BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	Rulemaking 21-06-017 (Filed July 2, 2021)

ENVIRONMENTAL DEFENSE FUND COMMENTS ON DRAFT ELECTRIFICATION IMPACT STUDY PART 2 REPORTS

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I. INTRODUCTION

On July 2nd, 2021, the California Public Utilities Commission ("Commission" or "CPUC") issued its *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future* ("High DER proceeding").[1] As part of this proceeding's focus on load forecasting and system planning for electrification, the Commission contracted with Kevala and Verdant Associates to conduct the Electrification Impacts Study ("EIS") Part I, which they published on May 9th, 2023.[2] On March 14th, 2024, Administrative Law Judges Hymes and Lakhanpal issued the *Administrative Law Judges' Ruling Seeking Comment on Staff Proposal*.[3] In this Staff Proposal, Staff recommended the Commission direct the utilities to conduct a flexible load Distribution Planning Process ("DPP") assessment that "quantifies the potential for flexible load strategies to reduce future distribution costs at the primary and secondary distribution level."[4]

On October 23rd, 2024, the Commission issued its Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps ("DPEP Decision").[5] The DPEP decision directed Pacific Gas & Electric ("PG&E"), Southern California Edison ("SCE"), and San Diego Gas & Electric ("SDG&E") (collectively "utilities") to conduct an EIS Part 2 in time to inform the 2025-2026 DPP cycle with a focus on "estimate[ing] and assess[ing] potential impacts (e.g., potential costs of upgrading the primary and secondary distribution grid) of meeting electrification needs under multiple scenarios."[6] The Commission also directed the utilities to include Staff's proposed flexible load DPP assessment in the EIS Part 2 in the form of a load flexibility mitigation scenario as well as an equity scenario.[7] The Commission directed parties to file any comments on the utilities' EIS Part 2 reports within 44 days of that filing.[8] The utilities filed their EIS Part 2 Reports

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[1] R.21-06-017, *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future* (July 2, 2021).
[2] R.21-06-017, *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, Electrification Impacts Study Part I: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates (May 9, 2023).
[3] R.21-06-017, *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, Administrative Law Judges' Ruling Seeking Comment on Staff Proposal (March 14, 2024).
[4] Staff Proposal at 82-83.
[5] R.21-06-017, *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps (Oct. 23, 2024) [hereinafter "DPEP Decision"].
[6] DPEP Decision at 97.
[7] *Id.* at 97-98.
[8] *Id.* at 99.

on October 31st, 2025. Pursuant to the Commission's DPEP order, these comments on the EIS Part 2 Reports are timely filed.

II. Comments on EIS Part 2 Reports

Taken as a whole, the utilities' EIS Part 2 Reports represent commendable analyses that demonstrate the scale of potential impacts to their distribution systems from electrification and the necessary role of demand flexibility in mitigating these impacts and the resulting costs. The Commission's primary conclusion from the utilities' efforts should be that the utilities should be doing more to maximize load flexibility on their systems and to target that flexibility to circuits where flexibility can maximize cost savings. There remain, however, omissions and unrealistic assumptions that impact the utilities' results and in particular likely underestimate the potential of load flexibility has a tool for mitigating, deferring, and avoiding grid upgrade needs.

a. None of the utilities' reports adequately capture the potential role of flexible service connections as a load flexibility tool

Flexible service connections are an emerging load flexibility tool with significant potential for creating distribution cost savings, but garner almost no consideration in their utilities' EIS Part 2 Reports. SCE states it is "assessing the role of demand flexibility, in part, enabled by…flexible interconnection options."[9] Neither PG&E nor SDG&E mention flexible service connections in their Reports, and none of the utilities appear to have included it as a demand flexibility tool. PG&E's Enhanced Demand Flexibility Scenario includes active and passive electric vehicle ("EV") managed charging, vehicle-to-grid, battery storage, and building electrification demand response.[10] SCE relied on the California Energy Commission's Enhanced Demand Flexibility ("D-Flex") tool to estimate load shifting from "light-duty EV, medium/heavy-duty EV, non-residential energy storage, residential energy storage, and HVAC-cooling."[11] And SDG&E produced demand flexibility load shapes for different use cases that includes both active and passive load management.[12] While these programs increase load flexibility in their respective utility territories, none of these programs should be considered flexible service connections as they were not implemented with the intention of "limiting the amount of peak power drawn from the grid by the

