STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

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TO PARTIES OF RECORD IN RULEMAKING 19-01-011:

This is the proposed decision of Commissioner Houck. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's May 15, 2025 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

/s/ MICHELLE COOKE
Michelle Cooke
Chief Administrative Law Judge

MLC:jnf
Attachment

Decision **PROPOSED DECISION OF COMMISSIONER HOUCK**
(Mailed 3/26/2025)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Building Decarbonization.	Rulemaking 19-01-011

PHASE 4 TRACK A DECISION ESTABLISHING NEW ELECTRIC SERVICE LINE UPSIZING RULES, MODIFYING ELECTRIC LINE EXTENSION RULES AND REPORTING REQUIREMENTS, AND IMPLEMENTING ASSEMBLY BILL 157

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Summary

This decision resolves the Phase 4 Track A issues identified in the Assigned Commissioner's Phase 4 Scoping Memo and Ruling issued on July 1, 2024, and the implementation issues relating to Assembly Bill 157 (Gabriel, Chapter 994, Statutes 2024) identified in the Assigned Administrative Law Judge's Ruling issued on October 8, 2024. Specifically, this decision:

1. Authorizes up to $5 million annually through the end of 2029 for California's electric utilities to provide electric service line upsizing to qualified under-resourced customers pursuing full electrification of their home or business;
2. Adopts measures to help prevent unnecessary electric service line upsizing, including expanding the existing electric utility safety evaluation processes to authorize non-isolating devices that interface with utility metering equipment;
3. Clarifies and modifies various aspects of Decision 23-12-037, including extending the energization deadline for mixed-fuel new construction projects to receive electric line extension subsidies;
4. Requires, starting in 2026, all annual reports ordered pursuant to decisions in this proceeding to be submitted on April 15 of each year via an Advice Letter and made available on the utility's website; and
5. Authorizes augmentation of the Technology and Equipment for Clean Heating Initiative budget by an additional $40 million using funding from the Aliso Canyon Recovery Account, directed for use in Southern California Gas Company service territory in a manner consistent both with new legislative direction and past precedent.

This decision furthers the Commission's goal to adopt policies aimed at reducing greenhouse gas emissions associated with energy use in buildings while also furthering the State of California's goals of reducing economy-wide greenhouse gas emissions to 40 percent below 1990 levels by 2030 and achieving carbon neutrality by 2045 or sooner.

Lastly, this decision promotes and furthers the Commission's goals adopted in the Environmental and Social Justice Action Plan (Version 2.0).

This proceeding remains open.

1. Procedural Background

On September 13, 2018, Governor Jerry Brown signed into law Senate Bill (SB) 1477 (Stern, Chapter 378, Statutes 2018). To promote California's building -related greenhouse gas (GHG) emissions reduction goals, SB 1477 made available $50 million annually for four years, for a total of $200 million, to establish two new building electrification pilot programs: the Building Initiative for Low-Emissions Development (BUILD) Program and the Technology and Equipment for Clean Heating (TECH) Initiative. Program funding derived from the revenue generated from the GHG emissions allowances directly allocated to gas corporations and consigned to auction as part of the California Air Resources Board (CARB) Cap-and-Trade program.

In response to the passage of SB 1477, the Commission initiated Rulemaking (R.) 19-01-011.

On May 17, 2019, the Assigned Commissioner issued a Scoping Memo and Ruling setting forth the issues to be considered in Phase 1 of R.19-01-011 (Phase 1 Scoping Memo). The Phase 1 Scoping Memo was amended on July 16, 2019, to include additional issues. Phase 1 issues were resolved in Decision

(D.) 20-03-027, which established the two building decarbonization pilot programs required by SB 1477: the BUILD Program and the TECH Initiative.

On August 25, 2020, the Assigned Commissioner issued an Amended Scoping Memo and Ruling setting forth the issues to be considered in Phase 2 of R.19-01-011, and included an associated Energy Division Staff Proposal. Phase 2 issues were resolved in D.21-11-002, which: (1) adopted guiding principles for the layering of incentives when multiple programs fund the same equipment; (2) established a new Wildfire and Natural Disaster Resiliency Rebuild program to provide financial incentives to help victims of wildfires and other natural disasters rebuild all-electric properties; (3) provided guidance on data sharing; (4) directed California's three large electric investor-owned utilities to study energy bill impacts that result from switching from gas water heaters to electric heat pump water heaters, and to propose a rate adjustment in a new Rate Design Window application if their study reflected a net energy bill increase (resolved in Resolution E-5233); and (5) directed the large electric utilities to collect data from all customers commencing electric service on fuels used to power various appliances, including propane.

On November 16, 2021, the Assigned Commissioner issued an Amended Scoping Memo and Ruling setting forth the issues to be considered in Phase 3 of R.19-01-011, and included an associated Energy Division Staff Proposal. Initial Phase 3 or Phase 3A issues were resolved in D.22-09-026, which eliminated gas line extension subsidies (i.e., allowances, refunds, and discounts) for all new gas line extension requests submitted on or after July 1, 2023, for all customer classes unless otherwise exempted.

On July 26, 2023, the Assigned Commissioner issued an Amended Scoping Memo and Ruling (Phase 3B Scoping Memo) setting the scope and schedule for

Phase 3B of this proceeding, and included an associated Energy Division Staff Proposal. D.23-12-037 resolved Phase 3B issues, eliminated electric line extension subsidies for mixed-fuel new construction, and set reporting requirements.

1.1. Phase 4

On July 1, 2024, the Assigned Commissioner issued an Amended Scoping Memo and Ruling (Phase 4 Scoping Memo) setting the scope and schedule for Phase 4 of this proceeding. The July 18, 2024 ruling by the Assigned Administrative Law Judge (ALJ) included Energy Division's Phase 4 Track A or Phase 4A Staff Proposal (Staff Proposal) and directed parties to file comments on the Staff Proposal while also extending the time to file comments in response to the Phase 4 Scoping Memo questions.

On or before August 7, 2024, parties filed 18 opening comments in response to the Phase 4 Scoping Memo and the Phase 4A Staff Proposal. Parties who filed opening comments included: (1) Association of Bay Area Governments for the Bay Area Regional Energy Network Program and County of Ventura for the Tri-County Regional Energy Network Program (collectively "the Joint RENs"), (2) California Solar & Storage Association (CALSSA), (3) Clean Power Alliance of Southern California (CPA), (4) Coalition of California Utility Employees (CUE), (5) ConnectDER Inc. (ConnectDER), (6) County of Los Angeles for the Southern California Regional Energy Network (SoCalREN),[1] (7) Pacific Gas and Electric Company (PG&E), (8) Public Advocates Office at the California Public Utilities Commission (Cal Advocates), (9) San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) (collectively "Sempra Utilities"), (10) San Francisco Bay Area Planning and

[1] This late-filed comment was received into the record.

Urban Research Association (SPUR), (11) Sierra Club, California Environmental Justice Alliance (CEJA), and Natural Resources Defense Council (NRDC) (collectively "the Joint Parties"), (12) Small Business Utility Advocates (SBUA), (13) Southern California Edison Company (SCE), (14) Vermont Energy Investment Corporation (VEIC), (15) Western Riverside Council of Governments (WRCOG), and (16) Wild Tree Foundation (Wild Tree). While most parties consolidated their opening comments on both the Phase 4 Scoping Memo and the Staff Proposal into a single filing, PG&E and SDG&E (exclusive of SoCalGas) both filed two sets of opening comments addressing the Phase 4 Scoping Memo and the Staff Proposal separately.

On or before August 19, 2024, parties filed 12 reply comments. Parties who filed reply comments included: (1) the Joint RENs, (2) Cal Advocates, (3) California Building Industry Association (CBIA), (4) CALSSA, (5) CUE, (6) the Joint Parties, (7) PG&E, (8) SBUA, (9) SCE, (10) Sempra Utilities, (11) The Utility Reform Network (TURN), and (12) WRCOG.

1.2. AB 157 Implementation

On October 8, 2024, the Assigned ALJ issued a ruling directing parties to file comments on how the Commission should implement the portion of Assembly Bill (AB) 157 (Gabriel, Chapter 994, Statutes 2024) regarding new TECH Initiative funding in SoCalGas service territory.

On or before October 28, 2024, parties filed nine opening comments in response to the October 8, 2024 Ruling regarding AB 157. Parties who filed opening comments included: (1) Cal Advocates, (2) Climate Action Campaign

(CAC), (3) ConnectDER, (4) the Joint Parties, (5) PG&E, (6) SCE, (7) SPUR, (8) TURN, and (9) VEIC.[2]

On or before November 7, 2024, parties filed eight reply comments. Parties who filed reply comments included: (1) A.O. Smith Corporation (A.O. Smith), (2) CAC, (3) CEJA (exclusive of Sierra Club and NRDC), (4) Los Angeles Department of Water and Power (LADWP), (5) PG&E, (6) SCE, (7) SoCalGas (exclusive of SDG&E), and (8) VEIC.

2. Submission Date

As to the Phase 4A issues, the matter was deemed submitted on November 7, 2024.[3]

3. Issues Before the Commission

In this decision, the Commission addresses the following Phase 4 Track A issues outlined in the Phase 4 Scoping Memo:

- Whether the Commission should allocate a portion of the ratepayer savings from elimination of the gas and electric line extension allowances for mixed fuel developments to provide necessary electrical service line upsizing to under-resourced customers, and define what is necessary electrical service line upsizing.
- Whether the Commission should adopt measures to prevent unnecessary service line upsizing; and if so what those measures should be.
- Whether the Commission should revisit the line extension subsidy July 1, 2024 energization deadline, established in D.23-12-037 Ordering Paragraph 5; and if so under what circumstances.

[2] VEIC filed its opening and reply comments on behalf of the TECH Initiative team, which it is a part of.

[3] This is the date the last reply comments were filed concerning AB 157.

This decision addresses the broader environmental and social justice (ESJ) issue, which the Phase 4 Scoping Memo identified as the first of two issues to be considered across "All Tracks" of Phase 4:

- Are there potential impacts to ESJ communities and if so how best to incorporate the goals of the ESJ Action Plan 2.0 in developing the building decarbonization action plan.

Finally, the Phase 4 Scoping Memo identified and envisioned that, across all Phase 4 tracks[4] of this proceeding, we would continue to "consider all policy framework issues, including programs, rules, and rates, that will help accomplish building decarbonization, as part of the state's GHG reduction goals." Consistent therewith, this decision addresses the following issues as potential "additional actions that may help achieve California's climate and equity goals?":

- Whether the Commission should change any reporting requirement procedures previously adopted in this proceeding.[5]
- How the Commission should implement the portion of AB 157 regarding new TECH Initiative funding in SoCalGas service territory.[6]

4. Common Facility Cost Treatment for Electric Service Line Upsizing

The Phase 4 Scoping Memo directed parties to file comments on whether the Commission should allocate a portion of ratepayer savings from elimination of the gas and electric line extension allowances for mixed-fuel developments to

[4] *Citing* May 17, 2019 Scoping Memo, at 3-4, which established initial schedule for R.19-01-011.

[5] This issue is based on a question posed to the parties in Appendix A to the Phase 4 Scoping Memo (Question 8) and the parties' comments thereto.

[6] This issue is based on the October 8, 2024 ALJ ruling directing parties to comment on AB 157 implementation, and the parties' comments thereto.

provide necessary electric service line upsizing to under-resourced customers, and to define what is necessary electrical service line upsizing.[7]

The Phase 4 Scoping Memo additionally asked parties how the Commission should define who is considered an "under-resourced" customer in the event common facility cost treatment (i.e., full subsidization of an electric service line upsizing with no direct cost to the requesting party) is extended solely to such customers.[8]

Finally, the Phase 4 Scoping Memo asked parties whether the Commission should limit any potential extended common facility cost treatment solely to customers who participate in an incentive or assistance program.[9]

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[7] Parties were asked to comment on the following questions: (1) Should the Commission limit any potential extension of common facility cost treatment to just residential under-resourced customers? If not, what other customer segments should be considered? (2) Should the Commission limit any potential extension of common facility cost treatment solely to cases involving the installation of electric appliances or should service line upsizing be agnostic as to end use? If not, should investor-owned utilities (IOUs) be required to verify if only approved end uses were pursued? How should this be implemented? (3) Should the Commission limit any potential extension of common facility cost treatment in cases where a service line upsizing is estimated to cross a certain cost threshold? If so, what should that cost threshold be? (4) Should the Commission place limits on the amount of ratepayer funds that can be expended for any potential extension of common facility cost treatment policy (e.g., extension cost, extension length, need for undergrounding, etc.)? If so, what should those limits be and how should they be imposed? (5) How should any potential extension of common facility cost treatment be evaluated to determine future need for termination or modification? Should any such evaluation be done in concert with an evaluation of the same policy that is already in place for electric vehicle charging?

[8] Specific questions posed to parties included the following: (1) Should "under-resourced" be defined as broadly as possible, and be inclusive of existing definitions established by the California Legislature and by various Commission decisions? Or should narrower limits be put in place? (2) Should the income of the applicant requiring the service line upsizing be verified? If so, how, and by whom, should it be verified?

[9] Parties were asked the following: (1) Is participation in an incentive or assistance program essential or should participation in an incentive or assistance program not be necessary?

4.1. Summary of Opening Comments

The Joint RENs support allocating savings from the elimination of line extension subsidies for expanded common facility cost treatment, viewing common facility cost treatment as a necessary measure to help under-resourced customers benefit from building electrification, and to prevent those customers from bearing the costs of legacy gas systems. They also recommend tying this allocation to participation in other Commission-authorized programs.[10]

The Joint Parties argue service line upsizing costs triggered by building electrification should receive common facility cost treatment for all customers, not only for under-resourced customers, as is current practice when service line upsizing costs are triggered by electric vehicle (EV) charging, stating this policy is necessary to help California achieve its climate objectives and to facilitate compliance with upcoming zero nitrogen oxides regulations. They further recommend against linking the socialization of costs to savings from eliminated electric line subsidies. Finally, the Joint Parties suggest common facility cost treatment could be piloted for four years, with the last and fourth year to be used for Commission decision-making on whether to extend such treatment based on the prior three years of data.[11]

PG&E also supports common facility cost treatment for all customers – not just under-resourced customers – and similarly argues that it is consistent with the common facility cost treatment policy the Commission established for service line upsizing triggered due to installation of EV charging infrastructure.[12]

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[10] Joint RENs Opening Comments on Phase 4 Scoping Memo at 3 and 5.

[11] Joint Parties Opening Comments on Phase 4 Scoping Memo at 1-3 and 9.

[12] PG&E Opening Comments on Phase 4 Scoping Memo at 3.

Both the Joint Parties and PG&E favor all the following: (1) no income verification of the applicant; (2) limiting the final upsized line to no more than 200-amp service; (3) not imposing verification requirements on utilities to check whether the customer first pursued alternative pathways; (4) no upper cap, or cost threshold, per project; (5) no cap on funding availability; and (6) not limiting common facility cost treatment only to participants of electrification programs.

Cal Advocates supports allocating a portion of ratepayer savings for service line upsizing for under-resourced customers, emphasizing this can help reduce the capital barriers to electrification. Their other recommendations include: (1) common facility cost treatment to be agnostic to end use to avoid undue verification burdens; (2) a budget cap for total ratepayer expenditures equal to savings from elimination of gas line extension subsidies and proportionally allocated by residential and non-residential customer classes; (3) a soft limit of $10,000 per project, with higher limits subject to case-by-case review; (4) creation of a biennial review process to determine new funding and project cap limits; and (5) defining "under-resourced customer" as a participant of the Energy Savings Assistance (ESA) program, or "hard-to-reach customers," as defined by the Commission's Energy Efficiency proceeding (R.13-11-005).[13]

SBUA supports allocating savings from the elimination of line extension subsidies for expanded common facility cost treatment, but argues that common facility cost treatment should not be limited to residential under-resourced residential customers alone, and should include under-resourced small business customers, as defined in D.23-06-055:

- 25 or fewer employees and/or classified as Very Small (Customers whose annual electric demand is less than

[13] Cal Advocates Opening Comments on Phase 4 Scoping Memo at 1-9.

20 kilowatts (kW), or whose annual gas consumption is less than 10,000 therm, or both), and/or

- Leased or Rented Facilities – Investments in improvements to a facility rented or leased by a participating business customer.[14]

SCE supports allocating a portion of the savings from eliminating gas and electric line extension subsidies to provide common facility cost treatment for under-resourced customers. SCE emphasized this should be implemented gradually to ensure actual savings from line extension subsidy elimination to materialize before implementation. SCE proposes the process should begin by establishing a methodology for estimating savings and include rules for administration, eligibility, and accounting challenges.[15]

Sempra Utilities oppose allocating savings from the elimination of line extension subsidies for expanded common facility cost treatment until the ratepayer savings from elimination of line extension subsidies are quantified. They contend that extending customer incentives without reliable data could burden all ratepayers, including those who do not benefit from such programs.[16]

SPUR supports using a portion of the savings from line extension subsidy elimination for service line upsizing for all electric utility customers seeking to electrify, at a minimum, home heating alone. SPUR contends it is necessary to enable affordable electrification and compliance with California's clean heating goals. SPUR cites the PG&E website on Building and Renovation Services noting that for at least 80 percent of customers, existing allowances do not cover the full cost of upsizing, with 75 percent of customers paying up to $10,000 post-

[14] SBUA Opening Comments on Phase 4 Scoping Memo at 1 and 12.

[15] SCE Opening Comments on Phase 4 Scoping Memo at 7 and 8.

[16] Sempra Utilities Opening Comments on Phase 4 Scoping Memo at 1-5.

allowance, 5 percent paying in excess of $30,000 post-allowance, and the remaining 20 percent paying between $10,000 to $30,000 post-allowance, for electric underground upsizing less than 400 amp.[17] For the method of verification, SPUR recommends utilities collect information regarding expected end uses directly from the customer (that is, self-attested by the customer) within the customer application, as well as information about replaced and installed equipment.[18]

4.2. Summary of Reply Comments

Most parties reinforced their original positions in their reply comments. Some parties modified their positions on specific sub-topics or issues only, as highlighted below.

The Joint RENs, replying to comments from PG&E and the Joint Parties, support extending common facility cost treatment to all customers, vis-à-vis their original position for supporting it for just under-resourced customers. They also agreed with SBUA that it should be extended to small business customers, as well. Further, they add that common facility cost treatment should be limited to participating customers of certain Commission-authorized programs with the idea that education materials ("program offering touchpoints") should be offered by the utility to applicants during the service upsizing application process, including workforce training program offerings for contractors.[19]

TURN, in its reply comments, recommended: (1) any potential expansion of common facility cost treatment should initially be limited to residential and small business under-resourced customers as a three-year pilot before

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17 "Solving the Panel Puzzle" SPUR report at 5; cited in SPUR Opening Comments at 3.

18 SPUR Opening Comments on Phase 4 Scoping Memo at 2-8.

19 Joint RENs Reply Comments on Phase 4 Scoping Memo at 1 and 2.

establishing a long-term policy; (2) limiting common facility cost treatment only for applicants pursuing appliance electrification; (3) requiring utilities to collect data, in line with SPUR's recommendations, so the Commission can determine whether to continue common facility cost treatment in the future; (4) limiting common facility cost treatment to customers with existing electric service line capacity of less than 100 amperes (amps), and limiting the final upsized electric service line capacity to no more than 200 amps; (5) requiring utilities to collect documentation of customer-pursued load mitigation strategies; (6) setting a budget cap for the common facility cost treatment to be equal to savings from elimination of gas line extension subsidies; and (7) limiting participation to residential customers receiving either California Alternate Rates for Energy (CARE) or Family Electric Rate Assistance Program (FERA) rate discounts, or customers participation in the ESA program, and for non-residential customers of disadvantaged communities (DACs), or the criteria provided by SBUA.[20]

SBUA agrees with the Joint RENs that common facility cost treatment should be tied to programs, not end use.[21]

4.3. Discussion

Any decision adopted that utilized ratepayer funds must keep in mind that many California ratepayers are currently experiencing the impact of recent rate increases. We therefore have carefully examined the issue of common facility cost treatment for an expanded segment of customers, as discussed below.

This decision finds that common facility cost treatment should be equitable, minimal, subject to re-evaluation, and any funds not expended

[20] TURN Reply Comments on Phase 4 Scoping Memo at 2-10.

[21] SBUA Reply Comments on Phase 4 Scoping Memo at 3.

returned to ratepayers. We therefore adopt common facility cost treatment solely for under-resourced customers, who are participants of an electrification program that triggers the need for service line upsizing. Customers should also first seek alternative approaches to fund service line upsizing. The program authorizes an amount up to an annual funding cap of $5 million statewide, and proportionally allocated across all electric utilities, including the Small Multi-Jurisdictional Utilities (SMJUs).[22] This initial program will be set for a four-year test period (July 1, 2025, to June 30, 2029), no more than six months after which any unspent funds will be returned to ratepayers.

The record in this phase of the proceeding demonstrates that cost relief is needed for a subset of customers who may find themselves in a situation where electrification otherwise would be unachievable. Given the current affordability crisis and need to assess actual savings that will result from gas line extension allowance elimination, we find it necessary to limit the funding for this program.

We adopt SBUA's proposed definition of "small business" as any business with fewer than 25 employees. The common facility cost treatment shall be made available to under-resourced residential and small business customers with existing service capacity below 100 amps. To qualify, the upsized line shall not exceed 200 amps, and the customer must remove or replace all gas appliances to achieve full electrification of the building. Within 60 days of finalizing the service

[22] Per a recent UCLA study, cited by SPUR in their Opening Comments at 4, 2 percent of single-family homes, and 1 percent of multi-family homes, in DACs have a rated electrical panel capacity of less than 100 amp, and less than 60 amp, respectively. Assuming a high co-relation between electrical panel capacity and existing service size, the common facility cost treatment policy is intended to provide cost relief to at least these subsets of customers.

upsizing and service restoration, the electric utility must automatically enroll the customer in the all-electric baseline.[23]

This decision does not adopt a single definition of "under-resourced." Instead, it accepts the need-based eligibility criteria established by the applicable program(s) through which the customer will receive incentives towards electrification measures. That is, the definition of "under-resourced" shall be determined by the equity-based programs through which the customer is being offered incentives resulting in full electrification of the premise, including but not limited to income-qualified programs and programs for under-served communities.

In this context, we define a "Program" to mean any collective public service initiative including but not limited to those overseen, managed, or led by utilities, Community Choice Aggregators (CCAs), local governments, Regional Energy Networks (RENs), state or federal agencies, non-profit organizations, or community-based organizations, with the general purpose of making a positive impact towards reducing climate change caused from building energy use. These would typically include, but are not limited to, initiatives supporting building electrification or fuel substitution, distributed renewable generation and onsite storage, and building electric efficiency. Gas efficiency programs do not qualify as an eligible Program and therefore fall outside of this definition.

