAND FLEXIBLE RATE APPLICATION – A.26-02-001
SDG&E RESPONSE
DATE RECEIVED: MARCH 5, 2026
DATE RESPONDED: MARCH 26, 2026

- b. Please describe in detail the criteria SDG&E uses to determine whether each project is peak-related.

SDG&E RESPONSE 1b:

SDG&E objects to this request as vague and ambiguous as to its reference to “each project.” Subject to and without waving the foregoing objection, SDG&E responds as follows:

SDG&E determined that out of its transmission projects, those that are defined as “Reliability” projects in the CAISO BMP (aka the CAISO tariff) are peak-related projects for purposes of determining transmission costs for this rate. The CAISO TPP divides transmission infrastructure into three categories: “Economic” projects that reduce market congestion if implemented, “Policy” projects that enable the interconnection and delivery of energy resources, and “Reliability” projects that ensure the overall grid can serve load according to current NERC, Western Electricity Coordinating Council, and CAISO reliability standards. Out of the three categories, the “Reliability” projects are the subset that is directly approved by CAISO to address year-to-year increases in system load. Therefore, the Reliability projects were chosen and submitted as the best representation of peak-related costs.

QUESTION 2

2. Please provide the Transmission Cost Study SDG&E relies on to determine that approximately 8.1% of SDG&E’s 2023-2025 total transmission capacity costs are peak- related.

SDG&E RESPONSE 2:

Please see SDG&E’s response to question 2a below.

QUESTION 2a.

- a. Please also provide, in Excel format, a table listing of all transmission projects covered in the Transmission Cost Study in the first column. For the next four columns, please specify for each project the dollar amount, the study year,⁵ whether the project is peak-related (e.g., “yes”, “no”), and why each project is/is not peak- related.

SDG&E RESPONSE 2a:

Please refer to the attached spreadsheet.

QUESTION 2b:

⁵ SDG&E referred to as study year during our meeting on March 4, 2026, when it stated that the 8.1% was based on an average of three years. Please state to which year (2023-2025) each project is associated.

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SDG&E RESPONSE
DATE RECEIVED: MARCH 5, 2026
DATE RESPONDED: MARCH 26, 2026

- b. In the sixth column, please categorize each transmission project based on proposed/approved function. Below is an example of such functions using PG&E's 2023 GRC as example.⁶ SDG&E may elect to provide its own list of functions. For this column, SDG&E may provide a legend listing reasons A to Z (or some other ordering) and in the Excel table just reference the letter in each cell.
- i. Projects that address capacity deficiency up to 25% deficiency;
 - ii. Projects where normal conditions (N-0) or a single contingency event could result in facility thermal overloads greater than 25 percent within the 5-yr horizon;
 - iii. Projects approved to reduce Local Capacity Adequacy Requirements;
 - iv. Projects that are driven by low voltage;
 - v. Projects needed to address high voltage conditions;
 - vi. Projects needed to address short circuit duty issues;
 - vii. Projects needed to enable generation interconnection, policy or economic;
 - viii. Projects needed to meet safety or resiliency needs; or
 - ix. Projects required to be initiated as soon as possible to mitigate an existing 4 thermal or voltage problem due to N-0 or N-1 contingency events.

SDG&E RESPONSE 2b:

SDG&E has elected to provide its own list of functions (see column F of the attached spreadsheet).

QUESTION 2c:

- c. Are the projects that SDG&E identifies as peak related also considered "deferrable costs"? Deferrable costs means that if forecasted load falls, the project would be cancelled and/or deferred. Based on this definition, please identify the projects that meet this definition/criteria in an additional column to the table provided in responses to parts 2a and 2b.

SDG&E RESPONSE 2c:

⁶ Inspired by PG&E. See A.24-09-014, at pages 4-8 to 4-11 of Exh. PG&E-2 dated 10/29/25 attached.

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SDG&E RESPONSE
DATE RECEIVED: MARCH 5, 2026
DATE RESPONDED: MARCH 26, 2026

Yes, all of the projects that SDG&E has identified as peak related are also deferrable costs pursuant to the definition listed. Deferrable projects have been noted in the attached spreadsheet (see column G).

