BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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UTILITY CONSUMERS' ACTION NETWORK COMMENTS TO ADMINISTRATIVE LAW JUDGES' RULING ON APRIL 6, 2023 REQUESTING RESPONSES TO QUESTIONS ON TRACK 1 PHASE 1

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I. INTRODUCTION

Pursuant to the April 6, 2023 Ruling from Administrative Law Judges Kelly Hymes and Manisha Lakhanpal Requesting Responses to Questions on Track 1 Phase 1 (April 6 Ruling), Utility Consumers' Action Network (UCAN)[1] respectfully submits these Comments. The April 6 Ruling included Attachment 1 with 26 questions and Attachment 2 which included all the reports referenced in Attachment 1. UCAN responds to some, but not all, of the 26 questions in Attachment 1 and indicates which questions are being answered.

Additionally, parties were encouraged to consider and comment on the information submitted by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) in response to the March 9, 2023, Administrative Law Judge's Ruling (March 9 Ruling) seeking additional information on their distribution planning processes. Because UCAN represents the interests of ratepayers in the San

[1] UCAN is a 501(c)(3) non-profit public benefit corporation dedicated to protecting and representing the interests of residential and small business customers in the San Diego Gas & Electric service territory. Approximately 98% of UCAN's members are residential customers. UCAN has been active in Commission proceedings since 1983 and strives to meet the Commission's goals for rates that are equitable and affordable for all ratepayers.

Diego Gas & Electric service territory, UCAN reviewed only the information submitted by SDG&E in response to the March 9 Ruling to include in these Comments.

Furthermore, UCAN notes the significance of the Workshop on May 17, 2023, that reviewed and discussed the Kevala, Inc. Electrification Impact Study (EIS). This Part 1 Study was admitted into the record of this proceeding in the ALJ Ruling on May 9, 2023 (May 9 Ruling). Comments from utilities and stakeholders on the Part 1 Study are forthcoming. The May 9 Ruling describes Kevala's EIS as follows:

> "This Part 1 Study is a *Bottom-Up Load Forecasting and System Level Electrification Impacts Cost Estimate* approach. This methodology estimates the scale of electrification impacts from the bottom up; enables premise-and circuit-specific grid integration analysis. This Part 1 Study is a granular customer electricity consumption data analysis across all customer classes related to electricity distribution grid planning processes to enable California to meet its state energy goals."[2]

UCAN anticipates the Part 1 Study will have a significant impact on utility distribution-related processes going forward. UCAN has only begun its analysis of the Part 1 Study. Therefore, these Comments will remain fairly high-level with more detailed responses coming in our filing on June 19, 2023. While supportive of the state's clean energy and air goals, UCAN is always concerned about the costs to ratepayers who are already suffering from high energy bills. Consequently, UCAN's focus is on finding ways to lessen this energy burden on ratepayers who should not bear the full cost of California's policy goals.

[2] Administrative Law Judges' Ruling Setting a Workshop, Admitting into the Record Part 1 of the Electrification Impacts Study and Research Plan, and Seeking Comments, May 9, 2023, at 4 (May 9 Ruling).

II. DISCUSSION – SELECT QUESTIONS FROM APRIL 6 RULING

A. LOCAL PLANNING ENGAGEMENT

3. How should the Utilities' local planning engagement efforts on DPP be combined or coordinated with the community engagement efforts in other proceedings?

<u>UCAN:</u> A coordinated community outreach and education effort in general could help ratepayers understand changes in how electricity can be managed for better cost savings.

<u>DISCUSSION:</u> In Southern California Edison's (SCE) Community Engagement Survey Report filed with the Commission on May 15, 2023, (required in the Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation (R.18-04-019)), SCE offers a Summary of [Community Engagement] Survey Results.[3] One of the "asks" from community members was "more outreach on resources that are available to them for financial assistance, access to solar, and how to equip their home with back-up power systems." UCAN finds this is a general concern for many ratepayers in the SDG&E territory as well. Consequently, UCAN supports the Energy Division's proposal[4] that a consultant conduct outreach to help inform not only this proceeding but several of the other related proceedings such as R.22-07-005 (with the fixed charged proposals and future dynamic pricing) to help ratepayers understand the upcoming changes. All of California's ratepayers would benefit from learning how to best manage their electricity utilizing dynamic pricing and available DERs for efficiency and bill savings.

