Application No.:	A.22-05-004 (Consolidated with A.22-05-002 and A.22-05-003)
Exhibit No.:	SCE–14
Witnesses:	See Table of Contents

(U 338-E)

Application for Approval Of 2023-2027 Demand Response Programs

Exhibit 14 – Phase II Rebuttal Testimony

Before the
Public Utilities Commission of the State of California

Rosemead, California
May 12, 2023

Exhibit SCE-14 – Phase II Rebuttal Testimony

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Southern California Edison Company (SCE), through the witnesses identified in the Table of Contents above, provides the following Phase II Rebuttal Testimony in accordance with the Assigned Commissioner's Ruling on January 27, 2023, and the Administrative Law Judge's Ruling issued in this proceeding April 25, 2023. The qualifications of the witnesses providing this testimony are set forth in SCE Exhibit-05 served in this proceeding on May 2, 2022. Each of these witnesses hereby affirms that the testimony herein corresponding to that witness was prepared by that witness and/or under the witness's supervision; that insofar as the material is factual in nature, the witness believes it to be correct; and that insofar as this material is in the nature of opinion or judgment, it represents the witness's best judgment.

I.
EMERGENCY LOAD REDUCTION PROGRAM PILOT

The Commission should not adopt party proposals for the Emergency Load Reduction Program (ELRP) pilot that would modify the program in ways that are contrary to its purpose and/or strike the wrong balance between the expenditure of funds and the emergency load relief the pilot provides. The ELRP is not the appropriate vehicle for the testing or adoption of specific technologies and business models, nor is it intended to provide a revenue stream for emerging technologies. The Commission adopted the ELRP pilot in the wake of the August 2020 grid emergency as an emergency program that seeks to enlist all available resources to participate in supporting the grid during an emergency. For this reason, there are broad participation options for various technologies, aggregators, and customer segments so that every potential resource can participate. While some new technologies are participating, such as vehicle to grid integration (VGI) aggregations and virtual power plants, ELRP is neither intended nor suited to be a support mechanism for these emerging technologies. ELRP's high incentives impose a significant cost on customers and SCE recommends a judicious approach to any potential use of the ELRP beyond emergency grid support. Any arguable gaps in programs or participation models necessary to support promising emerging technologies should be addressed through pilots tailored to meet the specific needs of those technologies. Ideally, clean capacity such as

storage should be used more extensively to support the grid rather than only in emergency situations.

A. VGIC's ELRP Recommendations Should Be Rejected

VGIC makes several recommendations related to the ELRP (and as to Sub-Group A.5 in particular), including that the investor-owned utilities (IOUs) should be prohibited from making certain program changes via advice letter, that the submission date of the annual advice letter should be moved up, that the compensation rate should be increased, and that electric vehicle (EV) participation should be expanded through via telematics.[1]

These recommendations are not well-founded and should not be adopted. First, the annual advice letter process appropriately allows the IOUs to make improvements to the Pilot based upon experience.[2] D.21-03-056 and D.21-12-015 correctly permit the IOUs to utilize the annual advice letter "to manage program enrollment, improve program efficiency, increase potential load reduction available to ELRP, improve program value, and reduce program cost."[3] The ability to make adjustments via advice letter is a critical tool to enable ongoing improvements rather than keeping program features that may not work as intended at the expense of customers. Second, the schedule of the annual advice letter process currently in place allows for adequate time to both assess the prior season and make appropriate changes for the coming season. An earlier filing date for the annual advice letter could prevent the IOUs from having sufficient time to develop potential improvements, particularly if ELRP events occur late in the season (which runs through October), where billing meter data could take up to 45 days after an

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[1] VGIC Testimony at 31-32. Unless stated otherwise, all citations to "Testimony" herein refer to Phase II DR Intervenor testimony served April 21, 2023, per the Assigned Commissioner's Ruling issued in this proceeding on January 27, 2023.

[2] D.21-03-056, which established the ELRP, authorized the Utilities to submit a joint Tier 2 Advice Letter on or before December 31 of each program year to propose changes for the upcoming season. D.21-12-015 expanded the ELRP and added to the types of changes that could be proposed through the annual Advice Letter. D.21-12-069 modified the deadline for submission of the annual Advice Letter from December 31 to January 15 to give the IOUs necessary time to evaluate the prior season.

[3] D.21-12-015, Attachment 2 at 20.

event to become available, and overall lessons learned from the entire season take time to formulate.

Third, as SCE discussed in its comments responding to the questions posed in the January 27, 2023, Assigned Commissioner's Ruling, SCE has concluded based on its experience and data from the ELRP after two seasons that $1/kwh for load reduction during ELRP events strikes the appropriate balance between incentivizing lower energy use and prudent expenditure of customer funds. As a result of the increased incentive amount (from $1/kwh in 2021 to $2/kwh in 2022), a significantly larger participant pool (due mainly to the addition of the residential ELRP subgroup),[4] and the heat events that occurred over several days in August-September 2022, ELRP incentive payments jumped from approximately $20,000 in 2021 to approximately $111 million in 2022. SCE is not aware of any load impact data indicating that resetting the ELRP incentive at the original level of $1/kwh will materially diminish load reduction during ELRP events. In fact, load impact data show weak load reduction attributed to the program.[5] VGIC's comparison to Massachusetts and Rhode Island's ConnectedSolutions programs[6] is inapt as those programs appear to be aimed at battery energy storage and virtual power plants, not vehicle to grid technologies. In addition, VGIC cites the capacity rate of Massachusetts ConnectedSolutions Daily Dispatch incentive rate ($200/kW) and parameters (30 to 60 events per year), but ELRP's program design is more akin to the Summer Targeted Dispatch. Based upon the example in their program material, a 200 kW system would yield $7,000 in incentives in the Summer Targeted Dispatch program, which is less lucrative than

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[4] Nearly two million CARE, FERA, and high usage residential customers were defaulted into the program as a result of the addition of subgroup A.6 by order of Decision 21-12-015.

