REBUTTAL TESTIMONY IN SUPPORT OF SCE’S APPLICATION FOR APPROVAL OF 2018 – 2022 DEMAND RESPONSE PROGRAMS

Before the

Public Utilities Commission of the State of California

Rosemead, California
June 5, 2017
# SCE-02: Rebuttal Testimony

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I.

Introduction

On October 5, 2016, the California Public Utilities Commission (CPUC or Commission) issued Decision (D.) 16-09-056, providing guidance to the investor-owned utilities (IOUs)\(^1\) regarding their respective applications for demand response (DR) programs and budgets for 2018-2022. On January 17, 2017, SCE filed direct testimony in support of its DR Application (A.) 17-01-018\(^2\) in compliance with the Commission’s guidance, and on February 27, 2017, various parties filed protests and responses to the DR applications, which SCE responded to on March 9, 2017.\(^3\) On March 15, 2017, Assigned Commissioner Guzman Aceves and Administrative Law Judges (ALJ) Hymes and Atamturk issued a Scoping Memo and Joint Ruling (Scoping Memo) that set the scope and procedural schedule, among other things, for A.17-01-012, et al. On May 11, 2017, several parties filed intervenor testimony in response to SCE’s application.\(^4\) SCE submits this rebuttal testimony in compliance with the Scoping Memo and an ALJ email Ruling, dated May 10, 2017, that extended the date to file intervenor testimony and rebuttal testimony by one business day each, to May 11th and June 5th, respectively.

SCE’s rebuttal testimony is organized into four chapters. Chapter I provides the procedural background and overview of SCE’s rebuttal testimony. Chapter II describes the recommendations from intervening parties that SCE supports. Chapter III provides SCE’s rebuttal to recommendations from

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\(^1\) The IOUs are Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas and Electric Company (SDG&E).

\(^2\) A.17-01-018 was later consolidated with the other IOUs’ applications as A.17-01-012, et al.

\(^3\) The following parties filed protests to the DR Applications on February 27, 2017: the California Large Energy Consumers Association (CLECA); the Joint Demand Response Parties (Joint DR Parties), consisting of Comverge, Inc., CPower, EnerNOC, Inc., and EnergyHub; the Office of Ratepayer Advocates (ORA); the California Energy Storage Alliance (CESA); and the Utility Consumers Action Network (UCAN). The following parties filed responses to the DR Applications on February 27, 2017: the California Energy Efficiency Industry Council (Efficiency Council); OhmConnect, Inc.; and SolarCity Corporation.

\(^4\) Intervenor testimony was filed by ORA; CLECA; OhmConnect; and the Joint DR Parties (consisting of CPower, EnerNoc, Inc., and EnergyHub). Intervenor testimony was also filed by UCAN, but their testimony concerns only SDG&E’s application.
parties regarding issues of cost recovery, program incentives, and program design. Chapter IV provides
SCE’s rebuttal to recommendations on other issues.

II.

Parties’ Positions Supported by SCE

The purpose of this Chapter is to describe the intervenor proposals supported by SCE. SCE
supports six positions that various intervenors presented in their testimony. As described below, SCE
supports parties’ recommendations concerning revisiting the reliability cap, aligning time-of-use (TOU)
and DR program time periods, revision of the AutoDR program, coordinating responses to changing
availability assessment hours between the California Independent System Operator (CAISO) and the
Commission, developing communication protocols between the CAISO and the Commission, and
eliminating the Permanent Load Shift (PLS) program.

A. SCE Agrees with ORA that the Reliability Cap Should Be Revisited

D.10-06-034 set a cap on the amount of reliability DR that would count toward an IOU’s
resource adequacy (RA) requirement. As both SCE and PG&E have stated that they have reached or
expect to reach their cap soon, ORA recommends that the Commission revisit the reliability cap issue in
the 2020 mid-cycle review as there will be more certainty at that time regarding potential extension of
the Demand Response Auction Mechanism (DRAM) and its effect on the reliability cap. SCE agrees
with ORA that the reliability cap should be revisited, as stated in its direct testimony. However, due to
the fact that the cap has already been reached or will be reached soon in two IOU territories, it should
be revisited sooner than 2020. SCE recommends that the Commission include this issue in either the
DR OIR (R.13-09-011) or the RA OIR (R.14-10-010).

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6 SCE-01, Volume 1, p. 14; PG&E Testimony, p. 2-16.
7 ORA Testimony, p. 6-2.
8 SCE-01, Volume 1, p. 15.
9 SCE-01, Volume 1, p. 14; PG&E Testimony, p. 2-16.
In addition, CLECA notes that the load of a DR resource that participates in both an energy-based and a reliability-based DR program does not count toward the reliability cap and states that one solution to the cap limitation is to create a new energy-based DR program so that Reliability Demand Response Resource (RDRR)\textsuperscript{10} participants can dual participate.\textsuperscript{11} SCE agrees that a new energy-based DR program could help address the reliability cap issue, and recommends the Commission explore this in the effort to define new models of DR in R.13-09-011. It is still appropriate, however, for the Commission to explore in this proceeding whether the reliability cap should be raised.\textsuperscript{12}

B. **SCE Agrees With CLECA’s Recommendation to Align DR Program Time Periods at the Conclusion of a General Rate Case (GRC) Phase 2 or Rate Design Window (RDW) Proceeding**

In its testimony, SCE proposed to revise its TOU periods for the Base Interruptible Program (BIP) at the end of its next GRC Phase 2 proceeding, in the DR mid-cycle review to occur in 2020.\textsuperscript{13} In its testimony, CLECA discussed the importance of aligning TOU rate periods and event periods for DR programs, and proposes that the Commission establish a policy and process to modify DR program event periods to align with TOU rate periods whenever they are changed in a GRC Phase 2 or RDW proceeding.\textsuperscript{14} SCE agrees with CLECA’s recommendation, but recommends the alignment be made through a Tier 2 advice letter, rather than a Tier 1 advice letter as proposed by CLECA. In its original proposal, SCE envisioned the need to align TOU periods and potentially update other attributes

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\textsuperscript{10} RDRR is a CAISO product for reliability DR. RDRR must always have a Day Of component that can be dispatched in the real-time market in response to reliability conditions. RDRR can also have a Day Ahead component that is dispatched on an economic basis.

\textsuperscript{11} CLECA Testimony, p. 19.

\textsuperscript{12} The ten percent “tolerance band” referenced by ORA in testimony and supplemental testimony is no longer applicable to the IOU reliability caps, thus supporting further exploration at this time.

\textsuperscript{13} SCE-01, Volume 3, p. 8.

\textsuperscript{14} CLECA Testimony, pp. 26-31.
associated with program incentive determination. The use of a Tier 2 advice letter provides a period of
time for Parties to review changes to the incentives prior to the incentives becoming effective. If further
changes are identified, these changes can be incorporated prior to implementation with the least
disruption to customers. By contrast, a Tier 1 advice letter is effective upon filing. Any subsequent
changes would need to be made through expensive post-implementation updates of the billing system
and a disruptive recalculation of customer bills. Additionally, the DR program time periods may need to
be re-aligned whenever the RA program rules and related requirements change, as further discussed in
section D below.

