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)

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

Witnesses: John D. Goodin
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(Witness: John D. Goodin)

I. PURPOSE OF TESTIMONY

A significant issue related to the evaluation and approval of investor-owned utility ("IOU") demand response ("DR") programs and budgets is the extent to which the programs will count for Resource Adequacy (often abbreviated as "RA"). The Commission imposes Resource Adequacy requirements on the PG&E, SDG&E, and SCE, as load serving entities to procure an adequate level of resources to serve their customer load. This means that the RA resources must be useful to the system operator.

The purpose of this testimony is to present the Commission with certain recommendations of the ISO in connection with Commission approval of the applications, portfolios and budgets of Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE). The recommendations set forth in this ISO testimony are intended to maximize the effectiveness of those DR resources from the standpoint of the system. There are also cost and efficiency issues to the extent that the resources operate as resource adequacy resources, and the testimony also presents and discusses these issues.

The ISO recommendations also promote cost-effectiveness from the standpoint of the ratepayer, since demand response resources which are integrated in the ISO market and configured to provide ancillary services and or energy can be many times more effective than currently structured retail demand response programs which the IOUs traditionally offer to the system operator.

II. BACKGROUND; THE ISO HAS BEEN ACTIVELY INVOLVED IN THE COMMISSION'S ONGOING EFFORTS SINCE JANUARY 2007 TO REFINE AND RESHAPE DR

The ISO has been an active participant in the Commission's DR refinement efforts since January 2007, when the Commission opened its primary and ongoing rulemaking proceeding R.07-01-041, intended to address and refine of IOU demand response programs. The order instituting rulemaking set out four major goals. The fourth major subject area of the rulemaking is integration of DR with the ISO market (known as "MRTU" prior to its March 31, 2009 market launch).

The Commission opened Phase 3 of R.07-01-041 to address the critical issue of what should be the optimal size (in terms of MW quantity) for traditional emergency-triggered DR programs which would count for RA. There were two primary reasons why the question is so important:

(1) Historically, the IOU DR programs that are counted toward the IOU's RA requirement (and thus added to the group of resource adequacy resources which the ISO is expected to utilize to run the system) have been emergency triggered programs; and

(2) The Commission has recognized in rulings issued in R.07-01-041 that emergency triggered programs are sub-optimal as an RA resource.[1]

Phase 3 resulted in a global settlement, adopted by the Commission in D.10-06-034, which set an overall MW limit on the amount of emergency-triggered demand response that the

[1] For example, this Commission opinion and policy is conveyed through the discussion in D.09-08-027 in Section 9 [Policy on Development of Emergency-triggered and Price Responsive Demand Response Activities] and Conclusion of Law no 3 that "it is reasonable to cap emergency triggered programs at their current enrollment (in megawatts) and funding levels pending resolution of [the optimal size of such DR as part of the IOU DR portfolio as compared to price responsive DR.]"

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.[2]

The ISO was also actively involved in the last DR program cycle proceeding which considered and approved IOU demand response programs and budgets for the program cycle 2009-2011.[3]

As the electric system operator and venue for the wholesale market, the ISO has also engaged in substantial efforts since 2007 to prepare the platforms for the retail DR to integrate with the ISO market. The ISO has established its Proxy Demand Resource (PDR) product, which has been open to market participants as of August 10, 2010, as a mechanism for economical demand response to participate in the ISO market. The ISO is also currently developing its Reliability Demand Resource Product (RDRP), know known as Reliability Demand Response Resource (RDRR) as a mechanism to integrate emergency-triggered demand response. The ISO submitted its ISO tariff amendment to implement RDRR on May 20, 2011. [4]

The Commission set out the history of its efforts on demand response in D.10-06-034. This history bears repeating, because it provides the context to the issue in this proceeding of how to evaluate IOU DR programs that the IOUs propose to count for Resource Adequacy:

> The Commission opened this rulemaking on January 25, 2007 as *part of a "continuing effort to develop effective demand response (DR) programs" and identified consideration of "modifications to DR programs needed to support the California Independent System Operator's efforts to incorporate DR into market design protocols" as an objective of the rulemaking*. (emphasis added)
>
> Phases 1 and 2 were initiated to address DR program cost-effectiveness, load impacts, and goals. *One specific issue that arose in Phase 2 was whether existing emergency-triggered DR programs should be modified to facilitate their integration into the California Independent System Operator's (CAISO or ISO) Market Redesign and Technology Upgrade (MRTU)*. A ruling issued in this proceeding requested comments

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[2] 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)

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

[4] The ISO's RDRR product Tariff Amendment filing to FERC can be accessed on the ISO's website at http://www.caiso.com/2b84/2b84bc9d17d00.pdf

on this issue, with the CAISO's comments due on June 25, 2008 and other parties' comments due on July 9, 2008. (emphasis added)

In response to this ruling, the CAISO provided its rationale for reducing the amount of emergency-triggered DR in the service areas of the three largest investor-owned utilities (IOU). The IOUs and other parties provided comments on the CAISO analysis of emergency-triggered DR.

