BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	R.13-09-011 (Filed September 19, 2013)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PROPOSAL IN RESPONSE TO ASSIGNED COMMISSIONER'S RULING DIRECTING ACTIVITIES IN RESPONSE TO NATURAL GAS LEAK AT ALISO CANYON STORAGE

JANET S. COMBS
ANGELICA M. MORALES

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-4435
Facsimile: (626) 302-6962
E-mail: Angelica.Morales@sce.com

Dated: **April 4, 2016**

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PROPOSAL IN RESPONSE TO ASSIGNED COMMISSIONER'S RULING DIRECTING ACTIVITIES IN RESPONSE TO NATURAL GAS LEAK AT ALISO CANYON STORAGE

Table of Contents

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PROPOSAL IN RESPONSE TO ASSIGNED COMMISSIONER'S RULING DIRECTING ACTIVITIES IN RESPONSE TO NATURAL GAS LEAK AT ALISO CANYON STORAGE

Table of Contents (Continued)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	R.13-09-011 (Filed September 19, 2013)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PROPOSAL IN RESPONSE TO ASSIGNED COMMISSIONER'S RULING DIRECTING ACTIVITIES IN RESPONSE TO NATURAL GAS LEAK AT ALISO CANYON STORAGE

I.

INTRODUCTION

Pursuant to the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC or Commission), and in compliance with the *Assigned Commissioner's Ruling Directing Activities in Response to Natural Gas Leak at Aliso Canyon Storage and Seeking Comments*, issued March 23, 2016 (ACR), Southern California Edison Company (SCE) hereby submits its proposal consistent with the direction provided in the ACR.

The ACR directs SCE to "intensify existing efforts in its demand response program activities in the geographic areas most impacted by the anticipated natural gas shortage" and to "propose new funding or changes to program rules that may be useful for ensuring reliability."[1] Consistent with the direction in the ACR, SCE proposes the following Demand Response (DR) enhancements to address the Aliso Canyon leak:

- Modifications to increase participation in the Summer Discount Plan (SDP) program;
- Efforts to increase participation in the Base Interruptible Program (BIP) and Agricultural and Pumping Interruptible (API) DR programs; and

---

[1] ACR, pp. 2-3.

- Modifications to the rebate for programmable thermostats in the Direct Load Control program; and
- Deferral of the retirement of Demand Bidding Program.

To implement these proposals, SCE requests $6.722 million in incremental funding. This funding is additive to SCE's 2017 Demand Response Program and Bridge Funding Authorization (2017 Bridge Proposal). SCE's proposal is discussed in detail in Section II. The ACR also includes four questions to which SCE is directed to respond. SCE's responses to the questions are in Section III.

II.

SCE'S PROPOSAL

In this section, SCE includes its proposal for meeting the requirements of the ACR and discusses how it aligns with the four qualifications described in the ACR. This section also includes SCE's requested incremental budget and provides the cost-effectiveness analyses for SCE's proposals.

A. Proposal Qualifications

The ACR states that SCE's proposal should be qualified in the following four ways:

- It should focus on reliable DR that can be quickly deployed;
- It should target geographic areas where electric reliability may be at risk as a result of anticipated natural gas shortages;
- It should focus on boosting DR for the summer seasons of 2016 and 2017, including September and October; and
- Efforts to boost DR in 2017 should be coordinated with SCE's 2017 Bridge Proposal and any subsequent direction given to SCE by the Commission in authorizing that proposal.[2]

---

[2] ACR, p. 4.

Given the California Independent System Operator's (CAISO) ability to optimize resources across a geographically wide electric network,[3] and the significant decrease in intra-day gas scheduling flexibility, SCE recommends that enhancement efforts prioritize a focus on fast-response system DR. The major impact from a reduction in gas storage capability on the Southern California Gas system is the reduction in flexibility the impacted gas-fired generation units have – where the specific flexibility at issue is the ability to generate more (or less) in Real Time than what was scheduled Day-Ahead.[4] Furthermore, the impacted gas units could be dispatched up (or down) in Real-Time due to a number of CAISO system-wide needs. Because of the system-wide impact of the proposed limitations on the use of gas, efforts to enhance DR should not prioritize the geographic area covered by Aliso Canyon. As directed in the ACR, SCE will continue to consult with Energy Division and the CAISO and refine its proposal as necessary. If it is determined that location-specific DR will help with intra-day gas scheduling flexibility, SCE will focus its efforts on specific regions.

SCE's proposal is consistent with the third qualification because it proposes modifications for 2016 and 2017 (with a focus on the summer months). Regarding the fourth qualification, SCE notes in these comments any instances in which its modifications for 2017 are incremental to what was already proposed in its 2017 Bridge Proposal. For efficiency in resolving the 2017 Bridge Proposal, SCE recommends that if the Commission authorizes SCE's DR enhancement recommendations in this proposal without modification, that it simultaneously approve SCE's 2017 bridge funding to account for the costs associated with those actions, as identified. If the Commission modifies SCE's Aliso Canyon proposal, SCE recommends that upon a decision from the Commission directing such modified DR intensification efforts, SCE

---

3 For example, Hoover Dam, located outside of California, is used daily to meet the CAISO energy and ancillary service needs. In fact, Hoover Dam can meet a significant portion of the CAISO regulation needs.

4 Please note that the relevant time-frame is the day-ahead gas nomination cycle, which starts before the Day-Ahead CAISO market results are published. As a result, units often have to schedule gas based on their forecast Day-Ahead market awards.

immediately file an amended budget to account for such actions by supplementing its 2017 Bridge Proposal for the Commission's expedited review and disposition.