C. **SCE Agrees With Joint DR Parties That SCE’s AutoDR Program Could Provide 100 Percent Upfront Incentives**

The Joint DR Parties recommend that SCE’s AutoDR program adopt a structure similar to
PG&E’s residential AutoDR program and SDG&E’s Technology Incentive program by providing
customers a 100 percent upfront payment. SCE agrees that this payment structure for AutoDR
Customized incentives would be beneficial as it would reduce administrative burden and simplify the
program for customers. However, if the Commission makes this change, SCE recommends a further
reduction in the incentive structure of SCE’s AutoDR Customized technology incentives. By reducing
the incentive amount and limiting the compensation these incentives provide toward the cost of the
installed enabling technology, the customer will be motivated to maximize its DR participation and its
DR incentives in order to recoup its investment in the DR-enabling technology. Paying a portion of the
DR-enabling technology costs, rather than the whole cost, supports the cost-effectiveness of paying for
technology that may not be solely used for DR. SCE recommends reducing AutoDR Customized
incentives to $150/kW, capped at 50 percent of the total eligible costs, whichever is less. This incentive

\[15\] The value of capacity, loss of load expectation, and A factors have the potential to be updated in the GRC
Phase 2. SCE may need to update all, or some, of these attributes in the DR program incentive calculation in
order to ensure alignment between the DR incentives and underlying base rates.

\[16\] Joint DR Parties Testimony, pp. 28-29.
reduction aligns with the proposal SCE made in its 2017 Bridge Funding filing to eliminate the 60/40 performance payment and reduce the incentive for AutoDR Customized technology incentives.\textsuperscript{17}

D. **SCE Agrees With CLECA That the CPUC and the CAISO Should Coordinate Regarding Changing Availability Assessment Hours**

CLECA identifies a concern regarding the availability assessment hours (the hours a resource must be available in the market to meet its RA Must Offer Obligation) established by the CAISO.\textsuperscript{18} CLECA’s concern is that the CAISO method for changing these hours is not easily visible to DR market participants, and any changes in hours without close coordination with the CPUC could result in existing programs no longer qualifying as RA.\textsuperscript{19} CLECA recommends that the CPUC and the CAISO work together to protect the RA value of DR resources and DRAM contracts in the event of changes to the availability assessment hours. SCE supports CLECA’s recommendation that the CPUC and the CAISO develop a plan to coordinate communications and processes to support the RA value of DR. SCE shares the concern that having different sets of rules between the CPUC and the CAISO with regards to the same resources could result in additional costs to customers. For example, if the availability assessment hours change, which has been proposed for 2018 in the CAISO Proposed Revision Request 986, while the CPUC RA requirements stay the same – there will be two different sets of hours in which resources must be available, which will negatively affect the value of DR resources. SCE supports a directive to the CPUC and the CAISO to coordinate communication and processes to support the RA value of DR.

\textsuperscript{17} SCE’s 2017 Bridge Funding filing, filed February 1, 2016, pp. 20-21.

\textsuperscript{18} The CAISO specifies the availability assessment hours in its Business Practice Manual (BPM). Changes to the BPM go through a public Proposed Revision Requests process at the CAISO.

\textsuperscript{19} CLECA Testimony, p. 40.
E. **SCE Agrees with ORA That the CPUC and the CAISO Should Develop Communication Protocols**

ORA, seeking to support dual participation for DR resources,\(^{20}\) and noting that it is difficult to determine when RDRR are directly bidding into the CAISO, recommends that the IOUs develop communication protocols, ostensibly between CPUC and CAISO, to remedy the issue.\(^{21}\) It is unclear what RDRR resources ORA is referring to because CAISO does not permit dual participation; customers can be registered for only one resource, either an RDRR or Proxy Demand Resource (PDR).\(^{22}\) While SCE agrees that more communication between these two entities is desirable and beneficial for supporting the DR market, the IOUs are limited in what they can do to develop these communication links. SCE recommends that instead of requiring the IOUs to develop this communication, the CPUC actively work with the CAISO to foster improved communication.

F. **SCE Agrees That the Permanent Load Shift Program is Not Cost-Effective and May Be Eliminated**

In its testimony in support of its DR application, SCE requested approximately $6.5 million over the 2018-2022 period for Permanent Load Shift (PLS) program management and incentives.\(^{23}\) SCE also reported that PLS has a cost-effectiveness Total Resource Cost (TRC) score of 0.10.\(^{24}\) ORA recommends that due to its low TRC score and the lack of interest in the program, PLS be eliminated.\(^{25}\) SCE has also noted the lack of interest in the PLS program, notwithstanding the one new project that has been approved since SCE filed its DR application.\(^{26}\) SCE agrees with ORA’s recommendation to

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\(^{20}\) DR customers are allowed to participate in a demand-based and energy-based DR program at the same time, with certain limitations.

\(^{21}\) ORA Testimony, pp. 2-3 – 2-4.

\(^{22}\) PDR is a CAISO product for economic DR that can be either Day-Ahead (DA) or Day-Of (DO).

\(^{23}\) SCE-01, Volume 2, p. 38.


\(^{25}\) ORA Testimony, pp. 3-6 – 3-7.

\(^{26}\) See ORA Testimony, Attachment 3-B-SCE 002 for an updated table of PLS projects in SCE territory.
remove the PLS program from its DR portfolio and instead incorporate it as a part of the Self-Generation Incentive Program or the Commission’s storage proceeding (R.15-03-011).

III.

**SCE Rebuttal to Intervenor Testimony**

The purpose of this Chapter is to provide rebuttal to certain intervening parties’ recommendations. This Chapter is organized into three sections. Section A responds to testimony concerning SCE’s cost recovery proposal. Section B responds to testimony related to SCE’s DR program incentives. Section C responds to intervenor recommendations regarding the design of SCE’s DR programs.

A. **Rebuttal to Issues Related to Cost Recovery**

1. **SCE’s Proposal to Reprogram Meters Is Reasonable**

   In its testimony in support of its DR application, SCE proposed to spend $6.4 million to reprogram its CAISO-integrated Residential meters from 60-minute intervals to 15-minute intervals and its Non-Residential meters from 15-minute intervals to 5-minute intervals, with a cap of 500,000 System Accounts.²⁷ This work would support integration into the CAISO market by allowing SCE to submit the 5-minute data required by the CAISO. The CAISO’s rules permit 15-minute data to be divided by three to obtain 5-minute data, and SCE currently has a temporary waiver from the CAISO allowing it to divide its 60-minute residential customer data by 12. Although SCE is conditionally permitted to perform these calculations, this method results in a sub-optimal level of accuracy.

   ORA proposes the Commission reject SCE’s request for meter reprogramming due to ongoing efforts to determine requirements for DR market participation and because the CAISO has granted SCE a waiver.²⁸ The availability of the CAISO waivers is not guaranteed. If the CAISO stopped approving additional waivers, SCE would lose a significant number of megawatts (MW) of RA value and would be required to procure additional resources to make up for the lost MW. For example,

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²⁷ SCE-01, Volume 2, p. 68.
²⁸ ORA Testimony, pp. 2-2 – 2-3.
SCE’s Summer Discount Plan (SDP), both Commercial and Residential, is integrated into the market as an RDRR, which requires settlement at the 5-minute interval level. SDP provides approximately 400 MW for SCE’s DR portfolio, and if the CAISO waiver is not renewed, SCE would lose 400 MW of RA value, raising many concerns about the viability of DR programs and DRAM contracts, and requiring additional expenditure of ratepayer funds to replace the RA MW. SCE recommends the Commission reject ORA’s proposal and approve SCE’s funding request to reprogram meters. CLECA, in its testimony, supports SCE’s proposal and states that reprogramming the meters will address several needs, such as providing data for fast-responding resources and compliance with any future local RA requirement. In addition, Joint DR Parties find SCE’s proposal to be appropriate.