[5] Load impact data *available at* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/emergency-load-reduction-program/elrp-2022-program-data/sce-elrp-hourly-with-lip-values.xlsx.

[6] Massachusetts ConnectedSolutions Program *available at* https://www.nationalgridus.com/MA-Business/Energy-Saving-Programs/ConnectedSolutions. Rhode Island ConnectedSolutions Program at https://www.rienergy.com/RI-Home/ConnectedSolutions/.

ELRP's compensation rate given ELRP's current parameters for Sub-Group A.5. (30 hours minimum dispatch at $2/kWh).[7]

Fourth, VGIC's recommendation to allow telematics-based aggregation to be eligible to participate in ELRP until permanent protocols are developed (which is coupled with recommendations to expand EV DR participation via telematics by increasing the budget for SDG&E's proposed EV DR pilot and to expand the scope of the workshop required under D.22-08-024 to include telematics for DR programs or require a separate workshop) is misplaced because the ELRP is not the appropriate program to test or advance new approaches to EV participation. The focus of the ELRP is to provide emergency load reduction, and the administrative work around the program is focused on being able to enroll and activate participants with ready capability to provide such load reduction. SCE supports electric vehicles, particularly those with grid service capabilities, as one of many types of distributed energy resources (DERs) that will help California achieve its clean energy goals. However, the ELRP Pilot is not the appropriate avenue to test or advance those capabilities and policies. As described in Exhibit SCE-03, SCE intends to explore how to incorporate EV capabilities as a grid resource in its proposed Mass Market DR pilot.

B. CEDMC's ELRP Recommendations Should Be Rejected

The Commission also should not adopt the proposal of the California Efficiency + Demand Management Council (CEDMC) to calculate ELRP Group B's Incremental Load Reduction (ILR) at the Meter Level rather than the Resource Level and create a minimum dispatch requirement for Group B Demand Response Providers (DRPs).[8] CEDMC's assertion that these recommendations would help create "a level playing field" or "parity" is not well-

[7] Massachusetts ConnectedSolutions Program Material at pp. 6-7 provides an example for a fictional customer with an average performance of 200 kW *available at* https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/connectedsolutions-ciprogrammaterials.pdf. Using the same average performance amount, ELRP compensation would be $12,000 (200 kW x 30 hours x $2/kWh).

[8] CEDMC Testimony at 13, 15.

founded. First, the Commission's pending draft Resolution E-5267 (assuming it is adopted) will net (sum positive and negative) a Group A participant's performance during an ELRP event, such that any assertion that Group A is unfairly favored will be moot. Second, a minimum dispatch requirement for Group B is not warranted because such a requirement should only be used to provide some revenue certainty for ELRP participants who do not have another revenue source, such as A.2 (Non-BIP Aggregators), A.4 (Virtual Power Plant (VPP) Aggregators), and A.5 (VGI Aggregators). While CEDMC asserts that a minimum dispatch requirement will motivate more frequent dispatch, B.1. participants (DRP Proxy Demand Resources (PDRs)) have the ability to dispatch themselves more frequently by submitting more economic bids in the California Independent System Operator (CAISO) wholesale energy market, thereby earning additional revenue from wholesale settlements. As with other proposals that would result in the expenditure of additional customer funds for increased ELRP incentives, the Commission should not authorize additional funds unless they will bring about clear load reduction benefits.

C. Cal Advocates' ELRP Recommendation Should Be Adopted

SCE appreciates the support of Cal Advocates for SCE's proposal to reduce the Residential ELRP (Sub-Group A.6) dispatch hours from five static hours (4-9 p.m.) in alignment with Flex Alert to a static two-hour period (6-8 p.m.) that aligns more closely to the time of greatest need (i.e., net peak).[9] SCE supports maximizing and aligning ELRP's use during the net peak hours which better align with times of grid stress. The Commission should modify ELRP A.6. dispatch hours to a static 6-8 p.m. dispatch window.

[9] Cal Advocates Testimony at 5-3.

II.
MASS MARKET DEMAND RESPONSE PILOT

Cal Advocates recommends that the Commission reject SCE's proposed Mass Market Demand Response pilot (MMDR) "on the grounds that there are already existing programs which accomplish this pilot's goal."[10] Cal Advocates describes MMDR as a pilot that "would replace several of the existing residential and small business programs offered by SCE" and suggests that SCE use the ELRP, with any necessary modifications, to acquire the learnings that SCE would otherwise acquire through the MMDR. Similarly, the Council states that MMDR "appears to be partially redundant with SCE's Smart Energy Program (SEP)" and argues that the pilot duration should be shorter.[11] However, these statements do not accurately characterize the purpose and approach of the MMDR pilot.

As described in Exhibit SCE-01, SCE is pursuing its vision of enabling mass DR participation by residential and small commercial customers with any type of distributed energy resource (DER) the customer may possess, in support of the State's environmental goals, a more flexible and reliable grid, and customer energy affordability. In support of this vision, the MMDR is meant to test the ability for SCE to enroll, communicate with, dispatch, measure, and compensate various types of DERs on a large scale. This is a fundamental shift in SCE's approach to DR and a large undertaking that will require several years of learning and testing to fully develop. In addition, as Cal Advocates described, SCE expects a growing enrollment in the MMDR, which will allow for more robust testing in the later years and allow for continuous participation for some customers from the MMDR pilot directly into a permanent program model in the next DR program cycle without disruption. As stated in SCE-01, SCE intends to pilot its MMDR approach over the 2024–2027 program cycle with the aim of transitioning to this paradigm in the 2028-2032 DR cycle. Therefore, the MMDR should not be thought of as

[10] Cal Advocates Testimony at 5-5.