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[23] Public Utilities (Pub. Util.) Code Section 739(a)(1) defines "baseline quantity" as "a quantity of electricity or gas allocated by the commission for residential customers based on from 50 to 60 percent of average residential consumption of these commodities, except that, for residential gas customers and for all-electric residential customers, the baseline quantity shall be established at from 60 to 70 percent of average residential consumption during the winter heating season." Pub. Util. Code Section 739(b) defines "all-electric residential customers" as "residential customers having electrical service only or whose space heating is provided by electricity, or both."

Income verification, if applicable, shall be the responsibility of the program administrator. The electric utilities are not required to collect any new proof of income. The customer shall provide information during the application process, as to whether the customer was part of an income-based program, the name of the program, and the year in which the customer enrolled in the program. Self-attestation on the application from the customer as having enrolled in an income-qualified program shall be considered sufficient. The electric utilities shall also collect and report information on the added loads triggering service upsizing, the existing service and panel size, and the installed service and panel size.

The electric utilities shall refer to Appendix A for the full list of requirements, and shall include this information as part of the annual reporting required under Resolution E-5105. All information required under Resolution E-5105, including the new requirements detailed in Appendix A, shall be submitted as a Tier 1 Advice Letter in accordance with the revised reporting timelines established in Section 7.3 of this decision.

We re-emphasize that in cases where service lines exist and are currently serving customers, service upsizing should be avoided unless necessary and when other reasonable options (e.g., panel optimization solutions) have been exhausted. However, in cases where entirely new electric utility infrastructure and electric service lines (i.e., front-of-the-meter equipment) must be newly installed or re-installed to residential buildings, installing 200-amp service lines and accompanying infrastructure is appropriate, as it will help prevent the need and costs for potential future upsizing.

Service line upsizing shall be agnostic to end use, provided it is part of a project resulting in termination of gas service to the premise. The utility must track through its application submittal process the end use(s) (electrification, solar panel installation, etc.) that triggering the need for the service line upsizing.

Single-family projects shall be extended common facility cost treatment up to a per project cost cap of $10,000 to ensure the maximum number of customers can use this limited funding. The utilities shall track total costs for all projects, and report annually – as part of the reporting required under Resolution E-5105 – how many projects were denied common facility cost treatment because they were estimated to exceed the $10,000 cap, and document the conditions and reasons resulting in the projects exceeding the cap. This reporting requirement shall automatically sunset after the final report, once the authorized funds have been fully expended or after four years, whichever comes first. Any funds not expended after four years shall be returned to ratepayers.

We do not adopt a per project cost cap for multi-family projects at this time, because a large proportion of under-resourced customers live in multi-family housing, and the barriers to electrifying larger properties that rely on multiple funding sources for upgrades are greater than for single-family projects. We also note that multi-family properties often have substantial costs associated with service upsizing on the customer/property owner side of the meter and up to the electrical panel. These costs could include upgrade the service mains, feeder cables, and associated trenching costs up to sub-panels of individual dwelling units. Currently, only the High-Efficiency Electric Home Rebate A (HEEHRA) program administered by the California Energy Commission (CEC) offers a modest incentive to offset some of these costs. High costs for service line extensions in multi-family properties can be a barrier to electrification for these properties. This program will not resolve this barrier but may provide funding to cover these costs for some properties.

Starting July 1, 2025, and continuing through the end of 2029, all electric utilities must offer common facility cost treatment under the parameters described in this section. This policy (four-year common facility cost treatment) provides a maximum budget of $5 million each year; and any unspent funds may be carried over into the following years until fully expended or December 31, 2029, whichever comes first. Any funds not fully expended by December 31, 2029, shall be returned to ratepayers. Each utility shall establish a Balancing Account to track program expenditures. Utility administrative costs shall be capped at 0.25 percent of total expenditures, with the expectation that utilities will leverage existing utility portals and personnel. Each electric utility shall submit a Tier 1 Advice Letter within 60 days of the issuance of this decision to establish its Balancing Account. The $5 million annual funding shall be allocated proportionally across the electric utilities' service territories as follows:

Table 4.3.1:
Proportional Annual Allocation Amounts for Electric Utilities to Establish Common Facility Cost Treatment Balancing Accounts July 1, 2025 through December 31, 2029

Utility Name	Number of Residential Accounts	Number of Small Business Accounts	Funding Percentage	Funding Amount
Bear Valley Electric Service	23,097	1,328	0.20%	$9,827.50
Liberty Utilities	44,087	5,321	0.40%	$19,880.00
PacifiCorp	36,427	8,218	0.36%	$17,963.50
Pacific Gas and Electric Company	5,171,416	480,629	45.48%	$2,274,168.00
Southern California Edison Company	4,621,605	538,525	41.52%	$2,076,240.00
San Diego Gas & Electric Company	1,371,321	124,648	12.04%	$601,921.00
TOTAL	**11,267,953**	**1,158,669**	**100.00%**	**$5,000,000.00**

Source: 2023 Energy Resource Recovery Account Compliance Proceeding. Decisions Approving the Return of Cap-and-Trade Program Funds for Electric utilities; PG&E: D.23-12022, SCE: D.23-11-094, SDG&E: D.23-12-021, PacifiCorp: D.24-03-011, Bear Valley Electric Service: AL 479-E. For Liberty Utilities, Prepared Testimony submitted in Application 24-04-010. Small Business numbers taken from electric utilities' testimonies submitted to each docket.

To ensure the applicant customer has been made aware of and pursued all possible alternatives to service line upsizing, the electric utilities shall provide information about alternatives to service line upsizing as set out in Section 5 of this decision. This information shall be provided in a manner the applicant or applicant's agent is likely to naturally encounter during the application process, such as the service upsizing application portal or website. The electric utilities shall leverage existing studies and the body of work on alternates to electrical service line upsizing, and avoid deploying administrative resources or commissioning new studies.

5. Adopting Measures to Prevent Unnecessary Electric Service Line Upsizing

The Phase 4 Scoping Memo directed parties to file comments on whether the Commission should adopt measures to prevent unnecessary service line upsizing and, if so, what those measures should be.[24] The Staff Proposal released with the Assigned ALJ's July 18, 2024 ruling addresses the aforementioned questions directed at parties as part of two distinct recommendations. Staff's recommendations are summarized below before turning to party comments and the Commission's adopted course of action.

5.1. Summary of the Staff Proposal

The Staff Proposal asserts building decarbonization is an essential strategy to help California meet its goal of carbon neutrality by 2045. Ensuring all California buildings transition to all-electric end uses requires strategic planning that builds in equitable safeguards to minimize costs to all ratepayers, especially low-income customers. Substantial distribution system upgrade costs will be needed to meet the growing electricity demand from the rapid electrification of

[24] Specifically, Attachment A of the Phase 4 Scoping Memo asked parties to comment on the following five questions: (1) Should the Commission require IOUs to test, certify, and evaluate different isolation technologies, approved in Resolution E-5194, including meter socket adapter technologies for non-isolating functionality in building electrification applications, such as heat pumps? (2) Should the Commission require IOUs to report peak annual and monthly electric demand of the premise on customer bills to help contractors determine whether service upsizing is necessary, and thus ensure service upsizing is pursued as a last resort? (3) Should the Commission require IOUs to collect proof a service line upsizing application was the last resort for the project, and that alternate strategies (load optimization, electrical panel optimization, etc.) were considered before submitting the application? If so, how should these safeguards be implemented and enforced? (4) If the Commission mandates IOU collection of service line capacity data, what is the best way for IOUs to begin collecting this data? Which of the existing mandates/processes requiring IOU staff to be on site (e.g., meter inspections) can the IOUs leverage to collect service line capacity for each premise? How can this be optimized for cost and procedural efficiency? (5) How should the IOUs determine whether a service upsizing request is necessary or unnecessary? What guidance, if any, should the Commission provide to define necessary and unnecessary service upsizing?

both buildings and vehicles. Helping customers avoid electrical panel and service upsizing has the dual benefit of reducing the cost of electrification to individual customers while reducing ratepayer bill impacts. The Staff Proposal's recommendations aim to support strategies that allow customers to electrify their homes and vehicles within the existing capacities of their electrical panels and electrical services.[25] The Staff Proposal recommends the Commission encourage alternatives to panel and service upsizing, where possible, using "panel and service optimization" strategies such as, but not limited to, employing power-efficient appliances (e.g., 120-volt HPWHs or low-amperage Level 2 EV chargers), smart panels, and circuit splitters and pausers.[26]

The Staff Proposal presents two distinct recommendations: (1) electric utilities provide customers with peak demand and service line capacity information on their bills, and (2) the Commission approve expanded cost recovery for utility safety evaluation processes of customer-owned, utility-interfacing devices to include applicable, non-electrically isolating devices.[27]

The first recommendation seeks to make it simpler for customers and contractors to identify a customer's existing peak electrical demand over 15-minute and hourly intervals.[28]

Given that utilities currently have data from installed smart meters readily available, the Staff Proposal recommends electric utilities report the peak energy consumption in kilowatt-hours (kWh) and peak demand in amps over a

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[25] Phase 4A Staff Proposal at 37.

[26] *Id*. at 12-13.

[27] *Id*. at 35.

[28] *Id*. at 1.

15-minute interval for two time periods: (1) the last 30 days, and (2) the last year (if applicable) from the billing date.[29]

The Staff Proposal also recommends electric utilities collect customers' service line capacity in amps when conducting any visits to customer premises. The Staff Proposal also recommends that the electric utilities are to gather such data in a database and report on customer bills to further aid customers and contractors to work within existing capacity constraints when electrifying and avoid unnecessary upsizing.[30] Though this information is not readily available from electric utilities currently, it would be helpful for contractors and customers to understand the existing constraints and capacity of the service line and find ways to work within this existing capacity.[31] Requiring the electric utilities to provide customers with readily available peak demand data would make it easier for contractors to be able to advise when panel and service upsizing might not be avoidable.[32]

The second recommendation seeks to widen the pool of technologies available to customers to help avoid electrical service and panel upsizing.[33] D.21-01-018 previously authorized the large electric utilities (i.e., PG&E, SCE, and SDG&E) to recover up to $3 million for safety evaluations of customer owned equipment that interfaces with utility infrastructure and can isolate a building from the grid.[34] The Staff Proposal and this decision refer to these devices as

[29] *Id*. at 1, 35.

[30] *Id*. at 2, 35.

[31] *Id*. at 35.

[32] *Id*. at 37.

[33] *Id*. at 36.

[34] D.12-01-018 at 79.

"isolating devices." The Staff Proposal recommends the Commission authorize the large electric utilities to also apply these previously authorized funds to evaluate the safety of technologically similar devices that do not have grid isolating capabilities, referred to in the Staff Proposal and in this decision as "non-isolating devices." The latter devices would also be customer-owned devices interfacing with utility equipment.[35]

It also recommends the large electric utilities begin using the existing safety and reliability evaluation process for isolating devices adopted in Resolution E-5194 to evaluate non-isolating devices. It is expected most, if not all, of the latter devices will likely be meter socket adapters (MSAs), though the evaluation process for non-isolating devices should remain neutral to specific technology types.[36]

Staff assert that allowing cost recovery for the large electric utilities to expand their approval process for MSAs and similar non-isolating technologies can help add another "tool" in the toolkit of panel and electrical service optimization strategies.[37]

These recommendations aim at reducing: (1) the costs of building and transportation electrification for customers, and to make these measures more accessible to low-income households, (2) delays for customers by eliminating the need to obtain permits and inspection approvals associated with upgrades to utility infrastructure, and (3) ratepayer impacts by avoiding additional utility

[35] Phase 4A Staff Proposal at 36.

[36] *Ibid*.

[37] Phase 4A Staff Proposal at 37.

spending for service line upsizing and further upstream distribution infrastructure.[38]

5.2. Capturing Customer Peak Demand Data and Service Line Size on Bills

5.2.1. Summary of Opening Comments

Parties were split on whether to mandate capturing customer peak demand data on customer bills.

The Joint Parties, SBUA, and SPUR strongly support Staff's recommendation to collect and make available 15-minute peak demand data to customers via bills and online portals. The Joint Parties and SBUA note this information will help contractors in assessing the necessity of service upsizing.[39] SPUR also supports this recommendation, suggesting the electric utilities provide peak demand as a single figure to simplify the process of utilizing the National Electrical Code (NEC) 220.87 pathway and eliminating risk of calculation errors, noting many contractors have "never performed 220.87 calculations."[40, 41]

SBUA notes the Staff Proposal focuses on residential buildings, and requests the Commission direct staff to prepare a similar study for small businesses to help better understand upsizing costs and "other considerations

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[38] *Id*. at 3.

[39] Joint Parties Opening Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 15 and SBUA Opening Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 15.

[40] SPUR Opening Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 12.

[41] NEC 220.87 describes a method of calculating the load of an existing residential dwelling, which uses actual observed load of the building. NEC 220.87 requires peak hourly load data over a period of a year, or peak 15-minute load data covering at least 30 days.

specific [to] small commercial customers," noting there are significant gaps in this type of information.[42]

VEIC and the Joint RENs also support the idea of empowering contractors with peak demand data for panel upsizing avoidance, but caution that the Commission should weigh the various options to balance benefits and costs before deciding on a solution. VEIC suggests the Commission "explore the feasibility of reporting approaches" to ensure any "proposed solutions can be implemented in a simple and cost-efficient manner."[43] VEIC proposes a possible solution of disclosing consumption data across an electric utility's billing system, focusing on a "subset of customers who might require upsizing." The Joint RENs "question whether costly billing upgrades are necessary to achieve the intended purpose" of helping customers avoid upsizing, noting "existing data sources should be evaluated first, before consideration of costly electric utility system upgrades or billing changes."[44]

PG&E and SCE strongly oppose the staff recommendations to put peak demand on customer bills due to the availability of 15-minute meter data and the cost of updating IT and billing systems to accommodate this change. SDG&E, noting it already provides this data on customer bills, opposes requirements for reporting peak demand in amps instead of kW, as is current practice.

Regarding availability of 15-minute data, PG&E notes only 20.29 percent of PG&E customers "currently log 15-minute interval data," and the cost of enabling this functionality to all customers would be "tens of millions of dollars in information technology (IT) expenses." PG&E notes it decided not to pursue

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[42] SBUA Opening Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 5.

[43] VEIC Opening Comments on Phase 4 Scoping Memo at 6.

[44] Joint RENs Comments on Phase 4 Scoping Memo at 9.

this work because of the expense and other competing priorities.[45] SCE notes it had previously estimated that replacing all residential meters with 15-minute metering capabilities, in addition to upgrades to infrastructure needed to handle an increase in data volume, would cost $58 million and take approximately three years to complete.[46] SCE also argues peak demand on customer bills is not useful additional information given the predictability of loads for a residential dwelling; additionally, they assert, contractors can already use existing Green Button data[47] to access a customer's interval data.[48] SDG&E states it already presents peak energy consumption in kWh for the past 30 days and peak demand in kW for the past 30 days and past year on the customer's printed bill. SDG&E says the Commission's requirements to have this data presented in amps is unnecessary, since contractors can convert from kW to amps, and this would add time and expense to SDG&E systems and processes.[49]

Regarding placing peak demand data on bills, PG&E notes its billing system would require "massive IT development" to accommodate this change. PG&E cites that there have been numerous requirements to add information to customer bills to support decarbonization policies, but that these requirements have not been adequately coordinated, and resulted in inefficiencies and costly changes. PG&E points to CEC updates to the Load Management Standards as an

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[45] PG&E Opening Comments on Phase 4 Scoping Memo at 8.

[46] SCE Opening Comments on Phase 4 Scoping Memo at 4.

[47] Green Button data is information about a customer's energy usage provided in a consumer-friendly and computer-friendly format. Customers can download this data from their utility website's customer portal.

[48] SCE Opening Comments on Phase 4 Scoping Memo at 14.

[49] SDG&E Opening Comments on Phase 4A Staff Proposal at 2.

example of such a requirement.[50] As an alternative, PG&E suggests the Commission issue a ruling focusing on developing a comprehensive strategy and approach for using customer bills to disseminate information supporting Commission policies such as decarbonization. PG&E argues this would allow entities such as the CEC, contractors, electricians and others who might use this data to weigh in. PG&E also points out that placing any new data on bills should be considered in context of all billing content, since any new information might generate more confusion for customers. Lastly, PG&E argues a real-time solution would be more ideal, since the info on the billing statement is already out of date once it has been issued.[51]

On implementation timing, PG&E requests flexibility since it is focused on implementing its Billing Modernization Initiative[52] and has other billing improvement projects in its pipeline. PG&E also requests flexibility to seek cost recovery for any billing updates, since this would be additional to any activities requested through its General Rate Case.[53]

SCE puts forth similar arguments and opposes placing peak demand data on customer bills, noting this would create confusion. In addition to the costs mentioned above related to updating meters and IT systems, SCE says there

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[50] The CEC updates and maintains the Load Management Standards. The most recent update to the Standards in 2022, and effective April 1, 2023, aimed to help customers manage their own energy use by giving them more timely and accurate information on the costs of electricity. The Standards are codified in the California Code of Regulations, Title 20, §§ 1621-1625.

[51] PG&E Openings Comments on Phase 4A Staff Proposal at 3.

[52] Application 24-10-014.

[53] PG&E Opening Comments on Phase 4A Staff Proposal at 5.

would be costs needed to add new information on customer bills, educate customers, and handle customer inquiries at their Customer Contact Centers.[54]

SBUA supports Staff's recommendation that electric utilities collect service line capacity data and report this data on customer bills to help customers make informed decisions on service upsizing alternatives.[55]

PG&E, SCE, and SDG&E all oppose Staff's recommendation to collect service line capacities and list this information on a customer's billing statement.

PG&E states it has the capability to calculate a customer's service wire capacity in amps, but recommends this not be "tracked, monitored, or recorded on a customer's monthly bill" for fear of creating "unintended safety risks for those customers who presume their electrical system has capacity or excess capacity" and then add or connect load without consulting with PG&E. PG&E fears this will also create additional costs due to the need to dispatch emergency resources as a result of panel fires or other issues as a result of customers not working with PG&E to assess conductor cable capacity.[56] If adopted, PG&E requests this requirement apply only to new customers, since gathering service line data for new customers would be impractical due to the number of existing customers in their service territory.[57]

SCE notes a customer's service line size is already collected when a panel upsizing is requested by a customer. Therefore, SCE contends, requiring SCE to develop new procedures and train field staff to collect service line capacity

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54 SCE Opening Comments on Phase 4 Scoping Memo at 4.

55 SBUA Opening Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 16.

56 PG&E Opening Comments on Phase 4A Staff Proposal at 4.

57 *Id*. at 4-5.

whenever utility staff visit customer premises is unnecessary and will add costs to collect data "in situations where the data will not be used."[58]

SDG&E notes it does not make service line capacity "readily available" to customers and would require "significant system upgrades and funding" to do so.[59] SDG&E points out that any customer requesting an upgrade can receive their service line capacity, and even if customers have this information, they must still consult with SDG&E to receive upgrades. Therefore, SDG&E argues this requirement is unnecessary, not "conducive to building decarbonization" and would be a "misuse of administrative and technological resources."[60]

5.2.2. Summary of Reply Comments

The Joint Parties concur with the Joint RENs, PG&E, SCE, and VEIC that costly billing upgrades may be unnecessary to communicate to customers peak demand data, and recommend the Commission consider directing the utilities to provide instructions on how to convert Green Button data into amp figures on utility websites as a "reasonable middle ground" approach. The Joint Parties assert "some burden on the utilities is warranted to ensure that a workable, accessible system is in place" for customers, which mirrors comments SBUA also allows.[61] PG&E reiterates there is a "massive cost" associated with putting peak load on customer bills and concurs with the Joint RENs' opening comments that alternatives should be considered to deliver this information to customers in a more cost-effective way.[62]

58 SCE Opening Comments on Phase 4 Scoping Memo at 4.

59 SDG&E Opening Comments on Phase 4A Staff Proposal at 2-3.

60 *Ibid.*

61 Joint RENs Reply Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 4.

62 PG&E Reply Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 3.

SCE states the Joint Parties' support for the Staff Proposal is based on the false assumptions that peak demand data is readily available and that providing this data to customers will not be overly burdensome.[63]

SCE agrees with PG&E's recommendation that the Commission obtain input from entities, such as contractors and the CEC, who would use peak demand information before requiring billing updates.[64] SCE suggests a potential solution could be the creation of customer and contractor resources to avoid panel upsizing, as PG&E suggested in its opening comments.[65]

CBIA disagrees with the electric utilities and supports both staff recommendations of collecting peak demand and service line capacity, and placing this information on customer bills, noting it will give customers immediate access to important information to make decisions regarding decarbonization measures.[66]

5.2.3. Discussion

As noted by the parties, we are mindful of balancing competing interests. While there is the need for providing accessible peak load data for customers, we cannot ignore the potential costs of upgrading utility billing systems that ratepayers will ultimately shoulder.

As stated in the Staff Proposal and in party comments, providing easy access to peak demand data will make it easier for customers to use NEC 220.87 as an alternative method for calculating existing electrical loads, and thus

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63 SCE Reply Comments on Phase 4 Scoping Memo at 3-4.

64 *Id*. at 4.

65 *Ibid.*

66 CBIA Reply Comments on Phase 4 Scoping Memo at 2.

potentially help customers avoid unnecessary and often costly panel and service upsizing.

SDG&E is currently the only utility reporting peak demand data in kW on customer bills. In weighing these competing interests, we are persuaded by SDG&E's contention that this information is sufficient, and that electric utilities need not report peak demand in amps, as contractors can perform this calculation.

PG&E and SCE, who do not currently report peak demand data on customer bills, point to two main categories of costs associated with implementing this recommendation: (1) those related to updating metering infrastructure and IT systems to ensure all meters log and store 15-minute interval demand data; and (2) those related to updating billing systems and implementing billing changes to add this information to customer bills.

Regarding the first category of costs, it is currently unclear what the cost breakdown, process, and estimated timeframe for implementation would be for PG&E and SCE to ensure all their meters can log average demand measured over a 15-minute interval ("demand data"), and that their IT systems can handle the large increase in data storage. SCE notes that if it were to replace all residential customer meters with 15-minute metering alongside its planned efforts, starting in 2028, to replace customer meters approaching their life expectancy, this would cost an additional $58 million and take three years to complete.[67] However, this estimate was made approximately two years ago, in January 2023, and does not contain a detailed explanation of costs.

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[67] SCE Opening Comments on Phase 4 Scoping Memo at 4.

For the second category of costs related to billing changes, which several parties claim will be expensive, and given the billing system updates PG&E is currently undertaking, we are convinced there may be a less costly alternative to communicating peak demand data to customers and their authorized third parties, such as via the existing online customer-facing energy use and billing data access portals.[68] However, it is also unclear what the cost, process, and estimated timeframe might be for PG&E and SCE to implement such updates to their existing online data exchange systems to include 15-minute interval demand data.