B. Rebuttal to Issues Related to DR Program Incentives

1. SCE’s Method for Calculating and Allocating Incentives Complies With D.16-06-029

D.16-06-029 ordered the IOUs to seek DR program funding and incentives through DR applications beginning with the 2018 and beyond application, which is the instant application. This represented a significant change, as DR incentives previously were calculated and allocated in GRC Phase 2 proceedings. In its testimony, SCE proposed the calculation for these DR incentives and identified the total estimated incentive amounts that would be provided over the five-year period. In addition, SCE included its DR incentives in its cost-effectiveness calculations. Therefore, SCE complied with the directive of D.16-06-029. As discussed in the following section, SCE is justified in addressing DR incentives in this manner. Although ORA states that it prefers the method used by PG&E for consolidating the DR incentives into their application, it does not allege that SCE is out of

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29 CLECA Testimony, pp. 35-37.
31 D.16-06-029, OP 22, p. 92.
32 Specifically, BIP, AP-I, and SDP incentives.
33 SCE-01, Volume 3, pp. 2-11. See also BIP, AP-I and SDP budget tables in SCE-01, Volume 2.
34 SCE-01, Volume 3, p. 24.
compliance with D.16-06-029 due to the method it used to consolidate its DR incentives. SCE recommends that the Commission deny ORA’s request to require SCE to include its DR incentives as budget line items and instead approve SCE’s DR incentive proposals as presented.

2. **SCE’s Method for Calculating and Allocating Incentives Is Reasonable**

As described above and in its testimony, SCE included the calculation and allocation of DR incentives in its DR application in compliance with D.16-06-029. Because DR program incentives do not increase SCE’s revenue requirement, DR incentives are not a budget line item in its DR application. Rather, DR incentives reflect a reallocation of SCE’s previously approved revenue requirement, resulting in a net zero change to SCE’s revenue requirement. ORA recommends that SCE include its DR incentives as a line item in its budget to provide greater transparency into the amount being spent on DR programs, similar to the method PG&E used for its application.

SCE’s DR program incentives are a reallocation of previously approved funds between customer rate classes, not additional revenue that SCE must collect, and so are not represented by a budget line item. SCE does not collect any additional funding to pay DR incentives. Rather, the overall rate for some customer classes is reduced, and the rate for other customer classes is increased, in order to provide the forecast incentive amount, resulting in a net zero change. Any deviation from the forecast incentives is “trued-up” in the following year. In addition, settlement agreements are still in effect from SCE’s 2015 GRC Phase 2 in which parties agreed to the allocation of incentive revenues and determined incentive levels. SCE recommends that the Commission avoid changing a complex agreement that resulted from significant time and effort by many parties. At the April 5, 2017 workshop on these applications, CLECA verbally expressed the same concern with changing the settlement agreement. SCE recommends that the Commission reject ORA’s proposal to require SCE to include DR incentives

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ORA Testimony, pp. 5-1 - 5-5.

SCE’s revenue requirement is established in GRC Phase 1 proceedings and allocated among the various customer classes in GRC Phase 2 proceedings.

ORA Testimony, p. 5-5.
as budget line items. However, if the Commission does not agree with SCE’s method, SCE does not
oppose using a method similar to that proposed by PG&E. PG&E’s method consists of the same steps
regarding revenue reallocation, but would result in a budget line item for DR incentives (although this
amount would still not be directly collected from customers, but reallocated among customer rate
classes).

Adopting a method similar to PG&E’s approach will result in rate recovery that is largely
consistent with SCE’s current methodology, the primary difference being DR Program incentives would
be reflected in DR Program funding request, and as a line item in SCE’s authorized revenue requirement
tables provided in the year-end consolidated revenue requirement and rate change advice letter. It is
important to note that the declaration of DR Program incentive revenues as a funding item does not
translate to a request for incremental funds. The declaration simply represents an amount of revenue
that will be provided to program participants and recovered from all customers through a net-zero
transfer of cost recovery. To achieve this transfer, SCE would take the following steps:

1. SCE will provide a forecast of 2017 incentives (that is, the capped amount) in its request for
   2018-2022 program funding.

2. The forecast of DR Program incentive credits and associated surcharge revenues will be included
   in the initial implementation to reflect downward and upward pressure on rates, at the total
   revenue requirement level and at the rate group level. The incentive credits and surcharge
   revenues will be of equal value and of opposite sign, thus leaving the total authorized revenue
   requirement unchanged.

3. SCE will record the actual incentive credits and surcharge revenues in a Base Revenue
   Requirement Balancing Account (BRRBA) sub-account. The sub-account will record
   differences between the forecasted amounts and the actual incentive credits and surcharge
   revenues.38

4. When the annual consolidated rate changes are made, SCE will update the DR Program surcharge revenue requirements to reflect any differences in the prior-year recorded incentive credits and surcharge revenues as shown in the BRRBA sub-account. The DR Program surcharge revenues will be updated if necessary to reflect that year’s forecasted amount.

5. SCE will retain the current allocation and rate setting methodology for DR Program incentives. To the extent changes are warranted in either methodology, these will be revisited in SCE’s GRC Phase 2 proceedings. SCE is not requesting incremental revenues associated with the DR Program incentives, as these revenues are authorized in various other proceedings.

3. **SCE’s Proposal to Raise the Incentive for BIP-15 and Lower the Incentive for BIP-30 is Appropriate**

   In its testimony, SCE proposed to raise the incentive for BIP-15 by ten percent and lower the incentive for BIP-30 by three percent to reflect the additional value the faster resource provides by complying with the expected CAISO rule for local capacity. CLECA recommends that the Commission adopt the higher incentive for BIP-15, but reject the lower incentive for BIP-30 until the local RA counting rules are finalized. SCE continues to support a higher value for resources that can reduce their load within 20 minutes. If the Commission declines SCE’s proposal, incentive levels should return to the current differential rather than change in an asymmetric manner. This will maintain the constant overall program incentive value reflected in SCE’s calculations. To revise one BIP incentive and not the other would upset this balance.

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30 BIP-15 can respond to a BIP event within 15 minutes, while BIP-30 can respond to an event within 30 minutes.

40 SCE-01, Volume 3, p. 8.

41 CLECA Testimony, p. 22.
C. Rebuttal to Issues Related to Program Design

1. BIP Program

   a) Evidence of the Value of SCE’s BIP Aggregation Program Has Not Materialized

      In its testimony, SCE proposed to eliminate its BIP Aggregation program because it has incurred costs but provided no benefits over the last ten years.\(^{42}\) SCE noted that although costs for the program were modest, there have been negligible benefits over the past ten years. SCE has not had an aggregator participate since 2009,\(^{43}\) but has consistently spent funds to respond to inquiries, update tariffs, and perform other program management activities. Joint DR Parties recommend that the Commission reject SCE’s proposal to eliminate the BIP Aggregation program because SCE is currently processing applications for BIP Aggregation, and because the other options for DR aggregators are not as beneficial as BIP.\(^{44}\) It is incumbent on stakeholders and the Commission to design, propose, approve, and implement programs that will provide value. SCE recommends the Commission approve SCE’s proposal to eliminate the BIP Aggregation program.

   b) SCE Provides More Clarity Regarding BIP Aggregation

      In its testimony, SCE stated that if the Commission rejected its proposal to eliminate BIP Aggregation, it would have to make several changes to the tariff to align it with SCE’s current processes and to enable its integration into the CAISO market.\(^{45}\) Joint DR Parties stated that SCE’s proposed tariff changes were unclear, and requested that SCE be required to submit proposed tariff language before the Commission approves changes to the tariff.\(^{46}\) Consistent with Commission procedure, SCE would propose any tariff language changes in an advice letter. All stakeholders, including Joint DR Parties, will have the opportunity to see any proposed tariff language and to raise any

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\(^{42}\) SCE-01, Volume 2, pp. 10-13.

\(^{43}\) The aggregation terminated its enrollment approximately three months after applying to enroll.

\(^{44}\) Joint DR Parties Testimony, pp. 14-15.


\(^{46}\) Joint DR Parties Testimony, pp. 16-17.
concerns with the Commission prior to implementation of the changes. Nevertheless, SCE provides additional clarity regarding the envisioned tariff changes here.