[9] SCE EIS Part 2 Report at 20.
[10] PG&E EIS Part 2 Report at 32.
[11] SCE EIS Part 2 Report at A-10
[12] SDG&E EIS Part 2 Report at 11-15.

fleets' chargers to avoid exceeding the capacity limits of the associated utility-side and/or customer-side electrical infrastructure".[13]

Ignoring the potential of flexible service connections, or simply lumping these agreements into a catch-all category of load flexibility, will likely produce an inaccurate and underestimated result for load flexibility impacts. This is because flexible service connections possess two beneficial characteristics as a load flexibility tool. First, flexible service connection agreements are geographically specific and can meaningfully impact the scale and pace of upgrade needs on specific circuits, allowing for the targeted demand management the utilities tout.[14] Recent research by Kevala found that allocating a set amount of demand flexibility across specific circuits can significantly increase capital cost savings when compared to allocating that flexibility across all circuits.[15] Flexible service connections can do just this as utilities can focus on offering such agreements on circuits that are already or expected to become constrained.

Second, flexible service connections can be a more predictable and reliable source of flexibility than price signal-based tools such as passive managed charging. Where utilities rely on time-of-use rates and other price signals to influence customers' demand, they can reasonably estimate average customer responsiveness over large scales but may struggle to accurately predict individual or small group behavior at the local level. Given this, they necessarily must make conservative assumptions for the purposes of system planning, such as discounting the amount of demand flexibility they expect when identifying needed grid upgrades. In contrast, flexible service connection agreements represent a clear contractual agreement outlining a customer's allowable demand during certain time periods. This means that utilities should have a greater level of certainty that participating customers' loads will interact with the grid as expected.

Ongoing work in both the Energization Timelines proceeding and High DER proceeding demonstrates that there is significant interest from the Commission, customers, and stakeholder in the development and use of flexible service connections, and this tool cannot simply be ignored in

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[13] Casey Horan et. al, Environmental Defense Fund ,Let's Get Flexible: Considerations for Unlocking Grid Capacity Using Flexible Interconnection (Feb. 2025), https://library.edf.org/AssetLink/q812pd5afr3hboi61cm503fprla5ge0p.pdf.
[14] *See* PG&E EIS Part 2 Report at 30 ("This increase in flexible loads supports greater demand-side management opportunities, allowing consumption to be shifted away from peak periods and for more targeted management based on local feeder peaks that may differ from the system peak.").
[15] Kevala, GridLAB, *California Load Management Standard Avoided Distribution Grid Upgrade Study*, at 2 (Aug. 2025), https://gridlab.org/wp-content/uploads/2025/08/GridLab_Kevala_CA-Load-Management-Standard.pdf.

the utilities' EIS analysis. In incorporating this tool in their analysis, the above factors should be considered in how the utilities account for flexible service connection agreements in their models.

b. SDG&E's report makes unrealistic assumptions regarding EV charging

SDG&E's EIS Part 2 Report includes three unrealistic assumptions regarding EV charging that it should address in the final Report. First, SDG&E assumed that all medium- and heavy-duty vehicle ("MHDV") charging would happen at fleet depots. This assumption is already unreasonable today and is likely to become less and less accurate over time. MHDV charging will comprise multiple different use cases including depot charging, shared charging hubs, destination charging, and on-route charging. In California today, most MHDV charging happens at the depot or at shared charging hubs.[16] Shared charging hubs can have distinct load profiles from private fleet depots as they can serve fleets with numerous varied duty cycles. Destination and on-route charging is expected to grow over time as vehicle capabilities increase and battery costs decrease, and their load profiles will likely also vary widely from that of depot charging. While there is uncertainty over the exact scale and timing of these trends, 100% depot charging is not a well-supported assumption. Instead, SDG&E should use multiple MHDV load profiles to capture known and anticipated variations in uses cases and charging of these vehicles.