QUESTION 2d:

- d. Using the table provided in response to parts 2a, 2b and 2c, please show how SDG&E calculated that 8.1% of its 2023-2025 total transmission capacity costs are peak-related, keeping all formulas intact.

SDG&E RESPONSE 2d:

Please refer to the attached spreadsheet. Please note that in responding to this data request, SDG&E identified an error in its calculation. The corrected total peak-related transmission capacity costs is 7.6%. SDG&E will correct this information in revised testimony.

QUESTION 3

3. SDG&E's 2023-2025 Transmission Cost Study presumably covers data from 2023 through 2025. Please explain what information on dates related to the transmission projects was used to determine the projects that would be included. For example, do these dates simply indicate when projects were approved, when SDG&E would begin expenditures or the anticipated operational year⁷ for these projects?

- a. If the anticipated operational year for these projects fall outside of this range (i.e., 2023-2025), please provide the dates for each project as an additional column to the Excel table provided in response to question 2.

SDG&E RESPONSE 3:

SDG&E included costs for any projects with capital expenditures made during the years 2023 through 2025. In other words, all peak-related transmission costs accrued in 2023-2025.

SDG&E RESPONSE 3a:

SDG&E uses the term "in-service" date, rather than "operational year" to indicate when a project is complete and "used and useful." A new column H was added to provide the In-Service Dates for each project. As noted in the spreadsheet, these dates were taken from a combination of the Transmission Project Review (TPR), Transmission Development Forum (TDF), and CAISO TPP reports.

⁷ Operational year refers to the year when the project is built, used and useful.

TRANSMISSION ACTUAL CAP EX (\$000)							
	2023	2024	2025*				
Total Transmission Cap Ex in TPR (000's)	\$ 411,624	\$ 479,074	\$ 374,549				
Transmission Project Cap Ex Peak Related Costs				Peak-Related	Approved Function	Deferrable	In-Service Date**
SOCRE TO BBK (191555)	39,636	15,519	1,595	Yes (See 1b for explanation)	Reliability project (thermal overloads)	Yes	
TL605 Reconductor	8,171	15,142	2,031	Yes (See 1b for explanation)	Reliability project (thermal overloads)	Yes	
Sweetwater - TL603B Upgrade	681	836	497	Yes (See 1b for explanation)	Reliability project (thermal overloads)	Yes	2026-07-23
Escondido/San Marcos Reconfiguration and Addition of TL6975 (Escondido - San Marcos)	2,820	1,777	82	Yes (See 1b for explanation)	Reliability project (thermal overloads)	Yes	
Del Mar Reconfiguration	1,267	168	63	Yes (See 1b for explanation)	Reliability project (thermal overloads)	Yes	
Artesian Ranch 230kV Yard Addition	1,654	1,245	247	Yes (See 1b for explanation)	Reliability project (thermal overloads)	Yes	2022-12-04
TL663 MS - KY 69kV Reconductor	59	39	0	Yes (See 1b for explanation)	Reliability project (thermal overloads)	Yes	2020-02-26
Miguel-Sycamore Canyon (TL23021) 230 kV line Loop-in to Suncrest. (Revised name: Suncrest 230kV Loop-in)	0	1,769	1,478	Yes (See 1b for explanation)	Reliability project (thermal overloads)	Yes	2031-04-28
SG and OT Redundant Bus Differential Relay	113	647	429	Yes (See 1b for explanation)	Reliability project (thermal overloads)	Yes	
Downtown Reliability Enhancement	0	0	0	Yes (See 1b for explanation)	Reliability project (thermal overloads)	Yes	2037***
Coronado Island Project	0	42	781	Yes (See 1b for explanation)	Reliability project (thermal overloads)	Yes	2028-11-30
Total	54,402	37,184	7,204				
Percentage of Transmission Cap Ex Peak-Related Cost	13%	8%	2%				
Average 2023-2025			7.6%				
*Actuals through August/September							
** Future in-service dates are expected dates. These dates are provided only for projects in-service or expected to be in-service in years other than 2023-2025. These dates are based on Transmission Project Review, Transmission Development Forum and CAISO Transmission Planning Process Reports unless otherwise noted: https://www.sdge.com/sites/default/files/JAN26-SDG%26E-Public%20-%20Resolution%20E-5252%20TPR%20Process%20Data.xlsx							
*** Per TPP report: https://www.caiso.com/documents/reviced-draft-2024-2025-transmission-plan.pdf							

