**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates.	Rulemaking 22-07-005 (Filed July 14, 2022)

OPENING COMMENTS OF THE VEHICLE-GRID INTEGRATION COUNCIL ON TRACK B WORKING GROUP REPORT

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In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), and pursuant to *Assigned Commissioner's Phase 1 Scoping Memo and Ruling*, issued November 2, 2022, and the *Email Ruling Modifying Deadlines for Working Group Proposal and Comments* issued by Administrative Law Judge ("ALJ") Stephanie Wang on September 29, 2023, the Vehicle-Grid Integration Council ("VGIC") hereby submits these opening comments on the *Track B Working Group Report*, submitted by Southern California Edison Company ("SCE"), on October 11, 2023, on behalf of the Track B Working Groups.

I. INTRODUCTION.

VGIC commends the Commission for implementing the *Order Instituting Rulemaking To Advance Demand Flexibility Through Electric Rates* ("DFOIR") on July 22, 2022, to enable widespread demand flexibility.[1] Furthermore, VGIC appreciates the Energy Division ("ED") staff's extensive efforts in forming and facilitating the two working groups for Track B of this proceeding focused on developing guidance for demand flexibility design ("Working Group 1") as outlined in Issue 3 of Phase 1 Scoping Memo and Ruling, and systems and processes for

[1] CPUC R.22-07-005. *Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates*. July 14, 2022.
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K285/496285639.PDF

access to process and responding to price signals ("Working Group 2") outlined in Issue 4.[2] Importantly, VGIC appreciates all efforts from stakeholders involved in the Track B working groups' discussions to streamline and expedite the adoption of demand flexibility rates for large investor-owned utilities ("IOUs") while exploring options for new systems and processes for customers and service providers to access dynamic electricity prices.

VGIC strongly believes that electric vehicles ("EVs") are well-positioned to take advantage of dynamic pricing and provide immense load flexibility value. Vehicle Grid Integration ("VGI") strategies, including managed unidirectional charging, bidirectional charging and discharging, and distributed energy resource ("DER")-paired charging, can unlock EVs as strategic grid assets, including through participation in dynamic rates. These price signals can directly influence customer behavior or integrate with automated charge management systems for a "behind the scenes" customer experience. In other words, VGI strategies will play a key role in helping California meet its ambitious clean energy and transportation electrification goals, and the rates under consideration in Track B represent one important tool to unlock this capability.

VGIC generally supports various components of the Working Group 1 party proposals and notes that the three main party proposals – the ED staff proposal, Joint IOU proposal, and Microgrid Resources Coalition ("MRC") proposal – share a significant share of proposal elements. Similarly, VGIC supports certain core elements in proposals made by stakeholders on the systems and processes for access to process and respond to price signals in Working Group 2.

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[2] CPUC R.22-07-005. *Assigned Commissioner's Phase 1 Scoping Memo and Ruling*. November 2, 2022. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M498/K072/498072273.PDF

VGIC offers these comments, summarized below, in support of implementing fair, compelling, and productive demand flexibility rate components contemplated in Working Group 1 and Working Group 2 proposals.

- VGIC supports including certain key components in the final guidance for demand flexibility rate design to ensure the widespread participation of VGI resources, including:
    - Forward Price Curves
    - Import/Export Symmetry
    - Distribution Component
    - Transmission Component
    - Dual Participation

II. VGIC SUPPORTS INCLUDING CERTAIN KEY COMPONENTS IN THE FINAL GUIDANCE FOR DEMAND FLEXIBILITY RATE DESIGN TO ENSURE THE WIDESPREAD PARTICIPATION OF VGI RESOURCES.

VGIC reiterates its appreciation for the immense breadth and depth of stakeholder coordination that underpins the Working Group 1 party proposals. We believe that these proposals and the broader demand flexibility guidance effort are critical as California faces mounting energy and transportation transition challenges. VGIC urges the Commission to adopt the below elements of the party proposals in its demand flexibility guidance.

