SOUTHERN CALIFORNIA EDISON
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December 15, 2025

ADVICE 5706-E
(Southern California Edison Company U 338-E)

ADVICE 4768-E
(San Diego Gas & Electric Company U 902-E)

ADVICE 7781-E
(Pacific Gas and Electric Company U 39 E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: Joint IOUs' Proposal for Method that Identifies the Best Solution When Distribution Needs Overlap Pursuant to Ordering Paragraph 17 of D.24-10-030

PURPOSE

In accordance with requirements set forth in Decision (D.) 24-10-030 (the "Decision") Ordering Paragraph 17 (OP 17),[1] Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) (together, the Joint Investor Owned Utilities [IOUs] or Joint IOUs) hereby submit this Tier 3 advice letter (AL) for California Public Utilities Commission (Commission or CPUC) disposition. The Joint IOUs herein propose a method that "calculates and considers whether the increased project costs from the increased sizing of any related assets are less than or equal to the risk-adjusted benefit from avoiding future projects to upgrade grid capacity." Also, as required by OP 17, this AL provides the Joint IOUs' responses to the six questions included in the ordering paragraph. The Joint IOUs request that the Commission issue a resolution accepting the Joint IOU's proposal.

BACKGROUND

[1] "No later than December 15, 2025, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall submit a Tier 3 advice letter proposing a method(s) that calculates and considers whether the increased project costs from the increased sizing of any related assets are less than or equal to the risk-adjusted benefit from avoiding future projects to upgrade grid capacity." Decision, OP 17.

The Decision, issued on October 23, 2024, within the High Distributed Energy Resources Future (High DER) proceeding, R.21-06-017, requires a wide range of modifications to the Distribution Planning Process (DPP) and associated activities. With respect to Integrated Grid Planning (IGP), the Commission acknowledges that "Utilities are either planning or already conducting integrated planning," but also seeks "transparency…into the processes Utilities undertake to integrate planning."[2] To this end, OP 16 required the Joint IOUs to present proposals for integrated planning, including cost containment considerations, at two workshops facilitated by the Commission. OP 17 requires the Joint IOUs to submit one or more methods that consider whether the increased cost of upsizing an asset is less than the benefit of avoiding future upgrades, which the present AL provides.

DISCUSSION

The Decision requires that utilities "consider distribution planning results when performing other distribution work."[3] Consistent with this requirement, the Joint IOUs are proposing a method that addresses situations where there is an overlap between distribution capacity needs identified in the DPP and distribution non-capacity needs identified through other distribution work, e.g., wildfire safety initiatives.

The Joint IOUs presented their IGP processes at Workshop 1 on October 10, 2025. Subsequently, at Workshop 2 on November 18, 2025, the Joint IOUs showed how grid needs identified in the DPP and in other distribution workstreams are handled when they overlap on the same assets or line path. The examples provided by the utilities at Workshop 2 focused on hypothetical instances when a non-capacity need date occurs before a known capacity need date, and those needs co-exist on the same assets or line path. The Joint IOUs have shared that when a non-capacity project is required before a capacity project, the incremental cost of including the future capacity needs in the initial project is almost always lower than carrying out a separate project later, as it avoids additional permitting, crew visits and the associated mobilization and demobilization costs. There may be exceptions where increasing the size per standards leads to challenges with timing and execution, due to incremental efforts to accommodate the new size. In these instances, engineers perform further analyses to determine the appropriate solution, balancing the needs of the project at hand and building in future capacity to avoid a subsequent project. No comments received during the workshops, or submitted to the IOUs following the workshop, identified flaws in the IOUs' respective processes. As a result, the Joint IOUs are not proposing any changes to their existing engineering processes.

Since the IOUs' existing processes satisfy all distribution needs in a least-cost, best-fit manner, the Joint IOUs request that the Commission issue a resolution indicating that each IOU's existing engineering processes satisfy the OP 17 requirement. The Joint IOUs' responses to the questions in OP 17, shared later in this document, underscore the effectiveness of the IOUs' existing processes in reaching the best solutions for

[2] Decision, p. 86.
[3] Decision, p. 83.

customers when distribution needs overlap, in particular when there is intersection between distribution needs identified through application of the Risk-based Decision Framework (RDF) and distribution needs identified through the DPP.