Attachment 5: SDG&E Response to CALPA-DR-20 with Tables Reproduced from Workpapers

**CAL ADVOCATES DATA REQUEST 20
DEMAND FLEXIBLE RATE APPLICATION – A.26-02-001
SDG&E SUPPLEMENTAL RESPONSE
DATE RECEIVED: JUNE 22, 2026
DATE RESPONDED: JULY 8, 2026**

QUESTION 1:

Please update the workpaper titled “A.26-02-001 - CalPA DR 10 Q1 (SDGE Trans Cap Ex 2023 - 2025) 4-22” which SDG&E provided in response to DR CalAdvocates-010 to reflect all the relevant changes included in SDG&E’s revised testimony dated June 1, 2026. In its revised testimony, SDG&E states that the original 2025 Transmission Cost Study which forms the basis of SDG&E’s transmission proposal in this proceeding, only included 2025 cost data through September 2025. The updated 2025 Transmission Cost Study now reflects January through December 2025 costs and revisions to correct errors. The update results in the peak-related transmission percentage increasing from 8.1% to 10.7%.¹ In resubmitting the workpaper, please include and identify these additions and corrections.

SDG&E RESPONSE TO QUESTION 1:

Please see the attached file, titled “CalPA DR-20, Q1,” for SDG&E’s response to this question. The file provides the transmission costs included in the direct testimony based on the Original 2025 Transmission Cost Study, the transmission costs included in the supplemental testimony based on the Updated 2025 Transmission Cost Study, and the calculation of the change in the transmission costs identified in the Original 2025 Transmission Cost Study versus the Updated 2025 Transmission Cost Study.

¹ SDGE-03-R, at 8.

CAL ADVOCATES DATA REQUEST 20
DEMAND FLEXIBLE RATE APPLICATION – A.26-02-001
SDG&E SUPPLEMENTAL RESPONSE
DATE RECEIVED: JUNE 22, 2026
DATE RESPONDED: JULY 8, 2026

QUESTION 2:

In its response to question 2c of data request “A.26-02-001_CalAdvocates-SDG&E-004,” and in “A.26-02-001_CalAdvocates-SDG&E-010,” SDG&E identified the projects that are deferrable. In a call² discussing these responses, SDG&E stated that it modeled large-load reductions to determine whether a project is deferrable. Please describe in detail the specific criteria and/or load thresholds SDG&E employed to determine deferability.³

SDG&E SUPPLEMENTAL RESPONSE TO QUESTION 2:

On July 6, 2026, SDG&E requested an extension to this question until July 20, 2026.

SDG&E objects to this request on the grounds that it calls for speculation and misstates facts and/or assumes facts that do not exist. Subject to and without waiving the foregoing objection, SDG&E responds as follows.

Specifically, the request is based on an inaccurate representation that large loads reductions factor into determining whether a project is deferrable. Instead, to determine whether a project is peak-related (and thus deferrable), please refer to SDG&E’s previous response to Question 1b of DR04:

SDG&E determined that out of its transmission projects, those that are defined as “Reliability” projects in the CAISO BMP (aka the CAISO tariff) are peak-related projects for purposes of determining transmission costs for this rate. The CAISO TPP divides transmission infrastructure into three categories: “Economic” projects that reduce market congestion if implemented, “Policy” projects that enable the interconnection and delivery of energy resources, and “Reliability” projects that ensure the overall grid can serve load according to current NERC, Western Electricity Coordinating Council, and CAISO reliability standards. Out of the three categories, the “Reliability” projects are the subset that is directly approved by CAISO to address year-to-year increases in system load. Therefore, the Reliability projects were chosen and submitted as the best representation of peak-related costs.