We reiterate our support for pathways to help customers safely avoid panel and service upsizing. However, we currently lack the necessary information to weigh the costs and benefits of directing utilities to update meters and IT infrastructure to collect and store 15-minute interval demand data to share with all their respective customers. There are also other proceedings currently exploring the use and collection of metering data, including R.22-11-013, where requirements around metering data may be explored.

In addition, as SCE mentions, there are planned efforts for the electric utilities to replace meters approaching their life expectancy. This is an ideal opportunity to ensure any new meters have the capability to capture more granular metering data. We therefore direct all electric utilities, including the SMJUs, consistent with submission in their next General Rate Case, to update any new meters installed on customer premises with the capability of capturing at least 15-minute interval data (usage and average demand). At this time, electric utilities are not required to begin collecting 15-minute interval data; but

[68] PG&E: https://pge.com/en/account.html, SCE: https://sce.com/mysce/login, and SDG&E: "My Energy Center," https://myenergycenter.com/portal/PreLogin/Validate.

newly installed meters shall not require any further physical replacement, on-site intervention from utility staff, or software updates to ensure all electric utilities can easily begin collecting at least this 15-minute interval data in the future.

To help the Commission better understand the costs and challenges of sharing 15-minute peak demand data with customers, we direct all electric utilities to file a Tier 1 Advice Letter, within 90 days of the issuance of this decision, answering the following questions:

Customer Meters

1. How many customer meters are in your territory?
2. How many meters serve each of your respective customer classes (residential, commercial etc.)?

15-Minute Interval Data

3. How many meters in total and per customer class currently log at least 15-minute interval usage and demand data today?
4. How many meters in total and per customer class are currently capable of logging at least 15-minute interval data today, but are not currently logging 15-minute interval data?
    a. What actions and processes must the utility undertake to enable these meters to begin logging at least 15-minute data? Please describe in detail all the steps that need to happen, and describe who must take those steps (utility staff, third party contractors, etc.);
    b. Does this require multiple batches of changes? Does each make/model of meter require a separate over-the-air update? Please describe in detail; and
    c. How much time would be required to enable all the existing meters in this category to begin collecting 15-minute data?;

5. How many meters in total and per customer class require an over-the-air update to be capable of logging at least 15-minute interval data?
    a. What actions and processes must the utility undertake to enable these meters to begin logging at least 15-minute data? Please describe in detail all the steps that need to happen, and describe who must take those steps (utility staff, third party contractors, etc.)
    b. Does this require multiple batches of updates? Does each make/model of meter require a separate over-the-air update? Please describe in detail.
    c. How much time would be required to complete over-the-air updates for all meters in this category to enable collection of at least 15-minute interval data?
6. How many meters in total and per customer class require on-site work (but not replacement) to be capable of logging at least 15-minute interval data?
7. How many meters in total and per customer class require replacement to be capable of logging at least 15-minute interval data?

True Peak Demand Data

8. How many meters in total and per customer class currently capture true (instantaneous) peak demand?
9. How many meters in total and per customer class are currently capable of logging true peak demand, but are not currently logging true peak demand?
    a. What actions and processes must the utility undertake to enable these meters to begin logging at least 15-minute data? Please describe in detail all the steps that need to happen, and describe who must take those steps (utility staff, third party contractors, etc.)
    b. Does this require multiple batches of changes? Does each make/model of meter require a separate over-the-air update?

   c. How much time would be required to enable all the existing meters in this category to begin collecting true peak demand data?

10. How many meters in total and per customer class require an over-the-air update to be capable of logging true peak demand data?

    a. What actions and processes must the utility undertake to enable these meters to begin logging at least 15-minute data? Please describe in detail all the steps that need to happen, and describe who must take those steps (utility staff, third party contractors, etc.)

    b. Does this require multiple batches of changes? Does each make/model of meter require a separate over-the-air update?

    c. How much time would be required to enable all the existing meters in this category to begin collecting true peak demand data?

11. How many meters in total and per customer class require on-site work (but not replacement) to be capable of logging true peak demand data?

12. How many meters in total and per customer class require replacement meters to be capable of logging true peak demand data?

13. If there are other actions that need to be performed that are not captured in questions 4-7 to enable capture of true peak demand data, please describe.

Data Storage and System Updates

14. Please describe in detail the data storage, network, application, and other system updates required to handle the collection of at least 15-minute interval data.

    a. What is the process for performing each of these updates?

    b. Who performs each of these updates?

c. What is the approximate timeframe for making these back-end changes?

Green Button Data Updates

15. What type of IT infrastructure changes need to be made to ensure 15-minute interval demand data can be shared with customers via Green Button data?
    a. Who needs to perform these changes? Can the electric utility perform this in-house, or does this require a third party?
    b. What is an approximate timeframe for being able to make these changes for customers?

The above questions are not exhaustive, and the answers provided in each electric utility's respective Advice Letter may include additional information beyond what is specifically asked, as directed above. The electric utilities shall work with Energy Division to ensure their respective Advice Letter provides all appropriate and necessary information pertaining to the topics above.

PG&E mentions potential safety issues. PG&E, SCE, and SDG&E express concerns about costly billing updates required to report electric service line size on customer bills; however, we do not have sufficient information to assess the frequency of said risks and whether these risks outweigh the benefits of providing this data to customers.

Providing electric service line size information to customers is useful information. While reporting information on customer bills may be costly, we understand the importance of pursuing ways to find the least costly mechanism for communicating such information, and that we must consider whether communication through alternative channels would be more efficient and cost effective. SCE and SDG&E state that after a customer applies for a service upsizing, utility staff will visit the customer's premise and then provide customers their existing service line size.[69] These comments seem to misunderstand the intention of providing service line sizes to customers in the first place: to help customers, electricians, and/or contractors understand the existing capacity of a premise's service lines and gauge if the customer can safely add load, thereby avoiding applying for a service line upsizing altogether. Customers should not need to apply for an upsizing before finding out their service size.

We direct all electric utilities, including SMJUs, to collect electric service line sizes for (1) any new electric service lines installed in new construction and (2) any electric service lines replacing existing electric service lines (in the case of safety replacements, upsizing services, etc.), consistent with the requirement established in Section 4.3 of this decision. They shall collect this information during site visits that are already part of the service upsizing process, or other site visits that may be routine in utility procedures. The utilities shall record the electric service line sizes by service location and meter identification number and make this information available through a customer's online portal for customers to easily access. Starting in 2026, utilities shall also include in their annual reporting, as mandated by Resolution E-5105, the following information:

- Total Number of New Electric Services Lines Installed (# of service lines newly installed per category):
    - < 100 amp
    - 100-124 amp
    - 125-149 amp
    - 150-174 amp

[69] SCE Opening Comments on Phase 4 Scoping Memo at 15 and SDG&E Opening Comments on Phase 4A Staff Proposal at 3.

    - 175-199 amp
    - 200 amp
    - 200-299 amp
    - 300-399 amp
    - 400 amp or greater
- Total of Electric Service Lines Replaced (# of service lines replaced per category):
    - < 100 amp
    - 100-124 amp
    - 125-149 amp
    - 150-174 amp
    - 175-199 amp
    - 200 amp
    - 200-299 amp
    - 300-399 amp
    - 400 amp or greater

5.3. Expanding Utility Safety Evaluation Processes to Non-Isolating Devices that Interface with Utility Metering Equipment

5.3.1. Summary of Opening Comments

All parties generally support Staff's recommendation to require the electric utilities to test, certify, and evaluate different non-isolation technologies, including MSAs, using the same process and funding as approved in Resolution E-5194.

The Joint Parties agree with Staff's recommendation, stating that providing alternatives to panel upsizing is a "common sense strategy to help minimize building electrification costs."[70] SBUA similarly supports Staff's recommendation, noting that alternatives to electric panel upsizing can be more cost effective and can assist low-income customers in electrification efforts.[71] The Joint RENs also support Staff's recommendation, but argue electric utilities should not receive a return on equity on the purchase and/or installation of any non-utility-owned, third-party behind-the-meter equipment such as MSAs, even if they may help prevent infrastructure upgrades.[72]

CALSSA also strongly supports Staff's recommendation, but offers additional modifications. CALSSA asserts the Commission should explicitly name non-isolating MSAs as the "leading example of what [Resolution E-5194] funding is intended for" to ensure the electric utilities prioritize these devices and any other devices that can help avoid panel upsizing and aid in meeting California's decarbonization goals.[73]

CALSSA also urges the Commission to require electric utilities establish a "specific, criteria-based approach for MSA approvals" to mirror an approach other states have taken for approval of these products. CALSSA argues such an approach will lead to quicker approval timelines, than the current evaluation process.[74] CALSSA contends the current one-off evaluation processes are "duplicative" and "time-consuming," and argues pilots for testing products can last longer than a full year.[75] SPUR offers a similar recommendation and

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[70] Joint Parties Opening Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 15.

[71] SBUA Opening Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 15.

[72] Joint RENs Opening Comments on Phase 4 Scoping Memo at 9.

[73] CALSSA Opening Comments on Phase 4A Staff Proposal at 2.

[74] *Id*. at 2-3.

[75] *Ibid.*

proposes the Commission direct the electric utilities to authorize MSAs that meet a certain set of specifications rather than requiring evaluations for each individual product.[76]

ConnectDER supports Staff's recommendation and contends "without a clear source of funding for evaluation efforts" of non-isolating devices, "progress has been slow" in utility evaluation efforts of these technologies.[77] ConnectDER points out that non-isolating MSAs can reduce electrification timelines and lower decarbonization costs.[78] ConnectDER further proposes ratepayer funding should be used only to evaluate devices requiring explicit utility approval.[79]

ConnectDER also emphasizes that Finding 16 of Resolution E-5194 should apply to non-isolating MSAs as well. This Finding asserts the proposed evaluation process should be clarified "to indicate that customers will retain ownership of customer supplied equipment unless a utility clearly demonstrates a safety-based need for ownership to be transferred to the utility."[80]

PG&E supports Staff's recommendation and agrees products like MSAs can reduce the cost of decarbonization for customers. However, PG&E requests any additional devices eligible for testing "be specifically and deliberately limited to those which enable decarbonization."[81] PG&E argues there are many types of MSA products, and that there will likely be more in the future. As such,

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[76] SPUR Opening Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 9.

[77] ConnectDER Opening Comments on Phase 4A Staff Proposal at 9.

[78] *Id*. at 5-8.

[79] *Id*. at 9.

[80] *Id*. at 8; Resolution E-5194 at 23.

[81] PG&E Opening Comments on Phase 4A Staff Proposal at 6.

specifying decarbonization-specific products will ensure electric utilities can focus on their decarbonization goals.[82]

Regarding evaluation timeframes, PG&E notes that if more products require simultaneous evaluation in the future, then completing the evaluation under the timelines specified in Resolution E-5194 may not be possible. Though PG&E notes this has not been a problem thus far.[83] SCE makes similar comments, noting electric utilities should be given flexibility to adjust the timelines passed in Resolution E-5194.[84]

On coordinating safety evaluations and standards development across electric utilities, SCE requests Commission guidance and oversight on "scope and process" to forestall any antitrust concerns.[85] SDG&E makes a similar request of the Commission and asks for specific language to direct electric utilities to coordinate on evaluation plans to reduce "duplicative efforts."[86]

With respect to the types of technologies that should be evaluated, SCE requests the technology evaluation not focus on customer-owned and operated equipment lacking direct interfacing with a utility meter. SCE claims such technologies will require approval from the authority having jurisdiction, rather than from SCE, and therefore the utilities should not evaluate these devices.[87]

On funding, SCE is the only party to request that electric utilities be given permission to follow the process outlined in D.21-01-018 to submit a Tier 2

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[82] *Ibid.*

[83] PG&E Opening Comments on Phase 4 Scoping Memo at 6.

[84] SCE Opening Comments on Phase 4 Scoping Memo at 6.

[85] *Ibid.*

[86] SDG&E Opening Comments on Phase 4A Staff Proposal at 4.

[87] SCE Opening Comments on Phase 4 Scoping Memo at 6.

Advice Letter to request additional funding, if needed, due to a potentially large increase in the number of devices that will need to be evaluated.[88]

Lastly, SDG&E seeks clarification that the technology review processes outlined in Resolution E-5194 are the same processes that will apply to non-isolating devices.[89]

5.3.2. Summary of Reply Comments

The Joint RENs and CBIA support CALSSA's recommendations that MSAs be specified as the intended target technology and that the Commission adopt a criteria-based approach to approvals.[90]

SCE opposes CALSSA's recommendation for a specific, criteria-based approach and disputes CALSSA's characterization of the evaluation process as open ended, duplicative, and time-consuming. SCE asserts it formulates a testing plan based on "minimum safety and functional testing." Any additional testing, SCE says, is performed only if the data on certain products is insufficient or questionable.[91]

SCE disagrees with CALSSA that the Commission should comment on Finding 16 of Resolution E-5194 (regarding customer-owned equipment) in this decision, and proposes the Commission should instead consider ownership of non-isolating devices in its effort to assess cost recovery policies for zonal

[88] *Id.* at 5-6.

[89] SDG&E Opening Comments on Phase 4A Staff Proposal at 4.

[90] Joint RENs Reply Comments on Phase 4 Scoping Memo at 3-4; CBIA Reply Comments on Phase 4 Scoping Memo at 2-3.

[91] SCE Reply Comments on Phase 4 Scoping Memo at 5.

electrification and gas decommissioning in the Long-Term Gas Planning OIR (R.20-01-007).[92]

On evaluation timeframes, CALSSA disagrees that SCE should receive an "open-ended timeline extension" for evaluating non-isolating devices; instead, CALSSA believes PG&E's request for leniency on timelines when it needs to test multiple products simultaneously is a more reasonable request.[93]

CALSSA and the Joint Parties support collaboration across electric utilities to reduce duplication of testing.[94]

5.3.3. Discussion

Given the broad support for Staff's recommendations and the potential benefits to customers and ratepayers, we modify D.21-02-018 and Resolution E-5194, directing the funding approved in D.21-01-018 and the technology review processes specified by Resolution E-5194 to apply to non-isolating devices in addition to isolating devices. Similarly, we also modify the reporting requirements set forth in Resolution E-5194, which applied to isolating devices only, and we extend those reporting requirements to now apply to both isolating and non-isolating devices. These changes shall be effective immediately upon issuance of this decision.

Parties generally agree with Staff that non-isolating technologies, such as MSAs, can help customers add electrification loads without panel and service upsizing. The Commission reiterates that, in scenarios where an electric utility's

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92 *Id.* at 5-6.

93 CALSSA Reply Comments on Phase 4A Staff Proposal at 2.

94 CALSSA Reply Comments on Phase 4A Staff Proposal at 1 and Joint Parties Reply Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 8.

electrical infrastructure already exists and is already serving customers, service upsizing should be avoided unless necessary.

To clarify, all requirements and processes outlined in Resolution E-5194 now also apply to non-isolating devices (e.g., MSAs with expanded DER capabilities). Utilities must evaluate and approve these non-isolating devices for safety and compatibility in the same manner as the isolating devices covered by Resolution E-5194. Consistent with Resolution E-5194, we clarify that ratepayer funding shall be strictly used to evaluate devices located upstream from a customer's main electrical disconnection point and requiring explicit utility approval for deployment.

We are persuaded by SCE that customer-owned and operated equipment not interfacing directly with a utility meter should not be evaluated via the Resolution E-5194 process. However, customer-owned equipment that does interface directly with utility equipment, such as MSAs, would still need to be evaluated via the Resolution E-5194 process.

We decline to narrow the eligibility of devices qualifying for evaluation testing in Resolution E-5194 to apply to MSAs only. Resolution E-5194 remains neutral on form factor of technologies to be evaluated, and it shall maintain this neutrality, even with the inclusion of non-isolating devices. While most of the non-isolating technologies currently available are MSAs, we do not want to preclude future not-yet-known technologies from being able to participate in this evaluation process.

Similarly, while the Staff Proposal focused on the benefits of non-isolating MSAs for decarbonization purposes, we decline to narrow the eligibility of non-isolating devices eligible for the evaluation process to be limited to only devices that enable decarbonization. This would unnecessarily narrow the use cases for devices and may force the Commission to have to revisit this evaluation process in the future if other non-decarbonization use cases emerge as priorities.

We acknowledge that in the future, new non-isolating devices may emerge on the market and may require utility testing. If the large electric utilities receive a large influx of non-isolating devices requesting evaluation, we direct them, when using the Resolution E-5194 evaluation testing queue, to prioritize those non-isolating devices that enable decarbonization and distributed energy resources deployment over those that do not. These include devices that enable the addition of energy storage, solar panels, electric appliance loads, and EV charging.

We decline to adopt CALSSA's proposal to develop a criteria-based evaluation. CALSSA expresses concerns that testing is duplicative and unreasonably long, especially for products certified by a testing laboratory.[95] We are not persuaded, noting the process adopted in Resolution E-5194 is intended to fill in gaps where a formal evaluation standard does not yet exist, or where the use of a device in a utility's system is not adequately addressed in the device testing standard.[96] As stated in Resolution E-5194, Nationally Recognized Testing Laboratory "certification to applicable national safety standards does not address compatibility with a utility's equipment, standards, or operations."[97] Resolution E-5194 specifically requires the large electric utilities to have a clear purpose for any additional testing beyond that required by a Nationally Recognized Testing

95 CALSSA Opening Comments on Phase 4A Staff Proposal at 2.

96 Resolution E-5194 at 10-11 and 16-17.

97 *Id.* at 16-17.

Laboratory, and to define the criteria or thresholds for passing these tests.[98] Despite claims of duplicative testing, no specific examples have been provided of duplicative testing of either Nationally Recognized Testing Laboratory or other utility testing.

Furthermore, pursuing criteria-based evaluation would necessitate developing appropriate criteria, which may unnecessarily delay evaluation of devices under the currently approved process.

We also decline SPUR's request to direct the large electric utilities to authorize any devices meeting a minimum set of specifications, as SPUR has not provided any detail as to what these specifications should be. This approach is also subject to the same concerns noted above concerning criteria-based evaluations.

Regarding the timeline to complete evaluation, we are not persuaded by SCE that the large electric utilities should be given the ability to adjust the timeframes outlined in AL 4462-E-B and approved in Resolution E-5194 in anticipation of a greater volume of devices requiring testing. SCE has not provided any evidence where 90 calendar days for evaluation was insufficient. We do not see a compelling reason to change the timelines prior to encountering scenarios where these timelines cannot be met. We find PG&E's request that the large electric utilities be given more time to complete evaluations under specific scenarios, such as a large and sudden influx of device evaluation requests, to be more reasonable. We therefore decline to allow the large electric utilities to adjust

98 In relevant implementation Advice Letters, SDG&E AL 3734-E-A, PG&E AL 6153-E-A, and SCE AL 4462-E-A all clarified that any additional testing performed by the IOUs would be separate from Nationally Recognized Testing Laboratory testing. The IOUs state they will not repeat Nationally Recognized Testing Laboratory testing unless there are anomalies or concerns about test results. Resolution E-5194 at 6 also summarizes this point.

the timeframes for the evaluation process established in AL 4462-E-B and Resolution E-5194. However, on a specific scenario-by-scenario basis, the large electric utilities may request more time to complete an evaluation, after consultation with Energy Division Staff. Utilities shall file a Tier 1 Advice Letter specifying the reason for this extended evaluation timeframe request for a specific device and the new expected timeframe for completing the safety evaluation process. This shall apply to both isolating and non-isolating devices.

We do, however, expect the large electric utilities to work expeditiously to complete the evaluation of isolating and non-isolating devices. The Commission expects the large electric utilities to expedite testing to ensure that, if these devices meet safety standards, they have a quick and viable pathway to market. To help the Commission keep track of the progress of evaluation activities, we direct the large electric utilities to each submit Tier 1 Advice Letters regarding their evaluation activities.

For the entirety of calendar years 2025 and 2026, the large electric utilities shall submit these reports every three months, beginning July 15, 2025, for activity in the first two quarters of 2025. Starting January 15, 2027, each large electric utility shall file their respective Tier 1 Advice Letters annually on January 15 of each year until all approved funds are expended. These Tier 1 Advice Letters shall report on the following:

- Which devices have the electric utility evaluated or are in the process of evaluating since the last reporting period?;
- Where in the evaluation process is each device currently?;
- Descriptions of evaluation activities for each device that have occurred since the last reporting period, and the duration of each of these activities; and

- Anticipated evaluation activities in the upcoming reporting period.

SDG&E and SCE are correct in noting the large electric utilities must coordinate and collaborate on device evaluations. For devices undergoing safety evaluations, we reiterate the direction provided in Resolution E-5194: the large electric utilities must avoid duplicative testing, accept test results of other utilities for tests that are "agnostic to the unique characteristics of each utility system" and Advanced Metering Infrastructure, and coordinate where possible.[99] We also extend the direction provided in D.21-01-018 and Resolution E-5194 to non-isolating device evaluations: the large electric utilities should coordinate and collaborate on their respective evaluation plans and eliminate duplicative efforts where possible.[100] SDG&E AL 3734-E-A, PG&E AL 6153-E-A, and SCE AL 4462-E-A confirmed the large electric utilities will accept the results of each other's testing unless the tests are unique to a utility's specific system. This direction mitigates any antitrust concerns raised by SCE.

We uphold the direction provided in D.21-01-018 that allows the large electric utilities to submit Tier 2 Advice Letters requesting additional funding for safety evaluations, and that any additional funding for safety evaluations shall be applicable to both isolating and non-isolating devices.[101] This Tier 2 Advice Letter shall provide sufficient justification for any budgetary increases requested.

We add two additional requirements not ordered in Resolution E-5194. First, for all isolating and non-isolating devices evaluated, we direct the large electric utilities and suppliers to jointly serve on the proceeding service list an

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[99] Resolution E-5194 at 5-6.

[100] D.21-01-018 at 79.

[101] *Ibid.*

informational report to both this proceeding and R.19-09-009 (Rulemaking Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies), and to Energy Division at energydivisioncentralfiles@cpuc.ca.gov that includes the final evaluation report for every device either approved or not approved, or for which the evaluation process has ceased. The informational report for each device shall be served on the service list no later than 60 days after the evaluation process has concluded for the device.

Second, we direct each large electric utility to publicly list on their website which isolating and non-isolating devices have received utility approval, within 180 days of the issuance of this decision. Access to the website posting shall not necessitate a customer log-in. Additionally, the website where these devices are listed shall be on a new landing page specific to these types of devices. The large electric utilities shall each submit a Tier 1 Advice Letter informing Energy Division as to how they have complied with these website requirements within 180 days of the issuance of this decision. Together, these two actions will help provide transparency for suppliers and customers to understand which devices have and have not been approved for use in each electric utility territory.

