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COMMENTS OF THE PUBLIC ADVOCATES OFFICE ON THE ELECTRIFICATION IMPACT STUDY PART 2 DRAFT REPORTS

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I. INTRODUCTION

California Public Utilities Commission (Commission) Decision (D.) 24-10-030 orders each of the investor-owned utilities (IOUs)[1] to file *Draft Electrification Impact Study Part 2 Reports* (Draft EIS Part 2 Reports) in this proceeding and provides a schedule for related events and due dates for party comments on the Draft EIS Part 2 Reports.[2] On September 24, 2025, the Commission's Executive Director issued a letter that modifies the procedural schedule set forth in D.24-10-030 with regard to the Draft EIS Part 2 Reports, and establishes that party comments on the Draft EIS Part 2 Reports are due December 15, 2025.[3] The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) hereby submits the following comments on the IOUs' Draft EIS Part 2 Reports.[4]

The purpose of the Electrification Impacts Study Part 2 (EIS Part 2) is to "estimate and assess the potential costs of upgrading the primary and secondary distribution grid"

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[1] The IOUs include Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

[2] See D.24-10-030, *Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps*, October 17, 2024 at Section 3.11.4, and Ordering Paragraphs (OP) 19 and 20, available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF.

[3] Letter From Commission Executive Director Rachel Peterson, *Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company Request for Extension of Time to Submit Draft Energization Impact Study Part 2 and Comply With Subsequent Requirements in Ordering Paragraphs 19 and 20 of Decision 24-10-030*, September 24, 2025; served on service list for Rulemaking (R.) 21-06-017, Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resource Future. On December 8, 2025 Administrative Law Judge Jack Chang sent an email to the service list for R.21-06-017 clarifying that comments on the Draft EIS Part Reports "must be e-filed into the R.21-06-017 docket and served to the current service list for R.21-06-017."

[4] On October 31, 2025, the IOUs' filed their respective Draft EIS Part 2 Reports. See PG&E, *Pacific Gas and Electric Company's (U 39 E) Draft Electrification Impact Study Part 2*, October 31, 2025 (PG&E Draft EIS Part 2), available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M585/K834/585834115.PDF; SDG&E, *San Diego Gas & Electric Company's (U 902 E) Draft Electrification Impact Study Part 2*, October 31, 2025 (SDG&E Draft EIS Part 2), available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M586/K486/586486686.PDF; and SCE, *Southern California Edison Company's (U 338-E) Electrification Impacts Study Part 2 Draft Report*, October 31, 2025 (SCE Draft EIS Part 2) , available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M585/K820/585820156.PDF.

under multiple scenarios, in order to "produce learnings that translate into improvements for each utility's [distribution planning and execution process (DPEP)]."[5] To ensure that the Commission is able to effectively interpret and evaluate the EIS Part 2, and to support the ability of the reports to produce credible learnings that can be applied to the DPEP, Cal Advocates recommends the following:

- The Commission should direct the IOUs to describe how they have responded to party comments on the Draft EIS Part 2 Reports in their Final EIS Part 2 Reports (Final Reports).
- The Commission should seek comments and reply comments that encompass both technical feedback on the Final Reports and feedback on the IOUs' proposed implementation plans.
- Pacific Gas and Electric Company (PG&E) should provide additional information that substantiates and justifies its secondary distribution system modeling.
- All three IOUs should provide greater clarity on their cost, load profile, and demand flexibility inputs. Each IOU should explicitly report these values and the source data for these values.
- PG&E and San Diego Gas & Electric Company (SDG&E) should provide additional information and clarity on elements of their methods which are not clearly explained in their respective Draft EIS Part 2 Reports.

II. BACKGROUND

The ongoing EIS Part 2 builds on the *Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates* (EIS Part 1). This Commission-initiated study was conducted by the data analytics company Kevala, Inc. (Kevala).[6] In D.24-10-030 the Commission directed the IOUs to conduct a follow-up study to EIS Part 1.[7] The purpose of this follow-up study is to "estimate and assess the potential costs of upgrading the primary and secondary

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[5] D.24-10-030 at 97.

[6] Kevala, *Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates*, May 9, 2023 (EIS Part 1). Available at: https://www.kevala.com/resources/electrification-impacts-study-part-1.