² Video conference call between SDG&E and Cal Advocate on Friday, April 3, 2026.

³ Cal Advocates had requested an explanation in DR-010 but did not receive an adequate response.

Direct Testimony Transmission Cost Study			
TRANSMISSION ACTUAL CAP EX (\$000)			
	2023	2024	2025*
Total Transmission Cap Ex in TPR (000's)	\$411,624	\$479,074	\$374,549
<u>Transmission Project Cap Ex Peak Related Costs</u>			
SOCRE TO BBK (191555)	\$39,636	\$15,519	\$1,595
TL605 Reconductor	\$8,171	\$15,142	\$2,031
Sweetwater - TL603B Upgrade	\$681	\$836	\$497
Escondido/San Marcos Reconfiguratio and Addition of TL6975 (Escondido - San Marcos)	\$2,820	\$1,777	\$82
Del Mar Reconfiguration	\$1,267	\$168	\$63
New TL 6975	\$2,820	\$1,777	\$82
TL6906 Loop-in to Mesa Rim	\$0	-\$1	\$0
Artesian Ranch 230kV Yard Addition	\$1,654	\$1,245	\$247
Ocean Ranch Sub	\$0	\$0	\$0
TL663 MS - KY 69kV Reconductor	\$59	\$39	\$0
Miguel-Sycamore Canyon (TL23021) 230 kV line Loop-in to Suncrest. (Revised name: Suncrest 230kV Loop-in)	\$0	\$1,769	\$1,478
SG and OT Redundant Bus Differential Relay			
Short Circuit Mitigation for Imperial Valley 230 kV Circuit Breakers Project	\$0	\$10	\$129
Short Circuit Mitigation for Miguel 230 kV Circuit Breakers Project	\$0	\$0	\$26
Valley Center System Improvement	\$0	\$0	\$28
Downtown Reliability Enhancement	\$0	\$0	\$0
Coronado Island Project	\$0	\$42	\$781
12132 - SCADA Transmission Expansion - 5589537 (A SG Reliability Enhancement)	\$113	\$396	\$170
12132 - SCADA Transmission Expansion - 595005 (A OT Reliability Enhancement)		\$251	\$259
03171 - Transmission System Automation - 5438010 (A TSA ICON South Bay 230 kV)	\$420	\$338	\$157
Total	\$57,642	\$39,309	\$7,626
Percentage of Transmission Cap Ex Peak-Related Cost	14%	8%	2%
Average 2023-2025			8.1%
*Actuals through September			

Supplemental Testimony Transmission Cost Study			
TRANSMISSION ACTUAL CAP EX (\$000)			
	2023	2024	2025
Total Transmission Cap Ex in TPR (000's)	\$411,624	\$479,074	\$495,862
<u>Transmission Project Cap Ex Peak Related Costs</u>			
SOCRE TO BBK (191555)	\$39,636	\$15,519	\$631
TL605 Reconductor	\$8,171	\$15,142	\$2,344
Sweetwater - TL603B Upgrade	\$681	\$836	\$11,257
Escondido/San Marcos Reconfiguratio and Addition of TL6975 (Escondido - San Marcos)	\$2,820	\$1,777	\$13
Del Mar Reconfiguration	\$1,267	\$168	-\$18
TL6906 Loop-in to Mesa Rim	\$0	-\$1	\$0
Artesian Ranch 230kV Yard Addition	\$1,654	\$1,245	\$1
TL663 MS - KY 69kV Reconductor	\$59	\$39	-\$1
Miguel-Sycamore Canyon (TL23021) 230 kV line Loop-in to Suncrest. (Revised name: Suncrest 230kV Loop-in)	\$0	\$1,769	\$3,668
SG and OT Redundant Bus Differential Relay	\$113	\$647	\$491
Downtown Reliability Enhancement	\$0	\$0	\$0
Coronado Island Project	\$0	\$42	\$14,594
San Ysidro 69 kV Reconductoring (TL623C)	\$30	\$202	\$396
TL632 Granite Loop-In and TL6914 Reconfiguration	\$7,751	\$1,404	\$10,473
Total	\$62,184	\$38,791	\$43,849
Percentage of Transmission Cap Ex Peak-Related Cost	15%	8%	9%
Average 2023-2025			10.7%