RECAP OF WORKSHOPS 1 AND 2

The Joint IOUs presented their responses to OP 16 and OP 17 at Workshop 1 on October 10, 2025, and at Workshop 2 on November 18, 2025. A high-level summary of each utility's presentations is provided below.

At workshop 1, SDG&E recognized that aligning project scope and timing when overlaps occur can reduce costs, minimize customer impacts, and streamline permitting and construction. Although such overlaps between the DPP and other workstreams are uncommon within SDG&E's service territory, existing processes already incorporate checks for potential overlaps and apply standard engineering practices to evaluate alternatives. When overlaps are identified, SDG&E consistently selects the least-cost, best-fit solution, which is often evident without extensive analysis. Bundling upgrades typically adds minimal incremental cost compared to executing separate projects and helps avoid repeated permitting and customer disruptions. During the workshop, SDG&E provided an overview of workstreams that could overlap with capacity projects and explained its coordination process. The presentation concluded with SDG&E reaffirming its commitment to timely service for customers. SDG&E's portfolio remains modest and closely managed, with energization and capacity needs prioritized to ensure timely service to accommodate customer load growth.

At Workshop 2, SDG&E expanded on its proposal and shared its perspectives on the six questions outlined in OP 17. To illustrate its approach, SDG&E presented a hypothetical example involving a circuit undergrounding project that overlapped with a DPP-identified need to increase capacity on the same circuit. In addition, SDG&E addressed stakeholder questions submitted following Workshop 1. The presentation concluded with SDG&E reaffirming its proposal to maintain its current planning processes without introducing structural changes.

During the workshops, SCE shared that to fulfill OP 16, its integrated planning process combines system needs—safety, reliability, capacity (load growth), and wildfire risk—into a single view by consolidating data from various sources. These needs are mapped geographically. Solutions are then developed for each location, with the goal of addressing multiple grid needs with an integrated solution, such as upsizing conductors and using a different conductor type to improve both capacity and safety. In the final stage, solutions across the service area are scored and chosen to optimize the portfolio. This results in a preliminary 10-year investment plan that minimizes risk while staying within operational constraints, including funding and resource availability. The outcome would be a cost-effective risk mitigation plan.

SCE also presented how its engineering best practices determine asset sizing and integration to fulfill OP 17. SCE shared that when a non-capacity project is required before a capacity project, the modest costs associated with increasing the sizing of assets such as conductors and other equipment to address future load growth outweighs the cost of a separate project (including engineering, design, permitting, material, construction, and job-site management) to upgrade recently installed assets. The exceptions are when grid needs require complex project scoping. In those cases, further analysis is needed to determine the appropriate solution.

During the workshops, PG&E described its future Integrated Grid Planning approach for aligning multiple system priorities—such as safety, reliability, load growth, and wildfire risk—into a unified work identification and prioritization process. PG&E subsequently described the DPP, which is upstream of the IGP process, where PG&E applies engineering standards to determine equipment sizing and whether combining future requirements into current projects makes sense. PG&E shared that the company has found that when a non-capacity upgrade is scheduled before a capacity-related project, incorporating anticipated capacity needs into the initial work is almost always more economical than performing a separate upgrade later. Exceptions arise when the scope becomes highly complex—such as projects involving multiple interdependent upgrades or significant permitting challenges. In those cases, PG&E conducts further engineering analysis to identify the most appropriate approach.

JOINT IOUS' PROPOSED METHOD FOR CONSIDERING WHETHER THE INCREASED PROJECT COSTS FROM THE INCREASED SIZING OF ASSETS ARE LESS THAN THE BENEFIT OF AVOIDING FUTURE UPGRADES

The Joint IOUs propose the following process to comply with OP 17's requirement. All three IOUs identify assets to install based on engineering standards. In accordance with best practices, the Joint IOUs regularly assess their standards to ensure alignment with regulatory requirements, incorporation of emerging technologies, cost effectiveness, and continuous improvement for safety, reliability and operational efficiencies.