Second, SDG&E's MHDV demand flexibility load shape assumes a peak charging window between 7am and 12pm. SDG&E states this window was chosen as it "proved to be the most effective at reducing capacity needs."[17] There is no consideration, however of whether such a load shape reasonably reflects the current status quo for MHDV fleet operators. This window includes a significant share of the morning commute and normal business hours, when many fleets vehicles are in operation and not available for charging. There is also no explanation of what capacity needs SDG&E is optimizing for in selecting this load profile. A single MHDV fleet can represent a significant source of load that individually drives circuit or even substation upgrade needs, and optimizing load flexibility from these customers requires accounting for both coincident and non-coincident peaks and avoiding the creation of secondary peaks. While EDF supports using a load flexibility scenario that reaches the outer bounds of what is feasible, it is not clear that SDG&E's

[16] California Energy Commission 2024. California Energy Commission MDHD ZEV Station Development in California. Data Last Updated [Feb.23, 2024]. Retrieved [Jan. 12, 2025] from [https://cecgis-caenergy.opendata.arcgis.com/datasets/CAEnergy::medium-and-heavy-duty-infrastructure/explore?filters=eyJDaGFyZ2luZ19vcl9IeWRyb2dlbiI6WyJDaGFyZ2luZyJdLCJQcm9qZWN0U3RhdHVzIjpbIkNvbXBsZXRlZCJdfQ%3D%3D&location=33.394541%2C-119.009440%2C7.61&showTable=true].
[17] SDG&E EIS Part 2 Report at 14.

assumptions meet this. As minimum, the final Report should explain why SDG&E believes such a load shape could be implemented at meaningful scale by MHDV fleets, and provide additional details regarding the system capacity needs impacted by such a load shape.

Finally, SDG&E's light-duty EV load shape under active managed charging fails to account for the impact of other types of load outside of the system peak window. The active managed charging load shape shows relatively flat light-duty EV load between 8pm and 4pm, dropping to near-zero during the 4pm-8pm peak window. While minimizing charging during the peak window likely has the greatest effect on reducing upgrade needs, additional optimization can happen to this load outside of the peak window to maximize system benefits. This could include increasing load during the middle of the day to absorb excess energy from renewables, or reducing charging during the morning peak period for MHDV charging discussed above. SDG&E should consider additional variables such as these in its analysis to further optimize this load, and explain what factors were considered in this optimization.

c. PG&E properly used a mitigated base scenario, but does not assume enough mitigation

PG&E's EIS Part 2 filing is unique among the utilities in specifying that it includes a base scenario that is mitigated by including low-cost solutions and assuming customer responsiveness to current and future price signals.[18] But, PG&E's mitigated base scenario still does not go far enough in its mitigation assumptions. In particular, EDF recommends that PG&E revise its analysis to include assumptions regarding active managed charging of EVs consistent with expected application of programs PG&E currently offers.[19] Assuming PG&E could revise its analysis to encompass its current programs, EDF would recommend that the other two utilities' base scenarios include similar assumptions.

Active managed charging, as described by PG&E, is "based on driver response to price changes and assumed smoothing within different price periods to avoid rebound peaks (such as through staggered TOU periods, charging management programs, or an aggregator)."[20] PG&E's Report assumes no active managed charging for any EV charging load types under the base scenario. This is despite the fact that some level of active managed charging is not only a reasonable assumption for future EV charging behavior, but is reflected in programs PG&E offers

[18] PG&E EIS Part 2 Report at 10-11.
[19] *Id.* at 69.
[20] *Id.* at 68.

customers today. PG&E is currently operating at least two programs – its Charge Manager program and their V2X pilot program -- which by its own definition would be considered active managed charging programs.

The first of these programs is PG&E's Charge Manager Program.[21] PG&E designed the Charge Manager program so residential customers could charge their vehicles at times "when electricity prices and demand are at their lowest."[22] It is not clear how many customers are participating in the program, but there is clearly customer demand as PG&E states it is fully subscribed.[23] Similarly, PG&E has also conducted or is currently conducting multiple pilot programs offering customers vehicle-to-grid ("V2G") and vehicle-to-everything ("V2X") capabilities. While V2X is distinct from active managed charging, the technology and communication protocols deployed in active managed charging lay the foundations for successful V2X deployment. Thus, if an entity demonstrates the capability to set up and operate a V2X program, it is very likely that they have the means and knowledge to do the same for an active managed charging program. PG&E has deployed V2G pilots with workplace vehicles[24] and electric school buses.[25] PG&E also offers a V2X pilot to residential and commercial customers operating a select list of EVs.[26]