A. Forward Price Curves and Transactive Element.

The Energy Division ("ED") staff proposal would direct the investor-owned utility ("IOU") applications to "include an **optional** transactive pricing program for customer classes that are able to schedule their loads on a forward (e.g., week-ahead) basis in response to a forecasted price" (**emphasis added**).[3] The Joint IOUs note in their proposal that forward transactions (i.e., forward price curves) are too complex for initial offerings and proposes first to offer forward transactions in a pilot setting instead.[4] Notwithstanding their complex nature, forward price curves can help EV customers and fleets plan charging and vehicle operations well ahead of forecasted high or low-price hours, providing customers the incentive needed to provide demand flexibility and shift load to off-peak times. For example, a fleet may wish to adjust its delivery operations in response to a forward contracted price curve. While VGIC appreciates the Joint IOUs' concern about including forward transactions as an initial offering, we believe ED's proposal to offer an optional transaction pricing program for customers who wish to participate strikes an appropriately balanced opportunity for participants. First, it provides an option for participants but does not require all customers who take service under demand flexibility rates to utilize the forward price curves element. This "opt-in" structure means that any complexity, perceived or real, is not imposed on customers who do not wish to engage in it. Secondly, customers who *do* wish to engage in the forward price curve element may do so in partnership with an automation service provider, energy management service provider, smart device, or any other third party that offers relevant services, which means that customers who opt in have choices they can make to manage that complexity. VGIC urges the Commission to adopt demand flexibility guidance that includes a forward transaction component to ensure the goals set in the DFOIR are met.

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[3] CPUC R.22-07-005. *Track B Working Group Report and Notice of Availability – Attachment A: California Public Utilities Commission Demand Flexibility OIR Track B Working Group Report*. October 11, 2023. Pg. 4 and 24.

[4] CPUC R.22-07-005. *Track B Working Group Report and Notice of Availability – Attachment A: California Public Utilities Commission Demand Flexibility OIR Track B Working Group Report*. October 11, 2023. Pg. 4.

B. Import/Export Price Symmetry.

VGIC strongly supports ED staff's Working Group 1 proposal detailing that the dynamic price for demand flexibility rates should be symmetric and bidirectional. The Commission can unlock far greater value from EV customers and fleets by providing customers the needed price signal to not only shift load but also export energy during peak times. This price symmetry offers a "V2X multiplier": dynamic rates can align EV charging load with real-time grid conditions to achieve a maximum EV charging load reduction that is fundamentally limited by a customer's initial plan to charge during a given period. However, dynamic *export* rates can elicit exports from EVs that may not have otherwise been planning to charge at all during that period. In other words, the maximum EV charging export capability is not limited by a customer's initial plan to charge during a given period, so much deeper net peak system load reductions can be achieved, along with other grid benefits. To provide a more specific example, consider EV A charging at 4 kW during a local or system peak period. High dynamic price signals during that window could induce EV A to reduce charging to 0 kW. This achieves a net reduction of 4 kW at the local and system level. If exports were encouraged through compelling dynamic export price signals during that same period, EV A could stop charging *and* could export power back to the grid at, for example, 10 kW. Through the addition of bidirectional pricing, EV A provides a total net local and peak load reduction of 14 kW (i.e., 4 kW load reduction + 10 kW grid export). This demonstrates the critical importance of export price signals for bidirectionally capable EVs and EV chargers in particular.

C. Dynamic Distribution Component.

VGIC supports the inclusion for a dynamic distribution component as part of the demand flexibility rates from the outset, as proposed by ED staff, although we are uncertain whether the circuit-specific scarcity price curves is the best approach for customers.[5] It is critical that *some* distribution component is offered to customers, whether through dynamic rates or through a programmatic approach that complements dynamic rates, as explained below in Sections II.C.iv and IIC.v.