[3] R.18-04-019 Southern California Edison Company's (U 338-E) Submission of Community Engagement Survey Report Pursuant to Decision 20-08-046, filed May 15, 2023, at 3.

[4] Energy Division's 2022 Distribution Planning Community Engagement Needs Assessment Study Draft Scope of Work, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/distributed-energy-resources-action-plan/needs-assessment-sow-and-outreach-meeting-summary.pdf

B. DEMAND SCENARIOS AND PLANNING HORIZON

4. Should different demand scenarios, based on the California Energy Commission's Integrated Energy Policy Report (IEPR) load forecast data and/or other datasets, be used for utility DPP?

UCAN: The Kevala Part 1 Study reveals that the IEPR may be an insufficient planning tool to meet California's policy goals.

DISCUSSION: The Kevala Research Plan[5] described how the existing electric distribution planning processes may not be timely enough to select and deploy appropriate distribution infrastructure and DER solutions to meet grid needs. The Research Plan describes it this way:

> "The California Public Utilities Commission's (CPUC) current electric Distribution Planning Process' (DPP) Grid Needs Assessment (GNA) evaluates necessary grid investments based on a single forecast scenario selected from the latest, adopted version of the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR). This biennial statewide demand forecast focuses on an *economic* forecast of what is likely to occur rather than forecasting load based on *policy goals*."[6] (emphasis added)

The difference in the DPP planning process that Kevala developed is described as a "bottom up" premise-and circuit-specific grid integration approach versus the IEPR economic forecast or "top down" approach. The difference is striking. At the Workshop on May 17, Kevala discussed its high level preliminary findings that there is a potential for approximately $30-$50 billion in distribution grid investments by 2035 if measures aren't taken to reduce costs and manage loads.[7] Additionally, the EIS showed a potential annual peak demand reaching about 70

[5] May 9 Ruling, Attachment 3, submitted by Kevala, Inc. to CPUC on March 29, 2022, *Electrification Impacts Study Research Plan* (Research Plan).
[6] Research Plan, see Executive Summary.
[7] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/distribution-planning/2023-0517-eis-part-1-workshop_combined-slides.pdf, (May 17 Workshop Slides) see slide 16.

gigawatts for the State's three largest electric utilities combined by 2035.[8] In contrast, the 2022 IEPR Planning Forecast reached about 55 gigawatts by 2035.[9] One of the big differences noticed by UCAN was the timing of the IEPR and the GNA.

The Research Plan pointed out the gap in timing from when the investor-owned utilities developed their GNA's compared to when the IEPR was issued and adopted by the CPUC.

> "As an example, the investor-owned utilities' (IOU) 2022 GNAs were based on the 2020 IEPR. The 2023 GNAs are expected to be based on the 2021 IEPR. Since the IOUs require approximately one year to prepare the GNA, the process must begin before a more recent IEPR version has been adopted."[10]

Yet the Research Plan and commentors at the May 17 workshop noted that the IEPR is not accurately reflecting the number of electric vehicles (EVs) needed to meet state policy goals for transportation electrification and that it is behind in accounting for behind-the-meter storage. The grid is quickly changing at a customer-specific level (solar, batteries, load management) so it is woefully deficient to use historical data or averages. With GNAs based on a two-year old IEPR report that isn't accurately accounting for EVs and DERs, the current DPPs may not be timely enough to select and deploy appropriate distribution infrastructure and DER solutions to meet grid needs that will support California's policy goals.

UCAN believes that the Part 1 Study has identified a major flaw in the DPPs and the information relied on to plan for distribution investments. This could lead to costly and unnecessary investments for ratepayers. Further examination of this issue needs to take place as Kevala begins Part 2 of the EIS so that ratepayers are not over-charged for poorly planned and avoidable investments.