[11] Council Testimony at 29-30.

comparable to previous SCE pilots, which typically initiate, test, and draw conclusions in a shorter time frame.

SCE does not intend to "replace…the existing residential and small business programs offered by SCE"[12] with the MMDR. Rather, the MMDR would run in parallel with its current residential DR programs (namely, SDP and SEP) to identify customers that would be good candidates for the pilot and test the technological and programmatic features that would allow for a robust full-scale non-pilot mass market DR program, which SCE intends to propose for the 2028-2032 DR funding cycle. The Council is aligned with SCE's approach when it advocates that "[i]t may also be worthwhile to combine with the SEP. This would enable SCE to leverage the established, proven elements of that program while continuing to test the new elements under consideration for the MMDR Pilot."[13] Running in parallel with SEP and SDP, the MMDR would incorporate some of those customers into the pilot with new devices, which would generally be transparent to the customer (i.e., the participating customer would still be an SEP or SDP participant while SCE tests new program elements through an MMDR overlay). Although it is possible that a future mass market DR non-pilot program could supersede or absorb existing programs, the proposed MMDR (as a pilot) would not do so, and consolidation with existing programs and a future non-pilot program will depend on what SCE learns through the pilot. As described in testimony, one of the objectives of the MMDR pilot is to determine how multiple end use devices can participate under one program umbrella, allowing customers to provide more load and participate with the end uses that best suit their needs.

SCE's approach of MMDR operating in parallel with SEP and SDP also makes unnecessary Cal Advocates' recommendation that SCE be required to use the existing ELRP pilot as a vehicle to study new DR approaches, rather than creating a new pilot.[14] SCE is not creating a new pilot out of whole cloth but is rather leveraging engaged customers on its existing

[12] *Id.*

[13] *Id.*

[14] Cal Advocates Testimony at 5-5.

residential and small commercial DR programs to study new approaches to mass market DR programs. Moreover, the structure of the ELRP would make it a poor fit for testing the model presented by the MMDR pilot. ELRP has several well-defined sub-groups, only one of which, sub-group A.6, would be appropriate to test the sort of mass market approaches that SCE envisions. However, using A.6 would only yield residential customers and not small commercial customers. Further, ELRP is a voluntary, non-penalty program and most of the customers enrolled in sub-group A.6 were defaulted onto the program and may or may not be engaged with their participation. As SCE's recent Load Impact report shows, ELRP A.6 customers did not perform as well as expected in Summer 2022.[15] As such, it is unlikely that using ELRP A.6 participants would yield better results than using existing SEP and SDP participants.

For these reasons, Cal Advocates' recommendation to deny SCE's MMDR pilot proposal and the Council's recommendation to shorten the duration of SCE's MMDR pilot proposal should not be adopted. The Commission should approve SCE's MMDR pilot as proposed and enable SCE to develop and pursue the future of DR.

[15] Load impact data *available at* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-response/emergency-load-reduction-program/elrp-2022-program-data/sce-elrp-hourly-with-lip-values.xlsx.

III.
BASE INTERRUPTIBLE PROGRAM

A. Response To Intervenor Assertions Regarding BIP Incentives And Program Participation

SCE's proposed on-peak BIP incentives for 2024–2027 are more than 35% higher than those SCE proposed in its 2018–2022 DR Application. Comparing SCE's proposed BIP incentive factors to those currently in effect overlooks that current BIP incentive factors include a temporary 20% incentive adder that was authorized in the Emergency Reliability Rulemaking (R.20-11-003). Notably, proposed on-peak incentive factors for Sub-Transmission customers enrolled in BIP are +30% and +60% higher than those currently in effect and those reflected in SCE's previous application, respectively. These increases are reflected in the following table.

Table III-1
Summary of Current and Proposed BIP Incentives

BIP Credit ($/kW-Month)	Proposed (A.17-01-018)			Current (Including 20% Reliability Adder)			Proposed (A.22-05-004)		
Description	S | On-Peak	S | Mid-Peak	W | Mid-Peak	S | On-Peak	S | Mid-Peak	W | Mid-Peak	S | On-Peak	S | Mid-Peak	W | Mid-Peak
15-Minute Option									
Secondary Service	(21.59)	(1.70)	(9.14)	(26.11)	(2.04)	(10.97)	(31.35)	(7.18)	(10.31)
Primary Service	(21.60)	(1.42)	(8.55)	(26.11)	(1.70)	(10.26)	(30.06)	(4.46)	(9.00)
Sub-Transmission Service	(14.74)	(0.72)	(5.38)	(17.84)	(0.86)	(6.46)	(23.54)	(2.61)	(6.41)
30-Minute Option									
Secondary Service	(19.47)	(1.53)	(8.24)	(23.54)	(1.84)	(9.89)	(27.40)	(6.28)	(9.01)
Primary Service	(19.13)	(1.25)	(7.56)	(23.14)	(1.50)	(9.07)	(26.27)	(3.90)	(7.87)
Sub-Transmission Service	(12.71)	(0.61)	(4.62)	(15.37)	(0.73)	(5.54)	(20.57)	(2.28)	(5.60)

BIP Credit (% Change vs Proposed A.17-01-018)	Current (Including 20% Reliability Adder)			Proposed (A.22-05-004)		
Description	S | On-Peak	S | Mid-Peak	W | Mid-Peak	S | On-Peak	S | Mid-Peak	W | Mid-Peak
15-Minute Option						
Secondary Service	21%	20%	20%	45%	323%	13%
Primary Service	21%	20%	20%	39%	214%	5%
Sub-Transmission Service	21%	20%	20%	60%	262%	19%
30-Minute Option						
Secondary Service	21%	20%	20%	41%	310%	9%
Primary Service	21%	20%	20%	37%	212%	4%
Sub-Transmission Service	21%	20%	20%	62%	273%	21%