The 2023 Kevala Electrification Impacts Study Part 1 ("EIS Part 1") estimates that distribution system investment from electrification will amount to $51 billion by 2035. Cal Advocates' recent Distribution Grid Electrification Model ("DGEM") study and report indicates that through load management, including primarily EV load management, this value can be reduced to $26 billion. These studies underscore one simple, immutable fact: **<u>when and how EV charging occurs remains the largest factor in determining future distribution system costs</u>**. The DGEM study indicates that distribution system investments required to support high electrification through 2035 can be **<u>cut in half</u>** primarily through managing EV charging load. We believe there are even greater cost saving opportunities from bidirectional charging and Vehicle-to-Grid ("V2G") solutions. Senate Bill ("SB") 676 and the VGI Strategies Implementation Decision ("D.") 20-12-029 establish drivers for the Commission to advance VGI solutions and transition the VGI technology market from demonstrations and pilots to full-scale, sustainable commercialization. However, the comparative findings of EIS and DGEM establish an abundantly clear **$25 billion core imperative** for the Commission to develop and enact VGI strategies that target distribution level value.

A recent IEEE case study indicates how coordinated distribution system EV load optimization differs from California's current patchwork of EV load management strategies,

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[5] CPUC R.22-07-005. *Track B Working Group Report and Notice of Availability – Attachment A: California Public Utilities Commission Demand Flexibility OIR Track B Working Group Report*. October 11, 2023. Pg. 4 and 12.

which rely on traditional demand response, TOU rates, and emerging RTP pricing based solely on *system conditions*:[6]

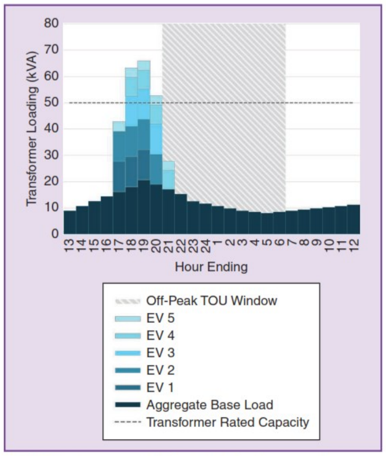

figure 2. An aggregate EV charging load on a single transformer with no management. kVA: kilovolt-amperes. (Source: WeaveGrid.)

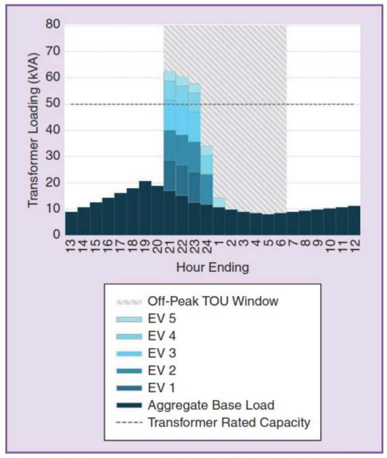

figure 3. An aggregate EV charging load on a single transformer when optimized solely for bulk system benefits. (Source: WeaveGrid.)

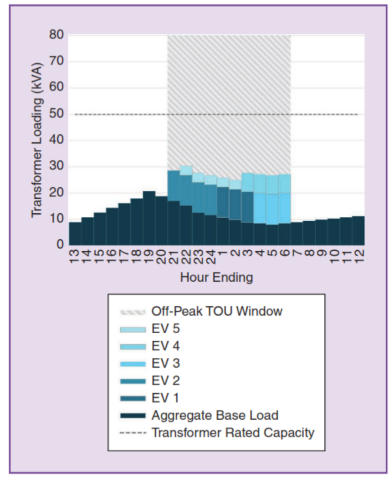

figure 6. An aggregate EV charging load optimization on a single transformer when considering distribution constraints. (Source: WeaveGrid.)

This data demonstrates the potential impacts of EV load management programs that target bulk system benefits ("Figure 3" above) compared to those that consider distribution load constraints ("Figure 6" above). In both cases, the system peak is reduced, but only in the distribution constraint case is the EV charging load kept below the distribution asset limit.