[7] D.24-10-030 at 99.

distribution grid" under multiple scenarios, in order to "produce learnings that translate into improvements for each utility's DPEP."[8] For the EIS Part 2, the Commission's Energy Division directed the IOUs to model at least the following three scenarios: a Baseline scenario which reflects current forecasts and planning practices, an Enhanced Demand Flexibility scenario which investigates the impacts of additional demand flexibility, and an Equity scenario which investigates the impacts of additional DER uptake in priority populations.[9]

Each IOU modeled the impacts of load growth on the distribution grid until 2040, using the forecasts laid out in the California Energy Commission's 2023 Integrated Energy Policy Report (IEPR).[10] The IOUs filed their Draft EIS Part 2 Reports on October 31, 2025 and presented them at workshops on November 19 and 20, 2025.[11]

Pursuant to Decision (D.) 24-10-030, the IOUs will publish their Final Reports by January 28, 2026, along with a description of how the study meets requirements and objectives, and a proposal and timeline for integrating key findings of the studies into future distribution planning processes.[12] The Commission will then issue a ruling seeking comment on the study and on implementation of the study.[13] After comments are filed on the study and implementation, the Commission will issue a proposed decision on implementation of study outcomes.[14]

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[8] D.24-10-030 at 97.

[9] D.24-10-030 at 97-98. Priority populations include low-income, disadvantaged, and tribal communities. See California Climate Investments, *Mapping Tool 4.0,* available at: https://gis.carb.arb.ca.gov/portal/apps/experiencebuilder/experience/?id=5dc1218631fa46bc8d340b8e82548a6a&pa=null&page=Priority-Populations-4_0.

[10] Available at: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report-iepr/2023-integrated-energy-policy-report.

[11] IOUs, *Electrification Impacts Study – Part 2 Workshop*, November 19 and 20, 2025 (EIS Part 2 Workshop).

[12] D.24-10-030, OP 20 at 198.

[13] D.24-10-030 at 99.

[14] D.24-10-030 at 99.

III. THE COMMISSION SHOULD SEEK COMMENTS ON TECHNICAL ASPECTS OF THE FINAL REPORTS AS WELL AS THE IMPLEMENTATION OF FINDINGS INTO THE DISTRIBUTION PLANNING PROCESS

In order to evaluate the potential for and benefits of implementation of the EIS Part 2 in future distribution planning processes, the Commission and parties must be able to clearly evaluate and interpret the results and findings of the EIS Part 2. Parties must have the opportunity to comment on both the technical aspects and the implementation proposals in the Final Reports. Parties have the opportunity to raise technical issues with the Draft EIS Part 2 Reports in their comments. However, D.24-10-030 does not direct the IOUs to address party comments in the Final Report or establish any point for Commission input based on party comments prior to the Final Reports. Thus, it is unclear whether the Commission will require the IOUs to address technical issues raised in party comments in the IOUs' respective Final Reports.

In order to ensure that the Commission is able to properly evaluate the value and credibility of the Final Reports, and in order to ensure that future decisions draw only from credible, reasonable findings, the Commission should take the following steps:

- The Commission should direct the IOUs to describe how they incorporated feedback from the workshop and party comments on Draft EIS Part 2 Reports into the Final Reports.
- The Commission should issue a ruling after the IOUs file the Final Reports that seeks parties' opening and reply comments on both the technical aspects of the Final Reports and on proposed implementation of the Final Report findings into each IOU's distribution planning process.
- After the Commission receives party comments on the Final Reports, the Commission should consider whether any elements of the Final Reports are not fit for use in distribution planning and, if this is the case, direct the IOUs to further modify the Final Reports or reject the Final Reports in whole or in part.[15]

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[15] This process would be similar to the Commission's well-established process for reviewing Renewables Portfolio Standard Procurement Plans (RPS Plans) of retail sellers pursuant to Public Utilities Code

IV. COMMENTS ON THE IOUS' DRAFT EIS PART 2 REPORTS

All three IOUs' Draft EIS Part 2 Reports contain valuable new modeling and insights. However, as detailed below, all three IOUs' Final Reports should provide additional information on methods and data sources so that parties can better understand the results. This additional information will allow the Commission and parties to more reasonably evaluate the Final Reports and the implementation of study recommendations in the distribution planning process.

A. PG&E Should Provide Additional Explanation of its Secondary Modeling Results.

1. Overview

PG&E's Draft EIS Part 2 base scenario finds a cost of $15.9 billion by 2040 for secondary distribution equipment upgrades to support load growth.[16] PG&E finds a cost of $9.6 billion by 2040 for primary distribution equipment such as new primary distribution lines and substation transformers.[17] PG&E's secondary costs therefore comprise approximately 60% of its total 2040 costs. This result is inconsistent with the other IOUs' Draft EIS Part 2 Reports, and also the EIS Part 1 Report, as shown below.