To ensure customers better understand how to facilitate the installation of these devices, we also direct each of the large electric utilities to file a Tier 2 Advice Letter within 90 days of the issuance of this decision to establish a new tariff supporting the installation of customer-owned MSAs, both isolating and non-isolating, which shall describe the process and requirements a customer must follow to install any MSAs approved through the Resolution E-5194 safety evaluation process. We also direct each of the large electric utilities to update their respective electric service requirement manuals to include descriptions of customer-owned MSA installation processes and procedures. The large electric utilities shall each file a Tier 1 Advice Letter within 90 days of the passage of this decision, demonstrating compliance with the aforementioned updates to their electric service requirement manuals.

In summary, we modify and expand all aspects of the safety evaluation process and funding approved in Resolution E-5194 to also apply to non-isolating devices such as, but not limited to, MSAs. If the large electric utilities receive a large volume of requests to evaluate non-isolating devices, we direct them to prioritize evaluating devices that enable decarbonization (e.g., energy storage, solar panels, electric appliance loads, and EV charging), but we do not limit the evaluation process to devices intended only to facilitate these end uses. For all isolating and non-isolating devices evaluated via the Resolution E-5194 process, the large electric utilities and suppliers shall file joint informational reports to the service lists of this proceeding and R.19-09-009, and to Energy Division, that include their final evaluation reports. The large electric utilities shall also file regular updates on their evaluation activities and shall list publicly on their website which isolating and non-isolating devices they have approved for customer use. The large electric utilities shall also propose a new tariff describing how customer-owned MSAs shall be installed, and shall make corresponding changes to their electric service design manuals.

5.4. Encouraging Service Upsizing Alternatives

5.4.1. Summary of Opening Comments

Parties were split on how to ensure customers only pursue service upsizing after considering all other reasonable alternatives, such as the panel and service optimization strategies mentioned in Section 5.2.

PG&E and SCE oppose a requirement to collect proof customers considered alternative strategies to avoid service upsizing. PG&E argues this extra step would add unnecessary complexity for customers and utilities, extend timelines for service upsizing and may even discourage customers from electrifying their homes.[102] PG&E also points out that collecting proof would be inconsistent with the current common facility cost treatment policy established for EVs as part of D.11-07-029 and renewed several times since.[103] Instead, PG&E proposes providing educational materials to customers and contractors before an application for an electric service line upsizing is completed, which PG&E contends is the optimal time for intervention.[104]

SCE similarly opposes the requirement to collect proof of customer consideration of alternatives to service upsizing, stating local governments, as opposed to utilities, have jurisdiction over electrical panel alterations, which subsequently affect service upsizing. Because utilities do not have jurisdiction over a customer's panel loading decisions, SCE argues it would be difficult to administer any requirement to collect proof of a customer's actions.[105]

The Joint RENs also oppose requiring proof, and argue the Commission should "empower customers and contractors" to evaluate if service upsizing is "appropriate" or "reasonable" as opposed to "as a last resort."[106] They argue there may be situations where alternatives to service upsizing may exist, but that these alternatives may be more complex, more expensive, or that the customer may want to add additional load on site. The Joint RENs also point out that the

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102 PG&E Opening Comments on Phase 4 Scoping Memo at 9.

103 D.11-07-029 at 59.

104 *Ibid.*

105 SCE Opening Comments on Phase 4 Scoping Memo at 14.

106 Joint RENs Opening Comments on Phase 4 Scoping Memo at 9.

"proof" in this situation is dependent on data held by utilities and distribution system operators, which are hard for customers to access.[107]

SPUR supports verification that alternatives have been considered, but only for single-family homes with existing service capacity between 100-199 amps. Such verification, SPUR argues, should also prove that switching from gas to electric end uses is the trigger for the upsizing. They suggest requiring a contractor to fill out an attestation form to confirm having met the latter requirements.[108] SPUR argues single-family homes with an electric service line capacity under 100 amps, or multi-family units under 80 amps, should not be subject to this verification requirement and should automatically qualify for a panel/service upsizing.[109]

SPUR states any requirements for verification should be simple, not adding more administrative burden. They reference examples such as a contractor verifying a simple check list of other panel optimization strategies considered, and use of "customer panel optimization tools" already developed by several third parties to assist customers going through the electrification process. Lastly, SPUR offers an idea similar to PG&E's, that utilities should "provide panel optimization tools and educational materials"[110] at "key junctures" throughout the electrification journey.[111]

VEIC offers a similar idea as SPUR, where customers with electric service line capacities of 100-200 amps would submit applications with documentation

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107 Joint RENs Opening Comments on Phase 4 Scoping Memo at 9-10.

108 SPUR Opening Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 13.

109 *Id.* at 12.

110 *Id.* at 13.

111 *Id.* at 14.

showing that alternatives to service upsizing were considered, which should be completed by certified contractors on the site. For homes with less than 100-amp service, the home can automatically qualify for service upsizing. VEIC echoes the concerns raised by other parties that making the process overly complex runs the risk of alienating contractors from pushing electrification for their customers.[112]

The Joint Parties also argue simple documentation demonstrating that an electric service line upsizing is triggered by a "qualifying electrification retrofit" may be useful. They point to similar documentation required for service line requests triggered by EV charging. The Joint Parties also support distributing educational materials on panel optimization strategies, and collecting attestations as part of the service line upsizing application process to confirm the applicant explored these strategies. Nonetheless, as with SPUR, the Joint Parties emphasize minimizing administrative requirements on customers.[113]

SBUA notes business owners will likely not opt for service line upsizing if an alternative is available.[114] They suggest, however, utilities should provide an energy audit that helps customers understand what energy efficiency upgrades can avoid upsizing. SBUA also proposes the utilities should provide a one-stop shop for information on programs that a customer qualifies for, such as energy efficiency, demand response, and DER programs.[115]

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[112] VEIC Opening Comments on Phase 4 Scoping Memo at 7.

[113] Joint Parties Opening Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 16.

[114] SBUA Opening Comments Phase 4 Scoping Memo and Phase 4A Staff Proposal at 15.

[115] *Id.* at 16.

5.4.2. Summary of Reply Comments

PG&E disagrees with SBUA's proposal of an energy audit or assessment during the service upsizing application process. PG&E considers this impractical and not cost-effective. PG&E reiterates providing panel right-sizing education for customers and contractors while they are "still scoping out the project."[116]

SBUA agrees with SPUR that verification practices should be "streamlined" to avoid deterring customers from electrification, especially since many customers may be upsizing their services to accommodate new appliances replacing recently broken ones.[117]

The Joint RENs emphasize the utilities should intervene at different "touchpoints" in the service upsizing process to make contractors aware of workforce training offerings from utilities, RENs, community choice aggregators, and others. They note this would be an opportunity to make customers and contractors aware of customer programs and funding offered by these entities.[118]

5.4.3. Discussion

As outlined in the Phase 4A Staff Proposal, service upsizing can be a costly and time-consuming process for customers and utilities. It is important to ensure service upsizing is pursued only after other reasonable alternatives have been considered; this reduces the overall volume of service upsizing requests.

As noted by several party comments, there needs to be more education provided to customers and contractors around alternatives to service upsizing. Panel and service optimization strategies and technologies are relatively new, requiring contractors, utility staff, and customers to understand these options

[116] PG&E Reply Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 3.

[117] SBUA Reply Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 6.

[118] Joint RENs Reply Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 3.

and be able to provide information as to when they should be pursued, and to understand the benefits and limitations of these strategies. Given the novelty of these strategies, the Commission acknowledges the benefit of ensuring customers and contractors are fully aware of alternatives to panel upsizing.

Accordingly, Energy Division staff will work with the TECH Initiative implementer to develop and maintain a website containing resources about alternatives to electric service and panel upsizing ("weblink"), and share the weblink with the service list of this proceeding within 180 days of the issuance of this decision or as soon as practicable thereafter. The TECH Initiative implementer may leverage existing or upcoming studies and resources to minimize redundancies. For example, the CEC recently awarded a grant to support decision-making tools that help avoid electrical panel upgrades for single family homes; materials and outputs of this grant could be made available on the website.[119]

We also recognize creating and maintaining resources that keep up with industry innovations for alternatives to service upsizing comes with a cost. Creating and maintaining these resources centrally would be more ideal than requiring each utility to do so separately. The TECH Initiative is well-positioned to take on this task, as it already engages with multiple industry actors and customers to ease building electrification.

We direct all electric utilities, including SMJUs, to appropriately link and reference the weblink shared by the TECH Initiative implementer on utility websites within 270 days of the issuance of this decision, or within 90 days after the TECH Initiative implementers shares the weblink with the service list,

[119] *See* https://energy.ca.gov/solicitations/2023-12/gfo-23-303-decision-tool-electrify-homes-limited-electrical-panel-capacity.

whichever comes first. All electric utilities shall encourage customers to consider alternatives to electric and panel upsizing and direct customers to this weblink. The weblink shall be included on electric utility web locations customers are likely to visit in the process of requesting service line upsizing, such as on utility application web portals for service upsizing requests. These educational materials shall, at minimum, provide information to customers about the strategies and technologies discussed in the Phase 4A Staff Proposal (Section 5.1 of this decision) and authorized as new measures for AB 157 implementation (Section 8.3.3 of this decision).

We direct all electric utilities to engage with service upsizing applicants about alternatives to service upsizing prior to any application submission, as proposed by SPUR, Joint Parties, and VEIC. There should be confirmation that applicants reviewed these materials, but we acknowledge parties' concerns about the resources needed for collecting proof as to whether these options have been considered. We also acknowledge any steps added to the process should not add unneeded administrative burdens to applicants or costs to ratepayers.

As a middle ground, we direct all electric utilities, including SMJUs, to distribute the materials developed by the TECH Initiative implementer about alternatives to upsizing to all applicants. The electric utilities shall also collect a simple attestation form from applicants confirming having received the materials. We are not persuaded by some party comments that only certain customers, based on their existing service size, should be required to complete attestation forms. However, we recognize administrative simplicity is important, and that all applicants should be informed of these alternatives regardless of their service size. We decline to require applicants to prove they are pursuing a fuel substitution measure (i.e., switching from a gas end use to an electric end use); this adds unnecessary administrative burden to the process. Therefore, we direct all electric utilities to make this attestation form a requirement for all applicants seeking a service line upsizing, without requiring electric utilities to make distinctions between applicants based on existing service size or reasons for pursuing upsizing.

As pointed out by several parties, educating customers and contractors before a service line upsizing application is submitted would be very important, and there should be broader education efforts for customers, contractors, and utility staff around alternatives to panel upsizing. Moreover, there is a need to explore how to ensure these strategies are incorporated into other programs and trainings, including workforce training programs.

We also find SBUA's idea of a "one-stop shop" for electrification and customer programs compelling, as it would educate customers more holistically about their options. This idea will need to be explored further in the future – in this proceeding or another.

6. Revisiting Aspects of D.23-12-037

The Phase 4 Scoping Memo directed parties to file comments on whether the Commission should modify the existing energization deadline for mixed-fuel new construction projects seeking electric line extension subsidies, which is currently established no later than 12 months after July 1, 2024, pursuant to Ordering Paragraph (OP) 5 of D.23-12-037, and, if so, under what circumstances.

Parties were additionally directed to comment on whether SDG&E should be compelled to change their Tariff Rule 13 gas and electric rules in conformance with the other gas and electric utilities, noting that, unlike the other electric utilities, SDG&E did not make conforming changes to line extension subsidies for temporary facilities governed by Tariff Rule 13 as a response to either D.22-09-026, Resolution G-3598 or D.23-12-037.

6.1. Modifying the Energization Deadline for Mixed-Fuel New Construction Projects Seeking Electric Line Extension Subsidies

6.1.1. Summary of Opening Comments

The Joint Parties oppose modifying the existing energization deadline for mixed-fuel new construction projects seeking electric line extension subsidies, stating the existing deadline "protects ratepayers from speculative or premature electric line extension applications that were submitted just before the July 1, 2024 deadline."[120] Additionally, the Joint Parties note the challenge in determining what delays are genuinely outside of the developer's control, adding that making such a determination "presents significant administrability challenges and should not be for the Commission to adjudicate."[121]

SBUA supports extending the existing energization deadline and states the current electric line extension process often results in delays beyond developers' control. SBUA refers to their suggestion in the lead-up to D.23-12-037 that a legacy exemption should apply to "projects that obtained final local approval, such as zoning permits, or [in] instances where no zoning permit is required, building permits, before July 1, 2024" because such projects "may have been financed and scoped in expectation of obtaining the subsidies that existed under the policy in place at the time that project was finalized."[122] SBUA makes an alternative recommendation to narrow this legacy treatment window to include

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[120] Joint Parties Opening Comments on Phase 4 Scoping Memo and Phase 4A Staff Proposal at 18.

[121] *Ibid.*

[122] SBUA Opening Comments on Phase 4A Staff Proposal and Scoping Memo at 18.

only "projects that obtained final local approval by the date of issuance of D.23-12-037 on December 14, 2023."[123]

SCE supports extending the existing energization deadline, concerned the deadline will result in "unfair outcomes and may cause disputes when developers believe a missed deadline was caused by the utility or otherwise outside the developer's control."[124] SCE adds that the deadline also places pressure on utilities to process numerous projects in lesser time as developers push to meet their deadlines. To address these concerns, SCE recommends "a six-month grace period for projects that have met the requirements outlined in the Phase 3B Decision, OP 5 (subsections a and b), on or before July 1, 2025."[125] This extension, SCE states, would prevent penalizing developers for unforeseen delays, such as material shortage in supply chain or permitting delays. They also recommend that any projects not completed within this grace period should be repriced without subsidies at actual cost, and utilities should not be held liable for the loss of these subsidies.[126]

Sempra Utilities strongly support extending the July 1, 2025 energization deadline to "36 months after the invoice and contract deadline."[127] They state this extension would accommodate delays from factors such as material shortages, permitting issues, and project complexity. Sempra Utilities argue the current one-year deadline is unrealistic for many projects, especially larger or more complex

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[123] *Ibid.*

[124] SCE Opening Comments on Phase 4 Scoping Memo at 17.

[125] *Ibid.*

[126] *Id.* at 18.

[127] Sempra Utilities Opening Comments on Phase 4 Scoping Memo at 17.

ones, and extending the deadline would provide a fairer timeline for all customers.[128]

6.1.2. Summary of Reply Comments

Sempra Utilities challenge the Joint Parties' assertion that developers that proceeded with mixed-fuel new construction assumed the risk of not recovering line extension costs if their projects were not energized by the July 1, 2025 deadline.[129] Sempra Utilities argue this view narrowly applies to a subset of developers and fails to consider the broader impact of D.23-12-037. They argue such approach would provide only six months for the developers to complete the project and energize, including any necessary time needed to reconsider or adjust construction plans.[130] They concur with SBUA's opening comments, which highlight that many projects were planned with the expectation of subsidies remaining available under the policy at the time.[131]

Sempra Utilities disagree with SCE's opening comments that a six-month extension to the energization timeline is sufficient. They point to data reported in R.24-01-018, stating "SCE's current average estimated energization timing for an Electric Rule 15 and 16 [project completion] is 268 business days,"[132] which is inconsistent with SCE's recommendation to extend the July 1, 2025 energization timeline by six months only. Sempra Utilities reiterate their recommendation of a

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128 *Id.* at 18.

129 Sempra Utilities Reply Comments on Phase 4 Scoping Memo at 2.

130 *Ibid.*

131 *Id.* at 3.

132 *Id.* at 3-4.

36-month extension would better accommodate delays and help customers either adjust to the loss of subsidies or redesign their projects.[133]

6.1.3. Discussion

SBUA, SCE, and Sempra Utilities all support extending the energization deadline for mixed-fuel new construction projects beyond July 1, 2025, due to the potential for delays beyond developers' control. We are persuaded by these comments and find an extension of the energization deadline is reasonable.

We acknowledge SBUA's recommendation that mixed-fuel new construction projects with contracts fully paid for prior to the date that the Phase 3B Decision was adopted (i.e., December 14, 2023) should not be subject to any energization deadline. However, we find it appropriate to adopt an approach combining elements of SBUA's recommendation with Sempra Utilities' recommended 36-month extension.

We therefore allow mixed-fuel new construction projects with contracts approved and fully paid for prior to the implementation of the Phase 3B Decision to have additional time to energize, by granting an extension up to 36 months from July 1, 2024 (i.e., the date of implementation of the Phase 3B Decision's core elements), making the new energization deadline for these projects no later than June 30, 2027.

We acknowledge extending energization deadlines for mixed-fuel new construction projects will likely result in electric line extension subsidy payments that would otherwise have ultimately been forfeited by developers. To better monitor electric line extension subsidy expenditures for mixed-fuel new construction – especially after July 1, 2025 – we find it appropriate to change the

[133] *Ibid* at 4.

reporting requirement established under OP 8 of D.23-12-037 to be both more frequent and more granular.

We require PG&E, SCE, and SDG&E to report to the Commission quarterly instead of annually starting in 2025. Calendar Year 2024 data shall be reported on May 1, 2025, as is the requirement currently, but data for 2025 onwards shall be reported quarterly. First quarter data shall be reported no later than July 15 of the same year, second quarter data shall be reported no later than October 15 of the same year, third quarter data shall be reported no later than January 15 of the following year, and fourth quarter data shall be reported no later than April 15 of the following year, which aligns with the new reporting requirement deadline established in Section 7 below for all annual reports ordered as part of this proceeding.

Instead of reporting aggregated data for the quarter, data shall be disaggregated by month. In addition to the monthly data for their whole service territory, PG&E, SCE, and SDG&E shall also provide the same monthly data broken down by baseline territory and distinguish single-family data from multi-family data. Quarterly reports shall be submitted in spreadsheet format via the Tier 1 Advice Letter filing method established in D.23-12-037. PG&E, SCE, and SDG&E shall coordinate with Energy Division on a revised standardized reporting template.

The foregoing modifications to the data reporting requirements shall apply to all data required under OP 8 of D.23-12-037 and not be limited solely to electric line extension subsidy expenditures. In addition to electric line extension subsidy expenditure data, we take note of Sempra Utilities' argument that it is important to reference available data on energization timelines when making policy decisions. However, the energization timelines for SCE that Sempra

Utilities highlight include numerous different steps, not all of which are relevant to the energization deadlines established in this proceeding.

For example, SCE's energization timeline includes an average of 45 days for "Customer Initiation," an average of 36 days for "Engineering & Design," an average of 138 days for "Dependencies," including "Site Readiness," and an average of 49 days for "Construction" to get to the grand total of 268 days on average for overall completion.[134] The energization deadlines set in this proceeding apply only to projects fully paid for before July 1, 2024, which generally occurs after engineering and design work is completed. To better understand energization timelines in the context of this proceeding, we require PG&E, SCE, and SDG&E to all include in their quarterly reports additional data on the average number of days between when a contract for a building project is fully paid and when that project is energized. This data shall be computed for all projects reported as energized in each quarter.

6.2. Tariff Rule 13 Conformance Considerations

6.2.1. Summary of Opening Comments

The Joint Parties[135] and SBUA[136] support requiring SDG&E to change their Rule 13 gas and electric rules in conformance with the other gas and electric utilities. They both argue line extension allowance rules should be consistent across all electric utilities.

Sempra Utilities note that SDG&E submitted updates to Tariff Rule 13 on July 23, 2024, via Advice Letter 4478-E/3320-G.[137]

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134 *See* Response filed on April 22, 2024, in R.24-01-018.

135 Joint Parties Opening Comments at 18.

136 SBUA Opening comments on Phase 4A Staff Proposal and Scoping Memo at 18.

137 Sempra Utilities Opening Comments on Phase 4 Scoping Memo at 23.

6.2.2. Summary of Reply Comments

No reply comments were received on this topic.

6.2.3. Discussion

SDG&E submitted updates to their Tariff Rule 13 on gas and electric rules to the Commission through Advice Letter 4478-E/3320-G on July 23, 2024. SDG&E's Advice Letter 4478-E/3320-G has since been approved by Energy Division and is effective as of its filing date. Hence, there is no longer any need for SDG&E to be compelled to file an update to Tariff Rule 13. This issue is moot, and no further action in this proceeding is needed on this issue.

6.3. Additional Clarifications

6.3.1. Summary of Opening Comments

Some party comments request changes to D.23-12-037 other than those concerning the energization deadline and the Tariff Rule 13 conformance issue.

SCE requests the Commission establish a process where Energy Division share an annual update to SCE on all customers receiving an exemption from gas line subsidy elimination pursuant to the exemption request process established by OP 2 of D.22-09-026. SCE claims this information will help them prepare their systems and accommodate those customers.[138]

Sempra Utilities request the Commission extend the deadline of July 1, 2024, for applicants seeking electric line extension subsidies for mixed-fuel new construction to sign their contracts and pay estimated electric line extension costs. They support allowing exceptions for customers who were in the design review approval process and missed the deadline. Sempra Utilities argue extending the deadline would offer more equitable treatment, as some

[138] SCE Opening Comments on Phase 4 Scoping Memo at 19.

developers suffered financial losses due to the short implementation timeline and challenges beyond their control.[139]

Sempra Utilities further recommend modifying the implementation approach of actual cost billing by aligning the date of actual cost billing with the date of elimination of subsidies. They highlight the current misalignment would require substantial administrative work to update costs and contracts if customers miss the energization deadline.[140]

Both SCE and Sempra Utilities urge the Commission to clarify various additional issues electric utilities are facing in the implementation of the Phase 3B Decision. On July 9, 2024, the large electric utilities jointly submitted Advice Letters (SCE AL 5331-E, PG&E AL 7320-E, and SDG&E AL 4468-E, respectively) to the Commission requesting clarification on the implementation of the elimination of electric line extension subsidies for mixed-fuel new construction projects pursuant to D.23-12-037.[141] Sempra Utilities propose several recommendations to address administrative challenges and clarify criteria for receiving electric line extension subsidies. These include defining "mixed-fuel" based on contract obligations, excluding trench sharing as a mixed-fuel identifier, and seeking clarification on propane usage standards impacting electric subsidies. Sempra Utilities emphasize these changes are necessary to streamline internal processes and provide customers with clear guidance, ultimately supporting the Commission's building decarbonization goals.[142]

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139 Sempra Utilities Opening Comments on Phase 4 Scoping Memo at 17.

140 *Id*. at 20.

141 SCE Opening Comments on Phase 4 Scoping Memo at 18.

142 Sempra Utilities Opening Comments on Phase 4 Scoping Memo at 21 and 22.

Furthermore, Sempra Utilities repeat a request originally made by SDG&E in Phase 3B opening comments: the Commission should "take a more holistic approach in promoting decarbonization by examining a broader range of considerations and impacts of the policies that were to be addressed in this rulemaking."[143] They cite SDG&E's prior comments that if the Commission "intends to eliminate electric line extension subsidies on grounds of affordability or otherwise, it should not do so selectively and instead should consider eliminating all electric line extension subsidies for all new customers, subject to an exception or other reasonable accommodation for low-income housing."[144]

6.3.2. Summary of Reply Comments

No reply comments were received on the above Section 6.3.1 topics.