Joint DR Parties’ request for additional clarity centered on (1) whether the use of the term “load zone” is meant to be consistent with Sub-Load Aggregation Points (Sub-LAPs); (2) how eliminating the aggregated firm service level (FSL) in favor of an individual FSL allows SCE the latitude to not require aggregations to be on the same voltage level and to not require the aggregations to be comprised wholly of either bundled, direct access (DA), or community choice aggregation (CCA) customers; and (3) whether if, by providing individual FSLs for each service account (SA), performance will be determined on a SA basis or upon the entire aggregation.\textsuperscript{47}

In response to the question regarding load zones, SCE clarifies that the term “load zone” is related to, but not equal to, a Sub-LAP. Load zones are different from Sub-LAPs because they are determined according to the SCE distribution system. SCE dispatches BIP at the load zone level, which SCE defines at the A-Bank substation level, and each load zone maps to a Sub-LAP. Due to the CAISO market integration rules, SCE groups RDRR resources so as to not exceed 50 MW each.\textsuperscript{48} If SCE were to bid BIP at the Sub-LAP level, the 50 MW threshold would be exceeded in Sub-LAPs where SCE has RDRR resources in excess of 50 MW. To support efficient communications with customers, SCE provides BIP customers a load zone at the A-Bank substation level. SCE can then group different load zones within the same Sub-LAP under 50 MW. If the BIP resource grows in the future, SCE may be required to make the load zones at a more granular substation level to avoid exceeding 50 MW.

If the CPUC requires SCE to continue to support the BIP Aggregation option, aggregators will not submit entire aggregated groups at once, but will submit individual enrollments

\textsuperscript{47} Id.

\textsuperscript{48} CAISO rules do not allow a “discrete dispatch” requirement on RDRRs that exceed 50 MW. Not having discrete dispatch complicates market operations and is not compatible with DR program designs; e.g. BIP customers are required to drop down to their FSL when called. The BIP program doesn’t contemplate a partial dispatch where they would be asked to drop down their usage to an alternative level.
(SAs) into their portfolio. At the time the enrollment is approved, SCE will provide the aggregators the load zone for each individual SA. When SCE dispatches BIP, both directly enrolled and aggregation customers located within the same load zone will be dispatched at the same time.

Regarding Joint DR Parties’ questions concerning individual versus aggregated FSLs, the BIP tariff currently requires BIP aggregated groups to provide an aggregate FSL in which the associated SAs must meet the aggregate FSL as a group. Once an FSL is established for the aggregated group, it can only be changed, and additional enrollments can only be added to that aggregation, during November 1 - December 1 of each year. This is because the aggregate FSL must be frozen to maintain consistency in the expected MW reduction for emergencies.

In addition, SCE’s BIP incentives are differentiated by voltage level and 15 or 30-minute participation options. If there is an aggregated group consisting of SAs with various voltages or participation options, there would be no way to apply the different incentive amounts to individual SAs, as the FSL would be at the aggregate level. The same applies for excess energy charges. Therefore, the entire aggregated group currently needs to be on the same voltage level and participation option. SCE has proposed having BIP aggregators set individual FSLs for the SAs within their portfolio, in which performance will be measured against each individual FSL for each individual SA.\textsuperscript{49} Aggregators will not need to create multiple aggregated groups by voltage level or participation option because the incentive multiplier (determined by voltage and participation option) can be applied to individual SAs. SCE would also eliminate the requirement to separate aggregated groups by bundled, DA, or CCA. Aggregators will be allowed to enroll additional SAs into their portfolio throughout the year because there will be no need to freeze an aggregate FSL.

2. **Capacity Bidding Program (CBP)**

In their testimony, the Joint DR Parties and ORA made several recommendations regarding modifications to SCE’s CBP program.\textsuperscript{50} D.16-06-029 states that the Commission would

\textsuperscript{49} SCE-001, Volume 2, p. 12.

\textsuperscript{50} Joint DR Parties Testimony, pp. 9, 20-24; ORA Testimony, p. 2-3.
address whether to expand CBP participation to residential customers in a Ruling on the 2018 and
beyond DR Applications.51 However, the Scoping Memo makes it clear that changes approved in D.16-
06-029 to SCE’s CBP are out of scope in this proceeding.52 As such, SCE addresses only the proposal
to expand CBP to residential aggregators.

Both Joint DR Parties and ORA recommend that SCE expand its CBP to residential
aggregators. Joint DR Parties state that residential DR aggregators currently have no program options
other than DRAM, which is subject to procurement limits.53 ORA likewise proposes for SCE to provide
CBP for residential aggregators, to promote statewide consistency.54

SCE is not opposed to expanding CBP to residential aggregators, but a significant issue
must be resolved before a residential CBP will be successful, namely the issue of the current CBP
settlement baseline. CBP uses the 10-in-10 baseline with a 40 percent day-of adjustment to measure and
reward performance.55 This baseline method does not work well for residential customers because
residential loads are typically inconsistent, varying greatly from day to day. A 10-in-10 baseline is more
appropriate for business customers. The CAISO is currently in the process of examining other baseline
methods for use in DR programs.56 SCE recommends the Commission incorporate the results of the
CAISO’s baseline process to implement a baseline more suitable for residential customers before
opening CBP to residential aggregators. SCE further discusses baseline issues in Chapter IV, Section B
below.

51 D.16-06-029, pp. 57-58.
52 Scoping Memo, Footnote 4, p. 3.
53 Joint DR Parties Testimony, p. 21.
54 ORA testimony, p. 2-3. Note that ORA states, “SCE proposes to expand its CBP program offerings from the
commercial, industrial, and agricultural sectors to include residential aggregators as well. ORA supports this
expansion and recommends that the Commission require PG&E and SDG&E do the same.” SCE did not
propose this expansion. It appears ORA mixed up SCE and PG&E in this regard.
55 See SCE’s Schedule CBP, Special Condition 12.
56 See Energy Storage and Distributed Energy Resources Stakeholder Initiative Phase 2 Revised Straw Proposal,
2.pdf
3. **Summer Discount Plan**

The Joint DR Parties’ proposal to eliminate SDP for a bring-your-own-thermostat (BYOT) program is premature. Specifically, the Joint DR Parties recommend the Commission consider directing SCE to convert SDP, its air conditioner (AC) cycling program, to a BYOT program, consistent with SDG&E’s proposal for its AC cycling program. Joint DR Parties state that SCE should make this change as SDP reaches “the end of [its] useful life,” and that making the change would provide more kilowatts (kW) per customer and more kW per dollar.\(^{57}\) SCE is confused by Joint DR Parties’ statement regarding “the end of [SDP’s] useful life.”\(^{58}\) There is nothing in the record that states SDP is reaching the end of its useful life. In fact, SDP is one of SCE’s largest DR programs by participating customers and MW of capacity. In addition, SCE already has a BYOT program, which is the Peak Time Rebate-Enabling Technology-Direct Load Control (PTR-ET-DLC, also known as simply PTR or Save Power Day (SPD)), as acknowledged in Joint DR Parties’ testimony.\(^{59}\) It is unclear why SCE would need to phase out SDP in favor of PTR at this time when both programs provide benefits.

As stated in its testimony, SCE plans to transition SDP customers to PTR, and sees PTR as a long-term replacement for SDP,\(^{60}\) but SCE has not yet developed a timeline or specific criteria for replacing the SDP program with the PTR program. SCE will continue to work with the Commission, the CAISO, and other stakeholders to meet future and near-term market, grid and customer needs prior to establishing a timeline or specific criteria for this transition. SCE views both SDP and PTR as playing an important role in its current DR portfolio. SCE will continue to evaluate the outcomes of the DR Potential Study and process to develop new models of DR, as well as the effectiveness of the newly redesigned and integrated PTR program in 2018 and beyond. The rate of customer adoption of newer

\(^{57}\) Joint DR Parties Testimony, pp. 29-30.