On July 18, 2008, the Commission initiated Phase 3 of this rulemaking to address the "operation of the investor-owned utilities' emergency-triggered DR programs in the future electricity wholesale market." Parties were asked to file prehearing statements on nine questions regarding the emergency-triggered DR programs.

…

Subsequently, in Application (A.) 08-06-001 et al. (regarding the IOUs' 2009–2011 DR program portfolios), the Commission adopted Decision (D.) 09-08-027 on August 20, 2009, *imposing interim caps on the IOUs' emergency-triggered DR programs*. D.09-08-027 reasoned [that]:

> In recognition of the ongoing examination of the appropriate size and role of emergency programs in R.07-01-041 Phase 3, we decline to expand existing emergency-triggered programs or adopt new emergency programs with similarly limited triggers. Instead, we cap these programs at their current enrollment (in megawatts) and funding levels pending the resolution of R.07-01-041 Phase 3, with a limited exception for the PG&E SmartAC™ program.

With the implementation of the MRTU, Phase 3 was re-activated on July 8, 2009 to hold workshops on the emergency-triggered DR programs.[5] Three workshops were scheduled to examine the optimal size of the emergency-triggered DR programs, consider alternatives to the emergency-triggered DR programs, and address implementation and transition issues for any alternatives identified in Workshop 2.

…[P]arties engaged in vigorous debate on whether the emergency-triggered DR programs should be reduced from their current size, and little party consensus was achieved.

… On February 22, 2010, a joint motion asking for the adoption of a settlement was filed in the proceeding. The Joint Motion reports that subsequent to Workshop 2, the Settling Parties met on numerous occasions to explore a possible settlement and that these efforts eventually resulted in a settlement in principle among the Settling Parties.

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[5] See Assigned Commissioner's Ruling Amending the Scoping Memo and the Schedule of Phase 3 of this Proceeding (Amended Scoping Memo), July 8, 2009.

The Commission adopted the settlement in D10-06-034; as the Commission explained the settling parties had proposed "changes to the emergency triggered and reliability-triggered DR programs" that will make the programs more useful and cost-effective."[6]

D.10-06-034 included directives that the IOUs include an implementation plan in their applications. The directive contained in Ordering Paragraph 1 (b) (c) is reprinted in the next section of this testimony. The ISO has reviewed the IOU applications and testimony and cannot determine whether or how the IOUs attempted to comply with this CPUC directive. Now that the applications are squarely at issue in this proceeding, the Commission should consider whether it is necessary to require the IOUs to amend or supplement their applications to document for the Commission how the IOUs have complied with the directive. The ISO would support a Commission ruling in this proceeding directing the IOUs to file an amendment for this purpose.

III. POLICY MANDATED DESIGN PARAMETERS SET OUT PRIOR CPUC DIRECTIVES

A. D.10-06-034; Decision Adopting Settlement Agreement On Phase 3 Issues Pertaining To Emergency Triggered Demand Response Programs

In this decision, the Commission also stated that: "*A goal of the Commission has been to ensure that ratepayer funds do not subsidize the reliability-based DR in amounts that exceed what the CAISO can use*."[7] The Commission went on to say that:

> To facilitate the Commission in determining the "appropriate action concerning 'oversupply'" in order to ensure that ratepayer funds do not subsidize reliability-triggered DR in amounts that exceed the settlement caps, the Commission needs further information. For this reason, we will require that in the filing of the 2011 DR applications, each utility will propose in its application a plan as to how it will limit enrollment in reliability triggered DR programs in accordance with the settlement caps as well as a regulatory mechanism that ensures that ratepayer

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[6] D.10-06-034 pt p. 8.
[7] D.10-06-034 DECISION ADOPTING SETTLEMENT AGREEMENT ON PHASE 3 ISSUES PERTAINING TO EMERGENCY TRIGGERED DEMAND RESPONSE PROGRAMS (June 25, 2010) at p. 20, emphasis added. Decision accessible on CPUC website at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/119815.pdf

> funds will not subsidize the tariff provision of reliability triggered DR if an oversupply is determined.[8]

To add teeth to the directive to transition to price-responsive DR, the Commission ordered that the IOU 2009-2011 applications include the following components:

> b. In their Demand Response applications to be filed in January 2011, PG&E, SCE, and SDG&E each shall:
>
> a. address integration of its reliability-based demand response programs into the RDRP developed by the CAISO;
>
> b. address and seek approval of its program marketing efforts; and
>
> c. Propose a plan as to how it will limit enrollment in reliability-triggered Demand Response (DR) programs in accordance with the settlement caps as well as a regulatory mechanism for consideration by the Commission that ensures that no Resource Adequacy payments or other ratepayer funds will subsidize the tariff provision of reliability-triggered DR if an oversupply is determined.[9]

(As the ISO has indicated Section II of this testimony, above, the ISO has reviewed the IOU applications but is still unclear on what IOU program design specifics and what program activities the IOUs have included in compliance with the Commission directive.)

B. Decision 10-06-002, Decision on Phase Four Direct Participation Issues (June 3, 2010)

In D.10-06-002, the Commission stated that:

> In existing retail DR programs, the IOU acts as the intermediary between the CAISO's markets and the customer or aggregator that is providing the DR resource. While these DR programs have not provided for a customer or aggregator to directly bid DR resources into the CAISO wholesale markets,[10] the Commission has directed the IOUs to better integrate their existing DR resources into the CAISO's energy and ancillary services markets.[11] Acting expeditiously to allow end use customers or aggregators to bid DR resources directly in these markets (to the extent that the laws or regulations applicable to the relevant

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[8] Id.
[9] D-10-06-034, at pp. 22-23,Ordering Paragraph 1
[10] The Commission has authorized three Participating Load Pilot (PLP) programs in which the IOUs bid DR load reductions into the CAISO ancillary service markets.
[11] See Decision (D.) 09-08-027.

> electric retail regulatory authority do not prohibit a retail customer's participation) is consistent with our identification of DR as one of the state's preferred means of meeting growing energy needs. (citing to *Energy Action Plan II: Implementation Roadmap For Energy Policies*, issued October 2005 by the Commission and the California Energy Commission (CEC))[12]

C. Decision 09-08-027; Decision Adopting Demand Response Activities and Budgets For 2009 Through 2011 (Aug 20, 2009)

D.09-08-027 included a discussion of Commission policy on emergency-triggered versus price responsive demand response.

> Since 2003, this Commission has emphasized the importance of price-responsive demand response as a key component of our overall demand response policy. While emergency-triggered demand response plays an important role in improving the reliability of our grid, price-responsive demand response can lower overall wholesale electricity costs for all customers as well as help mitigate wholesale market power. Additionally, reducing consumer electricity usage during peak periods can help reduce fuel use and overall air emissions. The CAISO's implementation of its new markets makes price responsive demand response even more important to pursue since demand response can now participate in more markets and, in the future, on a locational basis.
>
> The price-responsive programs adopted in this decision also play an important role in our efforts to increase price-responsive demand response. Since CAISO's implementation of its new markets, such programs have the potential to be aligned with wholesale markets. Our 2008 Energy Action Plan Update emphasizes the importance of such alignment, noting that retail demand response programs should be modified so that they can more fully participate in CAISO's new wholesale market structure (D.09-08-027 at Section 9.1, pp-30-31.)

IV. RECOMMENDED POLICY DIRECTIVES TO ALIGN IOU PROGRAM PORTFOLIOS WITH CPUC DESIGN CRITERIA AND DIRECTIVES

A. Consider Competitive Procurement for Direct Participation Demand Response

In a subsection of SDG&E's testimony entitled "The Commission should direct SDG&E's DR programs to provide RA, and leave DR providing only energy or ancillary service benefits to participate directly in CAISO markets," SDG&E's witness states that:

[12] D10-06-002 at 15-16.

> SDG&E believes the primary value of its DR programs and rates is to provide local capacity to meet peak demand and thus avoid the cost of purchasing or building additional resources to maintain reliability of the electrical system. We also recognize that DR resources can provide short-term value by participating in the ancillary services market and reducing the clearing costs of the CAISO's hour ahead and real time markets. SDG&E is fully supportive of the use of DR resources in the ancillary services market *but we believe that utility intervention in the form of DR programs is not desirable. Customers and Aggregators should participate in these markets directly, interacting with the CAISO, and avoid the utility as a middleman.*[13] (emphasis added)

The ISO concurs in this assessment by SDG&E: *when it comes to those demand response resources configured to participate in the ISO market, the Commission should consider transitioning them from an IOU-delivered resource to a competitively-procured resource*.

