BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Approval of Demand Response Programs, Pilots, and Budgets for 2012-2014	Application11-03-001 (Filed: March 1, 2011)
Application of San Diego Gas & Electric Company (U902M) for Approval of Demand Response Programs and Budgets for Years 2012-2014	Application 11-03-002 (Filed March 1, 2011)
Application of Southern California Edison Company (U338E) for Approval of Demand Response Programs, Activities, and Budgets for 2012-2014	Application11-03-003 (Filed: March 1, 2011)

RESPONSE OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO THE APPLICATIONS OF PACIFIC GAS AND ELECTRIC COMPANY, SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA EDISON COMPANY FOR APPROVAL OF DEMAND RESPONSE PROGRAMS, PILOTS, ACTIVIES, AND BUDGETS FOR 2012-2014

I INTRODUCTION

Pursuant to Rule 2.6 (c), the Notices of Filing dated March 1, and March 2, 2011, and the Ruling of ALJ Hymes consolidating proceedings of the Investor Owned Utilities,[1] the California Independent System Operator Corporation (ISO) submits this Response to the Applications of Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California

[1] *ALJ's Ruling Consolidating Proceedings and Setting a Prehearing Conference*, dated March 30, 2011.

Edison Company (SCE) for approval of demand response programs, pilots, activities, and budgets for the 2012-2014 program cycle.[2]

The ISO has been an active party in the Commission's ongoing proceeding addressing the refinement of IOU demand response programs and related issues including integration with the ISO market (R.07-01-041) and the ISO was also actively involved in the proceedings for consideration and approval of the last cycle of IOU demand response programs.[3] Phase 3 of R.07-01-001 resulted in a global settlement, adopted by the Commission, which set an overall MW limit on the amount of emergency-triggered demand response that the Commission would count for Resource Adequacy, and established a transition for adjusting program levels to achieve the MW limit within the 2012-2014 program cycle.[4]

The ISO has also established its Proxy Demand Resource (PDR) product as a mechanism for economical demand response to participate in the ISO market and is currently developing its Reliability Demand Resource Product (RDRP) as a mechanism to integrate emergency-triggered demand response.

---

[2] For convenience of the reader, the ISO places the following links to IOU applications and testimony supporting their applications here:

PG&E (Application) http://docs.cpuc.ca.gov/efile/A/131484.pdf
(Testimony) https://www.pge.com/regulation/DemandResponse2012-2014-Projects/Testimony/PGE/2011/DemandResponse2012-2014-Projects_Test_PGE_20110301_207098.pdf

SDG&E (Application and Testimony) http://www.sdge.com/regulatory/A11-03-002.shtml

SCE (Application and Testimony)
http://www3.sce.com/law/cpucproceedings.nsf/vwSearchProceedings?SearchView&Query=A.11-03-003&SearchMax=1000&Key1=1&Key2=25

[3] Applications 08-06-001, 08-06-002 and 08-06-003 for the 2009-2011 program cycle.

[4] The Commission adopted the settlement in *Decision Adopting Settlement Agreement on Phase 3 Issues Pertaining to Emergency Triggered Demand Response Programs*, D.10-16-034 (June 24, 2020), accessible on the CPUC's website at http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/119815.htm (Phase 3 Settlement)

II GENERAL COMMENTS PERTAINING TO ALL APPLICATIONS

A The IOU Applications Should Support State Energy and Environmental Policy Goals

The ISO agrees with PG&E's statement in its application that the growing dependence on renewable energy resources and the development of smart grid technologies is increasing opportunity to maximize the use and benefit of demand response. The ISO is committed to implementing California's energy and environmental policy goals which include making sure the grid is ready to support the 33% Renewable Portfolio Standard by 2020 (RPS), while maintaining grid reliability. California's increasing reliance on renewable energy creates fuel diversity benefits and forms the foundation of the state's greenhouse gas policy, but introduces unique operational challenges. As such, demand response must be configured to play a pivotal role in integrating greater amounts of variable energy resources, so that these resources may help address the operational challenges of intermittent renewable resource output and shaping load to match generation characteristics. This will be the critical fit for demand response in California's reliable energy future.