\(^{58}\) Id., p. 29.

\(^{59}\) Id., pp. 29-30.

\(^{60}\) SCE-01, Volume 2, p. 29.
technologies, such as programmable communicating thermostats (PCTs), will also affect SCE’s decision on the future of SDP.

4. **PTR Program**

In its testimony, SCE proposed to change the PTR dispatch window for economic events to be between 11:00 a.m. and 8:00 p.m. with a minimum duration of one hour and a maximum duration of six hours per day. This would be a change from the current limit of one four-hour event per day, with events occurring from 2:00 p.m. to 6:00 p.m. on non-holiday weekdays. Joint DR Parties recommend that SCE use a 1-4 hour event duration, or ensure that no single customer is called for more than four hours of an event if the 1-6 hour duration is adopted. Although Joint DR Parties note that it is reasonable to align PTR with SDP, their reasoning for this recommendation is that customers may not want to participate in a six-hour event, and events of this length could negatively affect customer satisfaction and cause greater attrition from the program.

Customer fatigue, although a real phenomenon that contributes to DR program attrition, is unlikely to occur with PTR due to the fact that customers can opt out of any particular event by overriding the temperature setting on their thermostat. Customers also have the option to override a portion of the PTR events. For instance, a customer participating in the first four event hours of a six-hour event can override the remaining two event hours. Providing customers with the ability to override and determine their own level of participation will decrease customer fatigue. In addition, the CAISO typically dispatches economic events for up to four hours, and dispatches reliability events up to six hours. The infrequency of reliability events will also combat customer fatigue. Finally, SCE dispatches its DR programs by Sub-LAP (or by load zone as discussed in Section C.1 above), and does not have the

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61 Currently, PTR events occur in a specified timeframe, 2:00 p.m. to 6:00 p.m.

62 SCE-01, Volume 2, p. 32. SCE inadvertently stated that its PTR program could be dispatched any time of day. This is incorrect. PTR can be dispatched from 2:00 p.m. to 6:00 p.m. on non-holiday weekdays.

63 Joint DR Parties Testimony, p. 30.

64 Participation in PTR events is voluntary, and there are no penalties for not participating or not providing enough load reduction.
ability to limit the dispatch of a single customer to four hours. For these reasons, SCE recommends that the Commission reject Joint DR Parties’ proposal and approve SCE’s PTR program as proposed in its testimony.

5. **Technology Incentive Program**

   a) **Technology Incentives Should Be Provided by the Customer’s DR Provider (DRP)**

     In its testimony, SCE proposed to continue the $75 rebate for PCTs established in D.16-06-029. Joint DR Parties requested clarification asking specifically whether customers participating in third-party aggregator programs like CBP and DRAM are eligible to receive the PCT incentive. Joint DR Parties recommend that customers receiving a PCT incentive be allowed to participate in any DR program, either IOU or third-party, as long as the PCT will be used for DR. Similarly, OhmConnect recommends that technology incentives be available to participants of both IOU and third-party DR programs on equal terms.

     SCE currently has contracts with qualifying thermostat manufacturers and service providers to participate in SCE’s PTR program, and SCE will examine the feasibility of extending this partnership to all DR programs where SCE is the DRP. Where SCE is the DRP for the customer, and responsible for bidding load into the CAISO Market, it makes sense for SCE to provide technology rebates or incentives to the participating customer because SCE can verify whether the incentive is being used for DR and whether the program is cost-effective. However, where SCE is not the DRP and has no visibility to the bidding of the DR resource or utilization of the enabling technology, SCE should not be responsible for providing technology incentives. In these cases, SCE has no visibility to the performance of the resource or if the DR enabling technology was used in response to the DR event

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65 Although third parties may be DRPs, SCE also serves as a DRP for its directly-enrolled DR customers.
66 SCE-01, Volume 2, pp. 39-40.
68 OhmConnect Testimony, p. 2-3.
signal, and therefore cannot identify the cost-effectiveness or benefits of the funds spent on these technologies.

The DRP for each program should be responsible for verifying all appropriate costs are allocated to the individual programs in a cost-effective manner. SCE included its technology incentive costs in the cost-effectiveness calculations for its various DR programs. For instance, the $3.75 million requested for PCT incentives was included in the PTR program’s cost-effectiveness calculations. SCE should not provide technology incentives for DR awarded through a competitive solicitation process, such as the DRAM, unless DRAM bids are subject to the same cost-effectiveness test as utility DR programs. All costs associated with DRAM resources should be “loaded” into the offer or bid by the DRP, including technology costs, administrative costs, and customer marketing/acquisition costs. This provides visibility into the full price the IOUs are paying for DR procured through competitive solicitations. It also avoids the IOUs paying a contract price, then providing additional ratepayer funds to provide a technology incentive for the same DR resource.

SCE recommends the Commission deny the recommendation of Joint DR Parties and OhmConnect to provide technology incentives to all DR customers, and instead adopt the technology incentive program proposal as described in SCE’s testimony.

b) OhmConnect’s Proposals to Revise the Technology Incentive Program Are Not Supported

In its direct testimony, OhmConnect recommends that SCE expand the technologies eligible to receive incentive payments under the Technology Incentive Program to various internet-connected consumer devices that could be used for DR, in addition to PCTs. In addition, OhmConnect also proposed that the IOUs provide a fixed technology incentive budget to DR customers that could be used for any combination of qualifying devices, rather than a set incentive per device.69 OhmConnect supports its recommendation by noting its concerns that the IOUs’ technology incentive

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69 OhmConnect Testimony, p. 2-3.
discriminates against customers participating in third-party DR programs and may not comport with certain DR market principles contained in D. 16-09-056. OhmConnect’s concerns are speculative at best and not supported by any evidence of discrimination against customers participating in third party DR programs.

Specifically, OhmConnect has not demonstrated that the current structure of SCE’s Technology Incentive Program impairs third-party DRPs from providing technology incentives for its customers. In fact, the cost associated with such technology incentives would be included in the contract the third party DRP has with SCE to provide the DR programs or in the agreement between the DRP and the customer. Similarly, OhmConnect has not provided any evidence to support its concern that SCE’s Technology Incentive Program may not adhere to the DR market principles identified in D. 16-09-056. In fact, as discussed earlier in this testimony, SCE currently has contracts with qualifying thermostat manufacturers and service providers to participate in SCE’s PTR program. This aligns with the DR market principles OhmConnect identifies in Ordering Paragraph 8 of D. 16-09-056. This testimony also describes the practical limitations of SCE providing a technology incentive when SCE is not the DRP for a customer, such as not having visibility to the performance of the resource nor if the DR enabling technology was used in response to the DR event signal. As such, SCE would not be able to identify the cost-effectiveness or benefits of the ratepayer funds spent on these technologies. Thus, in the absence of any evidence demonstrating discrimination or noncompliance with D. 16-09-056, OhmConnect’s recommendation should be rejected.