VGIC lists below several distribution system EV management strategies that can support capturing this $25 billion in potential savings, including several rate design components from Working Group 1 proposals and additional elements VGIC recommends the Commission consider:

i. **Circuit-Specific Pricing (i.e., ED staff proposal, SCE RATES TeMix Pilot).** This approach promotes economic efficiency and is particularly beneficial for exporting customers on congested circuits or EV charging customers on circuits

[6] *Utility Planning for Distribution-Optimized Electric Vehicle Charging.* Matthew Mills, Manasseh Obi, Kendall Cody, Kyle Garton, Amanda Myers Wisser, and Sammy Nabahani. October 19, 2023. IEEE Power & Energy Magazine.

with excess capacity. However, this may create challenges for customers that require a reasonable degree of reliable and predictable pricing in order to inform investment decisions. For example, customers installing bidirectional charging equipment will incur a high upfront cost that can be recovered over time through V2G revenues based on the various slices of the "value stack," which may include energy and generation capacity, transmission capacity, distribution capacity, and ancillary services value streams. While it may be feasible to forecast out changes to generation and transmission-related value stack components, the distribution component can be much more volatile over a few years as utilities add distribution capacity and/or neighbors add rooftop solar, for example. Since bidirectional charging equipment is not eligible for Self-Generation Incentive Program ("SGIP") funding or any other consistent market transition support, the volatility of circuit-specific pricing over the span of a few years can present a barrier to bidirectional equipment adoption. Additionally, utilities may face challenges with the computational burden behind circuit-specific pricing. One real-world example of circuit-specific pricing is SCE's ongoing RATES TeMix pilot. Another example is San Diego Gas & Electric's ("SDG&E") Power Your Drive ("PYD") VGI Rate, which offers a Distribution Critical Peak Pricing ("D-CPP") adder during the top 200 hours for that customer's circuit. While the D-CPP adder price is system-wide, the top 200 hours differ from circuit to circuit. Note SDG&E's PYD VGI Rate D-CPP is not a dynamic distribution component compliant with the California Energy Commission's ("CEC") Load Management Standard ("LMS"), although SCE RATES TeMix likely is compliant.

ii. **Circuit Clustering (i.e., Pacific Gas and Electric's ("PG&E") Proposed Vehicle-to-Everything ("V2X") Pilots approach).** Organizing circuits into tranches of circuits that share similar characteristics rather than modeling each specific circuit can mitigate both of the challenges cited above with the circuit-specific approach: uncertainty and complexity. In addition to PG&E's proposed circuit clustering methodology, utilities in New York have already implemented this approach, though with two clusters: congested and non-congested. New York's Value of Distributed Energy Resources ("NY VDER") tariff includes two distribution components: Demand Reduction Value ("DRV") and Locational System Relief Value ("LSRV"). The DRV is a system-wide distribution component, whereas the LSRV applies only to the most congested circuits. This is effectively the simplest form of PG&E's clustering methodology, containing two clusters. To the extent circuit clustering supports customer equipment investment and reduces complexity for utilities relative to ED staff's circuit-specific approach, NY VDER's LSRV approach may offer further customer support and complexity reduction. Note that NY VDER LSRV's approach is not a dynamic, hourly price, whereas PG&E's proposed clustering methodology would be a dynamic, hourly price signal in compliance with the CEC's LMS.

iii. **System-wide Dynamic Distribution Component (i.e., Joint IOU Proposal).** The Joint IOUs' proposal offers the simplest implementation initially for dynamic distribution component: a system-wide distribution component. Although this is the least economically efficient and fails to meaningfully support circuits that are most congested, it is undoubtedly the easiest for utilities to implement initially.