Section 399.13 for compliance with statutory and Commission requirements. The Commission requires retail seller to file Draft RPS Plans and allows party comments on those Draft RPS Plans. The Commission then issues an annual decision wherein the Commission deems final any Draft RPS Plan that does not require correction or clarification. Alternatively, the Commission's decision may require a retail seller to update and correct deficiencies in its Draft RPS Plan and then file the corrected plan as a Final RPS Plan. See e.g., D.24-12-035, *Decision on 2024 Renewables Portfolio Standard Procurement Plans*, December 19 2024; issued in R.24-01-017, *Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program*.

[16] PG&E Draft EIS Part 2 at 14, Table 2. Secondary distribution costs represent the costs of new and replacement service transformers. Service transformers are transformers located outside of substations.

[17] PG&E Draft EIS Part 2 at 14, Table 2.

Table 1: Comparison of Primary and Secondary Distribution Costs

	EIS Part 1, PG&E Only, 2035	*SCE Draft EIS Part 2*[18]	*SDG&E Draft EIS Part 2*[19]	*PG&E Draft EIS Part 2*[20]
Primary Costs ($Billion)	$13.01[21]	$12.295	$2.45	$9.6
Secondary Costs ($Billion)	$4.87[22]	$0.884	$0.56	$15.9
Total Costs ($Billion)	$17.88	$13.179	$3.01	$25.5
Secondary Percentage of Total Costs	27%	7%	19%	**62%**

PG&E fails to reasonably explain these anomalous results. PG&E states that its new methodology produces results which should not be compared to other studies;[23] however, PG&E fails to fully explain its new methodology and does not provide any information as to how it verified its results. PG&E's Final Report should include additional detail, context, and comparisons in order to allow parties to further evaluate its modeling and results.

2. PG&E's methodology may overestimate the number of needed of service transformers

PG&E states that its high secondary costs are due to a "significantly expanded" scope compared to the EIS Part 1.[24] EIS Part 1 allocated future load growth onto existing distribution infrastructure, evaluated whether the new load would overload the existing infrastructure, and allocated new and replacement service transformers to address those overloads.[25] PG&E's Draft EIS Part 2 instead uses a new spatial methodology. Rather than allocate load onto existing distribution infrastructure, under this methodology PG&E

[18] SCE Draft EIS Part 2 at 7.

[19] SDG&E Draft EIS Part 2 at 25, Table 14.

[20] PG&E Draft EIS Part 2 at 35, Table 8.

[21] EIS Part 1 at 27, Table 3.

[22] EIS Part 1 at 28, Table 4.

[23] PG&E Draft EIS Part 2 at 39-40 and 43.

[24] PG&E Draft EIS Part 2 at 39.

[25] EIS Part 1 at 81; and PG&E Draft EIS Part 2 at 41.

allocates load growth to locations on a hexagonal grid. PG&E then compares load growth in each location with the capacity of the distribution infrastructure in that location and adjacent locations.[26] In the new methodology PG&E is not constrained to allocate load growth to where distribution infrastructure already exists, it can allocate load growth and new service transformers in locations without any existing distribution infrastructure.[27]

PG&E's new model appears to overestimate the number of necessary service transformers. One way PG&E's new method could overestimate the number of service transformers needed is by spreading load growth across too many new locations. For example, consider a region without existing distribution infrastructure where PG&E forecasts 500 kilowatt (kW) of load growth. Now consider Scenario A: the 500 kW of load growth is concentrated in one location. PG&E might address that load growth with a 750 kilovolt-ampere (kVA) transformer.[28] Consider also Scenario B: the 500 kW of load growth is spread out in 10 separate locations. PG&E might address that load growth with 10 service transformers, each of 75 kVA.[29] PG&E's Draft EIS Part 2 uses the same cost in its modeling for every type of service transformer installation, so Scenario B costs ten times as much as Scenario A.[30] This means costs are extremely sensitive to small assumptions made about the spatial distribution of new load. If PG&E's method spreads load out too much, it could significantly overestimate costs.

PG&E's new method could also produce an overallocation of new service transformers by inaccurately allocating new load to existing grid infrastructure. For an

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[26] PG&E Draft EIS Part 2 at 82-83.

[27] PG&E Draft EIS Part 2 at 41 and 83.