6. **Marketing, Education and Outreach (ME&O)**

   a) **OhmConnect’s Online Marketplace Proposal Raises Significant Issues**

   OhmConnect recommends that the Commission require the IOUs to develop an online marketplace where customers can view information about available IOU and third-party DR programs, and that the IOUs’ ME&O activities promote the marketplace, rather than their own programs. OhmConnect also provides a list of items that the marketplace should display, including the
name and logo of the DR provider, a description of the DR program, and an average customer rating of
the program.70

The limited concept of a DR marketplace may have merit, but OhmConnect goes
too far. Its overly prescriptive proposal raises many issues related to the role of the IOU vs. third
parties, funding, and the IOU/DR “firewall.” SCE is not opposed to the general idea of a DR
marketplace, and notes that it already has similar information, namely DRP name, address, contact
information, and whether they serve residential or small commercial customers, on its Rule 24 website.71
In addition, SCE is in the process of developing a similar technology marketplace as required in
Resolution E-4820 on the IOUs’ Assembly Bill 793 proposals.22 However, the additional information
OhmConnect requests be shown in a marketplace raises funding concerns. For instance, implementing a
rating system for DRP programs would be costly, requiring a new technology project to be initiated. In
addition, it is unclear how marketing to “customers most likely to perform during DR events,” as
proposed by OhmConnect, would comply with the IOU “firewall” meant to protect against SCE DR
employees knowing which SCE customers participate in third-party DR programs.23

Further, it is unclear where funding would come from, including funding for
maintenance of the online marketplace. Any time a third party changes their name, their logo, the name
of their program, or other information, SCE would have to change it on its website. This is not SCE’s
role. Rather, third parties should prepare, post online, and maintain their own marketing materials rather
than look to IOUs to do it for them. This position has Commission precedent, as D.12-04-045 denied
SCE’s proposed marketing budget for CBP on the grounds that it is unnecessary for IOUs to market a
program administered by a third party.24 It is still unnecessary for the IOUs to market programs

70  Id., pp. 3-3 - 3-5.
71  Demand-Response-Service information is available at
https://www.sce.com/wps/portal/home/partners/partnerships/Demand-Response-Service
72  See Resolution E-4820, OP 1b, pp. 34-35.
73  See D.15-03-042, p. 43.
74  D.12-04-045, p. 88. [Decision Adopting Demand Response Activities and Budgets for 2012 through 2014]
administered by third parties. SCE is not opposed to providing DRP information, including a link to the third party website, similar to SCE’s current Rule 24 webpage, but opposes including the type and quantity of information proposed by OhmConnect.

b) **SCE Should Have Flexibility to Market its Own Programs**

Joint DR Parties recommend that the Commission condition the use of ME&O funds on the IOUs’ use of neutral marketing messages between IOUs and third parties, and that the Commission order the IOUs to work with third parties in developing its ME&O messaging. SCE is committed to respecting the role third parties play in providing DR, and does not use messaging that disparages or directly opposes any third-party program. SCE should maintain the flexibility to develop its messaging in the manner it sees fit; requiring collaboration or input from any number of third parties could unnecessarily result in increased costs for customers.

7. **Cost-Effectiveness**

a) **It Is Premature to Change the Threshold for Cost-Effectiveness**

In D.12-04-045, the Commission established that a Total Resource Cost (TRC) score of 0.9 or above would be considered cost-effective for DR programs, as that was the first time using the cost-effectiveness protocols. ORA recommends the Commission revise the threshold for considering a DR program or portfolio to be cost-effective from 0.9 to 1.0, to be consistent with other programs like energy efficiency. Although the 0.9 threshold was used in the IOUs’ 2012-2014 DR application proceeding, ORA’s recommendation is premature as a record has not been established supporting that this is an appropriate time to change the threshold to 1.0. The cost-effectiveness protocols have changed significantly since the IOUs’ 2012-2014 DR applications that resulted in D.12-04-045, as noted by ORA. Cost-effectiveness portfolio calculations were not performed for the bridge.

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75 Joint DR Parties Testimony, p. 38.
76 D.12-04-045 at 44 and Finding of Fact (FOF) 12, p. 207.
77 ORA Testimony, p. 3-3.
78 ORA Testimony, p. 3-1, discussing changes to the CE protocols made in D.15-11-042.
funding years of 2015-2017, and there has not been the continuity that would obviate the need for the
ten percent error band described in D.12-04-045. In addition, the Commission is currently considering
new models of DR, and the IOUs are preparing to design and propose these new models of DR. As
there will be new types of DR programs in the near future, now is not the time to make the cost-
effectiveness threshold more difficult to reach. The Commission should examine cost-effectiveness
calculations, and whether the threshold should be changed, as part of R.13-09-011, not in this “business
as usual” DR funding application. SCE recommends the Commission deny ORA’s recommendation,
continue to use a 0.9 TRC score as the threshold for cost-effectiveness, and approve SCE’s DR portfolio
as cost-effective.

b) SCE Included its AutoDR Costs in its Cost-Effectiveness Calculations

Joint DR Parties state that, examining SCE’s workpapers in support of its
testimony,\textsuperscript{79} it appears that SCE did not include AutoDR costs in its CE calculations, and they
recommend that technology incentives no longer be included in the IOUs’ program-specific cost-
effectiveness analyses. SCE included AutoDR costs in its cost-effectiveness calculations, as required by
the cost-effectiveness protocols,\textsuperscript{80} and these costs are visible in SCE’s workpapers.\textsuperscript{81} For cost-
effectiveness purposes, SCE apportioned its AutoDR costs among its DR programs by the percentage of
the overall DR budget represented by each DR program. If in a given year, CBP represented ten percent
of the total DR budget, it received ten percent of the AutoDR costs for that year. SCE has endeavored to
apportion AutoDR costs in a manner that is consistent and logical, but acknowledges that there is no
simple way to apportion AutoDR costs to programs such that the costs match the benefit received by
customers of that program.

\textsuperscript{79} SCE’s workpapers were provided to ORA, the Commission’s Energy Division, and any party to the
proceeding that requested them.

\textsuperscript{80} 2016 Cost-Effectiveness Protocols, pp. 39-40, available at

\textsuperscript{81} See SCE Workpaper titled, “Final-Overhead Calc and Program CE Breakout (Final_011517_v2).xlsx,
worksheet titled “Program Allocation.”
SCE disagrees with Joint DR Parties’ recommendation that AutoDR costs be excluded from cost-effectiveness calculations altogether, as that would exclude a significant source of costs that should be accounted for in cost-effectiveness calculations. Excluding AutoDR costs would over-state the value of DR programs and create less transparency into the costs and benefits of DR. SCE recommends the Commission deny Joint DR Parties’ proposal and approve SCE’s DR portfolio and cost-effectiveness test scores as presented.

c) SCE’s Capacity Bidding Program Does Not Qualify for a G-Factor Adder

In its testimony, SCE provided the results of its cost-effectiveness calculations, including a detailed discussion of each factor (A-G) used in the calculation. As part of this discussion, SCE noted that it used a G-Factor of 100 percent for its CBP program. As noted in SCE’s testimony, the two requirements for using a G-Factor of 105 percent for a program are (1) that it is technically able to dispatch locally (called at A-bank level or lower level) in the areas of Big-Creek Ventura or the LA Basin; and, (2) bid into the CAISO Energy Market. Joint DR Parties recommend that SCE’s CBP be allocated a G-Factor of 105 percent, rather than the standard 100 percent, because it is integrated into the CAISO market and is dispatchable at the Sub-LAP level. Although Joint DR Parties’ statement regarding CBP integration and dispatchability is accurate, CBP does not qualify for the higher G-Factor because the Sub-LAP level is a higher level of dispatchability than the level required to be considered locally dispatchable. According to the 2016 cost-effectiveness Protocols, “the G-Factor accounts for those DR resources which can be called locally in geographical regions that are resource-constrained.” The protocols do not specify at what specific dispatch level the G-Factor adder applies, and the dispatch level threshold SCE uses for its programs is the A-bank level. This is because programs called at the

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82 SCE-01, Volume 3, pp. 24-41.
83 Id., pp. 33-34.
84 Id.
85 Joint DR Parties Testimony, p. 43.
86 2016 Cost-Effectiveness Protocols, p. 34.
Sub-LAP level are not guaranteed to realize local MW impacts at a targeted A-bank, B-bank, or circuit. SCE recommends that the Commission deny Joint DR Parties’ recommendation and adopt SCE’s CE calculations as presented in its testimony.

IV.