Before the asset size is finalized in the design of the non-capacity needs, it is reviewed by a distribution engineer who has responsibility for capacity needs on the impacted circuit and/or substation. The distribution engineer determines the asset size based on the utility's engineering standards and load forecasts. This engineering decision accounts for the possible avoided cost of a separate future capacity project.

In addition to that, engineers consider project-specific factors beyond cost in deciding on asset sizing. These factors include feasibility of construction, schedule impacts to the non-capacity project, consolidation of outages, operational flexibility impacts, permitting requirements, the long-term grid design for the area, forecast uncertainty, and other factors as relevant to the project.

As stated in the Decision, utilities are required to assess grid needs based on multiple forecast scenarios in their distribution planning process.[4] Although final Resolutions

[4] Decision, OP 6.

regarding scenario planning and the related topic of pending loads are still forthcoming, the draft Resolutions are founded on the premise that identifying grid requirements across several forecasts—including those with varying levels of pending load—enables utilities to more effectively account for the likelihood of future capacity demands. Assuming the final Resolutions are substantially similar to the draft Resolutions, engineers will evaluate grid needs and design solutions considering a range of possible load forecasts. This approach is expected to inform determinations regarding potential upsizing, ensuring that capacity planning is responsive to diverse future conditions and that optimal solutions are achieved.

The engineering decision framework used by the IOUs to reach a final decision is as follows:

Engineering Decision Framework

1. **Identify Needs**
   Determine the timing and magnitude of distribution needs.
2. **Apply Engineering Standards and Best Practices**
   Develop proposed solutions in accordance with utility standards and best practices to effectively address the identified needs.
3. **Assess Overlaps Between DPP Needs and Distribution Needs Identified Through Other Work Streams**
   Evaluate solutions that address overlapping needs considering load forecasts, technical, and operational benefits.
4. **Perform Engineering Evaluation**
   Consider design feasibility, constructability, construction scheduling constraints, operational flexibility and potential customer impacts.
5. **If Needed: Perform Net Present Value Cost Analysis**
   If least cost solution is not self-evident, use economic analysis to compare incremental costs against future avoided costs.
6. **Final Decision**
   Considering all relevant factors, including costs and benefits, determine which solution meets overlapping distribution needs at lowest cost to ratepayers.

At the end of step 6, the resulting projects are prioritized according to the timing of customer energization needs, as well as budget and resource constraints, as each IOU creates its final investment plan.

1JOINT IOU RESPONSES TO SPECIFIC QUESTIONS SET FORTH IN ORDERING PARAGRAPH 17

1. **How does the proposed method maintain the flexibility of the distribution planning process, and allow for that process to develop over time?**

Consistent with the objective of this proceeding, the primary goal of each IOU's distribution planning process is to meet load growth and customer energization needs in a timely manner. The Joint IOUs' proposal to use their existing processes to find the least-cost, best-fit solutions for customers utilizes the outputs of the DPP. Therefore, because engineering standards and evaluations are applied to the output of the DPP, the DPP can continue to develop over time and remain responsive to evolving grid needs.

2. **How does the proposed method estimate the increased costs for current projects, and how can this estimate change or improve over time? Include increased costs for wildfire mitigation and associated Rulemaking (R.) 20-07-013 Risk-based Decision-making Framework (RDF) cost benefit ratio data.**

When determining equipment sizing for a project, engineers select among approved equipment in the utility's standards. The standards are regularly updated to address new information including technology strategies, risk assessments in the field, industry best practices, etc. When these standards are applied to determine project scope, standard cost estimating tools are used, including but not limited to: unit costs, number of units, and other cost elements (e.g., project management, vehicles). Therefore, assessing increased costs again is not necessary.