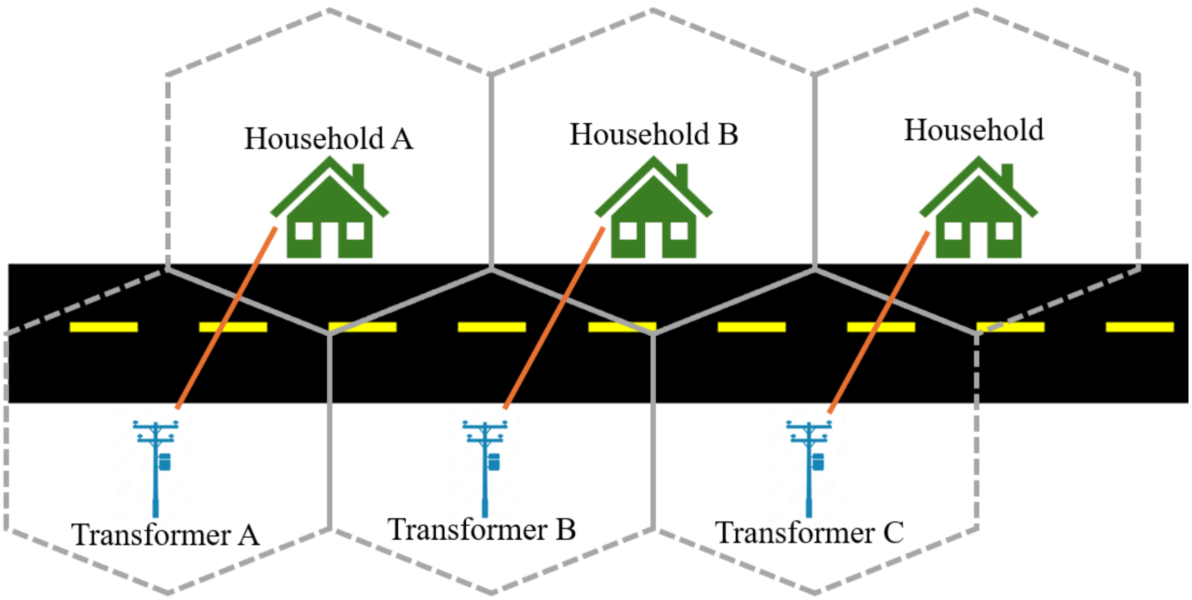
[28] kW and kVA are both units used for power flow. kVA includes "virtual power" which occurs when voltage and current oscillations are misaligned. For the purposes of this analysis, Cal Advocates treats kVA and kW as identical units – a 50 kW load can be served by a 50 kVA service transformer. In practice, when serving power to certain kinds of equipment such as high-power motors, the service transformer may need to be slightly larger, but not to a high enough degree to affect this analysis.

[29] CPUC, *Electrification Impact Study – Part 2 Draft Results Presentation*, November 19-20, 2025 (EIS Part 2 Workshop Presentation) at slide 73; served to the R.21-06-017 service list on December 1, 2025.

[30] PG&E Draft EIS Part 2 at 83.

example of how this could occur, consider three adjacent households, each with a connection to a service transformer across the street, spatially placed as follows:

Figure 1: Example of Hexagonal Allocation



In this example, each service transformer has 25 kVA of available capacity, and each house has 20 kW of load growth. While Household A is served from Transformer A, it is close enough to Transformer B that it could also be served from Transformer B. However, Household A is not close enough to Transformer C to be served from Transformer C. The same principles apply to the other households.

The method Kevala used in EIS Part 1 would allocate new load directly to existing service transformers.[31] Because each service transformer can accommodate the load growth on the house it is connected to, no new service transformers or other upgrades are necessary.

The method used in PG&E's Draft EIS Part 2 allocates new load spatially, and then associates load spatially with capacity on nearby service transformers.[32] Starting with Household A, its load could be assigned to either Transformer A or Transformer B,

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[31] EIS Part 1 at 22.

[32] PG&E Draft EIS Part 2 at 82-83.

as both are in adjacent areas and PG&E's spatial method does not associate loads with specific service transformers. If load is assigned to Transformer B, Transformer B no longer has available capacity, so Household B's load must be assigned to Transformer C. Transformer C no longer has available capacity, so Household C appears to need a new service transformer, even though capacity is actually available for all three houses. Errors like this, if present, could compound to mistakenly allocate new service transformers for loads which can in fact be served from existing transformers.