The California Large Energy Consumers Association (CLECA) and Industrial Pumping Customers (IPC) assert in testimony that BIP participation is declining due to insufficient incentive levels.[16] As an initial matter, SCE has followed an established methodology for setting BIP incentives (described further below). Moreover, the issue of BIP participation is complex and does not hinge solely on incentive levels. Indeed, several other

[16] *See* CLECA Testimony at 18; IPC Testimony at 2.

factors can play into a customer's decision not to continue to participate in a DR program and BIP in particular. In 2018, the Commission's adoption of a more restrictive policy on the use of Prohibited Resources (PR) to earn incentives in Commission-approved DR programs[17] caused a number of customers to either unenroll from BIP or adjust their firm service level commitment, resulting in a decrease of approximately 50 MW[18] in potential load reduction. Another factor that appears to have driven decreased BIP participation is the shift in SCE's on-peak time-of-use (TOU) period and the subsequent shift in the resource adequacy availability assessment hours from Noon–6 p.m. to 4–9 p.m., which took effect in January 2019, after which, in the next program opt-out window, enrolled BIP MW dropped by 61 customers and more than 100 MW.[19] SCE also attributes the decline in BIP participation over the years to customers ceasing electric services; removal of customers from the program as they were no longer meeting the eligibility requirements; CAISO market integration, which resulted in increased program dispatches; and customer fatigue from the extreme weather events in 2020 and the numerous dispatches that resulted. SCE also experienced loss of BIP MW in the 2022 November opt-out window due to the multiple BIP dispatches during the 2022 summer heat wave.

Nevertheless, SCE continues to seek opportunities to maintain and grow MW for the program. SCE reiterates that its pending DR application proposes to significantly increase BIP incentives with the goal of encouraging participation by eligible customers. SCE does not discount that incentive levels have relevance with respect to a customer's decision to participate in BIP. SCE continues to take full consideration of the feedback of customer groups like

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[17] See D.16-09-056.

[18] Load Impact Evaluation of California Statewide Base Interruptible Program for program year 2018, *available at* https://edisonintl.sharepoint.com/:u:/t/Public/regpublic/EZNx_VpNSXxLmS1lTFhiYDABhUUGmvTfk0TRXmLsZN1mhg.

[19] Load Impact Evaluation of California Statewide Base Interruptible Program for program year 2019, *available at* https://edisonintl.sharepoint.com/:u:/t/Public/regpublic/EfSIty_T4XpCpcAoOKxZP0cBpXVb2fWRJYuI3BTJPj4VXQ.

CLECA, IPC, and Joint DR Parties, including as to the incentive rates for customers served at Sub-Transmission voltages (> 50kV) relative to those served at the Primary and Secondary service voltage (less than 50 kV). At the same time, SCE's determination of incentive levels must follow the appropriate methodology and strike the appropriate balance between DR program load reduction capacity and prudent expenditure of customer funds. To the extent BIP participants (or customers eligible to participate in BIP) experience cost pressures relating to the cost of electricity in California relative to other states or other exogenous policy, market, and/or operational factors, BIP incentives are not intended to correct for such factors.

B. Response To Assertion That BIP Credits Should Be Increased In Line With Updated Avoided Cost Calculator Outputs

The witnesses for CLECA and IPC assert that SCE's proposed incentives for BIP for the years 2024-2027 should be increased in line with the updated Avoided Cost Calculator (ACC) for 2022, which shows an increase in the cost of new resources.[20] However, SCE's DR Incentive Rates are calculated based on the generation capacity marginal costs adopted in its most recent GRC Phase 2 proceeding, and not based on avoided cost valuation published in the Commission's Avoided Cost Calculator.

When determining DR Avoided Cost, SCE uses the A times B (A x B) methodology that is applied to Generation Capacity Marginal Cost adopted in Phase 2 of SCE's most recent General Rate Case (GRC). Generation Capacity Marginal Costs (GCMC) are a foundational element in the design of Retail Generation Rates for various consumer groups, and by extension are foundational to the design of Incentive Rates for SCE's Demand Response Programs. The assumption that the design of BIP incentive rates is based on the most recent publication of the CPUC's avoided cost calculator is factually incorrect and inconsistent with the

[20] CLECA Testimony at 17-18; IPC Testimony at 4-6.

broader suite of considerations that go into the settlement and adoption of marginal costs and rate design in Phase 2 of SCE's GRC.

SCE supports the use of marginal cost in the design of Incentive Rates for several reasons. First, using the same consistent basis of marginal cost ensures that the valuation of capacity in the design of Retail Rates is the same as that used in the design of Incentive Rates, and thereby avoids inconsistency as between the design of retail and incentive rates that would cause an asymmetry in costs recovered as compared to costs avoided across different consumer groups. Second, long run marginal costs adopted in Phase 2 of the GRC present a thoughtful and deliberate balance of perspectives across the wide range of participating stakeholder groups and bake in a host of considerations guided by the Commission's adopted principles of marginal cost, revenue allocation, and rate design. The symbiotic relationship of these principles as vetted in the GRC ensures that proposals support inter-class and intra-class equity while also promoting a common sense of how customers interpret and intuitively understand rate design proposals. Third, designing Incentive Rates on the same cost basis as Retail Rates ensures parity in the response a customer may have to the same consistent basis of a long-run equilibrium price by modifying consumption behavior, such as through a DR program or on-site device, to accrue value to the customer based on costs recovered or avoided as determined by retail rates. Fourth, this alignment ensures that the inputs used to calculate incentives for SCE's Demand Response programs correspond with the generation capacity value used to derive SCE's retail rates. This aligns the rate structure for demand response programs with the applicable retail tariffs specific to each rate group.