6.3.3. Discussion

We decline SCE's request for Energy Division to provide an annual update on the list of customers that applied and succeeded in receiving the exemption from gas line subsidy elimination. Instead, we place the responsibility to inform electric utilities as to the disposition of an application requesting an exemption from the gas line extension subsidy elimination on the gas utility applicant. Any application for exemptions from the gas line extension subsidy elimination requirement must be formally requested and approved by the Commission, such as in the pending PG&E application on this topic (A.24-07-002). If the Commission approves such an application for exemption, the gas utility that submitted the application must inform other electric utilities – both investor owned and publicly owned utilities – active in their service territory as to the final disposition of the application and which customers are affected.

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[143] *Id.* at 3.

[144] *Ibid.*

We further grant Sempra Utilities' request to extend the deadline for applicants to finalize contracts for mixed-fuel new construction projects that can still receive electric line extension subsidies. Although developers were given more than six months from the date of issuance of D.23-12-037 to finalize their plans, we acknowledge the final plans for some development may have been completed where contracts had not been finalized and there may not have been sufficient information on the end of the subsidies provided after commitments had been made and prior to finalization of contracts. A successful transition to decarbonized new construction necessitates the Commission set a firm but fair timeline as to the date after which mixed-fuel new construction would no longer be eligible for electric line extension subsidies.

Regarding Sempra Utilities' concern about actual cost billing, the energization date extension granted under Section 6.1.3 resolves and moots these concerns, as this decision extends the deadline for both energization and finalization of contracts to June 30, 2027.

Regarding SCE and Sempra Utilities' request to clarify various implementation questions relating to D.23-12-037, the aforementioned Advice Letters addressing the same concerns were dispensed with pursuant to Resolution E-5352 on December 19, 2024. As such, the large electric utilities shall refer to that resolution when determining how to implement the new electric line extension rules.

We decline to modify the definition of "mixed-fuel" new construction adopted in D.23-12-037, where we defined "mixed-fuel" new construction to mean "building projects that use gas and/or propane in addition to electricity." We reiterate the clarification provided in Resolution E-5352: "a new construction project that uses propane to power any appliance other than an outside grill is considered to be mixed-fuel and is not eligible for electric line extension subsidies after July 1, 2024." "Mixed-fuel" new construction does not include otherwise all-electric building projects that use a fuel other than gas or propane solely for backup electricity generation. When determining whether new construction projects are "mixed-fuel," the electric utility is to consider each building within a project. For example, if a housing development includes all electric homes with a single structure such as a community center that is "mixed fuel," the electric line extension subsidies will not apply to the community center, but those subsidies will apply to the homes.

We are unpersuaded by Sempra Utilities' argument that eliminating electric line extension subsidies should not be done selectively. We are persuaded, however, by their position on the importance of examining a broader range of considerations, as well as examining the impacts of policies adopted in this proceeding. While it is appropriate to reconsider this proceeding's Phase 3B Decision (D.23-12-037) insofar as it declined to eliminate electric line extension subsidies for a broader range of buildings – notably existing buildings – today's decision does not change that position.

7. Modifications to Building Decarbonization Reporting Requirements

The Phase 4 Scoping Memo directs parties to identify ways to simplify reporting requirement procedures previously adopted in this proceeding.[145]

[145] Parties were asked to comment on the following two questions: (1) Resolution E-5105 established a reporting deadline of September 1 of every year for various decarbonization-related data; D.21-11-002 established a reporting deadline of February 1 of every year for new customer data relating to appliance usage; D.23-12-037 established a reporting deadline of May 1 of every year for data relating to line extension requests and subsidies. Should the Commission align the reporting requirement deadlines to be delivered on a single date? Alternatively, should the Commission consider new dates for any particular reporting

7.1. Summary of Opening Comments

PG&E opposes changing the current reporting timelines, stating it would create reporting complexity for 2025 reporting requirements creating either greater than, or less than, 12 months of data.[146]

SBUA supports aligning the reporting requirement deadlines on a single date but defers to the affected utilities to propose a single feasible date. They also support data required under D.21-11-002 being made available on each utility's public website, stating this data is very helpful for customers to better understand the impacts of appliance usage on both their electricity demand and their electricity bills.[147]

SCE prefers the reporting deadlines to stay as currently authorized, stating multiple reports due at the same time cause resource constraints. Nevertheless, if the Commission decides to align all reporting deadlines, SCE requests it to be no earlier than September 1 of each year, to allow sufficient time to collect and analyze prior calendar year data. They also request changing the deadline for any changes to annual reporting requirements from Energy Division Staff, as allowed by Resolution E-5105, from July 1 of each year to June 1 of each year. For public disclosure of data required under D.21-11-002, SCE states no one has ever reached out to SCE to locate these reports, and requests the Commission does not require these reports to be posted on a public website if they are not proving to be useful tool for stakeholders. SCE also requests the Commission establish

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requirement? (2) Unlike in Resolution E-5105 and D.23-12-037, D.21-11-002 did not require new customer data relating to appliance usage to be posted to each IOU's respective website. Should such data be required to be posted to each IOU's public website?

146 PG&E Opening Comments on Phase 4 Scoping Memo at 11.

147 SBUA Opening Comments on Phase 4 Scoping Memo at 19.

either an end date for these reports or a mechanism to terminate these reports when no longer useful.[148]

Sempra Utilities state SDG&E is neutral on reporting schedules, but note timelines may need re-evaluation for future additional reporting requirements.[149]

7.2. Summary of Reply Comments

No reply comments were received on the above Section 7.1 topics.

7.3. Discussion

The Commission has adopted numerous different reporting requirements since January 2019. The Phase 1 Decision (D.20-03-027 at OP 25) in this proceeding required large electric utilities to submit data and maps needed for program planning and assessment by September 1 of each year for the prior calendar year. The details and format of this requirement were set in Resolution E-5105,[150] which adopted a spreadsheet format for electric utilities to report various confidential and non-confidential information regarding number of customers by rate type, age of premise, as well as information about certain gas pipeline infrastructure.

The Phase 2 Decision (D.21-11-002 at OPs 3 and 5), as well as Appendix C and Appendix D of the same decision, added further reporting requirements for the large electric utilities. Appendix C outlined information regarding other programs the large electric utilities must provide to the implementers and evaluators of the TECH Initiative, the BUILD program, and the Wildfire and Natural Disaster Resiliency Rebuild Program (WNDRR) program every six months. Appendix D laid out data collection and reporting requirements for the

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148 SCE Opening Comments on Phase 4 Scoping Memo at 20 and 21.

149 Sempra Utilities Opening Comments on Phase 4 Scoping Memo at 23.

150 Resolution E-5105, issued Nov 19, 2020.

large electric utilities regarding prospective customer data on the type of water and space heating systems used, as well as propane usage on customer premises, with a reporting deadline of February 1 of each year.

The Phase 3A Decision (D.22-09-026) did not set any reporting requirements for the gas utilities. However, OP 8 of the Phase 3B Decision (D.23-12-037) required the three large electric utilities to report electric line extension expenditures and additional information relating to new construction starts by May 1 of each year for the prior calendar year.

To streamline reporting across the various decisions of this proceeding, and to make data collected through them more accessible, we align and adopt April 15 as the annual deadline for all reporting requirements discussed above. For any reporting required more than once annually, such as quarterly intervals, this April 15 deadline aligns with the close of the fourth quarter reporting for the prior calendar year and shall include annual summaries.

To address PG&E's concern regarding the complexity of 2025 reporting, we keep all previous reporting deadlines as is for 2025. Therefore, starting April 15, 2026, the annual reporting deadline for Resolution E-5105, D.21-11-002, D.23-12-037, and the additional requirements established by today's decision shall be April 15 of each year, submitted via a Tier 1 Advice Letter. D.23-12-037 reporting shall be quarterly going forward, with the annual reporting aligning with April 15.

Based on SCE's comments, we establish the third year following the close of this proceeding as the sunset year for all building decarbonization proceeding reporting requirements set in this proceeding. The affected utilities (individually or collectively) may also request an earlier sunset by submitting a Tier 2 Advice Letter to the Energy Division. Resolution E-5105 does not obligate Energy

Division to update reporting requirements every year, and requires electric utilities to continue reporting on previously established requirements unless directed otherwise. As such, we find the July 1 deadline for Staff to revise the Resolution E-5015 data requirements to be moot. If requirements are changed, either through the resolution process or the formal proceeding process, we will continue to afford the electric utilities reasonable amount of time to comply with the new requirements.

We are not persuaded by SCE's comments that no one having reached out to SCE for appliance proliferation data, as evidence of lack of data usefulness. There are many reasons why that could have occurred, including industry stakeholders' and the public's failure to recall every reporting requirement from Commission decisions and failure to realize such data may be sought from SCE. Data reporting and data inquiries can be onerous and place a burden on the requestor to track down the correct contacts, define the purpose, and refine their request. A public disclosure of non-confidential data adds relatively little additional burden on the utility in addition to a Tier 1 Advice Letter, but can be hugely transformative for the market, and informative for both industry stakeholders and the public.

Therefore, we require that, unless deemed confidential, the affected utilities shall make all building decarbonization proceeding-related reporting publicly accessible on their website, and notify the service list of this proceeding when information is updated. To allow for year-over-year comparisons, each electric utility shall retain all previously reported data until the reporting requirements sunset. Annual reports shall be submitted by each utility as a single

Tier 1 Advice Letter, and once approved, posted on each electric utility's respective website, similar to the practice established under Resolution E-5105.[151]

8. AB 157 Implementation

AB 157 allocated $40 million of the $71 million penalty paid by SoCalGas to the Aliso Canyon Recovery Account to the TECH Initiative for use solely in SoCalGas service territory. The bill directs funding to be spent as follows:

- Communities in the Aliso Canyon Disaster Area shall be granted priority for receiving funds;
- Funding shall be for both single-family and multi-family home electrification, and, in addition to being used for measures historically supported by the TECH Initiative pursuant to Section 922 of the Pub. Util. Code, may also be expended for additional new measures for enabling comprehensive building electrification, including energy audits, panel upgrades, and electrical wiring repairs;
- These funds may be used in combination with other funding sources, if available, to cover up to 100 percent of net participant and program costs;
- Funds shall be prioritized for efforts that reduce winter natural gas demand from the Aliso Canyon natural gas storage facility, accelerate heat pump deployment, and provide equitable benefits to multifamily building residents; and
- The expenditure of funds shall not cause the displacement of tenants in upgraded rental housing units and shall be used to limit cost impacts on tenants.

The bill provides two additional clarifications:

- For the purposes of this item, "Aliso Canyon Disaster Area" means the City of Los Angeles communities of Porter Ranch, Granada hills, Northridge, Chatsworth,

[151] Confidential data is submitted to CPUC's Energy Division via secure file transfer, while non-confidential version of the data is made available on the IOU website.

North Hills, Canoga Park, Reseda, Winnetka, West Hills, Van Nuys, and Lake Balboa; and

- The funds in this Item shall be available for encumbrance or expenditure by the Commission until June 30, 2027, and shall be made available for liquidation until June 30, 2030.

The Assigned ALJ's Ruling issued on October 8, 2024, sought comments on the following six questions:

1. Should AB 157's new TECH Initiative funding be allocated to program costs, administrative costs of the implementer, administrator costs for the contractor agent, and evaluation costs paid to the program evaluator in a manner consistent with D.20-03-027 and D.23-02-005? Why or why not? If not, how else, specifically, and why should those allocations be made?
2. Regarding the new TECH Initiative funding, should the Commission retain or modify the requirement introduced by D.23-02-005 that 40 percent of all new program costs for activities must serve equity customers?
3. Is further clarification needed on what "additional new measures for enabling comprehensive building electrification" should be authorized by the Commission beyond "energy audits, panel upgrades, and electrical wiring repairs" for the TECH Initiative implementer? Why or why not? If so, what should those additional new measures be?
4. What other programmatic changes should the Commission consider in order to effectively implement the new TECH initiative funding consistent with the requirements of AB 157 (e.g. how should "priority" be determined for receiving funds in the Aliso Canyon Disaster Area, how can the Commission ensure that the expenditure of funds shall not cause the displacement of tenants in upgraded rental housing units and shall be used to limit cost impacts on tenants, etc.)?

5. What, if any, new direction should be given to the TECH Initiative contracting agent to facilitate the transfer and accounting of the new TECH Initiative funding?
6. What, if any, new reporting requirements should be imposed on the TECH Initiative implementer regarding expenditure of the new TECH Initiative funding?

8.2. Budgetary Considerations

8.2.1. Summary of Opening Comments

Parties filed comments on whether the new TECH Initiative funding from AB 157 should maintain the same cost caps consistent with D.20-03-027 and D.23-02-005 for program implementation (10 percent), program evaluation (2.5 percent), and contracting agent responsibilities (1 percent).

Cal Advocates states the cost caps should remain consistent with D.20-03-027 and D.23-02-005, noting what remains is 86.5 percent of funds for program costs, which include both customer incentives and additional programmatic expenditures (e.g., contractor training, quick start grants, loan loss reserve, pilots, etc.).[152] Of those costs, Cal Advocates recommends placing a cost cap of 6.5 percent on additional programmatic expenditures while reserving the remaining 80 percent of funding for customer incentives.[153] SCE recommends allocating the full 86.5 percent of program costs for customer incentives, emphasizing the need to scale up electric heat pump adoption in the state and asserting that funding should not be utilized for efforts like quick start grants, pilots, or loan loss reserve.[154] SCE further recommends eliminating any further

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152 Cal Advocates Opening Comments on AB 157 Ruling at 1.

153 *Id.* at 1-2.

154 SCE Opening Comments on AB 157 Ruling at 2.

program evaluation, and instead directing that 2.5 percent of funding to program incentives.[155]

CAC recommends 120-volt heat pump water heaters (HPWHs) be the only appliance supported with AB 157 funds. CAC argues HPWHs are the most cost-effective way to decarbonize the Aliso Canyon Disaster Area because they are less likely to necessitate panel upgrades, would maximize winter gas use reductions,[156] and have a lower average cost than heat pump heating, ventilation, and air conditioning (HVAC) units.[157]

CAC adds that its proposal to focus on 120-volt HPWHs would work by coordinating with LADWP to combine new AB 157 funds with its own rebates, and could utilize HEEHRA Program funds, as well.[158] CAC also recommends the Commission require SoCalGas to distribute an e-mail and bill insert announcement regarding the new AB 157 funds, which should be created by the TECH Initiative implementer, and not SoCalGas.[159]

VEIC recommends keeping the existing budget allocation caps established in D.20-03-027 and D.23-02-005.[160]

8.2.2. Summary of Reply Comments

In response to CAC, A.O. Smith agrees 100 percent of the AB 157 funds should be directed at HPWHs, but notes it should include all HPWHs regardless

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155 *Ibid.*

156 CAC Opening Comments on AB 157 Ruling at 4.

157 *Id.* at 6.

158 *Id.* at 8.

159 *Id.* at 12.

160 VEIC Opening Comments on AB 157 Ruling at 4-5.

of their required voltage.[161] SoCalGas disagrees with CAC's recommendation that the Commission should require SoCalGas to distribute an e-mail and bill insert announcement regarding the new AB 157 funds.[162] They argue utility bill inserts are an extension of the company's main business and operational funds, as they are generally intended to communicate information in a consistent manner to all customers and not within a specified geographical area.[163] SoCalGas further adds since AB 157 funding is limited to a subset of SoCalGas customers, sending bill inserts to all customers would create unnecessary confusion for those ineligible for funding.[164]

LADWP recommends AB 157 funds be entirely allocated to downstream incentives in the form of direct customer rebates, excluding administrative costs. LADWP argues this approach maximizes the funds' impact by focusing on GHG reduction and efficient community electrification efforts within the Aliso Canyon Disaster Area.[165]

VEIC disagrees with CAC that the AB 157 funds be used exclusively for the installation of 120-volt HPWHs, and argues that by constraining the program to a single technology solution, this may limit the TECH Initiative implementer from delivering on the other stated priorities of AB 157.[166]

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[161] A.O. Smith Reply Comments on AB 157 Ruling at 2-3.

[162] SoCalGas Reply Comments on AB 157 Ruling at 1-2.

[163] *Id.* at 2.

[164] *Ibid.*

[165] LAWDP Reply Comments on AB 157 Ruling at 2.

[166] VEIC Reply Comments on AB 157 Ruling at 7.

8.2.3. Discussion

Many parties support maintaining the existing budgetary allocations of 10 percent for program implementation and 1 percent for contracting agent responsibilities. We are persuaded by these parties' comments.

Regarding program evaluation, we are not persuaded by SCE's argument that funding should be eliminated and reallocated for program costs. While it is necessary to direct funding first and foremost for scaling up the adoption of heat pump appliances through the provision of program incentives, we recognize AB 157 includes additional requirements not previously addressed in either D.20-03-027 or D.23-02-005, including (1) the prioritization to direct funding to communities in the vicinity of the Aliso Canyon natural gas storage facility, and (2) the requirement that the use of funds not result in tenant displacement. Given these additional requirements, maintaining 2.5 percent of the augmented budget for program evaluation is appropriate and will ensure we learn new lessons from the expenditure of AB 157 funds for new purposes not previously authorized as part of the TECH Initiative.

We are persuaded by SCE's other recommendation for new funds to be dedicated exclusively to customer incentives and not be utilized for additional programmatic expenditures like quick start grants, pilots, or loan loss reserve. However, we do not restrict the TECH Initiative implementer from continuing to provide workforce education and training. As such, we direct the TECH Initiative implementer to only utilize new program cost funding for customer incentives, the administration of tenant protections, as well as workforce education, and training efforts.

We decline to adopt CAC's recommendation to dedicate customer incentive funding exclusively for 120-volt HPWHs. Rather, we share VEIC's concern that constraining program funding to a single technology solution may limit the TECH Initiative implementer's ability to deliver on AB 157's stated priorities. We also decline to adopt LADWP's recommendation to direct funding for downstream customer rebates, as AB 157 did not authorize such a change and Pub. Util. Code Section 922 states TECH Initiative funding must be directed exclusively for "the provision of upstream and midstream incentives."

We further decline to adopt CAC's recommendation that SoCalGas distribute bill inserts and e-mail notices informing customers of available incentives. In addition to the $40 million provided by AB 157 to augment the TECH Initiative budget, the legislation provided an additional $2 million to the Commission's Equity and Access Grant Program "for community-based organizations to provide education and outreach about building decarbonization, healthy homes, and related health impacts."[167]

Consistent with legislative intent and to minimize duplication of efforts, we direct the TECH Initiative implementer to coordinate with the Equity and Access Grant Program for outreach-related activities.

8.3. Equity Allocation

8.3.1. Summary of Opening Comments

Parties filed comments on whether AB 157's new TECH Initiative funding provided should be subject to the same requirement introduced by D.23-02-005 that 40 percent of all new program costs must serve equity customers.

In their opening comments, CAC and the Joint Parties both recommend initially setting the equity allocation to 100 percent. More specifically, CAC recommends customers with incomes less than 80 percent of area median income

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[167] *See* AB 157.

in the Aliso Canyon Disaster Area be prioritized, followed by any customer in the Aliso Canyon Disaster Area becoming eligible for funding starting in January of 2026, and then any SoCalGas customer in LADWP service territory with an income less than 150 percent of area median income becoming eligible for funding starting in July of 2026.[168] The Joint Parties recommend exclusively funding customers with incomes at or below 80 percent of area median income, as defined by the California Department of Housing and Community Development (HCD). They state their recommendation will ease compliance with AB 157's requirement to prioritize funding for efforts that provide equitable benefits to multi-family building residents.[169]

The Joint Parties contend that if the Commission continues to allow the TECH Initiative to use its current broad equity customer definition, then there needs to be more transparency as to how many households qualify as equity customers under this definition.[170] They further add that the TECH Initiative should be required to publish datasets and maps showing which and how many households currently qualify as equity customers, and that if many middle- and high-income households are included in the equity customer definition, then the Commission should require the TECH Initiative to limit the equity customer definition to just DACs or low-income households.[171]

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168 CAC Opening Comments on AB 157 Ruling at 13.

169 Joint Parties Opening Comments on AB 157 Ruling at 3.

170 The TECH equity community definition includes DACs, income-qualified customers (e.g. CARE/FERA/ESA), hard-to-reach, affordable housing (at least 66 percent of living units have incomes below 80 percent the area median, or live in a deed-restricted housing unit; or live in a subsidized deed-restricted housing unit), and low-income household or low-income community, and low-income and ½ mile from a DAC, both as defined by California Climate Investment's Priority Populations. See TECH website, https://TechCleanCa.com.

171 Joint Parties Opening Comments on AB 157 Ruling at 6.

The Joint Parties also note that D.23-02-005 set out "at a minimum, 40 percent of the TECH Initiative program costs to fund activities that serve equity customers." They add that this definition, which was established by the TECH Initiative implementer, captures a larger segment of households where some may be more affluent than their low-income neighbors. For example, the Joint Parties state just 14.5 percent of appliance incentives through the TECH Initiative have gone to DAC households, which is a metric used by numerous programs and agencies to allocate funding and target Californians most in need. The Joint Parties state the 14.5 number was obtained by analyzing publicly available data available on the TECH website.[172]

To ensure more than 14.5 percent of funding goes to DACs, the Joint Parties recommend allocating new AB 157 funding toward a low-income direct install program and pilots akin to the low-income San Francisco direct install programs and pilots. They argue this will ensure that equitable electrification occurs and that a direct install program would make it easier to target the communities in the Aliso Canyon Disaster Area.[173]

On the other hand, LADWP, ConnectDER, PG&E, Cal Advocates, SCE, and VEIC recommend maintaining the same 40 percent equity community percentage found in D.23-02-005. LADWP asks to prioritize disadvantaged and income-qualified customers affected by the Aliso Canyon incident.[174] Cal Advocates goes further by asking the Commission to limit the equity community definition to DACs, CARE and FERA, hard-to-reach customers, and residents of

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172 Joint Parties Opening Comments on AB 157 Ruling at 3-4.

173 *Id.* at 5-6.

174 LAWDP Reply Comments on AB 157 Ruling at 3.

affordable housing, with distinct allocations for customers who qualify under criteria other than being low-income.[175]

8.3.2. Summary of Reply Comments

CAC supports the Joint Parties' recommendation that the Commission allocate the AB 157 funds to a direct install program to ensure access for low-income customers.[176]

In response to the Joint Parties' support for a 100 percent low-income direct install program and Cal Advocates' support for creating distinct allocations for customers who qualify for incentives under criteria other than being low-income, VEIC notes a direct install program is a clear pathway to serving customers if comprehensive building electrification is deemed to be the primary priority of AB 157.[177]

VEIC adds that comprehensive building electrification devotes more resources to fewer customers than single-measure approaches, which would help accelerate heat pump deployment, reduce winter natural gas demand from Aliso Canyon, and prioritize communities in the Aliso Canyon Disaster Area. They then suggest a mixed portfolio of incentives encompassing direct install incentives, single-measure equity incentives, and single-measure market rate incentives may be best in optimizing all priorities articulated in AB 157.[178]

VEIC agrees with the Joint Parties' argument that the TECH Initiative's "equity community" definition for AB 157 be directed toward a low-income direct install program, and notes low-income customers should be prioritized.