To evaluate the possibility that PG&E's model overestimates the need for new service transformers, Cal Advocates estimates the load growth served by each service transformer in PG&E's model. Unlike the other two IOUs, PG&E does not report the total number of new and replacement service transformers projected in its Draft EIS Part 2. To estimate the number of new and replacement service transformers allocated in PG&E's Draft EIS Part 2, Cal Advocates divides the total secondary cost by the unit cost of each service transformer (adjusted for inflation across the study period). PG&E's model therefore estimates that approximately 350,000 new service transformers are needed to serve load growth through 2040.[33] PG&E reports 4.09 gigawatts (GW) of non-coincident peak load growth between 2030 and 2040.[34] Assuming the same rate of load growth between 2025 and 2030, Cal Advocates finds that each allocated service transformer is serving approximately 17 kW of non-coincident peak load growth. This value is significantly lower than the load growth served by each service transformer in the other IOUs' studies. Table 2 below explains this calculation for each of the three IOUs.

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[33] Cal Advocates estimates this number of installations by calculating the average cost per service transformer (PG&E Draft EIS Part 2 at 91) across the study period, accounting for the 2.6% inflation rate used by PG&E (PG&E Draft EIS Part 2 at 34). Cal Advocates then divides PG&E's total secondary cost by that average cost.

[34] PG&E Draft EIS Part 2 at 31, Figure 8.

Table 2: Estimate of Load Growth Served by Each Service Transformer

	SCE Draft EIS Part 2	*SDG&E Draft EIS Part 2*	*PG&E Draft EIS Part 2*
Secondary Costs (Billions)	$0.884[35]	$0.56[36]	$15.9[37]
Cost Per Service Transformer	~$23,200 (average)[38]	$19,810 (2025)[39]	$41,225 (2030)[40]
Number of Service Transformer Installations (New and Replacement)	38,051[41]	23,684[42]	~350,000
Peak Load Growth from 2030 to 2040	3.21 GW[43]	0.803 GW[44]	4.09 GW[45]
Approximate Load Growth Served by Each New and Replacement Service Transformer	~127 kW	~51 kW	**~17 kW**

As Table 2 shows, PG&E's Draft EIS Part 2 forecasts approximately ten times more service transformers than SCE and SDG&E. PG&E's forecasted service transformers also serve approximately three to seven times less load than each of SCE and SDG&E's projected service transformers. While the three IOUs have different distribution grids and do not need to allocate service transformers identically, such large

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[35] SCE Draft EIS Part 2 at 7.

[36] SDG&E Draft EIS Part 2 at 25, Table 14.

[37] PG&E Draft EIS Part 2 at 35, Table 8.

[38] Estimated based on SCE Draft EIS Part 2 at 7, Tables 3 and 4. Cal Advocates divides $884,000,000 in total secondary costs by 38,051 service transformers to calculate an average cost of ~$23,200.

[39] SDG&E Draft EIS Part 2 at 18, Table 6.

[40] PG&E Draft EIS Part 2 at 87.

[41] SCE Draft EIS Part 2 at 7, Table 3.

[42] SDG&E Draft EIS Part 2 at 23 and 24, Tables 12 and 13.

[43] SCE Draft EIS Part 2 at 7, Table 1, 41.54 GW by 2040 - 38.33 GW by 2030.

[44] SDG&E Draft EIS Part 2 at 10, Table 1, 7,007 MW – 6,204 MW.

[45] PG&E Draft EIS Part 2 at 31, Figure 8.

discrepancies are anomalous. For each of PG&E's new service transformers to serve only approximately 17 kW of load growth suggests one of two possibilities:[46]

1. PG&E's load growth will occur disproportionately in areas without existing service and therefore will not be supported by existing service transformer capacity. PG&E's load growth will also be very spread out such that serving the new load requires installation of a very large number of new service transformers, each serving a comparatively small load; or
2. PG&E's model has allocated too many service transformers for some other unexplained reason, such as the possible errors described above.

While PG&E's results are not impossible, they are anomalous and unjustified. PG&E's Final Report needs to provide significantly more information about its methodology and its results in order for stakeholders to evaluate their credibility. Without additional information and justification, the Commission should not treat PG&E's results as fit for use in future distribution planning processes.