Other Issues

A. Policy Issues

1. Identical Statewide DR Programs Are Unnecessary

   The IOUs’ respective DR programs, although consistent in their underlying rationale and value, differ in certain ways. Joint DR Parties state that the Commission’s intent was to minimize program differences, but offer no evidence in support of this claim. Joint DR Parties assert that these differences create problems for third-party DRPs because they must adapt to different eligibility and operating requirements for the different IOUs. SCE agrees that the IOUs’ respective DR programs should generally be consistent, however, consistency does not require the programs to be identical. The IOUs have different operating characteristics and needs, and they should be granted flexibility to design programs to fit their unique situations. In fact, third-party DRPs should prepare for increased variation in program design and requirements as CCAs may elect to enter the marketplace to initiate their own DR programs and portfolios where IOU programs will no longer be applicable.

   Joint DR Parties state that for BIP, the IOUs’ differing notification times are an issue for customers and aggregators. They also state that there should be no notification time other than what is required to meet the CAISO’s 40-minute notification requirement. Due to the IOUs’ differing computer systems and business operations, notification times necessarily may vary. For instance, for SCE there are several steps that must occur to dispatch BIP, and a resource that nominally meets the 40-

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87 For instance, SCE’s CBP program is available year-round, while PG&E and SDG&E’s programs are available part of the year.

88 Joint DR Parties Testimony, pp. 6-7.

89 Id.
minute requirement may have difficulty meeting it in practice. For instance, on May 3, 2017, CAISO triggered the BIP program due to a reliability event. After receiving a notification from CAISO at 6:54 p.m., which began the 40-minute response window, SCE initiated its BIP program at 6:58 p.m. SCE’s system made automated calls to customers at 7:06 p.m. Because SCE currently meters at the 15-minute interval level for commercial customers, it must round to the next 15-minute interval and then begin the BIP response time. This means that, in this example, customers had 15 or 30 minutes, depending on their BIP option, from 7:15 p.m. to reduce their load to their FSL. Therefore, customers on the 15-minute option that reduced by 7:30 p.m. would meet the 40-minute CAISO requirement, while those that reduced by 7:45 p.m. would not. As shown in this example, once CAISO calls a BIP event, there are still many steps that must occur to meet the 40-minute response time. As these steps and time intervals may vary by IOU, SCE recommends the Commission reject Joint DR Parties’ proposal to make the BIP notification times identical across the IOUs.

The Joint DR Parties’ testimony is written in a way that suggests SCE made affirmative proposals regarding the CBP event window and day-of option. SCE made no such proposals in its Testimony. SCE did reference certain changes to CBP approved in D.16-06-029 that it would implement, but did not make any new proposals regarding CBP as part of this proceeding. As discussed in Chapter III.2 above, the Scoping Memo did not include CBP changes for SCE in the scope of this proceeding.

2. **Joint DR Parties Have Not Demonstrated a Lack of Competitive Parity Between IOU and Third-Party Programs**

Joint DR Parties ask the Commission to “recognize [] ‘advantages’ to a Utility service and either make the same options available to third party DR providers or remove the advantage from

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\(^{20}\) SCE has proposed to reprogram up to 500,000 DR meters to 5-minute intervals for commercial customers and 15-minute intervals for residential customers. See SCE-01, Volume 2, p. 68.

\(^{21}\) This is a representative example. Time intervals may vary.

\(^{22}\) Joint DR Parties Testimony, p. 8.

\(^{23}\) Scoping Memo, footnote 4, p. 3.
the Utility service.” First, the Joint DR Parties assert an undue preference exists if an IOU can give priority of access to available capacity to its customers under the reliability cap. SCE has implemented a first-come, first-served waitlist to queue new RDRR resources whose MW exceed the reliability cap. Therefore, SCE does not give preference to its customers under the reliability cap, and no undue preference for SCE’s DR programs exists.

Second, Joint DR Parties assert an undue preference exists if customers can access technology incentives more easily or in greater amounts in IOU programs versus third-party programs. SCE agrees that customers should be able to access technology incentives from both IOU and third-party programs, but as discussed above in Section III.C.5, customers should be granted technology incentives by their DRP. Specifically, SCE should provide technology incentives for DR programs where SCE is the DRP, and the third-party DRPs should provide the technology incentives for their programs. Currently, third parties can design technology incentive programs and build the costs of these programs into their contracts (such as DRAM) or customer agreements.

Third, Joint DR Parties assert an undue preference exists if customers can dual participate and be bid into the CAISO market in IOU DR programs, but not in third-party DR programs. SCE does not oppose allowing third-party DR customers to dual participate on a basis similar to IOU DR customers. In addition, no rule exists preventing third-party DRPs from creating their own energy-based DR program and having their customers dual participate with a capacity-based program. In fact, DRAM contracts assign all CAISO market energy revenues to the Sellers (third-party DRPs), leaving them the option to bid their energy at will. Therefore, no undue preference for SCE’s DR programs

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24 Joint DR Parties Testimony, p. 5.
25 Joint DR Parties Testimony, pp. 5-6.
26 SCE discusses this point further in Chapter IV.E.
27 The DRAM contract sets minimum CAISO bidding requirements, such as bidding during the Resource Adequacy Must Offer Obligation hours. The contract does not prohibit Sellers from bidding during other hours, and it leaves them latitude on the market bid price, enabling them to maximize their energy revenues.
exists. SCE recommends that the Commission confirm for the record that there is no evidence of undue preference for SCE’s DR programs.

3. **DR’s Effect on Disadvantaged Communities Is an Important Issue**

Issues of how DR can address and alleviate the problems facing disadvantaged communities is included in the scope of this proceeding. Commissioner Guzman Aceves, at the April 5, 2017 workshop on these applications, identified this issue as one of particular interest. ORA recommends that the Commission explore this issue, along with the issue of locational value for DR resources, in a rulemaking proceeding such as the Integrated Distributed Energy Resources and Distribution Resource Plans proceedings (R.14-10-003 and R.14-21-10-003), the Net Energy Metering proceeding (R.14-07-002), or the current DR rulemaking proceeding (R.13-09-011). ORA’s recommendation has merit, as addressing these issues would likely be a lengthy process and outlast the duration of this DR funding application proceeding. SCE recognizes the importance of these issues, particularly the issue of increasing utilization of DR in disadvantaged communities, and affirms that it is committed to addressing these issues in whatever venue the Commission ultimately decides is appropriate.

B. **Baseline Issue**

Joint DR Parties recommend the Commission require its staff to participate in the development of alternative baselines that is under discussion at the CAISO. Joint DR Parties also recommend that once alternative baselines are adopted, the Commission re-open this proceeding to examine and adopt those baselines. Similarly, CLECA recommends the Commission consider whether the alternative baselines approved by the CAISO should be permitted for DR programs in time for 2018 implementation. SCE supports the Commission exploring whether alternative baselines are a good fit.

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98 Scoping Memo, p. 4.
99 ORA Testimony, p. 7-1.
100 Commercial DR programs currently use the 10-in-10 baseline.
101 Joint DR Parties Testimony, pp. 40-41.
for DR programs. The purpose of the alternative baselines is to improve the measurement of the
performance of DR resources integrated into the CAISO market. If the IOUs are not permitted to use
the improved baselines but third-party DRPs are allowed to do so, the value of the IOUs’ DR resources
will be negatively impacted relative to third-party DRPs. However, SCE does not support reopening the
proceeding if the approval of alternative baselines occurs after this proceeding is closed. Rather, the
Commission should use another venue, such as R.13-09-011.

C. Local RA Issue

In its testimony, SCE proposed to adjust its BIP incentives to reflect the greater value provided
by BIP-15 relative to BIP-30. This greater value results from BIP-15 meeting the CAISO requirement
that resources be able to respond within 20 minutes to qualify for meeting the Local Capacity
requirements. CLECA opposes SCE’s proposal and outlines four options for addressing this matter
once it has been decided by the Commission.