B. SCE's Proposed Program Modifications and Activities

The ACR states that SCE's proposal must include the following elements:

- Increase participation in SCE's SDP, BIP, and AP-I programs;
- Conduct a custom DR auction targeted at the affected areas, or adjust the focus of the current 2017 DR Auction Mechanism (DRAM) pilot; and
- Offer customers incentives for the purchase and/or installation of programmable thermostats combined with enrollment in an effective tariff or load control program.

SCE discusses these elements in this subsection.

1. Increasing Participation in Summer Discount Plan (SDP)

a) SDP Residential & Commercial Plan for 2016

SCE has begun the process of acquiring new enrollments for the Residential and Commercial SDP program. The new acquisition campaign is expected to begin by May 1, 2016. In order to compensate for a late season launch and to maximize contractor capability for installing load control devices, SCE will target approximately one million residential and commercial customers in high density areas with interval data high enough to indicate air conditioner (A/C) usage. Estimated costs for these efforts in 2016 include marketing costs, device purchases and installation, and administrative processing at approximately $2.8 million, with an estimated 8-14 MW of incremental load reduction. SCE will use current available funding within the SDP budget and Other Local Marketing category to fund these efforts.

b) SDP Residential & Commercial Plan for 2017

In 2017, SCE will continue efforts to acquire new enrollments for SDP. In SCE's Proposal for Approval of its 2017 Demand Response Program and Bridge Funding

Authorization[5] (2017 Bridge Proposal), SCE requested $4,507,000 in program expenses and $1,293,000 in "Other Local Marketing" for SDP. The funding request was reduced from previous funding cycles because SCE expects SDP enrollment to "decrease significantly due to a high rate of event-related attrition and less spending on large-scale enrollment campaigns."[6]
In support of the Aliso Canyon reliability efforts, SCE requests additional funding for marketing campaigns, program administration, and purchase and installation of direct load control devices in 2017. Table 1 shows SCE's requested SDP funding from its 2017 Bridge Proposal and incremental funding requested in this proposal. SCE estimates it can achieve 10-16 MW of incremental load reduction in 2017.

Table 1 - SCE's Requested SDP Funding

	Original 2017 Funding Request	**Incremental Aliso Canyon**	**Total Request for 2017**
SDP Program Budget	$4,507,000	$3,178,350	$7,685,350
Other Local Marketing	$1,293,000	$1,000,000	$2,293,000
	$5,800,000	$4,178,350	$9,978,350

Marketing tactics include launching a territory-wide campaign to approximately 1.6 million residential and commercial customers with a target launch date of March 15, 2017, to enable the majority of new enrollments to be on the program by the time the summer season begins. SCE also plans to leverage other customer communication opportunities, as applicable.[7]

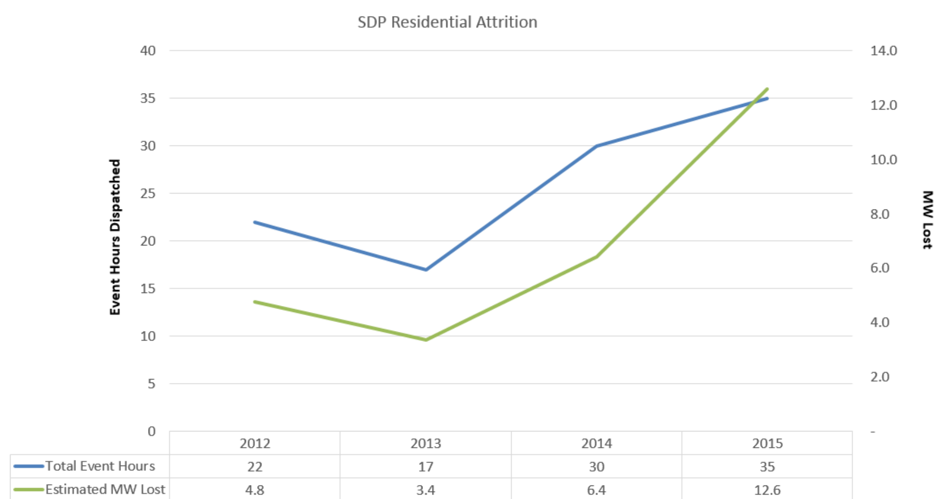
---

[5] Filed February 1, 2016, in this proceeding.
[6] 2017 Bridge Proposal, p. 30.
[7] *See*, *e.g.*, Advice Letter 3294-E-A, Supplement to Advice 3294-E, Proposed Outreach & Education Plan for Super-User Electric Surcharge (SUE) Pursuant to Decision 15-07-001, filed on March 25, 2016: "SCE will also analyze when customers breach the SUE threshold and will use that information to inform which energy efficiency or demand response programs may be most suitable for outreach. For instance, those customers who breach the SUE threshold in the summer season may be prime candidates for pool pump rebates, Summer Discount Plan, Peak Time Rebate with Direct Load Control, or even an air conditioner tune-up."

c) Reduction in Economic Dispatch Event Hours

SCE conducted a study on event-related attrition from SDP in recent years. As SDP has transitioned from a reliability-only to a price-responsive program, the event burden on participating customers has increased. With the increase in resource utilization comes an increase in customer-requested attrition.[8] Residential SDP was dispatched for 30 economic event hours in 2014 and 35 economic event hours in 2015. From 2014 to 2015, SCE observed a 96 percent increase in the number of customers opting out of the program (6,835 to 13,405) and a 97 percent increase in the associated lost MW (6.4 MW to 12.6 MW). Figure 1 shows the load loss due to customer attrition from residential SDP from 2012-2015.