C. Response To Proposals For A Third Party Independent Program Monitor For BIP

The witnesses for CPower and Enel X North America, Inc. (the "Joint DR Parties") assert that, with respect to SCE's BIP proposal, "consideration should be given to adding a Third Party Independent Program Monitor" due to SCE staff turnover, slower payment

timing than with PG&E, purported payment errors, and purported data quality issues.[21] SCE has not experienced any atypical staff turnover, and to date, SCE is unaware of any formal escalated issues around the timing and accuracy of its BIP payments. SCE notes there have been recent staffing changes on the aggregator side which have necessitated training and education between SCE and aggregator staff on payment processes. It is unclear what issues exist for an Independent Monitor to resolve, nor do these parties indicate how this position would be funded. This proposal should be rejected by the Commission, and if there are matters to be resolved SCE recommends these parties bring them to the attention of SCE BIP program staff and management in order to address outstanding questions or issues.

[21] Joint Demand Response Parties Testimony at 20-21.

IV.
SCE'S PROPOSED CAPACITY BIDDING PROGRAM

A. SCE's Proposal Complies With The Commission's Ruling And SCE Should Not Be Ordered To Model A Program On SDG&E's Day-Ahead CBP Elect Program

The Joint DR Parties assert in testimony that SCE's CBP Elect proposal is not "akin" to PG&E and SDG&E's CBP Elect Options, and that the Commission should order SCE to implement a CBP Elect program that is modeled after SDG&E's Day-Ahead CBP Elect program.[22] The January 27, 2023 Assigned Commissioner Ruling directed SCE to file a proposal with "sufficient details regarding program design, schedule, budget, cost-effectiveness, and any other element that could be an important factor in a party's comment," adding that "[i]n the interest of time, SCE is invited to model its proposal on the Elect products offered by PG&E and/or SDG&E."[23] SCE-10 (served March 3, 2023) provides a CBP Elect proposal that complies in all respects with the referenced ruling, which did not order SCE to model its proposal on products offered by other IOUs, but gave SCE the option to do so "[i]n the interest of time."

SCE considered several program design options and ultimately crafted a proposal intended to help reduce the summer net peak loads in a cost-effective manner, bearing in mind concerns regulators have expressed that DR is not available during summer net peak load hours. For example, in a recent report, the California Independent System Operator Department of

[22] Joint DR Parties' Testimony at 2.

[23] January 27, 2023, Assigned Commissioner's Ruling at 4.

Market Monitoring (CAISO DMM) stated:

> From September 5 – 8, between 4-9 pm, around 21 percent of utility demand response bids and 87 percent of third party demand response bids exceeded $750/MWh. Over this period, about 68 percent of the utility proxy demand response that was bid into the day-ahead market was scheduled in the day-ahead market, while about 45 percent of bid-in third party demand response was scheduled."[24]

With such concerns in mind, SCE designed its CBP Elect proposal to be dispatched during summer net peak periods. Because high prices, Flex Alerts, CAISO Energy Emergency Alert (EEA) Notices, and Governor Executive Orders may (individually or in combination) be indicative of the occurrence of net peak loads, SCE proposed all of these conditions as potential triggers. To the extent there is a concern that SCE's CBP Elect Program could be overused due to having multiple triggers, SCE submits that if such a scenario occurs, new program parameters could be explored, but the initial program design should not be restricted based on that theoretical concern. SCE anticipates its proposed CBP Elect Program will be used and provide load reduction when needed most by the grid as a result of having multiple triggers rather than being solely dependent on wholesale energy prices.

[24] See CAISO Demand Response Issues and Performance,2022, *available at* https://www.caiso.com/Documents/Demand-Response-Issues-and-Performance-2022-Report-Feb14-2023.pdf (CAISO Department of Market Monitoring 2022 Demand Response Issues and Performance Report, dated February 14, 2023, at p. 12); see also CAISO Department of Market Monitoring 2021 Demand Response Issues and Performance Report, dated January 12, 2022, at p. 12 and CAISO Department of Market Monitoring 2020 Demand Response Issues and Performance Report, dated February 25, 2021 at p. 12, *available at* https://www.caiso.com/Documents/ReportonDemandResponseIssuesandPerformance-Feb252021.pdf https://www.caiso.com/Documents/Demand-Response-Issues-Performance-Report-Jan-12-2022.pdf (corresponding reports for 2020 and 2021).

B. The Commission Should Not Adopt Cal Advocates' Statewide Capacity Bidding Program Proposal

SCE disagrees with the proposal of Cal Advocates for a statewide CBP. Cal Advocates' assertion that such a program would "reduc[e] program administrative costs"[25] is speculative and indeed the opposite result could transpire due to the complexities of running such a statewide program across different utility territories and administrative systems. It is unclear if there is any administrator or agency that could take on the task of running such a statewide program and would accept the risks associated with market integration. Managing demand response programs and associated complexities with retail and wholesale settlements requires a high degree of specialization that currently exists within a narrow group of companies. As such, SCE questions whether a statewide program would create economies of scale, and indeed the limited set of vendors that can perform these services could drive increased costs due to limited competition.

Table 1-3 of Cal Advocates testimony indicates that the administrative costs for SCE's proposed CBP for the 2024-2027 period are approximately $5.72 million. To be clear, however, the $5.72 million referenced are the administrative costs used for the cost-effectiveness test, which includes portfolio costs shared between programs, such as AutoDR, EM&T, and technology systems, rather than administrative costs pertaining only to that program. SCE has estimated that administrative costs directly attributable to the CBP program (total labor and non-labor costs) are $2.32 million[26] for the 2024-2027 period, and $0.348 million for Evaluation, Measurement, and Verification (EM&V)). Excluding one-time system and EM&V costs, SCE estimates an administrative budget of approximately $1.47 million over the four-year period or an average of $0.368 million per year. SCE has no basis to conclude that a lower cost could be

[25] Cal Advocates Testimony at p. 1-1.