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[175] Cal Advocates Opening Comments on AB 157 Ruling at 4.

[176] CAC Reply Comments on AB 157 Ruling at 4.

[177] VEIC Reply Comments on AB 157 Ruling at 5.

[178] *Ibid.*

VEIC adds that if the Commission should determine that the AB 157 funding be subject to additional equity requirements, VEIC recommends the Commission consider implementation feasibility. For example, VEIC states utilizing existing equity definitions ensures consistency and allows the public and participating contractors to understand qualification requirements.[179]

8.3.3. Discussion

To help ensure the new AB 157 funding benefits the greatest number of customers and keeps administrative costs down, we decline to direct the TECH Initiative implementer to create a direct install program in the Aliso Canyon Disaster Area. However, as recommended by CAC, Cal Advocates, and Joint Parties, the equity customer definition requires more specificity to ensure funds are going to customers with the most need. As such, we direct the TECH Initiative implementer to require that a minimum 40 percent of all program costs be limited to low-income households with incomes at or below 80 percent of the area median income, as defined by HCD.[180]

Further, because the CEC's HEEHRA and Equitable Building Decarbonization (EBD) programs also target low-income households with income at or below 80 percent area median income, we believe using the same eligibility criterion will improve alignment across the three programs. We further direct the TECH Initiative implementer verify the incomes of all participants to ensure only true low-income customers qualify for the equity funding allocation.[181]

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179 VEIC Reply Comments on AB 157 Ruling at 6-7.

180 For the context of AB 157 within this decision, "low-income" is defined as households with incomes at or below 80 percent of the area median income, as defined by HCD.

181 Income-verification by the AB 157-funded TECH Initiative may not be needed if households' incomes are being verified by the CEC's HEEHRA or EBD programs.

We are not persuaded by the Joint Parties' recommendation to require the TECH Initiative to publish datasets and maps demonstrating which and how many households qualify as equity customers. We do not see the value of imposing these requirements on the TECH Initiative implementer, as they have already been doing this reporting. As for reporting on which specific households qualify as equity customers, while it may constitute an invasion of privacy, the TECH Initiative implementer already publicly reports installation data at the city level with at least one hundred participants to minimize identification of customers and contractors.[182] Moreover, the implementer also already visually reports installation data on the TECH Initiative's data reporting website.[183]

8.4. Authorization of New Measures

8.4.1. Summary of Opening Comments

Parties provided comments on whether further clarification is needed on what additional new measures for enabling comprehensive building electrification should be authorized by the Commission beyond energy audits, panel upgrades, and electrical wiring repairs.

ConnectDER recommends the Commission authorize MSAs as an additional measure.[184] ConnectDER contends these can help avoid panel and/or electric service line upgrades, and reduce the time "required to add clean generation or new electric load to an existing service by reducing the complexity

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[182] TECH Public Reporting Download Data, https://techcleanca.com/heat-pump-data/download-data/.

[183] *Ibid.*

[184] ConnectDER Opening Comments on AB 157 Ruling at 3.

and time to complete installation and limiting the work done inside customer premises."[185]

SPUR also recommends the Commission authorize MSAs and direct the TECH Initiative implementer to encourage or require contractors to use panel optimization planning processes and tools, explore options for incentivizing the use of load management technologies and power efficient equipment when possible and necessary to avoid panel upsizing costs, and limit subsidies for panel and service upgrades to households with under 200-amp service.[186]

PG&E recommends the Commission authorize new AB 157 funding to cover electric service line upgrades due to increased electric load from building electrification equipment, and explains such upgrades are a cost barrier to electrification retrofits for customers.[187]

Cal Advocates and SCE both recommend the Commission withhold expansion to new measures. If new measures are authorized, however, Cal Advocates states those new measures should contribute to market transformation efforts for clean heating technologies,[188] with SCE specifying electric clothes dryers and induction cooking appliances, for example, be made eligible as long as funding is prioritized for the highest GHG reduction potential technologies like heat pump space and water heaters.[189]

185 *Id.* at 8.

186 SPUR Opening Comments on AB 157 Ruling at 7-9.

187 PG&E Opening Comments on AB 157 Ruling at 1- 2.

188 Cal Advocates Opening Comments on AB 157 Ruling at 4-5.

189 SCE Opening Comments on AB 157 Ruling at 4.

VEIC recommends the Commission adopt the same measure list[190] for "comprehensive building electrification" as was adopted by the CEC for the EBD program, noting the Commission should establish that comprehensive building electrification is not required for all AB 157-funded projects.[191]

8.4.2. Summary of Reply Comments

CAC agrees with SPUR's approach to electrification in avoiding panel upgrades and right-sizing electric appliances, and argues that focusing solely on installing 120-volt HPWHs would help avoid costly panel upgrades.[192]

PG&E supports ConnectDER's proposal to authorize MSAs, but highlights that all MSAs must be subject to testing, evaluation, and piloting, as described in AL 6687-E.[193]

As for expanding the list of eligible measures necessary to enable comprehensive building electrification, CEJA supports alignment with the EBD program. CEJA notes that expanding eligible measures in such a manner would especially benefit low-income households who struggle to access whole home electrification upgrades.[194]

8.4.3. Discussion

We are persuaded by ConnectDER's recommendation to add MSAs as an additional measure, as doing so has the potential to help avoid additional costs in panel and/or electric service line upsizing. We are also persuaded by SPUR's general recommendations that there should be incentives for the use of load

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190 *See* Equitable Building Decarbonization Direct Install Program Guidelines submitted to the CEC on October 23, 2023, Docket Number 23-DECARB-03, at 13-17.

191 VEIC Opening Comments on AB 157 Ruling at 6.

192 CAC Reply Comments on AB 157 Ruling at 10-11.

193 PG&E Reply Comments on AB 157 Ruling at 1.

194 CEJA Reply Comments on AB 157 Ruling at 2-3.

management technologies and power efficient equipment when possible and necessary to avoid panel and electric service line upsizing costs. Therefore, we authorize the use of funds for MSAs, smart splitters, and any other load management device (being sure not to duplicate any available incentives) that can be deployed to avoid the need for panel and/or electric service line upsizing.

PG&E is correct that MSAs must be subject to testing, evaluation, and piloting as described in AL 6687-E, but we note this currently applies only to isolating load management devices. This decision expands this process and authorizes the remainder of the $3 million previously dedicated to funding these safety evaluations via D.21-01-018 (Adopting Rates, Tariffs, and Rules Facilitating the Commercialization of Microgrids per SB 1339) to apply to evaluating non-isolating devices such as MSAs that can help avoid electric service line upsizing.

PG&E's comments regarding cost barriers to electrification retrofits in the form of electric service line upgrade expenses are informative. We are mindful, however, that doing so could expend AB 157 funds rapidly while aiding only a limited number of customers. We therefore decline to include measures offsetting the cost of electric service line upgrades that could be triggered due to adoption of building electrification measures. MSAs and related devices should be the first recourse of customers electrifying their homes, and the cost of a necessary service line upsizing can be covered using the new funding authorized for eligible under-resourced customers as discussed in Section 4 of this decision.

Cal Advocates and SCE make an important point: even if the list of eligible measures is expanded, the TECH Initiative should still prioritize the market transformation of clean heating technologies with the highest GHG reduction potential. As such, we direct the TECH Initiative implementer to use the new

AB 157 funds to prioritize incentivizing heat pump space and water heaters for market rate customers while authorizing the expansion of eligible measures for low-income customers. While all customers regardless of income status shall be eligible to receive incentives for MSAs, smart splitters, and other load management devices using the new AB 157 funding, we direct the TECH Initiative implementer to use the measure list[195] developed for "comprehensive building electrification" for the CEC's EBD program for customers in the Aliso Canyon Disaster Area communities who have incomes at or below 80 percent of area median income.

This approach will ensure the market transformation of heat pump space and water heaters continues to occur, and the list of eligible measures is expanded to help avoid costly utility service upgrades and provide comprehensive building electrification to low-income households in the Aliso Canyon Disaster Area.

8.5. Programmatic Changes

8.5.1. Summary of Opening Comments

Parties filed comments on how "priority" should be determined for allocating funds in the Aliso Canyon Disaster Area, and how the Commission can ensure the expenditure of funds do not cause tenant displacement in upgraded rental housing units, as well as limiting cost impact on those tenants.

Cal Advocates recommends the Commission prioritize communities in the Aliso Canyon Disaster Area by allocating 100 percent of funds to the specified communities identified in AB 157 until June 30, 2027, and that after this date, if there are any remaining funds, then those should be made available to customers

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[195] *See* Equitable Building Decarbonization Direct Install Program Guidelines submitted to the CEC on October 23, 2023, Docket Number 23-DECARB-03, at 13-17.

in other parts of SoCalGas service territory.[196] SCE recommends the Commission use a needs-based approach prioritizing low-income and equity customers in addition to prioritizing communities within the Aliso Canyon Disaster Area.[197] CAC also recommends the Commission prioritize low-income households in the Aliso Canyon Disaster Area.[198]

Consistent with their other related recommendations, the Joint Parties recommend the TECH Initiative implementer should look at low-income households and communities in Porter Ranch and surrounding areas for electrification direct installs.[199] Lastly, VEIC, as part of the TECH Initiative implementation team, asks the Commission for high-level guidance that provides the TECH Initiative implementation team with flexibility to optimize the program to meet all the stated priorities in AB 157.[200]

To ensure the expenditure of funds does not cause displacement of tenants in upgraded rental housing units and that cost impacts on tenants remains limited, SCE[201] and TURN[202] recommend the Commission direct use of the "Split Incentives Agreement," as originally adopted in Resolution E-5043 for use in the San Joaquin Valley Disadvantaged Communities Pilot program adopted under D.18-12-015.

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[196] Cal Advocates Opening Comments on AB 157 Ruling at 5.

[197] SCE Opening Comments on AB 157 Ruling at 4.

[198] CAC Opening Comments on AB 157 Ruling at 16.

[199] Joint Parties Opening Comments on AB 157 Ruling at 6.

[200] VEIC Opening Comments on AB 157 Ruling at 8.

[201] SCE Opening Comments on AB 157 Ruling at 5.

[202] TURN Opening Comments on AB 157 Ruling at 2.

SCE and TURN explain the Split Incentives Agreement has also been used and required in SCE's ESA Building Electrification Pilot,[203] as well as the ESA Pilot Plus and Pilot Deep programs.[204] TURN recommends the Split Incentives Agreement should apply to all rental properties receiving AB 157-funded TECH Initiative measures,[205] arguing AB 157 did not distinguish between income groups but instead required protections for all tenants.[206]

Alternatively, the Joint Parties recommend the Commission use, as a baseline, protections established for the CEC's EBD program and adopted in the Solar on Multifamily Affordable Housing (SOMAH) program.[207] They note it is easier to require tenant protections in direct install programs as compared to appliance incentives, where they again reiterate their support for a low-income direct install program.[208] Specifically, the Joint Parties recommend the following minimum protections from the EBD and SOMAH programs:[209]

1. Protect Tenants from Evictions
    a. Landlords participating in the TECH Initiative cannot evict tenants for five years for any reason other than nonpayment, an illegal activity, or severe nuisance;
    b. Tenants should have clear information of the program and be able to contact the TECH Initiative implementer should any problem arise; and
    c. Landlords should be required to sign affidavits that they will not evict tenants other than for nonpayment

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203 SCE Opening Comments on AB 157 Ruling at 5.

204 TURN Opening Comments on AB 157 Ruling at 4.

205 *Id*. at 5-6.

206 *Ibid.*

207 Joint Parties Opening Comments on AB 157 Ruling at 7.

208 *Ibid.*

209 Joint Parties Opening Comments on AB 157 Ruling at 7-8.

and that tenants will be given contact information that they may reach out to when they receive eviction notices.

2. Rent Protection

    a. Tenants should not be subject to rent increases due to a TECH Initiative-funded project, and restrictions should mirror rent increase restrictions in the SOMAH program and be at least as stringent as restrictions to access the Low-Income Housing Credit.

        i. As an additional example, the Joint Parties note the property owner and tenant agreements that required the administrators in the San Joaquin Valley Pilot to ensure tenants would not experience increased rents or evictions for five years following appliance installations.

3. Avoid or Mitigate Temporary Displacement and Disruption

    a. If temporary displacement is needed to enable retrofits, the Joint Parties recommend the following requirements:

        i. The TECH Initiative and partner community-based organizations (if applicable) must be notified of the displacement so it is tracked and monitored; and

        ii. The tenant should be granted the right to return to the same unit with the same rent rate.

8.5.2. Summary of Reply Comments

Regarding the prioritization of funds, LADWP recommends making funds available on a first-come, first-served basis to incentivize early participation.[210] On tenant protections, LADWP explains it cannot regulate property owner and tenant protections, and instead defers to the City of Los Angeles's Housing

[210] LADWP Reply Comments on AB 157 Ruling at 4.

Department for managing these agreements. LADWP highlights their Comprehensive Affordable Multifamily Retrofits (CAMR) program, which requires participating property owners to maintain property affordability for at least 10 years after receiving CAMR funds.[211]

CAC supports use of the "Split Incentives Agreement" or a similar tenant protection agreement, as recommended by TURN, SCE, and the Joint Parties.[212]

8.5.3. Discussion

As noted earlier, AB 157 funds shall be implemented as upstream and midstream incentives that will be available on a first-come, first-served basis to the communities prioritized in AB 157. This is consistent with how the TECH Initiative has been administered for the last several years. Additionally, we are persuaded by Cal Advocates' position that 100 percent of these funds should be allocated to the specified communities identified in AB 157 until June 30, 2027, and after this date, if there are any remaining funds, those remaining funds should be made available to other customers in SoCalGas service territory.

Based on the similarities among the various proposals for tenant protections, we direct the TECH Initiative implementer to adopt and use the "Tenant Protection Agreement" attached as Appendix B. AB 157 states funds "shall not cause the displacement of tenants in upgraded rental housing units and shall be used to limit cost impacts on tenants." This agreement fulfills AB 157's mandate to prevent tenant displacement and rent increases tied to building upgrades. We will implement this by requiring any property owner, or property manager acting on behalf of the owner, seeking incentives to sign the

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211 *Ibid.*

212 CAC Reply Comments on AB 157 Ruling at 6-7.

Tenant Protection Agreement, as a condition of receiving the incentives. We will also require the TECH Initiative implementer to sign and use this agreement.

If a property owner, as defined in the agreement, violates these terms, the Commission, through the TECH Initiative implementer, may revoke or deny future participation in the TECH Initiative, and the TECH Initiative implementer would be authorized to seek the recovery of incentives. Because these conditions govern the use of public funds, they are within the Commission's authority: the Commission can require property owners to agree to these terms as a prerequisite for receiving incentives, and the Commission can withdraw funding if the owners fail to comply. This structure meets AB 157's displacement-avoidance goals without exceeding the Commission's jurisdiction.

This Tenant Protection Agreement ensures that, due to building retrofits conducted because of participating in the TECH Initiative, no tenant displacement attributable to the electrification project and no rent-based or other cost shifting for those upgrades shall occur. The agreement must clearly state that the Commission is neither interpreting nor applying local or state landlord-tenant law; and its enforcement is limited to eligibility for program incentives. Property owners and tenants remain subject to all existing rent-stabilization and eviction rules outside the Commission's purview.

Recognizing the strong public policy against displacing tenants or shifting costs, we also require property owners applying for incentives to provide the rental property's address so the TECH Initiative implementer can send notice to tenants. That notice should briefly describe the TECH Initiative, the subsidy program, and building electrification, and explain that the property owner or manager cannot evict or raise rents based on the property's participation in the program. The notice should direct tenants to contact the implementer if a property owner or manager allegedly violates these tenant protections. Although the Commission and the TECH Initiative program cannot give legal advice, the notice will provide general information to tenants, informing them that, as third-party beneficiaries to the agreement between the implementer and the property owner, the tenant may use a breach of that agreement—such as rent increases or evictions connected to the electrification retrofit—as a cause of action or defense in any unlawful detainer proceeding.

Tenant protections should be expanded to all customer groups regardless of income status and shall be expanded not only to all customers receiving incentives from AB 157, but to all TECH Initiative customers.

8.6. Contracting Agent Arrangements

8.6.1. Summary of Opening Comments

Parties filed comments on what new direction should be given to the TECH Initiative contracting agent to facilitate the transfer and accounting of the new TECH Initiative AB 157 funding. SCE, as the contracting agent, recommends the following direction from the Commission:

(1) Modify the existing contract with the TECH Initiative implementer to disburse the $40 million in new AB 157 funding in proportions consistent with D.23-02-005 *and* as recommended by SCE in their responses to the AB 157 ruling questions;

(2) Within 15 days of modifying the contract with the TECH Initiative implementer, file a Tier 1 advice letter seeking Energy Division approval of the modified contract and to update SCE's tariffs for AB 157's new TECH Initiative funding;

(3) Create a sub-account under the Building Decarbonization Pilot Program Balancing Account (BDPPBA) to differentiate the source and use of funds for AB 157's new TECH Initiative funding; and

(4) Work with the TECH Initiative implementer to identify and track within the BDPPBA, the source and use of funds.[213]

Cal Advocates recommends the TECH Initiative contracting agent should file a Tier 2 Advice Letter rather than a Tier 1 Advice Letter when seeking approval of contract execution or modification. Cal Advocates argues this will increase transparency on compliance with established program cost caps.[214]

8.6.2. Summary of Reply Comments

SCE opposes Cal Advocates' recommendation. SCE notes that under General Order (GO) 96-B, matters appropriate to Tier 2 Advice Letters include changes in rates, tariffs, and other matters listed in GO 96-B. SCE explains that under prior TECH Initiative funding decisions (i.e., D.20-03-027 and D.23-02-005), the filing of Tier 1 Advice Letters has allowed parties to comment and for Energy Division to ensure SCE's compliance with program requirements.[215]

LADWP replies by stating they defer to the TECH Initiative implementer on this question, arguing they are best positioned to identify any specific needs or adjustments for the TECH Initiative contracting agent.[216]

8.6.3. Discussion

We find merit in SCE's position that a Tier 2 Advice Letter is not necessary, and we direct the contracting agent to follow the same provisions listed in D.23-02-005 for all new requirements applicable to the use of AB 157 funds by filing a Tier 1 Advice Letter. Consistent with D.20-03-027 and D.23-02-005, we

[213] SCE Opening Comments on AB 157 Ruling at 5-6.

[214] Cal Advocates Opening Comments on AB 157 Ruling at 6.

[215] SCE Reply Comments on AB 157 Ruling at 3-4.

[216] LADWP Reply Comments on AB 157 Ruling at 5.

also direct SCE to place the AB 157 funds in an interest-bearing account for the benefit of the TECH Initiative implementer to be used for incentives.

8.7. Reporting Requirements

8.7.1. Summary of Opening Comments

Several parties made recommendations on what new reporting requirements should be imposed on the TECH Initiative implementer, including information on reducing winter natural gas demand from the Aliso Canyon natural gas storage facility, accelerating heat pump deployment, and providing equitable benefits to multi-family building residents, as required in AB 157.[217]

CAC recommends reporting on the following metrics:[218]

- MMcf (Million Cubic Feet) of gas reduced per gas storage withdrawal season;
- Number of heat pumps installed;
- Percentage of dollars spent on programs benefiting multi-family building residents; and
- Percentage of dollars spent in the Aliso Canyon Disaster Area.

In its recommended metrics, CAC does not specify where, when, or how frequently these should be reported. However, CAC identifies the gas storage withdrawal season as the winter months of November through March.

Cal Advocates recommends tracking the dollars spent in the Aliso Canyon Disaster Area and adding data on geographic participation. Cal Advocates recommends requiring the TECH Initiative implementer to include the total amount of funding authorized and the source of funds in their annual report,

217 AB 157 Sec. 99, Provisions 1(b)(iv).

218 CAC Opening Comments on AB 157 Ruling at 17.

and include line-item expenditures for program administrator, program implementation, and incentives to demonstrate compliance with cost caps.[219]

SCE recommends the TECH Initiative implementer report on the following:[220]

- Strategies employed to target communities in SoCalGas territory and the TECH Initiative dollars given to customers there;
- Strategies employed to prioritize communities in Aliso Canyon Disaster Area and the TECH Initiative dollars given to those communities;
- Strategies employed to prioritize efforts that reduce winter natural gas demand from the Aliso Canyon natural gas storage facility, accelerate heat pump deployment, and provide equitable benefits to multi-family building residents;
- Strategies and funding for workforce training targeted towards serving Aliso Canyon Disaster Area customers; and
- Strategies employed to prevent expenditure of funds from causing the displacement of tenants in upgraded rental housing units and limit cost impacts to tenants.

The Joint Parties highlight the requirement to reduce gas demand and recommend the TECH Initiative implementer be directed to report reductions in gas demand from participant gas bills in the months after installation.[221]

VEIC recommends the TECH Initiative implementer be directed to report on several metrics, including the number of projects completed and households served with AB 157 funding in the Aliso Canyon Disaster Area, success reducing

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219 Cal Advocates Opening Comments on AB 157 Ruling at 6.

220 SCE Opening Comments on AB 157 Ruling at 5-6.

221 Joint Parties Opening Comments on AB 157 Ruling at 8-9.

winter natural gas demand, success enabling comprehensive building electrification, success accelerating heat pump deployment, and the percent of funds benefiting equity communities.[222]

8.7.2. Summary of Reply Comments

In response to CAC, SCE, VEIC, and the Joint Parties, SoCalGas notes that while the proposed reporting on gas reduction is focused on the winter withdrawal season, the Aliso Canyon storage facility is also critical in supporting summer electric generation demand.[223]

CAC disagrees with VEIC that reporting on the number of projects and households is necessary as static numbers, arguing instead for the use percentages.[224] CAC explains that by assuming 100 percent of funds would be directed at electrification projects in the Aliso Canyon Disaster Area, tracking at the percentage level would be more accurate.[225] CAC also disagrees with VEIC that reporting on comprehensive building electrification is necessary and notes the Commission should not spend funds on its implementation or evaluation until all water heating is electrified.[226] Consistent with CAC's other related recommendation, CAC opposes VEIC's recommendation of reporting on the percentage estimated reduction in winter natural gas demand.[227]

CAC recommends the Commission define the geographic area where funds are made available. Contending that reporting on the number of projects is

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222 VEIC Opening Comments on AB 157 Ruling at 12-13.