The Commission has the authority to implement a policy on this issue prior to its final resolution
in the RA proceeding (R.14-10-010). Even absent a final Commission determination on the Local RA
rule, faster-responding DR is more valuable to the grid. SCE recommends that the Commission
acknowledge this value by rejecting CLECA’s proposal and adopting SCE’s BIP incentives that take
into account the 20-minute response time. Once a final determination has been made in the RA
proceeding, the Commission can review its impact on SCE’s DR programs.

D. CAISO Integration Issues

ORA recommends SCE specify the amount of funds it allocates to CAISO integration efforts,
and remove any funding that is not narrowly related to ongoing operations, such as maintaining staff to
conduct bidding. ORA bases its recommendation on the fact that DR market integration must be

103 D.16-06-045, pp. 27, 34-38.
104 CLECA testimony, pp. 23-25.
105 See Chapter III, Section B of this document for further discussion of SCE’s incentive calculations.
complete by January 2018 to receive RA value. SCE has already integrated approximately 90 percent of its DR MW into the CAISO market, and therefore opposes ORA’s proposal. With the exception of the funds requested for meter reprogramming, there is no funding request in its application that is specifically meant to support market integration. Rather, SCE requests funding to improve and make programs and processes more efficient. These activities may include enhancing program operations such as market integration, which is one element of a program design. Costs to support market integration are “baked into” the program management funding SCE requests, and as such, it is difficult to identify the specific amount supporting market integration. SCE recommends the Commission deny ORA’s request and approve SCE’s programs and budgets as proposed.

ORA also recommends that each IOU provide a timeline for completing DR market integration by January 2018. ORA states that it is concerned that integration will be delayed without clear interim targets. SCE re-affirms that it has integrated approximately 90 percent of its DR portfolio into the CAISO market. SCE is unable to integrate the remaining 10 percent of DR that has not been integrated into the market due to existing CAISO rules or the burden created by such rules. SCE refers to these MW as the “crumbs,” and has raised this issue to the Commission. SCE’s integration of these remaining MW depends on changing the CAISO rules that currently require resources to be defined by Sub-LAP and load-serving entity, and a timeline would be speculative. As stated in its testimony, SCE intends to work with the CAISO, CPUC, and other stakeholders to explore solutions that would allow the integration of additional DR capacity.

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106 ORA Testimony, pp. 2-1-2-2.
107 See SCE-01, Volume 2, pp. 18-20.
108 SCE’s funding request for meter reprogramming is discussed further in Chapter III.A.
109 ORA Testimony, pp. 2-1 – 2-2.
110 SCE-01, Volume 1, pp. 18-20.
111 Id., p. 19.
E. **Dual Participation Issues**

In their testimony, Joint DR Parties identified as an issue that IOU DR customers can dual participate in a demand and an energy DR program, while aggregator customers cannot dual participate in, for instance, DRAM and critical peak pricing (CPP), an IOU energy program. Joint DR Parties recommend that the Commission re-examine its position on dual participation and allow the customers of third-party DRPs to dual participate on a comparable basis to IOU customers, while warning of the complex issue raised by the “firewall” that limits IOU employees from knowing which customers are DRAM participants.\(^\text{112}\) SCE supports a process at the Commission to discuss dual participation rules, but concurs with Joint DR Parties that complying with Commission policy regarding the “firewall” will complicate the matter. This process should include stakeholder workshops, and could be incorporated into the process to design new models of DR currently underway in R.13-09-011.

SCE notes that there is no rule preventing third-party DRPs from creating their own energy-based DR program and offering it to their DRAM customers to dual participate in the market as a PDR. This would enable DRP customers to dual participate without running afoul of the CPUC or the CAISO rules. In fact, this is currently the only dual-participation option within the current CAISO market integration rules, as an individual customer (SA), can only be registered within a single PDR or RDRR resource at a time – preventing dual participation across multiple DRPs (e.g. an IOU and a DRAM Seller).\(^\text{113}\)

Joint DR Parties also recommend that BIP Aggregation customers be allowed to dual participate in the IOU CPP program.\(^\text{114}\) As a foundational matter, SCE continues to support its proposal to eliminate the BIP Aggregation option, as discussed in Chapter III above. However, if the Commission decides to continue the BIP Aggregation option, SCE agrees that BIP Aggregation customers should be

\(^{112}\) Joint DR Parties Testimony, p. 35-36.

\(^{113}\) For IOU programs / resources, SCE acts as the DRP for market integration purposes.

\(^{114}\) Joint DR Parties Testimony, p. 37.
allowed to dual participate with CPP, on the condition that they use an individual FSL, rather than the current aggregated FSL. This would require changes to the current BIP Tariff.

As it stands today, SCE’s BIP tariff does not allow BIP aggregated SAs to dual participate in other DR programs, and states,

For customers’ service accounts dual participating with Schedule CPP or Option CPP of an applicable TOU rate schedule, the sum of credits provided by TOU-BIP and CPP will be capped. The capped credit amount, also known as the Maximum Available Credit, is listed per the customer’s OAT in the applicable rate section of Schedule CPP or Option CPP.\textsuperscript{115}

Under the current BIP Aggregation tariff, aggregated groups are required to set aggregate FSLs. Specific SAs within an aggregated group are not necessarily required to perform to the FSL, as long as the group as a whole reaches the FSL. Because the FSL is set at an aggregate level and there is no way for SCE to determine what the individual FSL for a SA would be, SCE cannot ensure that a capped credit amount is applied for a SA that is dual enrolled in CPP and BIP aggregation.

If the Commission continues to require BIP Aggregation and approves individual FSLs for BIP Aggregation customers, SCE will be able to calculate the amount of incentives the individual SA will receive for BIP and the amount of incentives the individual SA will receive for CPP, and apply the Maximum Available Credit cap. Therefore, SCE agrees with Joint DR Parties’ proposal to allow BIP aggregated SAs to dual participate in CPP, but only if individual FSLs are established.

\textsuperscript{115} SCE’s Schedule TOU-BIP, Time-of-Use General Service Base Interruptible Program, Special Condition 15.
Appendix A

WITNESS QUALIFICATIONS
SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF ERICA KEATING

Q. Please state your name and business address for the record.
A. My name is Erica Keating, and my business address is 1515 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.
A. I currently manage the operations of the Large Power Demand Response programs within the Customer Programs and Services department at Southern California Edison (SCE). This includes responsibility for approximately 1,000 MW of demand response programs. My staff includes 4 program/project managers, and 3 analysts.

Q. Briefly describe your educational and professional background.
A. I hold a Bachelor of Arts Degree in Communications with minors in History and German from California State University at Fullerton. I completed a graduate degree from California State University at Long Beach where I received a Master of Public Administration. I began my career in 2001 at the city of Rancho Cucamonga as the administrator of the city’s capital improvement program, as well as the operations manager for the City’s municipal utility. In 2010 I started with Southern California Edison as a contracts and request for offer (RFO) originator in the Energy Procurement and Management Department and progressed to senior originator in 2012. In that period of time I oversaw the procurement of SCE’s resource adequacy portfolio, led the procurement of conventional generation resources in SCE’s Local Capacity Requirements RFO and more recently was responsible for SCE’s Renewables Portfolio Standard Procurement RFO. I was promoted to my current Manager 2 position in 2016. I have never previously testified before the California Public Utilities Commission.

Q. What is the purpose of your testimony in this proceeding?
A. The purpose of my testimony in this proceeding is to sponsor portions of SCE’s rebuttal testimony, preliminarily marked for identification as SCE-02, and titled Rebuttal Testimony In
Support of Southern California Edison Company’s Application for Approval of its 2018 – 2022 Demand Response Programs, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?
A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?
A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.