Given the existence of these programs, it would be most reasonable for PG&E's base scenario to include moderate assumptions regarding the use of active managed charging by the currently eligible customer categories: residential and fleet depot charging. Assuming no active managed charging in the base case scenario could result in underrepresentation of active managed charging in both scenarios built off the base case. It also runs counter to the definition of the base (mitigated scenario) PG&E puts forth at the beginning of its Part 2 filing, which states that PG&E's engineers "developed low-cost solutions where feasible (e.g., load transfers) and load profiles

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[21] PG&E, EV Charger Manager, www.pge.com/en/clean-energy/electric-vehicles/ev-charge-manager-program.html.
[22] *Id.*
[23] *Id.*
[24] PG&E, *PG&E, Nissan, Fermata Energy, and the Schatz Energy Research Center Demonstrate Vehicle-to-Grid Technology in California*, investor.pgecorp.com/news-events/press-releases/press-release-details/2025/PGE-Nissan-Fermata-Energy-and-the-Schatz-Energy-Research-Center-Demonstrate-Vehicle-to-Grid-Technology-in-California/default.aspx.
[25] PG&E, *PG&E and the Mobility House Launch Groundbreaking Vehicle-to-Grid Electric School Bus Fleet with Fremont Unified School District*, investor.pgecorp.com/news-events/press-releases/press-release-details/2025/PGE-and-The-Mobility-House-Launch-Groundbreaking-Vehicle-to-Grid-Electric-School-Bus-Fleet-with-Fremont-Unified-School-District/default.aspx.
[26] PG&E, *Vehicle-to-Everything (V2X) pilot program*, https://www.pge.com/en/clean-energy/electric-vehicles/getting-started-with-electric-vehicles/vehicle-to-everything-v2x-pilot-programs.html.

incorporated existing and future customer behaviors, like evolving time-of-use (TOU) rates." To rectify this, EDF recommends that PG&E account of the programs mentioned above to more accurately estimate the amount of active managed charging across vehicle classes in the base scenario rather than setting the active managed charging levels for all vehicle types at zero.

d. SCE scenario planning reflects two very unlikely scenarios

In its Part 2 filing, SCE included two demand flexibility scenarios: the initial demand flexibility case, and the alternative demand flexibility case. The initial demand flexibility case is based on "assumed levels of demand flexibility," while the alternative case includes "elevated levels of flexibility."[27] With respect to EV charging in particular, the initial case assumes 8% light -duty and 52% MHDV participation in EV charging demand flexibility by 2040.[28] The alternative case assumes 100% percent participation of all EVs in 2040.[29] Together, the two scenarios create an upper and lower bound of what is potentially possible, but it is uncertain whether either modeled scenario is particularly likely, which makes both scenarios of limited use when determining what demand flexibility in SCE's territory may look like in the future. While the two scenarios create a lower and upper bound in which the actual participation rate is likely to land, neither scenario produces a participation rate that feels meaningfully predictive. Participation by 100% of EV owners is unlikely given some light-duty EV owners' reliance on public charging, and some fleets' operational needs that preclude participation in such programs. But, a base flexibility assumption that assumes less than one in ten light-duty EVs will participate in demand flexibility programs appears quite pessimistic. At minimum, SCE should provide additional information in its final Report regarding the source of these figures and the basis for their applicability in SCE's territory. EDF also recommends that SCE modify the initial demand flexibility scenario to reflect expected EV participation based at least in part on participation trends from actual SCE programs. This would allow SCE's base scenario to serve as a lower bound on estimated customer participation, the alternative demand flexibility scenario as an upper bound, and the initial demand flexibility scenario to reflect SCE's best guess of actual participation if demand flexibility programs are made available at scale.

[27] SCE EIS Part 2 Report at 9-11.
[28] *Id.* at 44.
[29] *Id.* at 45.

III. Conclusion

EDF thanks the Commission and utilities for the opportunity to provide these comments and urges the utilities to make the modifications recommended above.

Respectfully submitted,
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