B The IOU Applications Should Align with State Energy and Environmental Policy Goals which State Agencies have Articulated in the California Clean Energy Future Collaborative

The California Clean Energy Future (CCEF) represents the state energy and environmental agencies' effort to collaborate to provide a distillation of key policy elements that must be put in place to achieve California's energy and environmental policies by 2020 and to build a platform for later years.[5] The constituent members of the CCEF collaborative include this Commission as well as the California Environmental Protection Agency (CalEPA), the California Air

[5] Information regarding CCEF can be found on the collaborate effort's webpage at www.cacleanenergyfuture.org

Resources Board (CARB), the California Energy Commission (CEC), and the ISO. The CCEF has prepared a guiding document entitled "*California's Clean Energy Future: An Overview on Meeting California's Energy and Environmental Goals in the Electric Power Sector in 2020 and Beyond.*"[6] This document describes the key elements on which the state is relying to achieve its 2020 electricity and natural gas policy goals and is "intended to guide State agency activities by providing a set of clear and quantifiable goals that will guide operational, technological and infrastructure needs analysis; program design, long-term planning and procurement functions; research and development activities; and further reforms of the wholesale power markets."[7]

The ISO respectfully submits that the CPUC should evaluate the programs that the IOUs put forth in their applications with an eye toward how demand response programs can be configured to achieve the "key elements" described in the CCEF. For example, integration of demand response into the Load Serving Entity procurement is an express objective of the CCEF. The goal of this activity is to integrate demand response into retail sellers' resource procurement efforts, so that these programs are considered *equally with other supply options*.[8]

With this guidance in mind, the Commission should ensure there is clear alignment between the objectives set forth by the CCEF and what the IOUs have articulated in their 2012-2014 applications. In this regard, the ISO notes that PG&E's witness states that:

> DR is a large component of the electric portfolio and cannot be represented by a single point forecast in the long-term plan process given the uncertainty with program design changes, enrollments, customer response to changing programs and the potential changes

[6] This document is accessible on the CCEF website referenced above, and has been included in the CEC's records and referenced by the CEC as CEC-100-2010-002 (Hereinafter "CCEF Overview Document").
[7] CCEF Overview Document at p.1.
[8] CCEF Overview Document at p. 51.

> in hours of operation and types of need to be satisfied by DR programs in the future.[9]

This statement appears to highlight a gap between the policy objectives of the CCEF and the certainty and confidence to which demand response programs can actually be relied upon in a utility's resource procurement and planning process. The ISO understands that changes and uncertainty in demand response programs would make it difficult to integrate demand response programs into the long-term planning processes. Yet the fact of any disconnect between demand response resource "procurement" and generation procurement and the implications for program design and approval need to be drawn out and better understood in this proceeding. In that way, whatever gaps exist between demand response program proposals and how they are ultimately used and relied upon for procurement and planning purposes, and whether they advance the Commission's policy purpose in funding them, can be identified and addressed.

III COMMENTS SPECIFIC TO PG&E's APPLICATION

A PG&E's Proposed Transition Activities for its Base Interruptible Program Sets a Timeframe that is Too Long

PG&E's Application includes a summary discussion of its proposed activities for the next three years with regard to PG&E's Base Interruptible Program (BIP), which is an emergency-triggered program.[10] PG&E states that

> PG&E proposes to incorporate demand response from BIP as RDRP *as early as 2013*, assuming the CAISO's proposed tariff revisions for RDRP are approved by FERC and PG&E obtains approval for necessary information technology upgrades.[11]

[9] PG&E Testimony, Chapter 7, page 19
[10] PG&E's Application Section C 2 [*Summary of PG&E's Proposals, Emergency Programs*] at p5.
[11] *Id.,* emphasis added.

The ISO submits that this timeline is too long and is not within the spirit of the Phase 3 Settlement.[12] The ISO has been diligently working on development of the RDRP product, and is on track to submit its tariff amendment to FERC within the second quarter of 2011, in line with the timeframe discussed in the Settlement. The ISO is concerned that PG&E's emergency-triggered program transition cannot happen until 2013 or 2014 (given that PG&E qualifies that it "proposes" action "as early as 2013," which signals that its actions may actually come later and not be completed for some time.). The ISO submits that incorporation of the program should not take multiple years and should not wait for a year or so following a FERC order on ISO's second quarter 2011 RDRP amendment filing. Additionally, the ISO envisions that its own information technology upgrades will be derived from the technology platform for ISO's PDR product. While the ISO understands that some approval process and technology work is necessary for PG&E to accomplish a transition of BIP into RDRP, the ISO believes that PG&E efforts would be based in some part on its PDR-implementation efforts which should come to fruition before a 2013-14 timeframe. The ISO looks forward to discussion of these particulars within the application proceedings, and hopes that a more "drilled down" evaluation will establish that transition efforts can begin before 2013 so that BIP transition to RDRP can be accomplished before the close of the program cycle, possibly substantially before this close.