223 SoCalGas Reply Comments on AB 157 Ruling at 2-3.

224 CAC Reply Comments on AB 157 Ruling at 9.

225 *Ibid.*

226 *Ibid.*

227 CAC Reply Comments on AB 157 Ruling 9-10.

unnecessary, CAC recommends 100 percent of funds to be spent reducing gas demand served by the Aliso Canyon natural gas storage facility.[228] Lastly, CAC supports VEIC's heat pump reporting recommendations, and notes instead that it should be separated out by heat pumps used for space and water heating, if the Commission does not require 100 percent of funds to be used for HPWHs.[229]

8.7.3. Discussion

We agree MMcf may be the most convenient unit to measure gas demand reduction, as noted by CAC, because it is one of the most typical units for measuring the load on the gas system. However, if the impacts are less than 0.01 MMcf, ccf (Centum Cubic Feet, i.e. hundreds of cubic feet) should be used, as this measurement can be readily convertible to/from MMcf. Although winter gas demand is higher than summer, both winter and summer demand should be reported. Additionally, since peak morning hours gas demand drives infrastructure need, the estimated reduction reporting should also include "peak morning hours" as defined by 5:00 a.m. through 10:00 a.m. on the coldest three weekdays of the previous year.[230] We direct the reporting of reduced gas demand to include hourly reduction during each hour between 5:00 a.m. and 10:00 a.m., so the Commission can identify the highest-demand hour and compare it with

[228] *Ibid.*

[229] CAC Reply Comments on AB 157 Ruling at 10.

[230] These gas peak hours drive the highest need for gas during cold winter days. A similar approach to gas peak hours is taken in Guidehouse, *Southern California Winter Gas Peak Savings Potential Analysis,* filed with the Commission on October 24, 2022, in I.17-02-002, which estimated "the potential for these energy efficiency (EE) and fuel substitution (FS) programs to reduce winter peak gas use beyond those impacts already generated by the existing IOU goals" in the Aliso Canyon service area. Gas peak demand curves for selected time periods may be viewed in CPUC Staff, *Winter 2020-2021 Southern California Gas Conditions and Operations Report*, dated October 24, 2022, (Figure 2), which also shows how gas is received during off-peak hours and consumed during peak hours (Figure 5).

adjacent hours. We direct utilities to report, for the three hottest summer days, the hourly demand across the same 5:00 a.m. to 10:00 a.m. window, averaged for each hour in that period. This information should be based on hourly collected data for each program participant. This data is critical in ensuring AB 157's intent to reduce demand from the Aliso Canyon natural gas storage facility is met.

Therefore, we direct the TECH Initiative implementer and evaluator to report on the estimated reduction of peak natural gas demand for winter and summer from the Aliso Canyon natural gas storage facility. This shall be done at the estimated ccf/hour level for each community identified in AB 157,[231] and include "peak morning hours" for summer and winter, as well as the hourly reduction during each of these hours. Reporting should also include the total annual average ccf/day or MMcf/day demand reduction.

In addition, we direct the TECH Initiative implementer and evaluator to report on the number of heat pump and non-heat pump installations, and the number of incentives provided to both single- and multi-family building residents. While providing equitable benefits to multi-family building residents is a requirement of AB 157, no party provided specific recommendations in this regard. As such, we believe reporting on the number of installations and incentives going to both single- and multi-family gives the Commission better insight into how funds are being distributed and make programmatic adjustments, as necessary.

At this point, we decline to adopt CAC's recommendation that reporting be done in percentages, because this is not a required component of AB 157, and

[231] These communities are: Porter Ranch, Granada Hills, Northridge, Chatsworth, North Hills, Canoga Park, Reseda, Winnetka, West Hills, Van Nuys, and Lake Balboa.

reporting on the number of installations is a more straightforward statistic that can always be converted to percentages.

Additionally, we direct the TECH Initiative implementer to report on the strategies undertaken to both prevent displacing tenants in upgraded rental housing units and limit the cost impact on tenants. As for additional reporting metrics, we direct adopting reporting requirements similar to what was previously outlined in D.23-02-005. More specifically, the TECH Initiative implementer and evaluator shall report, beginning with the second quarterly report in 2025, as available, the following information:

- The estimated reduction in peak natural gas demand for all seasons from the Aliso Canyon natural gas storage facility at the ccf/hour level for each City of Los Angeles community identified in AB 157, represented as the average across "peak morning hours" of 5:00 a.m. to 10:00 a.m. on the three coldest and three hottest days as well as the hourly reduction during each of those five hours, and the annual total average ccf/day or MMcf/day gas demand reduction in each of these communities;
- The number of heat pump installations, installations of individual eligible measures adopted by this decision, and number of incentives provided to both single- and multi-family building residents;
- Strategies employed to prevent expenditure of funds from causing the displacement of tenants in upgraded rental housing units and limit cost impacts to tenants;
- Strategies employed to target communities in the Aliso Canyon Disaster Area, and if applicable after 2027, to SoCalGas customers outside of the designated communities. Reporting should demonstrate how these strategies are supporting long-term market development for market-rate but also low-income customers;

- AB 157-funded TECH Initiative incentives given to low-income customers as a percentage of the total program funds;
- The geographic areas and project type (e.g., comprehensive home electrification, or installing heat pumps at a multi-family housing complex), where TECH Initiative funding was targeted and why; and
- Strategies and funding for workforce training targeted toward serving low-income customers.

9. ESJ Action Plan Goals

The issue of whether there are "potential impacts to ESJ communities and if so how best to incorporate the goals of the ESJ Action Plan 2.0 in developing the building decarbonization action plan" was examined as it relates to our actions in this decision. Rather than restating the discussions for each section set forth above and discussing how each section set forth in this decision affects under-resourced communities and broader ESJ communities, we incorporate the above discussions by this reference here and find this decision aligns with, furthers and promotes the Commission's ESJ Action Plan (Version 2.0), as exemplified below.

This decision integrates equity and access considerations (Goal #1). It prioritizes under-resourced customers by authorizing $5 million annually for four years to provide electric service line upgrades to qualifying customers transitioning to full electrification. The equity allocation for the TECH Initiative via AB 157 (40 percent minimum) ensures low-income households (≤ 80 percent of area median income) receive targeted electrification incentives. This ensures historically marginalized communities benefit from the clean energy transition.

The decision invests in clean energy and climate resiliency (Goals #2 and #4). It promotes clean energy investments by, for example, supporting panel upgrades, electrical wiring repairs, and load management devices to facilitate electrification; and allowing MSAs and smart splitters as cost-effective alternatives to electric service line upsizing, reducing infrastructure costs while supporting grid stability.

The decision enhances access to essential services (Goal #3). Subsidizing service line upgrades for under-resourced residential and small business customers ensures equitable access to safe, reliable electricity—especially critical for those in disadvantaged communities (DACs). The decision also aligns with programs supporting community-based outreach on building decarbonization.

The decision promotes economic opportunities (Goal #7). It supports workforce development by ensuring electrification incentives align with job training and employment programs. The funding structure for TECH Initiative includes workforce training, ensuring economic benefits for ESJ communities.

The decision ensures safety and consumer protection for all (Goal #6). The new service line upsizing rules prevent unnecessary costs to ratepayers in pursuit of greater affordability while ensuring customer protection.

Overall, this decision promotes the goals we adopted in our ESJ Action Plan by ensuring equity-centered building decarbonization, reducing financial and infrastructural barriers, and enhancing economic opportunities for disadvantaged communities. The electrification incentives and service line upsizing subsidies collectively ensure ESJ communities benefit equitably from California's clean energy transition.

10. Comments on Proposed Decision

The proposed decision of Commissioner Darcie L. Houck in this matter was mailed to the parties in accordance with Pub. Util. Code Section 311 and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on __________, and reply comments were filed on _____________ by ________________.

11. Assignment of Proceeding

Darcie L. Houck is the assigned Commissioner and Alberto T. Rosas is the assigned ALJ in this proceeding.

Findings of Fact

1. Electric service upsizing can be costly and time-consuming for both customers and utilities, and the high upfront costs of upsizing electric service lines pose significant financial barriers to building electrification, particularly for under-resourced residential and small business customers.
2. Service line upsizing is often necessary to support installation of electric heating, cooking, and other appliances, which are required for full building electrification while recognizing that avoiding unnecessary service upsizing is a priority for the Commission, as it reduces costs, minimizes delays, and optimizes grid utilization.
3. Failure to provide some cost relief for service line upsizing could disproportionately impact under-resourced communities and small businesses in disadvantaged areas, limiting access to equitable decarbonization benefits.
4. Allowing electric utilities to recover the cost of targeted service line upsizing through the rate base allows under-resourced customers to more fully participate in electrification programs despite infrastructure cost barriers.
5. Automatic enrollment in the all-electric baseline ensures electrified premises receive appropriate rate treatment.
6. With California electric rates at historic highs, certain service line upgrades may trigger unforeseen distribution infrastructure costs beyond the project site, necessitating budget controls to prevent disproportionate ratepayer impacts.

7. Capping the total funding available for electric service line upsizing ensures financial sustainability, prevents excessive ratepayer burden, and promotes equitable distribution of benefits.

8. Placing a per-project cap on single-family service upgrades allows the available funds to assist a greater number of eligible customers, including multi-family and small business projects.

9. Multiple ratepayer- and non-ratepayer-funded programs exist to assist under-resourced customers in electrification efforts, and each program utilizes its own criteria and verification process to determine income eligibility and qualification as an under-resourced customer.

10. Electric service upsizing requests can be triggered by factors other than electrification, including solar installation, energy storage systems, and other DERs, all of which can contribute to full electrification of a premise.

11. After the receipt of service upsizing applications, on-site utility personnel conducting service upsizing evaluations can efficiently collect data on existing service size and panel capacity without much additional administrative or operational burdens on utilities.

12. Under NEC 220.87, there is an alternative method for calculating existing residential load based on either hourly peak load measurements over one year or 15-minute peak load measurements over 30 days.

13. SDG&E currently provides 15-minute peak load data on customer bills.

14. Requiring 15-minute peak load data on PG&E and SCE customer bills requires updating metering infrastructure, IT systems, and billing systems to collect, store, and display residential customers' peak demand data.

15. Ensuring new electric utility smart meters are capable of capturing and logging 15-minute interval usage and demand data provides flexibility for potential future use without immediate cost implications.

16. Currently, electric utilities do not systematically collect and record the capacity of customer electrical service lines, which limits the utilities' ability to analyze service upgrade trends and grid impacts.

17. Systematic data collection will improve data accuracy for processes such as future grid planning, infrastructure investment planning, policy decisions, and equitable access to grid capacity.

18. In D.21-01-018, the Commission approved $3 million in funding for PG&E, SCE, and SDG&E to evaluate technologies that enable electrical isolation of a premise during grid outages, which currently does not cover the evaluation of non-isolating technologies that interface with utility equipment.

19. Resolution E-5194 outlines the process and criteria for evaluating the safety and reliability of electric isolation technologies before they can be deployed or implemented, but this process does not extend to non-isolating technologies.

20. Non-isolating devices, such as meter socket adapters with distributed energy resource capabilities, can support the state's decarbonization goals by facilitating electrification, optimizing energy use, and reducing the need for unnecessary panel and service upsizing.

21. D.21-01-018 directed PG&E, SCE, and SDG&E to submit Tier 2 Advice Letters to request additional funding for safety evaluations of isolating devices, ensuring adequate resources for rigorous testing and grid safety; but the need for expanded safety evaluations now includes non-isolating devices that interface with utility equipment.

22. Resolution E-5194 requires PG&E, SCE, and SDG&E, along with suppliers, to submit an informational filing in R.19-09-009 when a utility terminates an evaluation process for an electrical isolation device without approving it for deployment, or when progress has ceased after an evaluation process lasted more than six months.

23. Providing a publicly accessible list of approved non-isolating devices will enhance transparency, streamline the customer decision-making process, and prevent installation of non-compliant or unsafe devices.

24. MSAs can facilitate customer electrification by providing a cost-effective alternative to electric panel upgrades and service line upsizing.

25. Resolution E-5194 establishes a safety evaluation process for utility-approved devices and ensures only MSAs meeting the required safety and operational standards are allowed for installation.

26. MSAs approved through the Resolution E-5194 safety evaluation process require standardized installation procedures to ensure safe and effective deployment across all utility service territories.

27. PG&E, SCE, and SDG&E maintain electric service requirement manuals that provide technical and procedural guidance for customers, contractors, and utility personnel on installing utility-approved devices.

28. Currently, customers and contractors have limited access to information about strategies for avoiding service upsizing, such as load management technologies, panel optimization, and the use of smart devices.

29. Under OP 5 of D.23-12-037, the existing energization deadline for mixed-fuel new construction projects seeking electric line extension subsidies is no later than 12 months after July 1, 2024.

30. The building process frequently experiences unforeseen delays in energization due to factors beyond developers' control, such as supply chain disruptions, material shortages, labor constraints, permitting delays, and project complexities.

31. More frequent and granular reporting on electric line extension subsidy expenditures for mixed-fuel new construction projects is necessary to enhance transparency and enable the Commission to assess trends, expenditures, and project completion timelines more effectively.

32. Resolution E-5105 established a reporting deadline of September 1 of every year for various decarbonization-related data; D.21-11-002 established a reporting deadline of February 1 of every year for new customer data relating to appliance usage; and D.23-12-037 established a reporting deadline of May 1 of every year for data relating to line extension requests and subsidies.

33. To ensure electrification incentives reach customers with the most need, D.23-02-005 established an expanded definition of equity customers, which includes but is not limited to low-income households.

34. The TECH Initiative has historically been limited to providing incentives for heat pump space and water heaters, as specified in Public Utilities Code Section 922, and AB 157 expanded its scope of eligible electrification measures by allocating funds for additional technologies that support comprehensive building electrification.

35. Load management devices, such as MSAs and smart splitters, can help customers avoid costly electric service line upsizing by optimizing a customer's existing electrical infrastructure.

36. The CEC's EBD program includes a list of eligible measures that support comprehensive electrification for low-income customers, particularly in the Aliso Canyon Disaster Area.

37. Aligning eligible measures under the TECH Initiative with the CEC's EBD program ensures consistency in incentive offerings and expands access to critical electrification technologies for low-income households.

38. AB 157 mandates prioritizing funds for specific communities in the City of Los Angeles: Porter Ranch, Granada Hills, Northridge, Chatsworth, North Hills, Canoga Park, Reseda, Winnetka, West Hills, Van Nuys, and Lake Balboa.

39. The TECH Initiative contracting agent previously implemented similar directives under D.23-02-005 and supports continuing these procedures with the additional AB 157 funds.

40. Ensuring that the new AB 157 funds are allocated, tracked, and managed in a manner consistent with previous funding mechanisms will support program continuity, fiscal accountability, and efficient fund distribution.

41. AB 157 requires that funds "shall not cause the displacement of tenants in upgraded rental housing units and shall be used to limit cost impacts on tenants."

42. Creating a sub-account within the BDPPBA will allow for transparent tracking of AB 157 funds separately from other funding sources.

43. Placing the AB 157 funds in an interest-bearing account ensures that accrued interest can further support program incentives, maximizing the impact of available funds.

44. This decision aligns with the Commission's ESJ Action Plan (Version 2.0) by ensuring equity-centered building decarbonization, reducing financial and

infrastructural barriers to the ESJ communities, and enhancing economic opportunities for disadvantaged communities.

45. The electrification incentives and service line upsizing subsidies collectively ensure ESJ communities benefit equitably from California's clean energy transition.

Conclusions of Law

1. It is reasonable and equitable to provide cost relief for under-resourced residential and small business customers to upsize their electric service lines to facilitate full building electrification.

2. It is reasonable to require any additional costs passed on to ratepayers be carefully managed to balance affordability with decarbonization goals.

3. It is reasonable to require ratepayer-funded electrification programs be designed to maximize benefits across a broad number of customers, ensuring equitable access to electrification assistance while not increasing rates unreasonably.

4. It is reasonable to extend common facility cost treatment to under-resourced residential and small business customers to ensure they receive the necessary support to overcome financial barriers to electrification.

5. It is reasonable to offer common facility cost treatment starting July 1, 2025, and continuing through the end of 2029, under the parameters described in Section 4.3 of this decision, up to a per project cost cap of $10,000 to ensure the limited funding benefits and is made use of by the maximum number of customers.

6. Requiring full electrification and termination of gas service as a condition for ratepayer-funded electric service upsizing is consistent with state decarbonization goals and prevents redundant infrastructure investments.

7. It is reasonable to require automatic enrollment in the all-electric baseline within 60 days of service restoration.

8. It is reasonable and necessary to impose a time-limited cost relief period.

9. It is reasonable to: (a) impose an annual funding cap for service line upsizing; (b) set a per-project funding cap for single-family homes; and (c) establish this initial program for a four-year test period.

10. It is reasonable to (a) adopt existing definitions of under-resourced customers from the programs providing electrification incentives, rather than establishing a separate definition, and (b) require that verification criteria from these programs be used to ensure consistent eligibility determination and administrative efficiency.

11. It is reasonable to require policies being tested on a pilot basis to clearly identify the necessary data to evaluate its effectiveness for potential long-term adoption, specifying responsibilities for data collection and methodology.

12. It is reasonable to require electric utilities to collect certain data during the electric service upsizing process.

13. It is unnecessary to require utilities to verify customer income directly, as income verification is already conducted through other electrification incentive programs.

14. It is unnecessary to limit common facility cost treatment for appliance electrification only.

15. It is reasonable to require utilities to track the specific technologies and end uses that necessitate electric service upsizing.

16. It is reasonable to return funds remaining in Balancing Accounts after the policy's sunset date to ratepayers.

17. It is reasonable to require electric utilities to report additional data to the Commission.

18. It is reasonable to require electric utilities to install smart meters capable of logging at least 15-minute interval data without the need of further physical or on-site intervention to enable this capability consistent with any requests made in the utility's next general rate case.

19. When replacing smart meters that reach the end of their life cycle, all electric utilities should take actions necessary to ensure newly installed meters are fully capable of logging at least 15-minute interval average demand and energy usage data without requiring further physical or on-site intervention to enable this capability; these utilities, however, should not be required to begin collecting or reporting this data unless directed by the Commission in a future decision.

20. It is reasonable to (a) require electric utilities to begin collecting and recording: (i) the capacity of newly installed or replaced electrical service lines; and (ii) the original capacity of the electrical service line that was replaced; and (b) require utilities to link service line capacity records to a service location and meter identification number.

21. It is reasonable to require electric utilities to record and report the total number and amperage of existing and newly installed electrical service lines ("pre" and "post" installation); and it is reasonable to integrate this reporting requirement into utilities' annual submissions, aligning with Resolution E-5105 reporting requirements.

22. It is reasonable to require electric utilities (a) to include the information found in Appendix A of this decision as part of the annual reporting required under Resolution E-5105; and (b) to submit all information required under

Resolution E-5105 and Appendix A of this decision as a Tier 1 information-only Advice Letter.

23. It is reasonable to adopt April 15 as the annual deadline for all reporting requirements set in this proceeding.

24. It is reasonable to require reports mandated by OP 8 of D.23-12-037 to be on a quarterly cadence, given the importance of tracking proliferation of all-electric construction due to line extension elimination policies.

25. It is reasonable to extend the safety evaluation process outlined in Resolution E-5194 to include non-isolating devices; and it is also reasonable to allow PG&E, SCE, and SDG&E to use the existing $3 million funding authorized in D.21-01-018 to evaluate non-isolating devices, especially those that enable decarbonization and help avoid unnecessary service upsizing.

26. It is reasonable to allow utilities to request flexibility in evaluation timelines on a scenario-specific case-by-case basis.

27. It is reasonable to require utilities to consult with Energy Division before making the extension requests with regard to evaluating non-isolating devices, and to provide specific justification for such extension requests, including the reason for the delay and the anticipated new timeline for completing the evaluation.

28. It is reasonable for electric utilities to complete evaluations of non-isolating devices in a timely manner.

29. It is reasonable to require electric utilities to provide regular progress reports on evaluation activities, requiring quarterly reporting during the early years of the evaluation process (2025-2026).

30. It is reasonable to extend the provisions of D.21-01-018, permitting PG&E, SCE, and SDG&E to submit Tier 2 Advice Letters for additional safety evaluation

funding, to also include non-isolating devices; and it is reasonable to require that utilities provide detailed budget justifications for any requested increases, ensuring that funding is necessary, appropriate, and aligned with safety evaluation objectives.

31. It is reasonable to (a) extend the reporting requirements established in Resolution E-5194 to non-isolating devices; (b) require PG&E, SCE, and SDG&E to file final evaluation reports for all outcomes of the evaluation process, including devices that are approved, not approved, or for which evaluation has ceased; and (c) require utilities and suppliers to submit these reports within 60 days of the conclusion of the evaluation process.

32. It is reasonable to require PG&E, SCE, and SDG&E to publicly list all non-isolating devices that have received investor-owned utility approval; and it is reasonable to require that these publicly-available lists be updated regularly.

33. It is reasonable to require that (a) PG&E, SCE, and SDG&E publicly list all devices approved through the Resolution E-5194 utility safety evaluation process; (b) each utility file a Tier 1 Advice Letter within 180 days, detailing how they have complied with this website requirement; and (c) the public website be easy to use and freely accessible without login credentials, while providing broad access to this public safety information.

34. It is reasonable to (a) establish new tariffs that support the installation of customer-owned MSAs; (b) require that these tariffs apply only to MSAs that have been approved through the Resolution E-5194 safety evaluation process; and (c) require utilities to submit a Tier 2 Advice Letter within 90 days.

35. It is reasonable to (a) require PG&E, SCE, and SDG&E to update their respective electric service requirement manuals to include installation processes and procedures for customer-owned MSAs approved through the Resolution

E-5194 safety evaluation process; and (b) require utilities to file a Tier 1 Advice Letter within 90 days.

36. It is reasonable to require the TECH Initiative implementer to select educational materials that inform customers and contractors on alternatives to electric service upsizing, encouraging them to avoid service upsizing if feasible, and that these materials be made available on each utility's website.

37. It is reasonable to require utilities to inform customers and contractors about available alternatives to service upsizing before accepting an application for service upsizing; and it is reasonable to require applicants to acknowledge receipt and review of educational materials on service upsizing alternatives, promoting public awareness.

38. It is reasonable to extend the energization deadline for mixed-fuel new construction projects seeking electric line extension subsidies, set by OP 5 of D.23-12-037 (setting a deadline of 12 months after July 1, 2024), by adopting a 36-month extension to account for delays caused by factors beyond developers' control, such as material shortages, permitting issues, and project complexities, thereby providing a new energization deadline of no later than 36 months after July 1, 2024.

39. It is reasonable to (a) modify the reporting requirements established in OP 8 of D.23-12-037 to require quarterly reporting with more detailed, disaggregated data; (b) require data to be broken down by month, baseline territory, and project type (single-family vs. multi-family); and (c) require utilities to track and report the average time between contract payment and project energization.

40. It is reasonable to require gas investor-owned utilities to inform electric utilities of the final disposition of applications for projects that are granted an exemption from gas line subsidy elimination.

41. It is reasonable to establish a clear and standardized process for notifying electric utilities of these exemption decisions.

42. It is reasonable to consider new construction projects that use propane to power any appliances other than an outdoor grill as mixed-fuel projects, making them ineligible for electric line extension subsidies after July 1, 2024.