RDF and distribution capacity sizing are two distinct steps without overlap. RDF provides a framework to select wildfire mitigation solutions based on risk assessment and costs. Resolving overlaps between distribution projects selected through the RDF framework and distribution capacity projects identified in the DPP, including scope selection based on engineering standards, is independent of the selection of the wildfire mitigation solution.

3. **How does the proposed method incorporate cost effectiveness and cost efficiencies?**

Cost effectiveness and cost efficiencies are inherently built into the IOUs' Engineering Decision Framework (primarily step 4) detailed above and as explained in Question # 2. Engineers determine a one-time solution that addresses multiple grid needs. The Joint IOUs' proposal to continue using their existing frameworks, which apply distribution standards for purposes of project sizing and design, avoids the time-consuming need to scope and cost estimate each alternative solution (since the best solution will usually be self-evident and identified early in the process).

4. **How does the proposed method adjust for risk and potential risk reduction when considering potential future capacity projects, and how can this adjustment change or improve over time?**

A key risk relevant to the upsizing decision is the risk that load exceeds asset capability in a future year, resulting in missing or delaying customer energization. There is also a risk of a more inefficient process, resulting in multiple projects in the same location within a short time span. The load forecast provides the engineer with a graduated viewpoint of risk, as overloads in later years are more uncertain than those in the near term. In most situations, the risk of missing or delaying customer energization is fully mitigated by scoping for future capacity needs.

Implementation of the requirements in the Commission’s final resolutions on Pending Loads and Scenario Planning, expected in late-December 2025, will support identification of pending loads (via collaboration with communities and with existing and prospective customers) and provide a pathway for decision-making that accommodates the possibility of different load growth trajectories. The resolutions are intended to enhance the ability of utilities to anticipate and plan for customer energization demands. Improved forecast accuracy reduces the risk of building the wrong distribution infrastructure in the wrong place at the wrong time.

5. **How does the proposed method estimate cost of future distribution capacity projects, (including increased costs for wildfire mitigation and associated R.20-07-013 RDF cost benefit ratio data) and how can this estimate change or improve over time?**

Existing project cost estimation methodologies will continue to apply under each IOU’s Engineering Decision Framework detailed earlier. This includes an itemized list of equipment and may include the use of unit costs to produce a cost estimate for the project.

With regard to wildfire mitigation and RDF, refer to the Joint IOUs’ response to Question #2.

6. **How does the proposed plan address projects planned in the high fire threat districts or in areas of wildfire risk, or projects that will require new lines to be built that cross into the high fire threat districts?**

The IOUs apply engineering standards associated with fire hardening when designing projects in areas subject to wildfire risk. The proposed plan does not change the current approach. For example, currently, if a new circuit is built in a high fire risk location, covered conductor, fire hardened poles, and undergrounding will be considered.

<u>CONCLUSION</u>

The Joint IOUs request that the Commission issue a resolution approving the Advice Letter as submitted.

TIER DESIGNATION

Pursuant to General Order (GO) 96-B, Energy Industry Rule 5.1, and Ordering Paragraph 17 of Decision 24-10-030 this advice letter is submitted with a Tier 3 designation.

EFFECTIVE DATE

This advice letter will become effective upon Commission approval.

NOTICE

Anyone wishing to protest this advice letter may do so only electronically. Protests must be received no later than 20 days after the date of this advice letter. Protests should be submitted to the CPUC Energy Division at:

E-mail: EDTariffUnit@cpuc.ca.gov

In addition, protests and all other correspondence regarding this advice letter should also be sent electronically to the attention of:

Connor Flanigan
Vice President, State Regulatory Operations
Southern California Edison Company
E-mail: AdviceTariffManager@sce.com

Adam Smith
Director, Regulatory Relations
Southern California Edison Company
c/o Karyn Gansecki
E-mail: Karyn.Gansecki@sce.com

Greg Anderson
Regulatory Tariff Manager
Emails: GAnderson@sdge.com
SDGETariffs@sdge.com

Sidney Bob Dietz
Director, Regulatory Relations
c/o Megan Lawson
PGETariffs@pge.com

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and must be received by the deadline shown above.