[12] *Decision Adopting Settlement Agreement on Phase 3 Issues Pertaining to Emergency Triggered Demand Response Programs*, *supra*, Decision 10-16-034 (June 24, 2020)

B The ISO Supports PG&E Establishing a Pre-Qualification Process for BIP

In its testimony addressing its proposed activities for BIP, PG&E states that it is proposing to establish a pre-enrollment qualification process for BIP applicants, to ensure that new participants to BIP understand program rules and have the ability to effectively and reliably participate in the program.[13] The ISO supports PG&E's creation of pre-enrollment qualifications for participation, as described in this portion of PG&E's testimony. A pre-enrollment qualification as PG&E proposes should be universal feature for each of the IOU's Base Interruptible Program.

C PG&E'S Filing Erroneously Supposes A Scenario For BIP Customer Dual Participation In ISO Market that is Not Possible

In a subsection of Chapter 2 of PG&E's testimony where it discusses emergency programs and customer dual participation in BIP and PeakChoice, PG&E proposes a scenario for dual participation in the ISO market that is not possible under the ISO's product configurations for PDR and RDRP. In this subsection, entitled "Dual Participation with PeakChoice," PG&E states that:

> PG&E proposes to allow its BIP participants to dual participate in its Best Effort day-ahead PeakChoice program. Should the Commission approve PG&E's proposal to end DBP in 2012, this would maintain the concurrent program participation option BIP customers currently exercise with the DBP. (See Section 2 C.) Additionally, this would increase the MW available *to participate in PDR through PeakChoice*.[14] (Emphasis added.)

The ISO clarifies that, under the ISO's configuration of PDR and RDRP, *no such dual participation in both products is possible*. As the ISO products are configured, the only dual participation possibility is as follows: A PG&E

---

[13] PG&E Testimony, Chapter 2, pp 2-22 to 2-23.
[14] PG&E Testimony, Chapter 2, pp 2-24 (emphasis added).

customer could participate in the both BIP and PeakChoice only through the RDRP. This is because the RDRP allows for economic participation in the Day-ahead market (e.g. under the PeakChoice program) and then in the Real-time market under the Base Interruptible Program.

D Temperature Based Program Triggers Should Be Replaced With Economic Triggers

In its testimony regarding dynamic pricing, PG&E states that:

> [Dynamic pricing] retail rates increase price responsive demand response from individual customers. Like the price responsive programs proposed by PG&E in this application, dynamic prices motivate participants to reduce demand in response to higher retail rates triggered *by increases in the system wide temperature ….*[15]

To support this proposition, PG&E cites to authority as the ISO references in footnote 14 below. While that cited authority does reiterate the importance of price-responsive triggers, these authorities do not mandate (nor do they appear to endorse) use of *temperature based triggers*. The ISO agrees that dynamic pricing mechanisms which reflect the real time cost of energy will motivate consumers to reduce usage when those dynamic prices increase in correlation to increased real cost of energy occasioned by increased temperatures (not temperature-related triggers) and that the cited authority would endorse this. In any event, the chosen words provide the ISO with the opportunity to note that developments over the succeeding years have rendered temperature-triggers an inefficient and outmoded proxy for stressed system conditions that call for demand response resources to be dispatched. Program triggers should be based on economics, not on system-wide temperature, which at best substitutes as a rough proxy for system conditions. In

[15] PG&E Testimony, Chapter 2, Section F 1 (*Dynamic Pricing Programs, General Regulatory Background*) at p.2-31, emphasis added. This passage from PG&E cites as authority D.09-08-027at p. 30-31 and ALJ Hecht's Ruling Providing Guidance for the 2012-2014 Demand Response Applications, issued August 27, 2010 at Section 3.1.

actuality, ambient temperatures may not correlate to stressed system conditions, particularly if there is a mismatch between the point of stress on the grid and the geographic area of the retail load to be curtailed to relieve the adverse grid condition. For example, in a situation where there are high temperatures in the Sacramento Valley, demand curtailment in the San Francisco Bay area may do little to alleviate a situation on the grid which is specific to the valley. PG&E's own observation shows the over-inclusiveness of a temperature trigger, as opposed to more accurate indicators of stressed-system conditions:

> [Peak Day Pricing] events are triggered based on the day-ahead forecasted temperatures at specific locations in PG&E's service area and may occur any day of the week and year round.[16]

The ISO proposes that PG&E eliminate temperature triggers altogether and rely on either a resource heat rate trigger or, preferably, a wholesale price trigger. Updating these programs with appropriate economic triggers better aligns them as comparable supply options, which is a goal in the CCEF and a goal of this Commission.