[26] See SCE-10, Table 10-4 at p. 8.

achieved by way of a statewide CBP program and a statewide program administrator. For these reasons, the Commission should reject Cal Advocates' proposal for a statewide CBP.[27]

V.
COMPETITIVE NEUTRALITY ISSUES

A. Arguments That Commission Decisions Have Strayed From DR Principles Lack Merit

OhmConnect asserts that following the issuance of D.16-09-056, in which the Commission adopted a set of six principles for DR programs, "many Commission Decisions in the intervening years have violated these principles," thereby purportedly "contribut[ing] to the persistent lack of a level playing field between third-party and [IOU] DR programs."[28]

As an initial matter, the DR principles issued in D.16-09-056 are directed to the IOUs, and do not limit the Commission's ability to issue any decision it sees fit in a given proceeding. In any event, challenges to Decisions issued in other rulemakings should be asserted in those rulemakings and not in this proceeding. Nor is this proceeding the appropriate venue to address concerns with policies adopted in the Commission's Resource Adequacy proceedings.[29] Issues pertaining to DR resource adequacy, such as DR on Supply Plan, the DR MCC Bucket, DR Qualifying Capacity (QC) counting methodology, and/or testing requirements, should be addressed through those Resource Adequacy proceedings.

In addition, the DR principles from D.16-09-056 were adopted prior to the 2020 rotating outages, the 2022 extreme heat wave events, and the Demand Response Auction Mechanism (DRAM) Pilot assessments. These events and reports have resulted in changes that

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[27] CEDMC and OhmConnect also criticize SCE's CBP Elect proposal on grounds that it is not consistent with the principle of competitive neutrality as between IOUs and DRPs. That issue is discussed in Section V, infra.

[28] OhmConnect Testimony at 1 (citing D.21-06-019 (R.19-11-009), D.20-06-031 (R.19-11-009), and D.21-12-015 (R.20-11-003) as Decisions that purportedly have "violated" D.16-09-056).

[29] See D.14-03-026 at 10, 12 ("[s]etting resource adequacy capacity for demand response resources has been and should continue to be resolved in the resource adequacy proceeding").

affect DR resources, including those that relate to third-party DR providers (DRPs). Contrary to the suggestion that third party DRPs are disadvantaged relative to IOU DR programs, IOU DR programs are subject to greater regulatory oversight and scrutiny than third-party DR, and third-party DR has greater flexibility to adapt to change compared with IOU DR programs, which are tariffed and require multiple Commission approvals.

OhmConnect asserts that an example of the purportedly uneven playing field between the IOUs and DRPs is the exclusion of IOU DR from Supply Plans.[30] However, this assertion ignores that third-party DR resources are not subject to Commission least cost dispatch rules and oversight of bidding behavior, such that third-party DRPs have a higher degree of freedom in their market participation, whereas IOU resources must be bid and dispatched in accordance with least cost dispatch and other Commission rules and are subject to after-the-fact reasonableness review by the Commission. Thus, while IOUs are excluded from Supply Plans, they are subject to additional regulation that fulfills a related role. The playing field is leveled by this additional oversight of IOU activity.

Parties' arguments that the Commission has created an unlevel playing field do not recognize that differences that exist between IOUs and DRPs in terms of responsibility and regulatory oversight. The Commission has modified rules as necessary to address concerns that directly arise from these inherent differences, but has overall adhered to its principle of competitive parity.

B. Proposed Load Modifying DR Programs Do Not Raise Parity Issues

CEDMC and OhmConnect[31] assert that SCE's CBP Elect proposal is unfair to third-party DRPs because DRPs are not afforded the same ability to create load modifying programs. SCE has always had both load modifying and supply-side demand response programs. Creating a load-modifying CBP option for aggregators and their customers is appropriate,

[30] OhmConnect Testimony at 2-5.

[31] OhmConnect Testimony at 5-6; CEDMC Testimony at 7-9.

especially for those aggregators who have customers with battery storage behind-the-meter who would benefit from a 2-hour program option. Similarly, there is an urgent need for a program that specifically addresses the net/super peak hours of 6-8 p.m. The arguments of CEDMC and OhmConnect (which are not load serving entities) do not take into account the extent of the obligations that come with being an LSE. Moreover, aggregators like OhmConnect will have full opportunity to participate in the CBP program in future as many options are available, some of which were specifically designed to facilitate the participation of such aggregators.

VI.
OTHER ISSUES

A. SCE's Proposed Rule 24 Information Technology Budget Is Appropriate

Cal Advocates proposes to reduce SCE's Rule 24 information technology (IT) budget should registrations in 2024 fall short of the 116,000 accounts that are projected to be registered with CAISO.[32] However, this proposal incorrectly assumes that system costs are volumetric or tied to the number of registrations. Rule 24 system improvements do not vary based on the number of registrations; therefore, these costs cannot be effectively pro-rated should registrations fall short of projections. SCE's Rule 24 proposed IT budget is intended to implement automation and enhancements to its systems that will result in operational efficiencies, labor savings over the long term, and improved performance. SCE plans to make a number of improvements, including an enhancement to a process that downloads CAISO locations/registrations en masse and tracks enrollments in SCE's system and a new interface to convert paper Customer Information Standardized Request (CISR) forms to digital Click Through CISRs. The enrollment tracking is used to prevent dual enrollments and perform Utility Distribution Company (UDC) review to validate accounts ensuring they are eligible to enroll with the DRP. Currently, the enrollments in SCE's system need to be manually updated to accurately reflect what is in CAISO's systems. Creating an interface to convert paper CISR authorizations to Click Through authorizations will enable SCE to migrate away from supporting sharing data in two formats, csv format and xml, and move toward supporting xml data sharing that is done via the Click Through system. These system-based improvements are upfront improvements to SCE's IT infrastructure that will replace manual data entry and other labor-intensive processes which would otherwise grow in cost as customer registrations increase. SCE recommends pursuing these upgrades now rather than waiting until additional costs have been incurred processing additional registrations under its current system.