Figure 1 - SCE's Residential SDP Attrition 2012-2015



Estimated MW lost based on load impact ex ante results for September 2014; 1 in 2 year; average of 0.94 kWh per Residential Service Account

Future attrition rates are unpredictable and difficult to forecast, however in order to preserve the maximum number of MW in support of Aliso Canyon reliability risks, SCE recommends the Commission establish 20 hours as the minimum threshold for economic dispatch for residential SDP for 2016 and 2017. There would still be 160 hours of dispatch

[8] "Customer-requested attrition" is defined as eligible, participating customers opting to exit the program.

available for reliability purposes. The program typically experiences attrition spikes in the late spring when temperatures begin to rise (and also due to the annual reminder to program participants) and also after the first event call of the season. These customers make the decision to leave the program early in the event season, based on their past event season experience and will likely be lost in 2016, regardless of the minimum threshold. However, 75 percent of event-related attrition occurs during the summer months. SCE estimates that 40 hours of economic dispatch would cause between 18.8 MW and 24.44 MW to be lost due to customer attrition. By establishing 20 hours as the minimum threshold, SCE estimates that it would be able to retain 13-17 MW from the expected attrition at 40 hours of dispatch at no additional cost. SCE has included additional analysis of SDP Residential customer attrition in Appendix A.

On February 4, 2015 SCE Filed Advice Letter (AL) 3037-E-A, requesting authority to establish a minimum/maximum threshold for economic event dispatch of 30 hours for Residential SDP and 15 hours for Commercial SDP. In Resolution E-4722, the Commission set the thresholds at 35 (residential) and 20 (commercial) hours in 2015, increasing to 40 and 25, respectively, in 2016. On December 2, 2015, SCE filed AL 3320-E to modify its SDP tariffs to increase the event hours pursuant to Resolution E-4733. On December 18, 2015, Energy Division suspended AL 3320-E. SCE recommends the Commission issue a Decision on this filing that directs SCE to supplement AL 3320-E to update the event dispatch hours for Residential SDP to 20 hours for 2016 and 2017, and to defer the increase to the thresholds established by E-4722 until 2018. SCE has included a proposed redline tariff in Appendix B. SCE recommends the Commission maintain the commercial SDP economic event hours at the 2015 level (20 hours) because there is not enough data on commercial SDP attrition regarding event fatigue trend to make a different recommendation.

2. Base Interruptible Program (BIP)

To increase participation in BIP, SCE Account Managers will reach out to customers identified as potential candidates to enroll in the program.[9] SCE estimates it can obtain up to 5 MW of incremental load reduction by targeting customers that Account Managers deem as good candidates based on their familiarity with the customer's operations. SCE will use existing funding and does not require any incremental funding for BIP in 2016 or 2017.

3. Agricultural Pumping Interruptible (API) Program

To increase participation in API, SCE Account Managers will contact customers identified as potential candidates to enroll in the program.[10] SCE estimates it can obtain up to 4 MW of incremental load reduction by targeting customers who Account Managers deem as good candidates based on their familiarity with the customer's operations. In 2017, SCE will continue efforts to acquire new enrollments for API. SCE requested $302,000 in API program expenses in its 2017 Bridge Proposal. The funding request for API covers costs such as load control devices and installation and was reduced from previous funding cycles. In support of the Aliso Canyon reliability efforts, SCE requests incremental funding of $42,000 for load control devices and installation for increased enrollments in 2017. Table 3 shows SCE's requested API funding from its 2017 Bridge Proposal and incremental funding requested in this filing.

---

[9] Due to the types of customer accounts that are eligible for BIP, an SCE Account Manager is assigned to work with these larger customers in identifying SCE programs that may be beneficial to the customer.

[10] Similar to BIP, API customers have an assigned SCE Account Manager working with the customer to identify SCE programs that may be beneficial to the customer.

Table 3 – SCE's Requested API Funding

	Original 2017 Funding Request	**Incremental Aliso Canyon**	**Total Request for 2017**
API Program Budget	$ 302,000	$42,000	$ 344,000

4. **DR Auction Mechanism Considerations**

The objective of the DRAM Pilot design is to enable and test the viability of third-party direct participation in the CAISO energy markets.[11] The Pilot design was tailored so that procured resources meet CPUC Resource Adequacy (RA) requirements and compliance process timelines, and did not focus on recruiting new customers into the DR portfolio. Special allowances were made to allow customers to switch from IOU programs into third-party (Rule 24) aggregations. While these provisions were appropriate for the DRAM Pilot objectives, they are not useful for addressing potential reliability risks stemming from the Aliso Canyon leak, such as bringing new DR customers (resources) into the market and providing new fast-response DR resources. SCE appreciates the ALJ's recent ruling supporting the current DRAM schedule, recognizing, among other things, that any delay would leave less time for Sellers to deliver their products.[12]

Following the 2016 summer, SCE recommends Energy Division facilitate a discussion among SCE, the CAISO, and other stakeholders to review the experience managing the system in current conditions and review initial DRAM contracts' performance and impact. Based on this discussion, and available data, a determination could be made on whether an additional DRAM-like auction in support of the Aliso Canyon effort would be useful for 2017. If a decision is made to implement a separate DR auction for Aliso Canyon, SCE would request the necessary funding at that time.

---

[11] D.14-12-024, Findings of Fact 32 – 38 and 74 – 76, and Ordering Paragraph 5, approving the Settlement Agreement which proposed the DRAM Pilot, and described its objectives in Section C1.

[12] *ALJ Ruling Denying the Joint Demand Response Parties' Motion to Suspend the Demand Response Auction Mechanism Pilot Request for Offer Schedule*, dated April 1, 2016, p. 5.