43. It is reasonable to distinguish between mixed-fuel projects and otherwise all-electric buildings that use a fuel other than gas or propane for backup electricity generation, ensuring that backup generation does not disqualify an otherwise all-electric building from subsidy eligibility.

44. It is reasonable to extend the cost caps previously established for the TECH Initiative implementer, contracting agent, and evaluator in D.20-03-027 and D.23-02-005.

45. It is reasonable to require that the remaining AB 157 funds be allocated only toward program incentives, the administration of tenant protections, and workforce, education, and training efforts.

46. It is reasonable to require that a minimum of 40 percent of all program costs be allocated to low-income households with incomes at or below 80 percent of area median income; and this approach would align with the CEC's HEEHRA and EBD programs that are also aimed at low-income households with incomes at or below 80 percent of area median income.

47. It is reasonable to waive income verification requirements for households whose incomes have already been verified under the CEC's HEEHRA or EBD programs.

48. It is reasonable to authorize the use of AB 157 funds for load management devices that can help customers avoid the need for electric service line upsizing.

49. It is reasonable to adopt the eligible measures list from the CEC's EBD program for qualifying low-income customers in the Aliso Canyon Disaster Area, as enabled by AB 157.

50. It is reasonable to continue implementing the TECH Initiative as an upstream and midstream incentive program, as required by Public Utilities Code Section 922, with availability on a first-come, first-served basis.

51. It is reasonable to allocate 100 percent of AB 157 funds to the communities specified in the legislation until June 30, 2027, addressing the immediate needs of impacted communities, while allowing any remaining funds to be made available to other customers in SoCalGas service territory after June 30, 2027.

52. It is reasonable for the Commission to require tenant protections as a condition of receiving building electrification incentives through the TECH Initiative.

53. It is reasonable to adopt a Tenant Protection Agreement, found in Appendix B, that prohibits property owners (and property managers) from shifting electrification costs to tenants or evicting them for reasons tied to the retrofit, and to extend these protections not only to customers receiving incentives through AB 157 but to all TECH Initiative customers.

54. It is reasonable to direct the TECH Initiative contracting agent to follow similar provisions as outlined in D.23-02-005.

55. It is reasonable to (a) require the TECH Initiative contracting agent to modify the existing contract with the TECH Initiative implementer and evaluator; (b) require the creation of a sub-account within the BDPPBA; (c) require that AB 157 funds be held in an interest-bearing account; and (d) require

that all accrued interest is used to further support building electrification incentives.

56. It is reasonable to require the TECH Initiative implementer and evaluator to submit quarterly reports on AB 157-funded projects that include data on the reductions in peak natural gas demand, particularly in the Aliso Canyon Disaster Area; heat pump installations; workforce training efforts; incentives provided to under-resourced customers; anti-displacement strategies to prevent negative impacts on tenants in upgraded rental housing; and detailed geographic and demographic reporting on program implementation.

57. This decision aligns with the Commission's ESJ Action Plan (Version 2.0) and furthers the following ESJ Action Plan goals:

- Goal #1: integrating equity and access considerations;
- Goals #2 and #4: investing in clean energy and climate resiliency;
- Goal #3: enhancing access to essential services;
- Goal #6: ensuring safety and consumer protection for all; and
- Goal #7: promoting economic opportunities.

58. All assigned Commissioner and Administrative Law Judge rulings issued to date should be affirmed.

59. The proceeding should remain open.

O R D E R

IT IS ORDERED that:

1. This decision authorizes up to a total of $5 million annually, as a statewide annual maximum, for four years to be divided amongst Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities LLC, PacifiCorp, and Bear Valley Electric Service Inc.

to provide cost relief for electric service line upsizing to qualified under-resourced customers pursuing full electrification of their home or business through a building decarbonization program, as defined in Section 4.3.

2. Starting July 1, 2025, and continuing through December 31, 2029, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities LLC, PacifiCorp, and Bear Valley Electric Service Inc. shall each: (a) offer common facility cost treatment for under-resourced customers whose participation in an electrification program triggers the need for service line upsizing; and (b) establish a Common Facility Cost Treatment Balancing Account to track expenditures resulting from this policy. The costs associated with upsizing the electric service line for under-resourced residential and small business premises, as defined in this decision, shall be subject to the following financial limitations:

(a) The total amount of ratepayer-funded service line upsizing assistance shall be capped at $5 million annually, allocated proportionally among the investor-owned electric utilities;

(b) Any unspent funds may be carried over into the following years until fully expended or December 31, 2029, whichever comes first, and any funds not fully expended by December 31, 2029, shall be returned to ratepayers;

(c) Single-family projects shall be subject to a per-project cap of $10,000 in ratepayer-funded assistance toward electric service line upsizing; and

(d) Each of the aforementioned utilities' administrative costs are hereby capped at a quarter of a percent (0.25 percent) of all of its respective expenditures.

3. Within 60 days of the issuance of this decision, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities LLC, PacifiCorp, and Bear Valley Electric Service Inc.

shall submit a Tier 1 Advice Letter to the Energy Division establishing Common Facility Cost Treatment Balancing Accounts for the amounts described in Table 4.3.1 of Section 4.3 of this decision.

4. Starting July 1, 2025, and ending on June 30, 2029, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities LLC, PacifiCorp, and Bear Valley Electric Service Inc. shall annually deposit their proportional shares into the Common Facility Cost Treatment Balancing Accounts and shall use the monies set aside in the Common Facility Cost Treatment Balancing Accounts to fund utility-side costs not already covered by existing allowances for those premises where the following conditions are met:

(a) The existing capacity of the premises' service line is less than 100 amperes (amps);

(b) The upsized capacity does not exceed 200 amps;

(c) The premise, or premises, undergo full electrification through a Program, or Programs, as defined in Section 4.3, that results in the permanent termination of gas service for an under-resourced customer; and

(d) The electric utility serving the premise, or premises, shall ensure that the customer is automatically enrolled in the all-electric baseline no later than 60 days after service is restored, following completion of the service line upsizing and replacement of all gas appliances in the building.

5. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities LLC, PacifiCorp, and Bear Valley Electric Service Inc. shall track and report customer participation in a Program, or Programs, as defined in Section 4.3 of this decision, by asking the customer specific questions during the request for service line upsizing process, as a way to determine customer eligibility for common facility cost treatment.

6. Starting in 2026, April 15 is the new annual deadline for all reporting requirements established in this proceeding, which includes reports for Resolution E-5105, Appendix C and D reporting requirements for Decision (D.) 21-11-002, reporting required by Ordering Paragraph (OP) 8 of D.23-12-037, and the additional requirements established in OP 7 of today's decision. For quarterly reports, such as the revised D.23-12-037 reporting deadlines established in OP 28 of today's decision, the April 15 deadline shall align with the close of the fourth quarter reporting for the prior calendar year and shall also include annual summaries.

7. Starting in 2026, by April 15 of each year, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and Southern California Gas Company shall file a Tier 1 information-only Advice Letter containing all reports and data required under this proceeding, including the new data collection requirements detailed in this decision's Appendix A, with the annual reporting required under Resolution E-5105. Appendix A reporting requirements are applicable to PG&E, SCE, SDG&E, Liberty Utilities LLC, PacifiCorp, and Bear Valley Electric Service Inc., and will automatically sunset after the final report, which shall be submitted after the authorized funds have been fully expended, or after four years, whichever comes first.

8. Energy Division staff is authorized to update the reporting requirements established by Resolution E-5105 and this decision, by notifying the service list of this proceeding, and providing the new template on the California Public Utilities Commission's Building Decarbonization website as soon as practicable. If no new reporting requirements are provided, the prior reporting requirements shall remain in effect.

9. Within 90 days of the issuance of this decision, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities LLC, PacifiCorp, and Bear Valley Electric Service Inc. shall file a Tier 1 Advice Letter providing responses to the questions outlined in Section 5.2.3, regarding: customer meters, 15-minute interval data, true peak demand data, data storage and systems updates, and green button data updates. The aforementioned utilities shall collaborate with the California Public Utilities Commission's Energy Division to ensure the submitted information fully addresses all relevant topics necessary for evaluating future policies on customer access to peak demand data, as those topics are set out in Section 5.3.3.

10. When replacing electric smart meters that reach the end of their life cycle, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities LLC, PacifiCorp, and Bear Valley Electric Service Inc. shall only install meters that are fully capable of logging at least 15-minute interval average demand and energy usage data without requiring further physical or on-site intervention to enable this capability. The aforementioned electric utilities may begin collecting or reporting this data at a later time, when expressly directed to do so by the Commission.

11. When installing new electric service lines or replacing existing electric service lines, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities LLC, PacifiCorp, and Bear Valley Electric Service Inc. shall (a) no later than 90 days from the issuance of this decision, begin recording the capacity (in amperage) of the existing and newly installed service lines for each incoming customer application, and link this information with the corresponding service location, unique project identification (ID) number, and meter ID number; and (b) no later

than one year from the issuance of this decision, make this information easily accessible through a customer's online portal.

12. Within 90 days of the issuance of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each update their respective electric service requirement manuals to include descriptions of customer-owned meter socket adapter installation processes and procedures, and shall each file a Tier 1 Advice Letter, demonstrating compliance with the aforementioned updates to their electric service requirement manuals.

13. Resolution E-5194 is modified and expanded to include evaluation of customer-owned devices that interface with utility equipment, do not have grid isolation capabilities, and require explicit utility approval ("non-isolating devices"). Such non-isolating devices include, but are not limited to, meter socket adapters with distributed energy resource capabilities. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall evaluate and approve non-isolating devices for safety and compatibility in the same manner as isolating devices. All reporting, safety evaluations, technology review, and other requirements and applicable processes described in Resolution E-5194 shall apply to isolating and non-isolating devices.

14. Decision (D.) 21-01-018 is modified, and the funding it previously authorized is extended to apply to non-isolating devices in addition to isolating devices. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) are authorized to (a) use the existing $3 million in funding approved in D.21-01-018 to conduct safety and reliability evaluations of these non-isolating devices, and (b) prioritize safety evaluations for non-isolating devices that directly enable

decarbonization and facilitate electrification efforts. All directions in D.21-01-018 allowing PG&E, SCE, and SDG&E to submit Tier 2 Advice Letters requesting additional funding for safety evaluations shall continue to apply.

15. Within 90 days of the issuance of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 Advice Letter to establish a new tariff supporting the installation of customer-owned meter socket adapters, both isolating and non-isolating, which shall describe the process and requirements a customer must follow to install any device approved through the Resolution E-5194 safety evaluation process.

16. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall each file a Tier 1 Advice Letter if they seek an extension of time to complete an evaluation for a specific device. Prior to filing this letter, PG&E, SCE, and SDG&E shall consult with Energy Division to discuss the need for an extension. The Advice Letter shall include detailed justification for the requested extension, including reasons for the delay, steps taken to complete the evaluation, and new timeline for completion. This extension request process shall apply to both isolating and non-isolating devices.

17. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall submit Tier 1 Advice Letters to report on their progress in evaluating non-isolating devices, including activities completed in the prior reporting period and anticipated activities for the next reporting period, as outlined in Section 5.3.3. For 2025 and 2026, PG&E, SCE, and SDG&E shall submit these Tier 1 Advice Letters on a quarterly basis, with the first report due on July 15, 2025, covering

the first two quarters of 2025. Beginning January 15, 2027, PG&E, SCE, and SDG&E shall transition to annual reporting, continuing until all approved evaluation funds are expended.

18. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company may submit Tier 2 Advice Letters requesting additional funding for safety evaluations, as originally authorized in Decision 21-01-018. This additional funding shall apply to both isolating and non-isolating devices. Each Tier 2 Advice Letter shall include detailed justification in support of any request for budgetary increases.

19. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each submit an informational report, jointly with suppliers, to the service lists in this proceeding and Rulemaking 19-09-009, and to the California Public Utilities Commission's Energy Division at energydivisioncentralfiles@cpuc.ca.gov that includes the final evaluation report following the process outlined in Resolution E-5194 for all isolating and non-isolating devices that have been either approved for deployment, not approved, or for which evaluation has ceased, as described in Section 5.3.3 of this decision. Each informational filing shall be submitted no later than 60 days after the evaluation process for the device has concluded.

20. Within 180 days of the issuance of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall publicly list on their respective websites all non-isolating devices that have received Investor-Owned Utility approval, as described in Section 5.4.3 of this decision. Each utility shall ensure this list is updated to reflect newly approved devices and any changes in approval status within 30 days of the approval or change.

21. Within 180 days of the issuance of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall file a Tier 1 Advice Letter outlining compliance with the website requirements detailed in Section 5.4.3. Each of these utilities shall maintain a dedicated public webpage listing all devices approved for utility use through the Resolution E-5194 safety evaluation process. This public webpage information shall be freely accessible without access restrictions, login credentials, or other barriers.

22. Within 90 days of the issuance of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file a Tier 2 Advice Letter establishing a new tariff to support the installation of customer-owned meter socket adapters. The new tariff shall clearly outline the process, requirements, and responsibilities for customers and contractors to install devices that have been approved through the Resolution E-5194 safety evaluation process.

23. Within 90 days of the issuance of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company each shall:

(a) Update their respective electric service requirement manuals by providing detailed guidance on meter socket adapter installation requirements and descriptions of installation processes and procedures for all customer-owned devices approved for use through the Resolution E-5194 safety evaluation process; and

(b) File a Tier 1 Advice Letter demonstrating compliance with the manual updates in accordance with this order.

24. Energy Division staff will work with the Technology and Equipment for Clean Heating (TECH) Initiative implementer to create and maintain a website

that contains resources about alternatives to electric service and panel upsizing. This website link will be shared with the service list of this proceeding no later than 180 days from the issuance of this decision, or as soon thereafter as practicable. The TECH Initiative implementer may use existing or upcoming studies and resources to avoid duplication of efforts.

25. Within 270 days of the issuance of this decision, or within 90 days after the Technology and Equipment for Clean Heating (TECH) Initiative implementers share the website link with this proceeding's service list, whichever comes first, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities LLC, PacifiCorp, and Bear Valley Electric Service Inc. shall appropriately link and reference the website link created by the TECH Initiative implementer containing resources about alternatives to electric service and panel upsizing. The aforementioned electric utilities shall post this link at web locations customers are likely to visit in the process of requesting service line upsizing, such as on the utility application web portals for service upsizing requests.

26. Within 270 days of the issuance of this decision, or within 90 days after the Technology and Equipment for Clean Heating (TECH) Initiative implementer shares the website link to its resources for alternatives to upsizing, whichever comes first, Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Liberty Utilities LLC, PacifiCorp, and Bear Valley Electric Service Inc. shall revise its application for service upsizing to include (a) the TECH Initiative implementer's materials summarizing strategies to avoid service upsizing and informing applicants requesting a service upsizing about available alternatives, and (b) an applicant attestation form confirming the applicant reviewed the materials and considered available

alternatives before proceeding with the service upsizing request. The aforementioned electric utilities shall make this attestation form a requirement for all applicants seeking a service line upsizing.

27. Ordering Paragraph 5 of Decision 23-12-037 is modified to extend the deadline it sets, and mixed-fuel new construction projects with contracts approved and fully paid for prior to July 1, 2024, shall have until June 30, 2027, which equates to 36 months from July 1, 2024, as the new extended deadline to energize the project.

28. Ordering Paragraph (OP) 8 of Decision (D.) 23-12-037 is modified and the annual May 1 deadline it sets is now changed to a quarterly deadline, with the fourth quarter report including an annual summary and aligning with the April 15 annual reporting established in OP 6 of today's decision. Beginning in the year 2025, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each do the following:

(a) submit quarterly reports containing data as required in OP 8 of D.23-12-037, disaggregated by month;

(b) submit the same monthly data broken down by baseline territory and distinguish single-family data from multi-family data; and

(c) as part of quarterly reports, provide data on the average number of days between when a contract for a building project is fully paid and when that project is energized.

29. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Gas Company shall notify all electric utilities operating in their service territory, including both investor-owned utilities and publicly owned utilities, of the final disposition of any application submitted to the California Public Utilities Commission pursuant to Ordering Paragraph 2 of Decision 22-09-026 seeking an exemption from gas line subsidy elimination for

one or more building projects. Notification shall occur within 30 days of the Commission's issuance of a decision on each relevant application.

30. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall refer to Resolution E-5352 for guidance on how to interpret what building projects should be considered "mixed-fuel" for purposes of implementing Decision 23-12-037. "Mixed-fuel" new construction shall not include otherwise all-electric building projects that use gas or propane solely for backup electricity generation.

31. The cost caps established in Decision (D.) 20-03-027 and continued in D.23-02-005 shall apply to the use of Assembly Bill (AB) 157 funds for the Technology and Equipment for Clean Heating (TECH) Initiative as follows:

(a) 10 percent for administrative costs of the implementer;

(b) 1 percent for administrative costs of the contracting agent; and

(c) 2.5 percent for program evaluation. The TECH Initiative implementer shall ensure that the remaining AB 157 funds are allocated exclusively for the following purposes: program incentives; the administration of tenant protections; and workforce, education, and training efforts.

32. As to the new Technology and Equipment for Clean Heating (TECH) Initiative funding provided by Assembly Bill 157, a minimum of 40 percent of all program costs, shall be allocated to low-income households with incomes at or below 80 percent of area median income, as defined by the California Department of Housing and Community Development.

(a) The TECH Initiative implementer shall verify the incomes of all participants to determine eligibility for low-income program benefits; and

(b) Income verification shall not be required for households whose income has already been verified under the California

Energy Commission's Home Electrification and Appliance Rebates or Equitable Building Decarbonization programs.

33. The Technology and Equipment for Clean Heating (TECH) Initiative implementer is authorized to provide the following as additional measures to all TECH Initiative customers: meter socket adapters, smart splitters, and any other load management device that can be deployed to avoid the need for electric service line upsizing, provided that the use of funds for these devices does not duplicate any available incentives. The eligible measures list for comprehensive building electrification under the California Energy Commission's Equitable Building Decarbonization program is hereby adopted for qualifying low-income customers in the Aliso Canyon Disaster Area.

34. The Technology and Equipment for Clean Heating (TECH) Initiative, funded by Assembly Bill (AB) 157, shall continue to be implemented as an upstream and midstream incentive program, per Public Utilities Code Section 922, and shall be available on a first-come, first-served basis. Until June 30, 2027, one hundred percent of funds shall be allocated exclusively to the City of Los Angeles communities identified in AB 157 (Porter Ranch, Granada Hills, Northridge, Chatsworth, North Hills, Canoga Park, Reseda, Winnetka, West Hills, Van Nuys, and Lake Balboa). After June 30, 2027, any remaining funds shall be made available to other customers within Southern California Gas Company service territory.

35. The Technology and Equipment for Clean Heating (TECH) Initiative implementer shall require every property owner or property manager, if applicable, seeking or receiving building electrification incentives—whether funded under Assembly Bill 157 or otherwise—to enter into a Tenant Protection

Agreement, attached to this decision as Appendix B, which provides the following required terms:

(a) Prohibition of any rent increase attributable to the electrification retrofit, upgrade, or its costs;

(b) Prohibition of any eviction or forced move attributable to the electrification, upgrade, or its costs;

(c) Requirement that the TECH Initiative implementer shall ensure property owners or property managers, as applicable, provide addresses for all rental properties (and individual units) participating in the program;

(d) Requirement that the implementer shall send written or digital notice to tenants, explaining Tenant Protection Agreement, tenants' rights, and how to report violations; and

(e) Provision that if a property owner or property manager, as applicable, violates the Tenant Protection Agreement, the implementer may, upon notice to the Commission, revoke or deny future participation.

36. The Technology and Equipment for Clean Heating (TECH) Initiative contracting agent shall:

(a) Modify the existing contract, no later than 30 days after issuance of this decision, with the TECH Initiative implementer and evaluator to disburse the $40 million in new Assembly Bill 157 funding in proportions consistent with Decision 23-02-005;

(b) Within 15 days of modifying the contract, file a Tier 1 Advice Letter seeking Energy Division approval of the modified contract and updating Southern California Edison Company's tariffs for Assembly Bill 157's new TECH Initiative funding;

(c) Create a sub-account no later than 30 days after the issuance of this decision under the Building Decarbonization Pilot Program Balancing Account to differentiate the source and use of funds for Assembly Bill 157's new TECH Initiative funding;

(d) Deposit Assembly Bill 157 funds, no later than 30 days after issuance of this decision, into an interest-bearing account, with all accrued interest disbursed to the TECH Initiative implementer for use in program incentives, upon written request to Southern California Edison Company; and

(e) Work with the TECH Initiative implementer to identify and track the source and use of Assembly Bill 157 funds within the Building Decarbonization Pilot Program Balancing Account.

37. Beginning with the second quarterly report in 2025, the Technology and Equipment for Clean Heating (TECH) Initiative implementer and evaluator shall submit quarterly reports providing the following data on projects funded by Assembly Bill (AB) 157:

(a) The estimated reduction in peak natural gas demand for all seasons from the Aliso Canyon natural gas storage facility, measured at the Centum Cubic Feet (ccf)/hour level for each City of Los Angeles community identified in AB 157 (Porter Ranch, Granada Hills, Northridge, Chatsworth, North Hills, Canoga Park, Reseda, Winnetka, West Hills, Van Nuys, and Lake Balboa). Reporting shall include:

(i) The average reduction across peak morning hours (5:00 a.m. – 10:00 a.m.) on the three coldest and three hottest days of the year;

(ii) The hourly gas demand reduction during each of these five hours;

(iii) The total annual average gas demand reduction, measured in ccf/day or MMcf/day, in each of these communities;

(b) The number of heat pump installations, installations of other eligible measures adopted in this decision, and the total number of incentives provided to both single-family and multi-family building residents;

(c) Strategies implemented to prevent the expenditure of AB 157 funds from contributing to tenant displacement in upgraded rental housing units and to limit cost impacts on tenants;

(d) Strategies employed to target communities in the Aliso Canyon Disaster Area, and, if applicable after 2027, to Southern California Gas customers outside of the designated communities. The report shall demonstrate how these strategies support long-term market development for both market-rate and low-income customers;

(e) The percentage of AB 157-funded TECH Initiative incentives allocated to low-income customers relative to the total program funds;

(f) The geographic distribution area and project types (e.g., comprehensive home electrification, or heat pump installations in multi-family housing complexes) targeted by TECH Initiative funding, with justification for allocation decisions; and

(g) Workforce training efforts funded through AB 157, including strategies for recruiting, training, and supporting workers in low-income communities.

38. All assigned Commissioner and Administrative Law Judge rulings issued to date are affirmed.

39. Rulemaking 19-01-011 remains open.

This decision is effective today.

Dated ____________________, at ____________, California

APPENDIX A
Electric Utilities New Reporting Requirements Established by D.XX-XX-XXX

APPENDIX B

TECH Tenant Protection Agreement