[32] Cal Advocates Testimony at 5-4.

B. OhmConnect's Recommendations For New Measures Relating To Marketing, Sharing Of Customer Data, And Enrollment/Disenrollment Should Not Be Adopted

OhmConnect proposes a number of changes relating to the IOUs' marketing, data sharing, and enrollment/disenrollment practices.[33] OhmConnect's marketing proposals are not intended to strengthen ELRP, but rather to encourage customers to choose alternatives.[34] These proposals apparently address marketing practices broadly rather than any specific application to ELRP or another one of SCE's programs and are more generic policy concerns rather than proposals related to SCE's DR funding application.

OhmConnect proposes that IOUs place a sign-up form on their websites that would collect customer information and pass it on to third-party providers for marketing and further follow-up.[35] OhmConnect points to the Consolidated Edison Company of New York (Con Edison) as an example of a utility that currently engaged in this practice. SCE cannot speak to how many residential DR providers participate in Con Edison's programs or to what extent those programs provide an apples-to-apples comparison, but SCE notes that there are over a dozen third-party DR providers in SCE's territory, which could (based on OhmConnect's proposal) lead to a significant number of emails, phone calls, and mailers directed at customers from multiple providers without any limitation on their duration or quantity. Customers are better served by searching through the available listings on IOU websites and seeking more information from select providers.[36]

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[33] OhmConnect Testimony at 7.

[34] *Id.* at 10.

[35] *Id*. at 16.

[36] *See* D.17-12-003 at 106 ("it is not the responsibility of the Utilities to ensure that customers click through to the websites of third-party providers, only that customers have the ability to click through").

OhmConnect also proposes a new process for customers to authorize third parties to access to their data. While the process is not described in detail, OhmConnect proposes that a customer could prove their identity to a Commission-certified third party, and then the third-party could obtain the customer's data from a utility without further involvement from a customer.[37] SCE strongly believes that there should always be direct communication between itself and one of its customers before data is shared. This provides an additional layer of security and could potentially avoid situations where an individual uses stolen identity to authenticate with a third-party provider, and then a utility shares personal usage data, unbeknownst to the customer. The Click-Through process fulfills this critical step to ensure data has been duly authorized by the customer. OhmConnect's proposal also raises privacy concerns.[38]

OhmConnect also contends that SCE's DR webpage does not comply with D.17-12-003 and gives unequal treatment to third party DRPs relative to SCE.[39] In fact, SCE's DR webpages are fully compliant with the requirements of D.17-12-003,[40] describing the DR programs of SCE and third-party providers in the same font, with links to the home pages of all DRPs listed. Notably, in accordance with OP 46 of D.17-12-003, SCE submitted an advice letter and supplement (AL 37460E and 3746-E-A) describing its approach to educating customers about DR options through its website, and that advice letter was approved by the Director of Energy Division on December 17, 2018. OhmConnect's argument – over four years later – that SCE's webpages are non-compliant is specious.

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37 OhmConnect Testimony at 26.

38 As the IOUs discussed in Joint Comments filed in this proceeding on April 28, 2023, California law includes extensive privacy provisions with respect to personal information. It is unclear whether OhmConnect's proposal to have a customer automatically authorize sharing of their data by verifying their identity would meet these requirements, and a broad expansion of automated data sharing would have potential repercussions with respect to data security requirements and the administrative resources needed to respond to customer concerns and requests pertaining to the sharing of personal data.

39 OhmConnect Testimony at 13.

40 See SCE's Demand Response Programs, *available at* https://www.sce.com/business/demand-response; https://www.sce.com/residential/demand-response.

OhmConnect raises a number of data related issues that go well beyond the issues pertaining to data access that are scoped in this proceeding, which relate to the reasonableness and recovery of costs for IT systems supporting Rule 24 and other DR programs.[41] OhmConnect's out of scope data access issues are more appropriately raised in proceedings that address data access policies in general, such as the IOUs' Click Through Applications[42] or the IDER Successor OIR[43] rather than in utility demand response funding applications. In any event, OhmConnect's complaints of data delivery delays are not generally accurate. For example, OhmConnect states that SCE has "consistent delays in data delivery up to 10-15 days."[44] SCE did experience delays in November 2021 due to a system issue and also during the December 2022 to January 2023 period while it was upgrading to a new data warehouse. However, since the inception of SCE's new billing system in April 2021 (through the Customer Service Replatform Project (CSRP)), SCE is regularly providing 90% of the data in less than 4 days, with the exception of the system upgrade and system issue noted above. While SCE endeavors to provide data as soon as the data is available, CAISO does not require the data until settlement 48 business days after trade date.

As to enrollment/disenrollment, OhmConnect proposes a "One-Click" disenrollment process to make enrollments faster, claiming that disenrollments are a "lengthy and burdensome" process.[45] OhmConnect claims that SCE's Summer Discount Plan (SDP) program can take between 2-5 months based on estimates provided by its customer support team. However, this assertion ignores the realities of the disenrollment process. In fact, SCE processes SDP disenrollments on the day they are received, but must confirm that the customer has met the

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41 See Assigned Commissioner's Amended Scoping Memo and Ruling, A.22-05-002 et al., filed December 19, 2022.