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[8] *Ibid.*
[9] *Ibid.*
[10] Research Plan, Executive Summary, fn. 1.

C. TRANSMISSION AND LOAD FLEXIBILITY

9. How should load flexibility (dynamic rates and other flexible load management strategies) be addressed in utility DPPs and on what implementation timeline? Responses should consider the scope and status of the proceeding on Advance Demand Flexibility Through Electric Rates (Rulemaking (R.)22-07-005).

UCAN: The effect of dynamic pricing and load management strategies could create savings for ratepayers by shifting loads to times when energy is abundant and away from peak times when it is expensive thereby avoiding costly upgrades and investments. The impact of load flexibility on utility DPPs, including analysis of a high DER future, needs to be further explored and understood.

DISCUSSION: At the May 17 Workshop, Kevala explained that the Part 1 Study was about developing a "baseline net-load forecast by premise" that can then be used to further study mitigation and demand modifiers as the most accurate way to generate estimates of the "where and when of capacity needs at a secondary transformer, feeder, feeder bank, and substation across all three large IOU service territories."[11] Kevala explained how Part 2 of the study would include developing up to five case studies with building electrification and electric vehicles that will include studying localized DER[12] adoption, grid impacts and mitigation strategies. This type of data and information could have a profound effect on utility DPPs.

As far as timing, coordinating Part 2 of the EIS study and the results of the dynamic pricing proceeding (R.22-07-005) could be beneficial and efficient because both will inform the DPP process: Part 2 of EIS Study by developing scenarios that could help inform the DPPs and dynamic pricing by providing one of the key components of demand flexibility and load shift.

[11] May 17 Workshop Slides, see slide 34.
[12] The Plan 1 Study clarified the definition of DERs stating: "Pursuant to State Assembly Bill 327 and Public Utilities Code Section 769(a), DERs include Distributed Renewable Generation Resources (e.g., solar), Energy Efficiency, Energy Storage, Electric Vehicles, Demand Response/Flexible Load Management Technologies (e.g., thermostats, internet-connected water heaters). May 17 Workshop Slides, see slide 09.

D. DATA PORTALS AND INTEGRATION CAPACITY ANALYSIS (ICA) IMPROVEMENTS

10. How do registration requirements impact the accessibility of the data portals and what changes are needed to improve access?

UCAN: Data access in general is an ongoing issue that needs Commission attention and resolution.

DISCUSSION: At the March 8, 2023, Load Integration Capacity Analysis Workshop in this proceeding, much of the discussion centered on data being inaccurate, unreliable, and not updated frequently enough. Parties in attendance such as Tesla and EVGo described how the lack of good data with granularity (especially regarding capacity constraints) was slowing down charging infrastructure growth and the ability to meet state goals for increased transportation electrification.

The need for timely and accurate data is not only hindering TE but it is also hindering that ability to move forward with dynamic rates because non-IOU load serving entities and energy management system providers cannot participate without it. This is harmful to potential cost savings for ratepayers. The Commission should help resolve the data access and accuracy issue as soon as possible.

E. DPP ALIGNMENT WITH TRANSPORTATION ELECTRIFICATION

21. How should Utilities ensure that they have sufficient grid capacity and DER visibility to efficiently implement the secondary distribution infrastructure, non-wires alternatives, and load management strategies required to support the Transportation Electrification investments envisioned through 2030?

UCAN: Utilities should be required to develop DPPs with a non-utility entity (like Kevala, Inc) and start with the "bottom up" premise-and circuit-specific grid integration analysis rather than the current CEC IEPR "top down" system planning in order to have grid capacity and DER visibility.

DISCUSSION: In its filing responding to the ALJs March 9 Ruling asking for utilities to further explain their DPP process, SDG&E describes how its "…DPP currently has three primary steps: forecast development, determination of grid needs and evaluation of mitigation options."[13] However, based on UCAN's answers to Questions 4 and 9 above, UCAN recommends several improvements in how the current SDGE DPP is organized.

a) The CEC IEPR is an outdated tool for DPPs to incorporate a High DER Future

As noted above, the CEC IEPR is a "biennial statewide demand forecast focus[ing] on an *economic* forecast of what is likely to occur rather than forecasting load based on *policy goals*."[14] In the first step, SDG&E assesses the CEC IEPR and then "selects the system-level load and DER forecast components that the IOUs believe are best suited for identifying future distribution infrastructure needs that are consistent with the objectives of safe and reliable service as well as state policy goals."[15] SDG&E then requests CPUC approval to use this system-level load forecast components in its annual planning studies.