3. PG&E provides an inaccurate comparison between its results and those of EIS Part 1

PG&E justifies its secondary cost results by providing a comparison between the secondary distribution costs of EIS Part 1 ($4.87 billion) and the cost of *replacement* service transformers included in PG&E Draft EIS Part 2 ($3.42 billion).[47] PG&E excludes *new* transformers from this comparison on the basis that EIS Part 1 only adds service transformers in locations with existing transformers.[48] PG&E states that 78% of its secondary costs are associated with *new* transformers and therefore are not comparable

[46] A third possibility is that PG&E must use smaller capacity service transformers compared to the other IOUs. However, PG&E allocates service transformers of up to 1500 kVA in its model, each of which could serve hundreds of kW of load growth in a single location. See EIS Part 2 Workshop Presentation at slide 73.

[47] PG&E Draft EIS Part 2 at 43, Figure 15.

[48] PG&E Draft EIS Part 2 at 41.

to the service transformers in EIS Part 1.[49] PG&E therefore states that "[PG&E Draft EIS Part 2] had lower cumulative secondary costs than the EIS Part 1."[50]

This statement is incorrect because PG&E excludes the costs of some new transformers which should be included in the comparison. The following table shows the different types of service transformer installations included in the modeling of the EIS Part 1 and in PG&E Draft EIS Part 2. The shaded cells indicate the transformers included in PG&E's comparison.

Table 3: Comparison of Service Transformers in EIS Part 1 and PG&E Draft EIS Part 2

	Replacement transformer	***New transformer, in a location with existing transformers***	***New transformer, in a location without existing transformers***
Included in EIS Part 1	Yes	Yes	No
Included in PG&E Draft EIS Part 2	Yes	Yes[51]	Yes

As shown in Table 3, PG&E includes only replacement transformers on the PG&E Draft EIS Part 2 side of the comparison, while including both new and replacement transformers on the EIS Part 1 side of the comparison. This means PG&E omits the costs

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[49] PG&E Draft EIS Part 2 at 41:

> To compare secondary costs between the EIS Part 1 and EIS Part 2 studies, the secondary costs identified in the EIS Part 2 were split into two components: overloaded service transformers and new transformers (new service connections). The EIS Part 1 study modeled overloads to existing service transformers and identified either new or replacement transformers to address forecasted capacity overloads. The EIS Part 2 includes costs for both service transformer overloads and expanded the scope to include new transformers (i.e., new service connections). Overloaded service transformers correspond to $3.4B (~21%) of the secondary costs through 2040 in the EIS Part 2 Base Case, with the remaining $12.5B (~79%) of secondary costs corresponding to the new transformers added to service connections. Therefore, most of the secondary costs identified in the EIS Part 2 were not included in the scope of the EIS Part 1. To compare the EIS Part 2 and EIS Part 1, only the secondary costs corresponding to the overloaded service transformers are included in the comparisons to the EIS Part 1 results.

[50] PG&E Draft EIS Part 2 at 43.

[51] EIS Part 2 Workshop Presentation at slide 73.

of new service transformers installed in locations with existing transformers where it claims that "[PG&E Draft EIS Part 2] had lower cumulative secondary costs . . . ."[52]

PG&E fails to justify its high secondary costs through this comparison. If PG&E intends to draw a distinction between the scope of its PG&E Draft EIS Part 2 and that of other studies, it should make a more accurate comparison by including new transformers in locations with existing transformers in its comparison. PG&E should include such a comparison in its Final Report.

4. PG&E should provide additional information in order to allow the Commission to effectively evaluate its results

In order to provide further transparency and context and to allow parties to evaluate PG&E's anomalous results, PG&E should include all of the following in its Final Report:

- A more complete description of its secondary modeling, including all details provided at the EIS Part 2 Workshop.
- A full description of any analyses it performed to verify that the model allocates load growth in a realistic manner, allocates service transformers in a realistic manner, and does not underuse existing transformers or over-estimate new transformers. PG&E should include the results of those analyses and the sources of any additional data that PG&E used for those analyses. If PG&E has not performed any analyses to verify the accuracy of the model, it should include in the Final Report a statement that the methodology is not verified.
- The total number of service transformer installations projected. PG&E should also provide a table of the number of projected service transformer installations at each transformer capacity (25 kVA, 50 kVA, etc.).
- A more informative breakdown of service transformer installation costs in Figures 12 and 15 of the PG&E Draft EIS Part 2.[53] Rather than breaking down costs between "new" and "replacement," PG&E should report costs broken down between "in a location with

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[52] PG&E Draft EIS Part 2 at 43.

[53] PG&E Draft EIS Part 2 at 41 and 43.

existing transformers" and "in a location with no existing transformers."