Change in Transmission Cost Study			
TRANSMISSION ACTUAL CAP EX (\$000)			
	2023	2024	2025
Total Transmission Cap Ex in TPR (000's)	\$0	\$0	\$121,313
<u>Transmission Project Cap Ex Peak Related Costs</u>			
SOCRE TO BBK (191555)	\$0	\$0	-\$964
TL605 Reconductor	\$0	\$0	\$313
Sweetwater - TL603B Upgrade	\$0	\$0	\$10,760
Escondido/San Marcos Reconfiguratio and Addition of TL6975 (Escondido - San Marcos)	\$0	\$0	-\$69
Del Mar Reconfiguration	\$0	\$0	-\$81
New TL 6975	-\$2,820	-\$1,777	-\$82
TL6906 Loop-in to Mesa Rim	\$0	\$0	\$0
Artesian Ranch 230kV Yard Addition	\$0	\$0	-\$247
Ocean Ranch Sub	\$0	\$0	\$0
TL663 MS - KY 69kV Reconductor	\$0	\$0	-\$1
Miguel-Sycamore Canyon (TL23021) 230 kV line Loop-in to Suncrest. (Revised name: Suncrest 230kV Loop-in)	\$0	\$0	\$2,190
SG and OT Redundant Bus Differential Relay	\$113	\$647	\$491
Short Circuit Mitigation for Imperial Valley 230 kV Circuit Breakers Project	\$0	-\$10	-\$129
Short Circuit Mitigation for Miguel 230 kV Circuit Breakers Project	\$0	\$0	-\$26
Valley Center System Improvement	\$0	\$0	-\$28
Downtown Reliability Enhancement	\$0	\$0	\$0
Coronado Island Project	\$0	\$0	\$13,812
12132 - SCADA Transmission Expansion - 5589537 (A SG Reliability Enhancement)	-\$113	-\$396	-\$170
12132 - SCADA Transmission Expansion - 595005 (A OT Reliability Enhancement)	\$0	-\$251	-\$259
03171 - Transmission System Automation - 5438010 (A TSA ICON South Bay 230 kV)	-\$420	-\$338	-\$157
San Ysidro 69 kV Reconductoring (TL623C)	\$30	\$202	\$396
TL632 Granite Loop-In and TL6914 Reconfiguration	\$7,751	\$1,404	\$10,473
Total	\$4,542	-\$519	\$36,223

Attachment 6:

**CAL ADVOCATES DATA REQUEST 20
DEMAND FLEXIBLE RATE APPLICATION – A.26-02-001
SDG&E SUPPLEMENTAL RESPONSE
DATE RECEIVED: JUNE 22, 2026
DATE RESPONDED: JULY 8, 2026**

OBJECTIONS TO INSTRUCTIONS

1. SDG&E objects to the instructions to the extent they seek a verified response. SDG&E is providing responses in good faith and that it believes to be true and correct. SDG&E is not aware of any obligation to provide a verification to a data request.
2. SDG&E objects to the instructions to the extent they purport to require the individual(s) responsible for providing the response and/or designate the proper witness to cross-examine concerning the response. The responses reflect SDG&E's response as a Company to the requests and not the work of any one individual.
3. SDG&E objects to the instructions to the extent they state that the requests are ongoing in nature and require subsequent, supplemental information.
4. SDG&E objects to the instructions to the extent they request responses in multiple formats.
5. SDG&E objects to the instructions to the extent they provide shortened timelines for objections and requests for clarification.