After CPUC approval, SDG&E disaggregates the CEC IEPR forecast components to develop its circuit-level and substation-level forecasts of end-use loads and DER additions.[16] In its second step, SDG&E incorporates this circuit-and substation-level load and DER forecasts in its planning models and develops a "projected distribution grid topology" for short-and long-

[13] San Diego Gas & Electric Company's (U 902-E) Response to Administrative Law Judge's Ruling Seeking Additional Information from Investor-Owned Utilities on their Distribution Planning Process (SDGE DPP Response), filed April 10, 2023, at 2.
[14] Research Plan, see Executive Summary.
[15] SDG&E DPP Response, at 3.
[16] *Ibid.*

term gid needs. However, as noted above in UCAN's Question 4 response, there is a glaring timing issue that makes this current DPP methodology inefficient and outdated. Consequently, where SDG&E states that it filed its Grid Needs Assessment (GNA) on August 15, 2022,[17] it used the 2020 CEC IEPR. However, as noted above, the IEPR is not accurately reflecting the number of electric vehicles (EVs) needed to meet state policy goals for transportation electrification and that it is behind in accounting for behind-the-meter storage. Therefore, as the Kevala Research Plan pointed out, the way utilities currently develop their GNAs is by using old and inaccurate information.

b) SDG&E should be required to develop its DPP with a non-utility entity and use the "bottom up" premise-and circuit-specific grid integration analysis for load determinations

The Kevala Part 1 Study describes its "bottom up" approach as "start[ing] at the premise level to explore a "distribution first" planning approach where distribution capacity expansion needs are met by an integrated and efficient distribution, and ultimately sub-transmission and transmission planning processes that anticipate the value of DERs and load management technologies in addressing a high electrification future."[18] This bottom up approach includes disaggregating load and DER growth at the premise-level based on economic modeling using socioeconomic data and bill savings, customer by customer. [19] The end result is the development of a baseline net-load forecast by premise that incorporates varied assumptions of demand modifiers that could provide the most accurate way to generate estimates of the where and when of capacity needs. Not only could this bottom up approach better capture what current DERs are at premise and circuit-specific areas, but it could help identify where DERs could be best

[17]SDG&E DPP Response, at 6.
[18] May 17 Workshop Slides, see slide 25.
[19] *Ibid.*

incentivized and situated to capture and release their full value. This could generate system savings (less utility investment) which ultimately can create savings for ratepayers.

c) SDG&E should be required to have a non-utility entity assess its DPP plan and determine the most cost-effective, non-wires alternatives that captures the highest value of a High DER Future for ratepayers

In its third step, evaluation of mitigation options, SDG&E assesses the feasibility of distribution infrastructure improvements.[20] It also assesses whether "utility-owned Non-Wires Alternatives (NWAs) – for example, battery storage – would be a cost-effective option for addressing an identified need."[21] At this crucial step, UCAN believes it would be better for ratepayers to have a non-utility entity make an assessment for any NWA options. This could be used in conjunction with the "bottom up load forecast" methodology to determine the where and when of capacity needs and the most cost-effective and efficient way to incorporate DERs into this scenario. It is a conflict of interest between the utilities and ratepayers to have utilities determine NWA options because the utility is incentivized to make a return on these investments rather than incorporating customer-owned or other 3rd party DER options. UCAN urges the Commission to examine this particular part of the DPPs.

III. CONCLUSION

UCAN looks forward to working with the Commission and parties to explore all of the available options to improve the DPPs, achieve California's clean air and energy goals and help ratepayers save money.

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[20] SDG&E DPP Response, at 3.
[21] *Ibid.*

Respectfully submitted,
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