42 A.18-11-015, et al.

43 R.22-11-013.

44 OhmConnect Testimony at 27.

45 OhmConnect Testimony at 22.

Tariff Rule 12 one-year minimum participation requirement. Contrary to the assertion that customers can only disenroll through a 1-800 number,[46] SCE offers multiple channels for customers to disenroll from the program, including through live call center agents, sce.com, or Interactive Voice Response over telephone. The avenue for customers to disenroll through sce.com is also mentioned in a customer migration matrix available publicly to customers and third parties.[47] SDP disenrollments do not require a visit to the customer's home in order to remove equipment unless requested by the customer, and even in those cases, the timeframe for disenrollment in SCE's billing system is not affected. Once disenrollment requests are processed, they become effective on the customer's next scheduled meter read date. The time lag (i.e., 2-5 months) claimed by OhmConnect in its testimony likely reflects the time between when a disenrollment request is processed and a combination of the minimum participation requirement for SDP, the next meter read date, and the time for CAISO's system to reflect changes in registration. A one-click disenrollment would not expedite this process.

In addition, OhmConnect makes similar claims for SCE's Smart Energy Program (SEP) noting termination times can span from 2-3 months for most providers with Google Nest disenrolling within 1-2 weeks.[48] SCE's SEP thermostat vendors can submit enrollment and disenrollment requests daily. Once received, SCE processes requests within 3 business days as required by the program tariff.[49] Currently, there is no minimum enrollment requirement with SEP or a need to wait until the customer's next scheduled meter read date for the disenrollment to take effect. It is unclear how OhmConnect measures the disenrollment time, such as what beginning and endpoints are used, or how disenrollments could take the length of time that OhmConnect alleges. SCE invites OhmConnect to follow up directly with SCE with further

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[46] *Id.*

[47] SCE DR Customer Migration to Participate in Third Party Demand Response. p. 2 https://www.sce.com/sites/default/files/custom-files/Web%20files/SCE%20DR%20Programs%20Migration%20Matrix%2011-28-22.pdf.

[48] OhmConnect Testimony at 21.

[49] Schedule SEP – Smart Energy Program. Sheet 1.

detail on these claimed disenrollment times so that any issues, if present, can be addressed. Lastly, OhmConnect uses the Power Saver Rewards (Residential ELRP) program as an example of how disenrollments could be handled better. However, PSR is fundamentally different because it is not a market-integrated program and does not have the same tariff requirements as other programs; therefore, disenrollment from PSR can be achieved more quickly compared with a market-integrated or tariffed program.

C. The Necessity For Mid-Cycle Review In The Four Year 2024-2027 Period

The Council requests a mid-cycle review in 2026 to allow parties to provide feedback on IOUs' DR portfolios and for IOUs to make mid-course corrections to their programs.[50] SCE expressed openness to a mid-cycle review in its application and requested that any subsequent advice letter be resolved within five months.[51] As The Council noted, final approval for the IOUs' advice letters adopting changes from the mid-cycle review were not adopted until summer of 2021 for SCE and summer of 2022 for PG&E and SDG&E, which were after applications for this program cycle had already been filed. For this shortened cycle, SCE advocates for an efficient approach to any mid-cycle review that would allow for effective review without a lengthy process. As such, an alternative to the more formal mid-cycle review of the prior cycle could be a meeting with stakeholders early in 2026 to gather advanced feedback that could inform the IOUs' next DR applications at an early stage and allow minor program modifications to be implemented faster through advice letter, where possible.

D. Cost-Effectiveness Measurement Methodology

In opening testimony, Small Business Utility Advocates (SBUA) recommends using the Societal Cost Test (SCT) along with several Non-Energy Benefits (NEBs) for the evaluation of DR programs. SBUA notes that the SCT better evaluates the costs and benefits to

[50] Council Testimony at 11.

[51] Exhibit SCE-01 at 41.

society compared to the Total Resource Cost test (TRC), and therefore is the appropriate measure for evaluating IOUs' DR programs.

As a threshold matter, SBUA's proposal should be rejected because it is contrary to the Commission's existing policy to use the TRC test as the primary test for all activities requiring cost-effectiveness analysis of DERs.[52] The Commission is already evaluating the role of the SCT in DER-related proceedings in Rulemaking 22-11-013. It would not be appropriate to consider or set policy here on the use of the SCT for DR specifically while R.22-11-013 is simultaneously considering cost-effectiveness issues for all DERs.

As SCE commented in R.22-11-013, the SCT and the societal perspective may provide information to qualitatively consider additional societal program benefits, however, it should not be used for approving programs, budgets, or incentives. The SCT is similar to the TRC, except it includes a social cost of carbon rather than an abatement cost of carbon and can include additional adders and other changes, such as excluding tax benefits.[53] This social cost of carbon is determined by a model that produces a range of future climate change damage estimates, while the abatement costs used in the TRC are the costs incurred by utilities to meet California's clean energy and climate goals and derived from Integrated Resource Planning. Because the social cost of carbon is higher than the abatement cost and because the SCT considers a greater set of benefits that accrue to a larger cohort (society vs utilities and their customers), the SCT will nearly always produce a higher benefit cost ratio than the TRC. This would likely result in more programs being adopted, and more costs being charged to customers, than is necessary for California to reach its clean energy goals. As the CPUC Staff SCT Impact Evaluation states "any increased benefits shown by an SCT relative to a [Total Resource Cost

[52] D.19-05-019 at OP 1.

[53] California Standard Practice Manual *available at* California Standard Practice Manual Economic Analysis of Demand-Side Programs and Projects, October 2001, at p. 19.

test] are societal benefits, rather than ratepayer benefits, and therefore basing cost effectiveness on an SCT could cause an increase to rates."[54]

Further, the SCT only considers total costs and benefits without regard to who ultimately pays for and receives those benefits. The SCT does not consider shifts in costs and benefits between members of society. Justifying more programs and rate increases through the SCT creates greater potential for regressive transfers to take place from lower income customers to higher income customers absent additional guardrails.

[54] Societal Cost Test Impact Evaluation: CPUC Staff Report on the Impact of a Societal Cost Test on Resource Procurement (SCT Impact Evaluation), January 2022, p. 31.