Real-world examples of this include the Net Billing Tarriff's ("NBT") Avoided Cost Calculator ("ACC") distribution component and NY VDER's DRV component, which apply equally across each utility's system and reflect distribution value. Note these examples are static and not dynamic distribution components.

iv. **Programmatic Distribution Load Optimization.** VGIC recommends the Commission consider a programmatic alternative to dynamic distribution load management. This can be implemented in lieu of a dynamic distribution rate component. In this case, customers would receive a dynamic price signal to benefit system and transmission conditions but enroll in an EV distribution load management program to support local distribution system capacity. The exact compensation structure for this could be structured with different options: one that provides a relatively high degree of predictable savings/revenue opportunities for customers (e.g., fixed monthly compensation) and one that provides relatively less predictability but greater volatility for customers (e.g., event-based performance). This approach could reduce complexity for utilities as circuit-specific scarcity pricing curves do not need to be developed and communicated to customers. Instead, third-party aggregators can enroll EV charging customers in the utility distribution programs and integrate with the utility's operations to respond to real-time distribution conditions. Notably, this type of programmatic approach is likely required for other distribution level grid services, as detailed below. One key customer benefit of this programmatic approach is the ability to open enrollment and participation up to a range of capable end-use devices, including both networked EV chargers and connected EVs.

v. **Programmatic Distribution Grid Services Optimization.** While either a rate component (i.e., i-iii above) or programmatic approach (i.e., iv above) can support load reduction and energy export value streams, VGIC is unaware of examples or proposals for distribution-level rate components that can promote voltage support, frequency regulation, or other distribution level value streams. These grid support functions can support the fast-evolving grid, especially on circuits with a relatively high penetration of bidirectional energy flow and intermittent generation and load. From a customer perspective, program offerings that can unlock these grid services can bolster the value proposition of dynamic EV charging or exports and exceed the effective "price ceiling" represented by the ACC, which does not include these distribution-level values. This programmatic approach can also fulfill the vision of California's smart inverter requirements and provide compensation for inverter-based integration with utility DER Management System ("DERMS") platforms.

Ultimately, whether the Commission adopts *circuit-specific methodologies* like ED staff's proposal, SCE RATES TeMix Pilot, or SDG&E's Power Your Drive VGI Rate, *clustering methodologies* like PG&E's V2X Pilot Rate proposal or NY VDER's LSRV, *system-wide distribution components* like NBT/ ACC or NY VDER's DRV, or a programmatic approach to distribution optimization as detailed above by VGIC, **we strongly urge the Commission to adopt *some* meaningful mechanism for customers to optimize EV charging and export in response to distribution system conditions.** California has over 1.5 million EVs, including many light-duty EVs ("LDV") that co-exist on circuits in areas with uniquely high EV concentrations. Meanwhile, utilities can expect to see significant medium- and heavy-duty EVs ("MHDV") charging facilities deployed near one another, e.g., in industrial zones and along shipping corridors, where the challenges of distribution system management may quickly eclipse other utility priorities. Taken together, these factors paint a clear and daunting picture that can be meaningfully addressed through the Commission promoting dynamic EV distribution management. Whether this is done through the rate component examples noted above and in the Working Group 1 Proposals, VGIC's proposed programmatic approaches, or a combination of rate and nonrate programs, it is critical that this next step be taken.

VGIC recommends the Commission direct IOUs to implement these approaches sooner rather than later to support VGI. *If* the Commission chooses to adopt a relatively complex methodology, e.g., ED's staff's circuit-specific approach, and IOUs expect this complexity to delay implementation, then there should be an interim approach adopted. For example, the IOUs can leverage the already-developed PG&E circuit clustering methodology, the already-implemented SDG&E PYD VGI Rate D-CPP methodology, or a new but straightforward programmatic approach while they develop long-term implementation plans for circuit-specific pricing.