- A clear comparison between forecasted installations and historical installations and between forecasted costs and historical costs. In section 7.2 of PG&E Draft EIS Part 2, PG&E should include an additional table comparing historical service transformer installation rates to projected installation rates.
- A detailed qualitative discussion of these cost results, explaining PG&E's practical justification of the results and a description of the load growth drivers PG&E believes will place such a disproportionate burden on its existing secondary distribution system.[54]

Without further details, context, and evidence, PG&E's secondary system results are not sufficiently justified and the Commission should not consider the results as fit for purpose in any future distribution planning processes. With further details, context, and evidence, parties will be better able to evaluate the credibility of PG&E's results.

B. PG&E Should Clarify Several Elements of its Report

The PG&E Draft EIS Part 2 glosses over several finer details which warrant clarification in the Final Report. Specifically, PG&E's Final Report should:

1. Contextualize the scale of downward pressure on distribution rates;
2. Elaborate on PG&E's rate modeling;
3. Include all modeled load shapes rather than a sample;
4. Elaborate on how PG&E models the evolution of time of use (TOU) rates; and
5. Define key terms with respect to load factor calculations.

Regarding the first point, PG&E states that "[e]lectrification growth may provide downward pressure on distribution rates by as much as 25% by 2040."[55] However, PG&E does not provide a calculation of the actual rate value of this 25% downward pressure, and due to the complexity of rates, it could be misinterpreted to represent the

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[54] For example, if PG&E believes that serving load growth will require a disproportionately large number of new service transformers each serving small loads, it should provide a detailed explanation.

[55] PG&E Draft EIS Part 2 at 13.

impact on the larger *overall* electric rate, rather than the impact on the smaller *component* of rates associated with distribution. PG&E's overall electric rate is 0.40$/kWh, while the component of the electric rate associated with distribution is 0.14 $/kWh.[56] 25% of 0.14 $/kWh is about 0.035 $/kWh (or 3.5 cents) while 25% of 0.40 $/kWh is about 0.10 $/kWh (or 10 cents). Thus, interpreting a 25% downward pressure on distribution rates based on the overall electric rate would provide a result approximately 186% higher than PG&E's calculation of the potential downward pressure. To avoid confusion or misinterpretation about the magnitude of potential downward pressure on rates, PG&E's Final Report should make the exact scale of its rate impact clearer by explicitly reporting an estimated value in cents per kWh and stating the scale of the distribution rate in the Final Report body.

Regarding the second point, PG&E provides a preliminary rate model which predicts a small upward rate pressure in the near term, and an increasingly downward rate pressure thereafter.[57] PG&E does not address generation costs, transmission costs, wildfire safety costs, or uncertainties. PG&E's Final Report should include additional analysis and/or discussion of those elements. It should also make clear and explicit the scale of distribution rate impacts relative to the potential impacts due to generation.

Regarding the third point, PG&E includes several load shapes in its appendix slides for the EIS Part 2 Workshop[58] which are not included in PG&E Draft EIS Part 2. PG&E's Final Report should include all technology load shapes, as well as descriptions of the source data for each load shape.

Regarding the fourth point, PG&E repeatedly states that the load profiles used in the EIS Part 2 Base Scenario incorporate "existing and future customer behaviors (e.g., evolving TOU rates)."[59] However, nowhere in PG&E Draft EIS Part 2 does PG&E

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[56] PG&E Draft EIS Part 2 at 51. PG&E relegates this distinction to a footnote (footnote 49).

[57] PG&E Draft EIS Part 2 at 49.

[58] EIS Part 2 Workshop Presentation at slides 99-102.

[59] PG&E Draft EIS Part 2 at 15, 20, 21, 37, and 39.

describe how these future customer behaviors impact its load modeling, or how it models the evolution of TOU rates. PG&E's Final Report should include an explanation of specific future customer behavior and TOU rate modifications which affect PG&E load shapes.

Regarding the fifth point, PG&E discusses the impact of load factor on capacity in Section 9.2 of its Draft EIS Part 2.[60] PG&E's Final Report should explicitly clarify if the "peak day" on which PG&E calculates load factor is evaluated by PG&E on each circuit. PG&E should also clarify if higher load factors affect only the ratings of underground circuits and not the ratings of overhead circuits.

These clarifications will allow parties to better understand and evaluate PG&E's analysis, and the Commission to better evaluate the Final Report's findings for use in future distribution planning processes.