5. Programmable Thermostat Combined with Enrollment in Load Control Program

a) Delay Retirement of Peak Time Rebate (PTR) Programs

SCE proposes to delay the discontinuation of its PTR and PTR-ET (Enabling Technology) programs until 2017, rather than 2016, to avoid risks associated with making system changes during the summer season and mitigate customer confusion or dissatisfaction by not giving adequate notice prior to summer. On December 9, 2015, SCE filed AL 3323-E requesting approval to discontinue PTR and PTR-ET in 2016 due to low per-customer savings, poor cost-effectiveness, and low dispatch flexibility. To discontinue the PTR and PTR-ET options while retaining PTR-ET-DLC functionality, SCE needs to modify its customer-facing and billing systems. When it filed the AL, SCE had intended to begin the system updates in April 2016 so that they could be completed by June 1, 2016. SCE also planned to conduct rate analyses for affected customers to identify those customers who might benefit by switching to a residential time-of-use rate or another DR program, such as PTR-ET-DLC. SCE planned to begin notifying customers of the program retirement in April 2016 to enable them to elect other rates or programs prior to the summer season.

Because the AL is suspended and has not been approved, SCE has not begun the required system changes and outreach and does not expect the AL will be approved in time to enable these activities to be completed before summer. Therefore, SCE recommends that the PTR and PTR-ET programs be maintained during summer 2016. SCE requests that the Commission direct SCE to withdraw AL 3323-E and, in its decision on this proposal, authorize the retirement of PTR and PTR-ET prior to summer 2017. Because SCE's 2017 Bridge Proposal anticipated the discontinuation of PTR and PTR-ET in 2016, SCE did not request funding to decommission them in 2017 in its 2017 Bridge Proposal. Therefore, SCE requests incremental funding to decommission PTR and PTR-ET in 2017. SCE requests $600,000 for system changes and labor to decommission PTR and PTR-ET in 2017 and ME&O to communicate to customers about the decommissioning. These costs are included in the budget request identified in Table 4 below.

b) Increased Participation in PTR-ET-DLC

SCE's existing PTR-ET-DLC program offers customer incentives for energy saved when participating in SCE's Save Power Days Program (SPD) through the use of an installed and eligible thermostat. SCE's 2017 Bridge Proposal requests incremental funds to maintain and expand PTR-ET-DLC and to begin modifications to the program in 2017 that will enable integration into the CAISO markets in 2018. In this proposal, SCE requests additional funding for (1) a more targeted, rebate-based campaign to convert PTR and PTR-ET customers to PTR-ET-DLC, and (2) to acquire additional customers through the PTR-ET-DLC Program. SCE will determine the targeted group of customers by using customer usage data from SCE's SmartConnect™ meters to determine those who have the potential to achieve high benefits on the program and those who can contribute significant load. SCE estimates it can get an additional 22,000 – 28,000 enrollments (2016-2017) in the program by offering a universal rebate of $75 to customers who purchase and install an eligible thermostat. SCE estimates that it can obtain 40 percent of the targeted enrollments in 2016 with the remaining 60 percent in 2017. To implement this initiative, SCE requires incremental funding for 2017 from what it requested in its 2017 Bridge Proposal. SCE requires $1,647,500 in rebate costs, rebate processing, and program administration. The total incremental costs over the 2017 Bridge Proposal request is $2,247,500.

Table 4 – SCE's PTR Funding Request

	Original 2017 Funding Request	Incremental Aliso Canyon	Total Request for 2017
PTR Program Budget	$1,724,000	$1,944,500	$3,668,500
Other Local Marketing	$297,000	$303,000	$600,000
Total	$2,021,000	$2,247,500	$4,268,500

6. Additional Proposals

The ACR invites SCE to propose additional DR measures to support reliable electricity service.[13] This section includes SCE's additional DR proposals.

a) Maintain Demand Bidding Program through 2017

SCE recommends a modification to one of the proposals in its 2017 Bridge Proposal. In that filing, SCE requested authority to retire its Demand Bidding Program (DBP) effective for the 2017 program year. SCE proposes to delay retirement of DBP until 2018 as this is consistent with the ACR's requirement that "efforts should focus on boosting demand response for the summer seasons of 2016 and 2017."[14] Because SCE's request in its 2017 Bridge Proposal was to retire the program, SCE did not request any funding for DBP. Therefore, in this proposal, SCE requests incremental funding for DBP for the 2017 program year. SCE requires $255,000 for 2017. Administration costs for 2017 are $105,000 and expenses of $150,000 related to the discontinuation of DBP originally expected to be incurred in 2016, will be required for 2017.

Table 5 - SCE's DBP Funding Request

	Original 2017 Funding Request	Incremental Aliso Canyon	Total Request for 2017
DBP Program Budget	$ -	$255,000	$255,000

b) Defer Reporting

The ACR directs SCE to serve monthly reports on this emergency response to the service list beginning on April 15, 2016 and continuing through December 15, 2017.[15] Because these efforts are just beginning, there will not be material progress to report on April 15. Most of SCE's proposed activities require funding or other Commission approval and SCE will not be able to report on those activities until after the Commission issues a final decision. The only

---

[13] ACR, p. 3.
[14] ACR, p. 4.
[15] ACR, p. 7.

activities likely to begin by April 15 are efforts to enroll additional customers on BIP and API. Therefore, SCE recommends the date for the first monthly report be deferred until May 15, 2016.

c) Coordination with the Los Angeles Department of Water and Power

The ACR also invites SCE to include any proposals that can be coordinated with the Los Angeles Department of Water and Power (LADWP).[16] SCE has engaged in general DR-related discussions with LADWP, but does not have any specific proposals to make at this time.
SCE will continue to discuss reliability risks with LADWP and consider potential coordinated solutions, such as coordinated ME&O.