It is important to recognize that VGI solutions, unlike many other DERs, do not benefit from any existing market transition support paradigm that encourages the deployment of grid-friendly technology. For example, bidirectional charging equipment is not eligible to receive SGIP incentives, and networked charging equipment is not eligible to receive smart thermostat technology rebates. As a result, the need to adopt meaningful, customer-friendly strategies to unlock distribution value should be viewed as a high-priority goal within the Commission's upcoming dynamic rate guidance not only to support the grid but also to support the relatively nascent VGI market, as envisioned by SB 676 and the VGI Strategies Implementation (D. 20-12-029).

D. Dynamic Transmission Component.

VGIC supports ED staff's proposal to include a transmission component as part of the demand flexibility rates. As with the distribution and generation components, transmission components should also apply to imports and exports to ensure the value from EV customers and fleet participation is fully captured.

E. Dual Participation.

As indicated in Section II.C above related to distribution value, VGIC considers both dynamic rates and nonrate programs referenced in Section II.C.iv-v important levers to unleashing EV load flexibility to offset distribution upgrade costs. As demonstrated by the 2020 VGI Working Group Final Report, there are *thousands* of VGI use cases, which means a one-size-fits-all approach to recruiting and maintaining customer engagement is unlikely to be feasible. On the grid operator and utility side, it is clear resource diversity will be needed to usher in California's ambitious clean energy goals. VGIC believes this concept of portfolio diversity extends to demand-side reduction/export *strategies* as well as bulk system generation *resources*. As such, advanced demand flexibility requires a multi-prong approach.

California's existing dual participation rules, stemming from the bifurcation of supply-side demand response ("DR") and load modifying approaches, prohibit this diverse portfolio in order to guard against double counting and double compensation of resources. While this paradigm was appropriate at the time, California has since established programs that exist outside of both categories, for example, the Emergency Load Reduction Program ("ELRP"),[7] which necessitates updated Commission direction.

ELRP customers are compensated for reducing energy consumption or increasing electricity supply during electrical grid *emergencies*. However, while ELRP provides critical load reduction or capacity during grid emergency events, these events are limited in nature and only provide opportunities for customers to respond to these events during system peaks between May through October. In stark contrast, the dynamic prices considered in this DFOIR aim to promote year-round, 24/7 load and export optimization, including distribution-level benefits.

In the Emergency Reliability Phase 2 Decision (D.21-12-015), the Commission established ELRP Customer Group A.5: EV/VGI Aggregations and authorized dual participation between Customer Group A.5 and dynamic or real-time equivalent rate designs. However, authorized dynamic rate pilots (PG&E Commercial EV Day-Ahead Hourly Real-Time Pricing, or "DAHRTP", SCE RATES TeMix, and SDG&E's Export Compensation Pilot) do not permit dual participation with ELRP. Only one proposed pilot rate design – PG&E's V2X Pilots – would enable dual participation with ELRP, as required by Commission Resolution E-5192.[8] VGIC believes the Commission appropriately authorized dual participation between ELRP, an emergency demand response program existing outside of the existing DR paradigm, and dynamic rates in D.21-12-015. The Commission correctly implemented this provision in E-5192 for PG&E's V2X Pilots. As confirmed through these Commission directives, dynamic pricing should be able to work together with nonrate programs to maximize VGI.

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[7] *See* CPUC Emergency Load Reduction Program. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/emergency-load-reduction-program. Accessed November 3, 2023.

[8] CPUC Resolution E-5192. May 5, 2022. Pg. 20, 22, 23, 32, and 38.

As such, VGIC strongly recommends the Commission include in its dynamic rate guidance a directive for IOUs to enable dual participation between dynamic rates and appropriate nonrate programs, including, at a minimum, ELRP. VGIC believes prohibiting dual participation sends the wrong signal to customers, making them choose between two strategies that achieve different goals. VGIC recommends the Commission avoid pitting these two effective demand-side management strategies against one another rather than allowing them to work together.

III. CONCLUSION.

VGIC appreciates the opportunity to submit these opening comments on the Track B Working Group Report. We look forward to further collaboration with the Commission and stakeholders on this initiative.

Respectfully submitted,

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