EXPRESS RESERVATIONS

1. No response, objection, limitation or lack thereof, set forth in these responses and objections shall be deemed an admission or representation by SDG&E as to the existence or nonexistence of the requested information or that any such information is relevant or admissible.
2. SDG&E reserves the right to modify or supplement its responses and objections to each request, and the provision of any information pursuant to any request is not a waiver of that right.
3. SDG&E reserves the right to rely, at any time, upon subsequently discovered information.
4. These responses are made solely for the purpose of this proceeding and for no other purpose.

Subject to the foregoing general objections and express reservations, SDG&E responds as follows:

**DATA REQUESTS
SUBJECT: TRANSMISSION COST**

CAL ADVOCATES DATA REQUEST 20
DEMAND FLEXIBLE RATE APPLICATION – A.26-02-001
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Please see the attached file, titled “CalPA DR-20, Q1,” for SDG&E’s response to this question. The file provides the transmission costs included in the direct testimony based on the Original 2025 Transmission Cost Study, the transmission costs included in the supplemental testimony based on the Updated 2025 Transmission Cost Study, and the calculation of the change in the transmission costs identified in the Original 2025 Transmission Cost Study versus the Updated 2025 Transmission Cost Study.

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² Video conference call between SDG&E and Cal Advocate on Friday, April 3, 2026.

³ Cal Advocates had requested an explanation in DR-010 but did not receive an adequate response.

Attachment 7: Excerpt for Testimony of Southern California Edison Company (U-338-E) in Support of (1) Application for Approval of Large Power Dynamic Pricing Rate and (2) Application for Approval of Marginal Cost-Based Dynamic Pricing Rates in Compliance with Decision 22-10-022 and Load Management Standards (SCE-06-A) in A.24-06-014, *et al.* (Consolidated with A.24-12-008), at 5 line 16 and at 6 lines 18-19.

15 SCE RESPONSE (Witnesses: R. Behlhomji; E. Molnar)

16 Subscriptions are a relatively complex customer protection mechanism. This complexity
17 is due to: (1) needing 12 months of a customer's usage to determine and store subscription kWh;
18 (2) needing additional billing system logic and processing to calculate the subscription kWh and
19 to charge a portion of the customer's usage at the subscription price, another portion at the
20 dynamic price; (3) more complex bill presentation; and (4) the need for significant additional
21 customer education. If subscriptions are not required for any customers covered by the SDR, it
22 is possible that the costs and timeline associated with tariffed dynamic rates implementation
23 could be significantly reduced (to as low as 18-24 months, compared to SCE's estimate of 24 to
24 30 months under its current proposals).⁵ If bill limiters, bill protection, or some other type of
25 customer protection is offered, the costs and implementation time would be different because
26 doing so would require the development and implementation of different billing system
27 solutions. See Table 3 in response to Question 15 for more details on the estimated costs of
28 these alternative options.

⁵ The 18-24-month timeline assumes that the customer protection option selected is a price limiter, and that either no customers are offered a subscription option, or that the subscription option is limited to LPDR customers who will be manually billed, resulting in no subscription or bill limiter logic needing to be implemented in SCE's billing system.

18 | accounted for. The bill limiter feature would add significant complexity compared with
19 | subscriptions, because a limited bill (e.g., at the $\pm 50\%$ threshold) would have to be limited at
20 | each line item for accounting purposes. For example, if a customer's OAT bill was \$100, and
21 | their dynamic rate bill was \$175, the total bill would be limited to \$150, but the (\$25) could not
22 | simply be removed from the bill as a credit. Instead, under this example a third bill would need
23 | to be calculated, with new factors, which would result in a bill of \$150. Because of this
24 | additional complexity, using bill limiters in lieu of subscriptions would take an additional 6
25 | months and cost an additional estimated \$4 million in implementation costs (i.e., increasing
26 | SCE's total dynamic rates-related implementation costs to an estimated \$23 million and
27 | increasing the implementation timeline to 30-36 months). On the other hand, under this option

Attachment 8: Excerpt for SCE-06-A, at 25 Table 4: Summary Table of Customer Protection & Locational Price Options, Costs, and Timing.