In accordance with General Rule 4 of GO 96-B, SCE is serving copies of this advice letter to SCE's GO 96-B and R.21-06-017 service lists. Address change requests to the GO 96-B service list should be directed by electronic mail to AdviceTariffManager@sce.com or at (626) 302-4747. For changes to all other service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

To view other SCE advice letters submitted with the Commission, log on to SCE's web site at https://www.sce.com/wps/portal/home/regulatory/advice-letters.

For questions, please contact Ari Altman at (626) 302-4946 or by electronic mail at ari.altman@sce.com

Southern California Edison Company

/s/ Connor Flanigan
Connor Flanigan

CF:aa/wy:bvs

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Southern California Edison Company (U 338-E)

Utility type:

- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Darrah Morgan
Phone #: (626) 302-2086
E-mail: AdviceTariffManager@sce.com
E-mail Disposition Notice to: AdviceTariffManager@sce.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 5706-E et al.

Tier Designation: 3

Subject of AL: Joint IOUs' Proposal for Method that Identifies the Best Solution When Distribution Needs Overlap Pursuant to Ordering Paragraph 17 of D.24-10-030

Keywords (choose from CPUC listing): Compliance

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
Decision 24-10-030

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution required? [x] Yes [ ] No

Requested effective date:

No. of tariff sheets: -0-

Estimated system annual revenue effect (%):

Estimated system average rate effect (%):

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: None

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets: None

[1]Discuss in AL if more space is needed.

Clear Form

Protests and correspondence regarding this AL are to be sent via email and are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

California Public Utilities Commission
Energy Division Tariff Unit Email:
EDTariffUnit@cpuc.ca.gov

Contact Name: Connor Flanigan
Title: Vice President, State Regulatory Operations
Utility/Entity Name: Southern California Edison Company

Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email: AdviceTariffManager@sce.com

Contact Name: Adam Smith c/o Karyn Gansecki
Title: Director, Regulatory Relations
Utility/Entity Name: Southern California Edison Company

Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx:
Email: karyn.gansecki@sce.com

CPUC
Energy Division Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T

Albion Power Company
Alta Power Group, LLC

Anderson & Poole
BART

Ava Community Energy

BART
Buchalter
Barkovich & Yap, Inc.
Biering & Brown LLP
Braun Blaising Smith Wynne, P.C.

California Community Choice Association
California Cotton Ginners & Growers Association
California Energy Commission
California Hub for Energy Efficiency
California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
Calpine
Cameron-Daniel, P.C.
Casner, Steve
Center for Biological Diversity
Chevron Pipeline and Power

Clean Power Research
Coast Economic Consulting
Commercial Energy
Crossborder Energy
Crown Road Energy, LLC

Davis Wright Tremaine LLP
Day Carter Murphy
Dept of General Services
Douglass & Liddell
Downey Brand LLP

Ellison Schneider & Harris LLP

Electrical Power Systems, Inc. Fresno
Engie North America
Engineers and Scientists of California

GenOn Energy, Inc.
Green Power Institute

Hanna & Morton LLP

ICF consulting

iCommLaw

International Power Technology
Intertie

Intestate Gas Services, Inc.

Kaplan Kirsch LLP
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP

Leviton Manufacturing Co., Inc.
Los Angeles County Integrated Waste Management Task Force

MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McClintock IP
McKenzie & Associates
Modesto Irrigation District
NLine Energy Inc.
NOSSAMAN LLP
NRG Energy Inc.

OnGrid Solar

Pacific Gas and Electric Company
Peninsula Clean Energy
Pioneer Community Energy

Public Advocates Office
Redwood Coast Energy Authority

Regulatory & Cogeneration Service, Inc.
Resource Innovations
Rockpoint Gas Storage

San Diego Gas & Electric Company
San Jose Clean Energy
SPURR

Sempra Utilities

Sierra Telephone Company, Inc.
Southern California Edison Company
Southern California Gas Company

Spark Energy

Sun Light & Power
Sunshine Design
Stoel Rives LLP

Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

Utility Cost Management

Water and Energy Consulting

Yep Energy