C. Cost-Effectiveness Analysis and Budget

1. Cost-Effectiveness Analysis for PTR-ET-DLC

As discussed above, SCE proposes to add a rebate for customers joining our PTR-ET-DLC program in 2016 and 2017, the years of targeted DR activity for Aliso Canyon.
Because the costs associated with the rebate would not be covered by authorized funds, a revised cost-effectiveness analysis was conducted.

SCE calculated the Total Resource Cost (TRC) value for years 2016 through 2018 to assess if the program was cost-effective after the 2016 and 2017 enrollment push was implemented. Year 2018 does not contain the additional $75 rebate. The TRC value for the PTR-ET-DLC program under this proposal is 1.00. This result exceeds the DR TRC threshold of 0.90 and is therefore cost-effective.[17]

---

[16] *Id*.

[17] The Commission has stated that programs with TRC test results higher than 0.9 are considered to be cost-effective. *See* D.12-04-045, p. 44.

2. Budget Request and Cost Recovery Proposal

For this proposal, SCE requests a total incremental DR budget authorization of $6,935,350 for 2017.[18] Table 6 summarizes this funding request. The costs are described in terms of the applicable DR budget categories.

Table 6 - SCE's Incremental Budget Request in this Proposal

Funding Category	Cost Drivers	Cost
Category 1: Reliability Programs	API	$42,000
Category 2: Price Responsive Programs	DBP	$255,000
	SDP	$3,178,350
	PTR	$1,944,500
Category 7: ME&O	Local Marketing – SDP	$1,000,000
	Local Marketing – PTR	$303,000
Total		$6,722,850

As noted previously, SCE recommends that if the Commission authorizes SCE's recommended DR enhancements in this proposal without modification, that it simultaneously approve SCE's 2017 bridge funding to account for the costs associated with those actions, as identified. If the Commission modifies SCE's Aliso Canyon proposal, SCE recommends that upon a decision from the Commission directing such modified DR intensification efforts, SCE immediately file an amended budget to account for such actions by supplementing its 2017 Bridge Proposal for the Commission's expedited review and disposition.

Consistent with its recommendation in its 2017 Bridge Proposal, SCE requests that the 2017 DR bridge period revenue requirement become effective on January 1, 2017.[19] The requested revenue requirement in the 2017 Bridge Proposal was $44.283 million. Adding the $6.723 million from this proposal to that amount results in a total revenue requirement of $51.105 million. This amount is $35.048 million, or 41 percent, less than the

---

[18] This request is incremental to what SCE requested in its 2017 Bridge Proposal.

[19] This amount will be grossed up for Franchise Fees and Uncollectibles expense when reflected in rate levels.

average annual authorized amount for the 2015-2016 bridge period. SCE will record the revenue requirement approved for 2017, and the authorized expenditures incurred in 2017, in SCE's existing authorized ratemaking mechanisms for DR.[20]

III.

SCE'S RESPONSES TO QUESTIONS PRESENTED IN SECTION 3 OF THE ACR

In this section, SCE provides its responses to the four questions included in the ACR.

A. Question 1: Should potential SCE efforts to expand demand response to support reliability as qualified in Section 3 be required to achieve a particular Total Resource Cost value? Or should alternate cost-effectiveness criteria be applied? Given the emergency, should the avoided cost be the value of lost load?

The DR cost-effectiveness (DRCE) protocols are appropriate to evaluate the cost-effectiveness of the DR programs to be used to provide additional system or local capacity as a result of Aliso Canyon. In this unique situation, the proposed limitation on the use of gas from the Aliso Canyon facility has prompted Governor Brown to issue a State of Emergency. SCE supports the existing DRCE threshold of 0.90.[21] Additionally, SCE opposes assigning the value of lost load as the avoided cost for DR in the region. Doing so would assume that the counterfactual for not expanding DR in the area would be lost service. This is an assumption that would overstate the value of expanding DR, especially given that DR is currently valued at the cost of new entry of a combustion turbine.

---

[20] SCE recovers authorized DR costs through three balancing accounts: (1) the Demand Response Program Balancing Account (DRPBA); (2) Purchase Agreement Administrative Costs Balancing Account (PAACBA); and (3) Base Revenue Requirement Balancing Account (BRRBA).

[21] *See* D.12-04-045, p. 44.

B. <u>Question 2: Should the Commission suspend the requirement that SCE may only meet 2% of its resource adequacy obligation with emergency demand response programs?</u>

The two-percent reliability cap is not an SCE-specific requirement. The cap was established in D.10-06-034 "as a percent of the CAISO's all-time coincident peak demand."[22] The Settlement Agreement adopted by D.10-06-034 established the process for determining each IOU's MW limit for reliability-based DR. SCE's current limit is 659 MW. SCE recommends the Commission suspend the requirement that reliability DR across the IOUs be limited to 2 percent of the CAISO's system peak. As noted in the ACR, Governor Brown has declared a state of emergency and has directed the Commission to take actions to ensure the continued reliability of electricity supplies during the moratorium on gas injections into the Aliso Canyon Storage Facility.[23] In compliance with the ACR, SCE is seeking to increase participation in BIP and API, two of its reliability DR programs. Limiting SCE to its cap of 659 MW for meeting RA obligations conflicts with the Commission's requirement to ensure the reliability of electricity supplies during the emergency situation. Further, the cap was originally adopted, in part, to emphasize price-responsive programs and integration of DR into the CAISO's markets. SCE currently has 134 MW of price-responsive DR, 84 MW of which are integrated into the CAISO markets. SCE has an additional 722 MW of reliability-based DR integrated into the markets. Removing the two-percent cap would not likely revoke the progress that has been made on increasing price-responsive DR and integrating DR into the CAISO markets.