Table 4
Summary Table of Customer Protection & Locational Price Options, Costs, and Timing

Locational Level	Customer Protection	Estimated Cost	Estimated Duration
A-Bank	Subscription	\$19 million	24-30 months
A-Bank	Bill Limiter	\$23 million	30-36 months
A-Bank	Price Limiter	\$16 million	20-26 months
System-wide	Subscription	\$18 million	24-30 months
System-wide	Bill Limiter	\$22 million	30-36 months
System-wide	Price Limiter	\$15 million	18-24 months

- b. Is it reasonable for SCE's initial dynamic rates to be authorized with system-wide dynamic distribution prices, with locational distribution pricing considered for future implementation after the initial dynamic rate is operational?

SCE RESPONSE (Witnesses: R. Behlihomji; E. Molnar)

Yes. SCE's initial proposal for dynamic rates did not include locational distribution pricing. SCE filed supplemental testimony upon reviewing the Demand Flexibility OIR Track B decision (D.25-08-046) to incorporate locational distribution pricing by A-Bank regions. SCE began testing locational-based pricing at the A-Bank level in its Expanded Dynamic Rate Pilot and expects to share learnings about the challenges and benefits of locational-based pricing in the midterm (if reasonably available) and final evaluations of that pilot. SCE also understands that Pacific Gas and Electric (PG&E) is testing locational-based pricing using a "circuit clustering" method in their Dynamic Rate Pilot and anticipates that PG&E will share results of that approach in future evaluations of that pilot. Accordingly, until more is known about the benefits and

Attachment 9: Excerpt for PG&E-6, at 2-20, lines 22-24.

20 **2. Subscriptions**

21 **a. Learning: Subscriptions Complicate Load Response to Price**

22 PG&E has received considerable feedback from customers that they
23 find subscriptions challenging to understand and manage to ensure they
24 are achieving bill savings. Some RTP rates offered by other providers in
25 the United States include a subscription,²⁸ and the RTP pilots in
26 PG&E's service area have also included this feature. However,
27 subscriptions have generally been made available only for larger C&I

27 PG&E is proposing an alternative customer protection approach, see Section E.8 of this Chapter and Chapter 3, Section F.

28 Electric Power Research Institute (EPRI), Benchmarking Study of U.S. Regulated Utility Real Time Pricing Programs, Architecture and Design, Final Report, 3002021204 (Technical Update Mar. 2021), p. 3-10, available at: <https://www.epri.com/research/products/000000003002021204> (accessed May, 27, 2026).

Attachment 10: Excerpt for PG&E-6, at 2-34, lines 14-15.

14 PG&E shares SCE and SDG&E's concerns about the implementation
15 complexity and costs of the bill limiter approach and further considers that
16 bill limiters may also complicate the optimization algorithms that load
17 management providers would use to optimize bill savings, while also
18 introducing undesirable incentives. With a bill limiter approach, along with
19 considering the hourly price, the algorithms may also need to consider
20 whether cumulative charges will reach the limit set for a given time period,
21 and if they will, the incentive to reduce load may be compromised.
22 With regard to price limiters, PG&E notes that electric service providers
23 in Europe have used price limiters as a customer protection element of their

41 A.24-06-014 (consolidated with A.24-12-008), ALJ's Ruling Modifying the Proceeding Schedule Including the Addition of Supplemental Testimony (Mar. 25, 2026).

42 A.24-06-014 (consolidated with A.24-12-008), Testimony of SCE in Support of: (1) Application for Approval of Large Power Dynamic Pricing Rate and (2) Application for Approval of Marginal Cost-Based Dynamic Pricing Rates in Compliance with Decision 22-10-022 and Load Management Standards, Exhibit 06 – Supplemental Testimony Responding to Questions Posed in ALJ's Ruling Dated March 25, 2026 (Apr. 24, 2026), p. 23, Table 3.

43 A.26-02-001, Prepared Testimony of Jeff DeTuri on Behalf of SDG&E, Chapter 4 – Customer Protection (Feb. 2, 2026), p. 3.