E The ISO Supports PG&E's Pilot Projects Relating to Emerging Technologies

In Chapter 3 of its testimony, PG&E outlines its emerging technology efforts and pilot projects. The ISO strongly supports these efforts. In particular, the ISO supports PG&E's C&I Based Intermittent Resource Management Pilot 2 and the stated objectives that PG&E has set forth in this section of its testimony.[17] The ISO also supports the emerging technologies, objectives and proposals. The ISO finds these efforts relevant, pertinent areas where further investigation and

[16] PG&E Testimony, Chapter 2, at p-2-33, lines 7-9.
[17] PG&E Testimony at Chapter 3 Section C 2 [*C&I Based Intermittent Resource Management Pilot 2*], pp3-17 to 3-30

research must be conducted to elicit information to advance resource diversity and identifying demand resource shaping and firming opportunities.

IV COMMENTS SPECIFIC TO SCE's APPLICATION

A The ISO Endorses SCE's Emphasis on Market Integration and Price Responsive Demand Response

The ISO is appreciative of SCE's statements in Section II B [*Background, Demand Response Policy Emphasizes Market Integration and Price-Responsive DR*] of its application.[18] SCE notes that it seeks to find a balance between "maintaining successful programs" over the program cycle while preparing for a "consumer-centric, market-oriented, price-responsive future of DR."[19] As indicated above, the ISO urges the Commission to utilize the CCEF distillation of key elements in when it evaluates the pace of transition over this program cycle.

B The ISO Agrees with SCE's Treatment of CPP and its Save Power Day Programs as Forecast Reduction Mechanisms Rather than as Resource Adequacy Resources When They Cannot Be Locationally Dispatched

In Volume 1 of SCE's testimony, SCE relates that it does not intend for its Critical Peak Pricing Program to be treated as a Resource Adequacy resource at the outset of the program cycle:

> SCE would also like the Commission to note that SCE currently does not plan to bid CPP or Save Power Day as a Proxy Demand Resource (PDR) in the CAISO markets because they cannot be locationally dispatched. As SCE gains experience with these programs, it may consider requesting that the megawatt (MW) load reductions be treated as a reduction in the load forecast rather than as a resource requiring RA counting. At that time, the event hours would not be an issue for RA.[20]

SCE proposes similar treatment for its Save Power Day Program:

---

[18] SCE application at pp. 3-4.
[19] *Id.* at p. 3.
[20] SCE Testimony, Volume 1, Section III B [*SCE's Application Complies with Commission Guidance for DR; Alignment with Revised Resource Adequacy Counting Rules*], at p. 14

> Save Power Day provides incentives to customers for curtailing their usage during event days. The rebates provided by the program should translate to lower electricity usage by customers. The anticipated change in electricity usage is taken into account when SCE schedules its day-ahead load with CAISO. In addition, Save Power Day is not a program that can be locationally dispatched as required for PDR and RDRP in MRTU. Therefore, Save Power Day can be considered a "load modifying" DR program rather than a program that would be bid and dispatched through PDR or RDRP in MRTU.[21]

The ISO agrees with SCE's logic that, where demand response programs lack the ability to be dispatched when and where needed, those programs should not be counted for Resource Adequacy. The ISO concurs with SCE's comment above that, in such situations, the program is more appropriately treated as a mechanism for forecast reduction instead of Resource Adequacy.

C The ISO believes that SCE's Proposed Event Hours for its CPB and DBP Programs are Too Limited and Fail to Capture the Full Resource Potential

In its application, SCE notes that it proposes to retain the Capacity Bidding (CBP) and Demand Bidding Program (DBP) event hours, even though it acknowledges that they do not cover the entire hours required in Resource Adequacy rules.[22] The ISO believes that this approach is a mistake, and that the program event hours should be adjusted to maximize the resource effectiveness. The ISO believes that there a number of emergencies that can occur beyond weekday hours and on weekends. Accordingly, the ISO would like these programs to include weekends, as appropriate, or at minimum, as a program option for end use customers. Where a customer can provide DR in these times, there should be an opportunity to do so.