Under a competitive procurement paradigm, the Commission's continued directive-- that IOUs align DR with the ISO market and the loading order-- would be implemented through the further directive that IOUs use competitive procurement to solicit DR designed to satisfy long-term procurement and resource adequacy requirements *from aggregators*. From the IOU testimony submitted here, it appears that this approach would save ratepayers the substantial upfront costs that the IOUs have outlined as necessary for their budgets and the risks of "scope and budget creep" often associated with new information technology systems that must "seamlessly integrate" with legacy systems.

Looking to PG&E's testimony as an example, PG&E puts forth a cost estimate of $25,865,000 to implement direct participation, based on "best available data at the time of filing its application."[14] In Chapter 4 PG&E further testifies that:

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[13] Chapter I ,Prepared Direct Testimony of Mark Gaines at p. MFG-11. (emphasis added).

[14] Appendix 7A to testimony submitted by PG&E, at p. 7. PG&E has included more than 11 appendices to its submitted testimony. The testimony and appendices can be accessed on PG&E's website at: https://www.pge.com/regulation/DemandResponse2012-2014-Projects/Testimony/PGE/2011/DemandResponse2012-2014-Projects_Test_PGE_20110301_207098.pdf

(PG&E testimony, Chapter 4, at page 4-2)

> [PG&E's] DR Operations will assume new functions in 2011 and continuing through the 2012-2014 period, particularly due to the participation of DR products (as PDR and Reliability Demand Response Product (RDRP)) in the California Independent System Operator (CAISO) market, including:
>
> - Customer Registration and Validation.
> - Forecasting and internal bid preparations.
> - Preparing post event performance operational reporting.
> - Capturing PDR and other applicable DR positions in PG&E's trade capture system.
>
> PG&E's table 4-1 summarizes the cost to implement its system support activities as follows:

DR Enrollment & Support:	$15,787,000
InterAct/DR Forecasting Tool:	$14,408,000
Notifications: $11,328	,000
Total $41,523,000	___________

While not immediately clear because of ambiguity in the testimony presentation, PG&E's cost to implement the administrative and information technology systems is either i) approx. $41 million or ii) approx. $67 million (representing $41,523,000 + *$25, 865,000*). In either case, the costs for PG&E to build a direct participation demand response capability seems inordinate. If we should expect that each of the IOUs will expend similar amounts of ratepayer funds to build the administrative and information technology infrastructure they deem necessary to create in-house direct participation demand response capability, then the Commission and ratepayers should expect to see very high costs for the initial set up of the in-house option. And, of course, in addition to the initial set up costs, one must expect that there will be regular and ongoing operating and program maintenance and management costs.

Another example illustrating that it may not be optimal from a cost standpoint to build IOU in-house direct participation DR capability can be seen in SCE's testimony as to the potential cost for telemetry metering. In its testimony discussing its Ancillary Services tariff implementation efforts, SCE explains that it will need to limit the scope of AS tariff participation to only certain customers (those who can provide a minimum of 1 MW of load drop) because of the potentially high costs of telemetry metering. SCE estimates the telemetry metering installation and ongoing operating costs to be $70,000 per meter.[15] As the ISO explains further in this testimony, this number appears to the ISO to be unnecessarily high.[16]

The Commission should consider the competitive procurement approach as an alternative option to the "in-house approach." Under certain conditions, rather than "building it themselves" utilities have sometimes resorted to purchasing desired resources from the market through competitive solicitation. Frequently in the past, the Commission has considered competitive procurement as a preferred policy mechanism that can shift development costs and resource performance risk away from the ratepayer. In this regard, a competitive procurement approach to demand response resource acquisition could shift potential risks of undue start-up and maintenance costs from the ratepayer to the aggregator. Given the magnitude of costs referenced in PG&E's testimony, it may be appropriate for the Commission to consider competitive procurement as a tool for either i) resource acquisition (as is done for generation procurement) or ii) validation of IOU-proffered in-house cost estimates (i.e. as a cost comparison metric).[17]

A policy platform of competitive solicitation could free IOUs from the detail work and cost conundrum of re-inventing the aggregator wheel and allow the IOUs to focus instead on dynamic rate structures that tightly couple energy consumption with the time value of energy and on customer education and awareness, while aggregators would be free to focus on applying to California the business model that they have already successfully applied to the development and implementation of demand response resources in other regions.

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

[16] The ISO noted this in its initial comments to SCE's applications. In reply comments, SCE stated that

> SCE welcomes such information and has already had discussions with CAISO on ways to explore more cost-effective technologies to provide PDR Ancillary Services while complying with CAISO market requirements. Furthermore, if discussions with the CAISO provide approved telemetry options at a lower expense, SCE would then be open to lowering the proposed 1 MW eligibility threshold." (Reply of Southern California Edison Company's in Support Of Its Application For Approval Of Demand Response Programs Goals and Budgets for 2012-2014, dated April 14, 2011, at p.8.) The reply comments are posted on the docket page for this proceeding at http://docs.cpuc.ca.gov/efile/REP/133577.pdf

[17] Specifically, demand response resources that are configured to participate in the ISO day-ahead and real-time energy and ancillary service markets.