---

[22] D.10-06-034, p. 24.
[23] ACR, p. 2.

C. Question 3: If a custom demand response auction were initiated for summer of 2017, should the products on auction be identical to those offered by utilities during the pilot phase of the demand response auction mechanism, altered or expanded?

If a custom demand response auction were initiated for summer of 2017 to address potential reliability risks as a result of the Aliso Canyon supply issues, the following changes from the current DRAM pilot design should be considered:

- Such an auction would have to be focused on "new generation" resources. Any resources procured in the auction would have to come from customers not currently enrolled in another DR program, as shifting customers among programs is unlikely to yield any incremental system reliability benefits.[24]
- The auction should focus on fast-response resources that can help reduce the CAISO system needs for intra-day incremental gas generator dispatch. As previously discussed, long-start resources are not as effective as fast-start ones for mitigating the Aliso Canyon leak impacts.
- The auction could consider adding an IOU integration option, in order to provide more flexibility to potential Sellers. In such a design, the Sellers could choose to: 1) offer resources as an RA "tag" only, per current DRAM Pilot design, and keep the energy dispatch rights together with the CAISO integration obligations; or 2) offer resources in full to the Utility, passing the energy dispatch rights as well as the CAISO integration obligations onto the Utility Buyer as well. This added option may reduce the barriers to entry for potential new aggregators, and reduce cost and complexity for the existing ones.

To the extent any of these modifications are incorporated, the pro-forma contracts currently used for the DRAM Pilot solicitation would need to be modified accordingly. Until the 2017 DRAM contracts are awarded, it is unknown whether there will be adequate budget

[24] An exception could be if customers are moved onto a higher value program, *e.g.* from a longer-response (day-ahead) to a shorter-response (15-minute) program.

remaining to fund a custom DR auction. Pilot design changes, such as requiring customers to be "new generation," may result in additional Information Technology programming costs.

D. Question 4: Are there additional program rules or administrative details that should be reconsidered to enable the goals of this ruling?

SCE has not identified any additional program rules or administrative details that would help the Commission enable the goals of this ruling at this time.

IV.

CONCLUSION

SCE appreciates the opportunity to submit these comments on the ACR, and respectfully requests Commission approval of its proposals as outlined in Section II, above. SCE looks forward to continuing to work with the Commission and other stakeholders in mitigating the impacts to customers arising from the Aliso Canyon gas leak.

Respectfully submitted,

JANET S. COMBS
ANGELICA M. MORALES

/s/ Angelica M. Morales
By: Angelica M. Morales

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-4435
Facsimile: (626) 302-6962
E-mail: Angelica.Morales@sce.com

Dated: April 4, 2016

Appendix A

Residential SDP Event-Driven Program Depletion

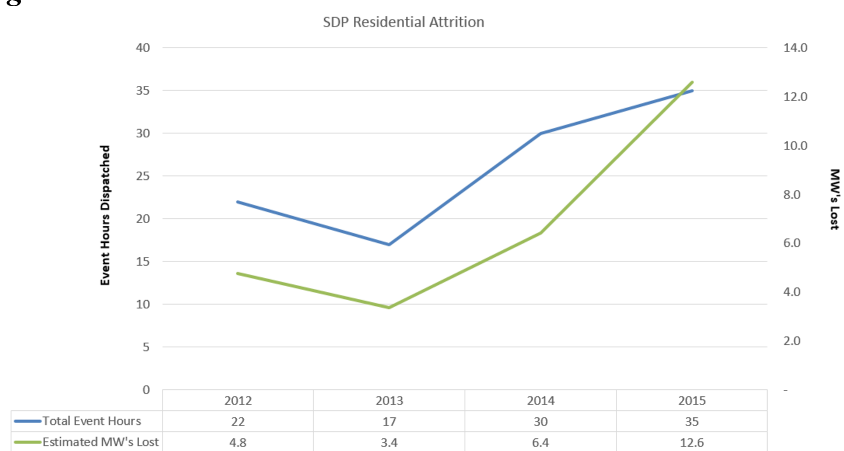
Appendix A
Residential SDP Event-Driven Program Depletion

A. Background

As SDP has transitioned from a reliability-only to a price-responsive program, the event burden on participating customers has increased. With the increase in resource utilization comes an increase in customer-requested attrition. (Customer-requested attrition is eligible, participating customers opting to exit the program; this excludes account closures and maintenance replacement-related exits.)

Residential SDP was dispatched for 30 economic event hours in 2014 and 35 economic event hours in 2015. From 2014 to 2015, SCE observed a 96 percent increase in the number of customers opting out of the program (6,835 to 13,405) and a 97 percent increase in the associated lost MW (6.4 MW to 12.6 MW). Figure 1 shows the customer attrition SCE experienced on SDP from 2012-2015.