---

[21]SCE Testimony, Volume 2, Section II (F) (3) [*Price Responsive Programs; Save Power Day Incentive Program*; *Save Power Day Integration with CAISO Market*] at p. 35.
[22] SCE Testimony, Volume 1, Section III (B) [*SCE's Application Complies with Commission Guidance for DR; Alignment with Revised Resource Adequacy Counting Rules*], at p. 14

D SCE's Cost Estimate for the Telemetry and Metering Infrastructure Needs Under its Ancillary Services Tariff Must Be Substantiated

In SCE's testimony discussing its Ancillary Services tariff implementation efforts, SCE proposes to limit the scope of AS tariff participation to customers who can provide a minimum of 1 MW of load drop. SCE states that this is due to the high cost of telemetry and metering associated with installation and ongoing operating costs, which SCE estimates *at $70,000 per meter*. SCE's witness states that SCE has "conducted an informal, internal assessment of potential enrollees for this type of product" and has discovered that "there are few customers that are large enough to reduce 1 MW and comply with the parameters of this type of tariff"[23]

It is the opinion of the ISO that the MW scope for participating customers should come down to 0.5 MW, which is the ISO's requirement for demand response resource participation in the ISO ancillary services market. Moreover, Edison's estimation of $70,000 per meter needs to be substantiated. The ISO's preliminary reaction is that this estimate is extremely high. In this regard, the ISO has been working on cost effective telemetry solutions, and that the ISO believes that these efforts may yield cost estimates for telemetry solutions that are lower than SCE's estimate by a factor of 10 or more.

Effectively, Edison's 1 MW eligibility threshold would limit the number of participating customer to only 3 to 5. The ISO believes that it is feasible to lower the minimum MW eligibility threshold and utilize more realistic cost estimates, through which Edison could increase the number of customers providing demand response services under its Ancillary Services tariff.

[23] SCE Testimony, Volume 2, Section II (D)(2) [*Price Responsive Programs; Ancillary Services Tariff, Program Proposal*] at p. 21

E As With PG&E's Application, the ISO Advocates that Outdated Temperature-Based Triggers Be Phased Out and Replaced With Modern, Better Proxies for System Conditions

SCE's testimony states that, like PG&E, it also intends to continue using temperature-based program triggers—in this case "the prior days' Downtown Los Angeles temperature" as the trigger "for the appropriate Schedule RTP-2 rates based on the temperature, season and type of day."[24]

As the ISO has commented above with regard to PG&E's stated intention to use temperature triggers in its application, the ISO suggests that, instead of temperature triggers, why not move to a price trigger. In this regard, price triggers such as ISO Day Ahead price or an alternative trigger that is more market- or operationally- based is more appropriately correlated to the stressed system conditions that would prompt dispatch of the resource and, accordingly, this approach is how the ISO would hopes dynamic tariffs would be structured and operate in the future. In general, ISO prices reflect expected grid conditions and are a more appropriate match to system needs.

V Information Included in One of SCE's Supporting Documents May Need Correction

The ISO points out that it appears that the Demand Response Programs Summary table included in SCE's application at Volume 5, Appendix D contains information which needs to be updated. The table references BIP as being triggered by an ISO Stage II emergency. This description should also list an ISO Warning Notice as an event trigger, as described in the Phase 3 Settlement approved by the Commission June 25, 2010 in D.10-06-034 in R.07-01-041. Similarly, the Summer Discount Plan (SDP) program listed in this table also requires updating and alignment with the Phase 3 Settlement. The ISO believes

[24] SCE Testimony, Volume 2, Section III (A) (2) [*Dynamic Pricing Programs; Real Time Pricing; Program Proposal*] at p. 38.

that the event trigger descriptions for BIP and SDP appear to describe the triggers as they were *before they were modified* as described in the Phase 3 Settlement.

Respectfully submitted,
By: ***/s/ Baldassaro "Bill" Di Capo***
Nancy Saracino
General Counsel
Sidney Davies
Assistant General Counsel
Baldassaro "Bill" Di Capo
Senior Counsel
California Independent System
Operator Corporation
250 Outcropping Way
Folsom, CA 95630
Tel.: (916) 608-7157
Fax: (916) 608-7222
bdicapo@caiso.com

Attorneys for the California Independent
System Operator

Dated: April 1, 2011

CERTIFICATE OF SERVICE

I hereby certify that on April 1, 2011. I served on the parties listed on the service list of Docket Numbers A11-03-001, A11-03-002, A11-03-003, R.06-04-010, R07-01-041, A.08-06-001., A08-06-002, and A08-06-003 by electronic mail, a copy of the foregoing

RESPONSE OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO THE APPLICATIONS OF PACIFIC GAS AND ELECTRIC COMPANY, SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA EDISON COMPANY FOR APPROVAL OF DEMAND RESPONSE PROGRAMS, PILOTS, ACTIVIES, AND BUDGETS FOR 2012-2014

/s/ Anna Pascuzzo

Anna Pascuzzo
An employee of the
California Independent
System Operator

Executed on April 1, 2011 at
Folsom, California