C. SCE Should Explicitly Report Unit Costs

Unlike the other two IOUs' draft reports, Southern California Edison Company (SCE) does not directly provide the unit costs for each mitigation type that it models in its Draft EIS Part 2. Each IOU should report its unit costs to make its modeling assumptions explicit and transparent; without unit costs, results are opaque and reports are more difficult to directly compare or contrast. While SCE does report the total number of projects and total cost for each project type, SCE should also explicitly report the unit costs it used in its analysis, describe the data it used to calculate these unit costs, and describe the methodologies it applied to these data.[61]

D. SDG&E Should Clarify Several Elements of Its Model

SDG&E Draft EIS Part 2 does not explain some details of SDG&E's methods. SDG&E's Final Report should:

1. Elaborate on how SDG&E constructed its Medium Duty/Heavy Duty Electric Vehicle (MD/HD EV) load shape;

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[60] PG&E Draft EIS Part 2 at 53.

[61] SCE Draft EIS Part 2 at A-18 and A-19, Tables 19 and 20.

2. Discuss how SDG&E performs weather normalization;
3. Elaborate on SDG&E's geospatial load disaggregation methodology; and
4. Modify SDG&E's Figures 4 through 6 for clarity.

Regarding the first point, SDG&E notes that it created its MD/HD EV load shape for the Demand Flexibility Scenario; however, SDG&E does not elaborate on what data it used to create its MD/HD EV load shape.[62] SDG&E notes that it tested several TOU rate structures to find a structure that most reduced capacity needs.[63] However, for completeness and transparency, SDG&E's Final Report should discuss the data SDG&E used as inputs to its MD/HD EV load shape, what data informed SDG&E's TOU rate structures, what data and methods it used to model customer response to TOU rate structures, and the resultant customer responses. SDG&E should include these details in its Final Report, either in the main body or in an appendix.

Regarding the second point, SDG&E's Final Report should provide greater detail on how SDG&E performs weather normalization. SDG&E Draft EIS Part 2 provides two stacked bar charts which illustrate the modeled load shapes of several devices on sample circuits for two scenarios.[64] SDG&E labels one "load shape" on the circuit as weather normalization. SDG&E mentions "assumed weather conditions [used] to generate typical and extreme peak day load profiles . . . ."[65] However, SDG&E does not otherwise elaborate on how it performed weather normalization. SDG&E's Final Report should further discuss weather normalization, either in the main body or in an appendix.

Regarding the third point, SDG&E's Final Report should discuss SDG&E's load forecast disaggregation methodology in further detail. SDG&E utilized "urban planning concepts and historical satellite imagery" in its geospatial analysis in LoadSEER to

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[62] SDG&E derived most of its other load shapes directly from the 2023 IEPR.

[63] SDG&E Draft EIS Part 2 at 14.

[64] SDG&E Draft EIS Part 2 at 10.

[65] SDG&E Draft EIS Part 2 at 6.

disaggregate load.[66] However, SDG&E does not elaborate on which specific urban planning concepts it utilized, what satellite datasets it drew upon, or exactly how SDG&E used either input in its geospatial analysis. SDG&E's Final Report should include these details, either in the main body or in an appendix.

Regarding the fourth point, SDG&E should modify its Figures 4 through 6 to make them clearer. SDG&E Draft EIS Part 2 provides area graphs that purport to illustrate SDG&E's modeled LDEV charging load shapes by management type and end use. However, counter to standard practice for area graphs, SDGE's graphs display end use areas that are set behind each other rather than stacked on top of each other.[67] This makes it difficult or, in some cases, impossible to read the entire load shape of a given end use. SDG&E should improve these graphs so that every load shape is fully visible.

With these clarifications, parties will be better able to understand and evaluate SDG&E's analysis, and the Commission will be better able to evaluate the Final Report's findings for use in future distribution planning processes.

V. CONCLUSION

All three IOUs' EIS Part 2 Draft Reports contain valuable new modeling and insights. However, as detailed in these comments, all three IOUs should include greater clarity and transparency in their respective Final Reports. In particular, the PG&E Draft EIS Part 2 secondary distribution modeling produces anomalous results. PG&E's Final Report should significantly expand PG&E's discussion of its secondary distribution modeling in order to provide more transparency, context, and justification. These improvements will allow the Commission and parties to better evaluate the Final Reports and consider the implementation of study recommendations in the distribution planning process.

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[66] SDG&E Draft EIS Part 2 at 6.

[67] SDG&E Draft EIS Part 2 at 13-14.

Respectfully Submitted,

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