Figure 1 - SCE's Residential SDP Event-Driven Attrition 2012-2015

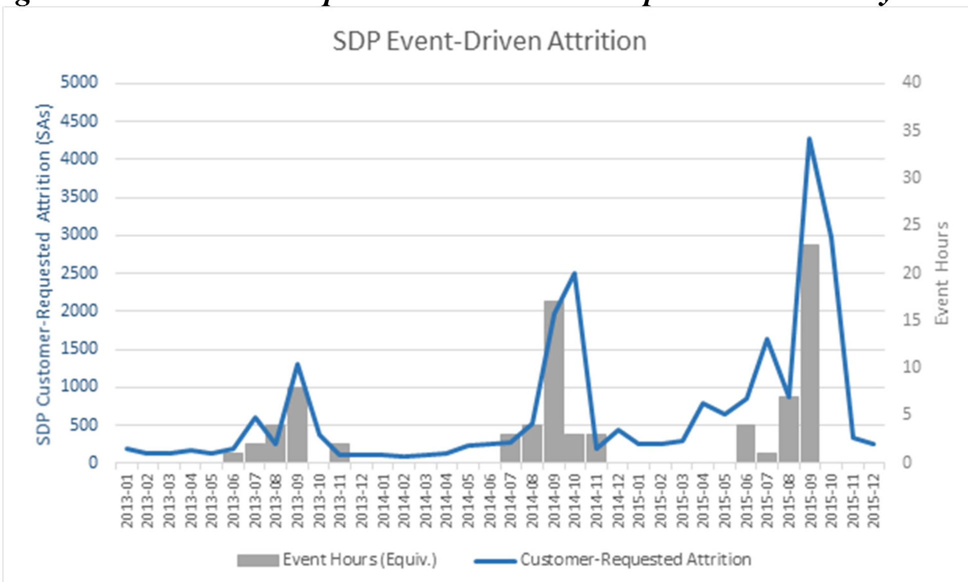


Estimated MW's lost based on load impact ex ante results for September 2014; 1 in 2 year; average of 0.94 kWh per Residential Service Account

B. Event-Driven Attrition

From 2013-2015, annual event hours dispatched has grown from 17 to 30 to 35, while customer-requested attrition has grown from 3,600 to 6,800 to 13,400. Figure 2 shows the relationship between event dispatch[1] and customer-requested attrition.

Figure 2 - SDP Event Dispatch and Customer-Requested Attrition by Month



This graph illustrates that customer-requested attrition ticks up sharply in the month of and month following significant event dispatches. This growth in attrition appears not to be merely linear, but may in fact be growing geometrically as event dispatches increase.

C. Exiting Customer Load Impacts

It is a reasonable expectation that customers requesting exit driven by event dispatch are also customers most highly impacted by events; these are customers in cooling mode, having their ACs cycled off, and providing load impact. We find exiting customers typically have provided significantly greater load impact compared to program averages.

An example of this difference for a particular event is depicted in Figure 3 below. This graph depicts the 3-hour SDP residential event on 8/28/2014 (4:00-7:00p), for the average customer compared to a customer who subsequently requested program exit.

---

[1] As events may be partial dispatches for various sub-sections of the service territory, this chart depicts *equivalent event hours*: event hours as experienced by a typical customer.

Figure 3 - Event Day Comparison – Program Participant v. Exiting Customer

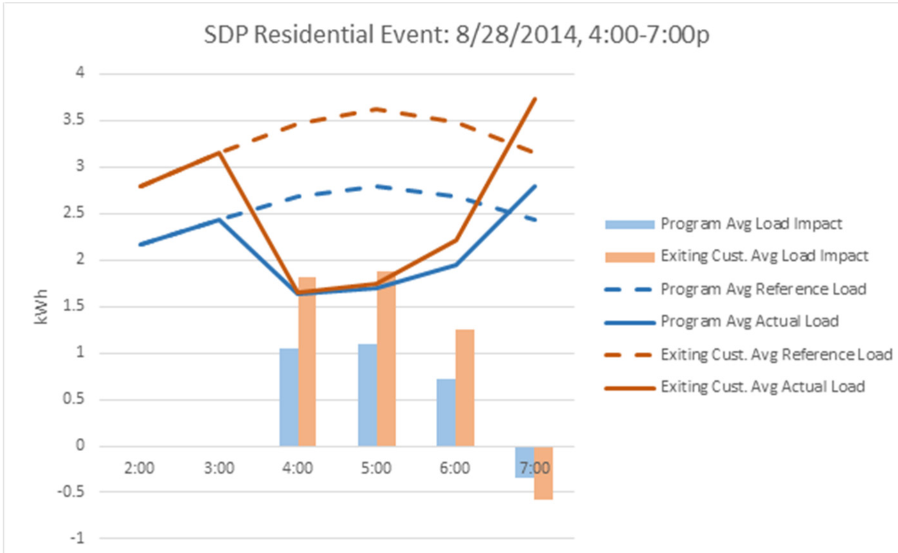


Table 1 depicts the event-day load and load impact for the average SDP residential customers in 2014 (July-September events).[2] The load in the hour prior to the event is depicted to provide an observable depiction of non-event customer load. Average load impact across these events is 0.8 kW per participant, with a high of 1.2 kW.

2 These are based on the 2014 Ex Post Load Impact Study findings; at the time of this analysis, the 2015 Study was still in development.

Table 1- Event Day Usage and Load Impacts (kW) – All Program Participants

Event Date	Avg. Load Prior to Event	Avg. Reference Load - Event Hours	Avg. Actual Load - Event Hours	Avg. Event Load Impact
7/30/2014	2.55	2.71	2.17	0.55
7/31/2014	2.43	2.68	1.77	0.91
8/27/2014	2.09	2.59	1.71	0.88
8/28/2014	2.17	2.72	1.76	0.96
9/11/2014	2.01	2.30	1.66	0.64
9/12/2014	2.30	2.46	1.78	0.68
9/15/2014	2.63	3.08	2.05	1.03
9/16/2014	2.73	3.12	1.93	1.20
9/23/2014	1.94	1.84	1.47	0.37
9/24/2014	1.94	2.13	1.56	0.57

Table 2 depicts event-day load and load impacts for customers requesting program exit in 2014 and 2015. Data are from the period when customers were still program participants. SCE observes both higher non-event load and higher load impact from these customers.

Table 2 - Event Day Usage and Load Impacts (kW) – Customers Requesting Program Exit[3]

Event Date	Avg. Load Prior to Event	Avg. Reference Load - Event Hours	Avg. Actual Load - Event Hours	Avg. Event Load Impact
7/30/2014	3.44	3.67	2.53	1.14
7/31/2014	3.38	3.73	1.75	1.98
8/27/2014	3.02	3.73	1.92	1.81
8/28/2014	3.16	3.95	1.87	2.07
9/11/2014	2.94	3.36	1.76	1.60
9/12/2014	3.32	3.55	1.87	1.68
9/15/2014	3.60	4.22	2.02	2.20
9/16/2014	3.61	4.13	1.83	2.30
9/23/2014	2.50	2.38	1.70	0.68
9/24/2014	2.93	3.21	1.77	1.44

The difference between customers requesting exit and average program participants are depicted in Table 3.

[3] Reference load assumes that the load profile for these customers are similar in shape to that of average program participants.

Table 3 - Event Day Differences (ΔkW) – Exiting Customers compared to All Program Participants

Event Date	Avg. Load Prior to Event	Avg. Reference Load - Event Hours	Avg. Actual Load - Event Hours	Avg. Event Load Impact
7/30/2014	+0.90	+0.95	+0.36	+0.59
7/31/2014	+0.96	+1.06	-0.02	+1.07
8/27/2014	+0.93	+1.15	+0.21	+0.94
8/28/2014	+0.98	+1.23	+0.11	+1.12
9/11/2014	+0.93	+1.06	+0.10	+0.96
9/12/2014	+1.02	+1.09	+0.09	+1.00
9/15/2014	+0.98	+1.14	-0.03	+1.17
9/16/2014	+0.88	+1.01	-0.10	+1.11
9/23/2014	+0.57	+0.54	+0.23	+0.31
9/24/2014	+0.99	+1.08	+0.21	+0.88

SCE observes that exiting customers tend to have greater load on the event day than the average customer. On average across these events, the pre-event load averaged +0.9 kW difference, expected to grow to +1.0 kW difference during event hours. During event dispatch, this load dropped to close to the same level as for both customer types (+0.1 kW difference), demonstrating that the load difference is nearly entirely AC utilization. Across these events, exiting customers had provided load impact on average +0.9 kW greater, with a high difference of +1.2 kW.

D. <u>Conclusion</u>

SCE is already experiencing SDP program depletion driven by growth in event dispatch. The correlation between event dispatch and customer-requested program exits is observable (and causation is inferable). Some evidence suggests the growth in customer-requested attrition is geometric (or possibly exponential) in event utilization growth. Additionally, the customers requesting exit typically have provided about twice the load impact per event as an average program participant. The customers being driven to leave the program are among the most dependable and cost-effective customers on SDP.

Appendix B

Redline Edits to Schedule D-SDP

Schedule D-SDP
DOMESTIC SUMMER DISCOUNT PLAN
Sheet 3

(Continued)

SPECIAL CONDITIONS (Continued)

6. SDP Event Period:

The number of SDP Events triggered under Special Condition 5 is unlimited, but the total SDP Event hours triggered under Special Condition 5 must be called a minimum of 20~~35~~ hours per calendar year, per service account and is limited to a cumulative total of no more than 180 hours per calendar year, per service account. Multiple SDP Events per day are possible, but the cumulative event hours are limited to a total of no more than six hours per day, per service account. (R)

SDP Event hours triggered under Special Condition 5.c. are limited per service account, as follows:

a. A maximum of 20~~35~~ hours per calendar year may be triggered and will be inclusive of all event hours triggered under Special Condition 5; (R)
b. Events will be limited to four hours per day;
c. Events will be limited to no more than three consecutive non-holiday weekdays; and
d. Events may only be called between the hours of 11:00 a.m. and 8:00 p.m. and cannot be called on weekends or SCE holidays.

In the event of a system emergency, SCE may, at its discretion, extend an SDP Event beyond the six hour limit. However, no new SDP Event will be initiated after the six hour limit has been met.

7. Customer Option Change: At the customer's request, subject to device availability, Customers may change their Option (Standard or Override) one time within each 12-month period of service under this Schedule.

8. Cycling Strategy Change: At the customer's request, SCE shall change the Cycling Strategy for participating SDP customers as follows:

a. Customers may change their Cycling Strategy from 50% Cycling Strategy to 100% Cycling Strategy at any time under this Schedule.

b. Subject to device availability, customers may change their Cycling Strategy from 100% Cycling Strategy to 50% Cycling Strategy one time within each 12-month period of service under this Schedule.

9. Direct Access (DA), Community Aggregation (CA), and Community Choice Aggregation Service (CCA Service): A customer receiving DA, CA, or CCA Service shall notify its Energy Service Provider (ESP) or Community Choice Aggregator (CCA), as applicable, and Scheduling Coordinator that its air-conditioning load is subject to SDP Events under this Schedule.

10. Relationship to Other Demand Response Programs: Customers' service accounts on this Schedule may additionally participate on Schedule CPP or Option CPP of Schedule TOU-D-T. For CPP customers' service accounts dual participating with this Schedule, the sum of credits provided by the D-SDP and CPP programs 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 in the Option CPP rate section of Schedule TOU-D-T.