B. Only Count For RA Those DR Resources That Directly Participate In the ISO Market To Provide Energy And Ancillary Services

The ISO has long held the position that only resources that are dispatchable "when and where needed" should count as resource adequacy capacity. This is also a central tenet of the CPUC resource adequacy program.

The ISO has opposed the notion of qualifying resources as resource adequacy capacity if they are not available to the ISO when and where needed. Rate structures, such as a critical peak pricing, that apply equally to all enrolled customers often require dispatch across an entire service territory when called. This type of "demand response" should not qualify as resource adequacy capacity because it is not available where needed in alignment with the ISO market, which is based on locational dispatch and the derivation of locational marginal prices.

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.[18] (emphasis added)

SCE proposes similar treatment for its Save Power Day Program:

> 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,

[18] 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 can be considered a "load modifying" DR program rather than a program that would be bid and dispatched through PDR or RDRP in MRTU.[19]

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, which can lower the IOUs procurement needs on the day the program is called.

C. Temperature Based Program Triggers Attached To Economic Dr Programs Should Be Disfavored

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 ….*[20]

To support its argument, PG&E's cites to decisional authority that does reiterate the importance of price-responsive triggers, and incidentally references temperature based triggers, although they are not endorsed by the cited authority. 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. However, over the succeeding years, temperature-triggers have been rendered an outmoded proxy for stressed system conditions that call for demand response resources to be dispatched.

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[19]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.
[20] 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.

Program triggers should be based on economics, not on temperature, which at best substitutes as a rough proxy for system conditions. In 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.[21]

The ISO proposes that the Commission direct the IOUs that temperature triggers are disfavored, or eliminate them altogether, and direct the IOUs to rely on either a resource heat rate trigger or, preferably, a wholesale price trigger. At the very least, if the IOU proposes to use a temperature trigger, should be required to demonstrate why more modern, better tailored heat rate or wholesale price triggers are not practicable for the specific program. A general requirement that IOUs update their programs to employ appropriate economic triggers better aligns them as a comparable supply option, which is goal of this Commission.

V. SPECIFIC POINTS FOR EACH IOU APPLICATION AND DR PROGRAM PORTFOLIO

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.[22] PG&E states that

[21] PG&E Testimony, Chapter 2, at p-2-33, lines 7-9.
[22] PG&E's Application Section C 2 [*Summary of PG&E's Proposals, Emergency Programs*] at p5.

> 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.[23]

The ISO submits that this timeline is too long and is not within the spirit of the Phase 3 Settlement.[24] The ISO has been diligently working on development of the Reliability Demand Response Resource ("RDRR") product, and submitted the ISO tariff amendment to FERC on March 20, 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 its timeframe to say "as early as 2013," and use of the qualifier signals that PG&E"s actions may actually come later and not be completed for some time.. In the ISO's opinion, it should not take multiple years to complete the effort, and the effort need not wait for a year or so following a FERC order on ISO's RDRP amendment filing.

Additionally, the ISO envisions that its own information technology upgrades will be derived from the technology platform for ISO's proxy demand resource product. While the ISO understands that some approval process and technology work is necessary for PG&E to accomplish a transition of BIP into RDRR, the ISO believes that PG&E efforts would be based in some part on its proxy demand resource implementation efforts which should come to fruition before a 2013-14 timeframe.

B. The ISO Supports PG&E Establishing a Pre-Qualification Process for BIP and Recommends a Global Requirement that each IOU Undertake the Effort

PG&E's testimony addressing proposed activities for BIP includes creating a pre-enrollment qualification process for BIP applicants, to ensure that new participants to BIP will understand program rules and have the ability to effectively and reliably participate in the program.[25] The ISO supports a pre-enrollment qualification enrollment effort as PG&E has

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[23] *Id.,* emphasis added.
[24] *Decision Adopting Settlement Agreement on Phase 3 Issues Pertaining to Emergency Triggered Demand Response Programs*, *supra*, Decision 10-16-034 (June 24, 2020)
[25] PG&E Testimony, Chapter 2, pp 2-22 to 2-23.

described. A pre-enrollment qualification as PG&E proposes should be universal feature for each of the IOU's Base Interruptible Program.

The ISO recommends that the Commission should order each of the IOUs to implement a pre-qualification process in alignment with the settlement agreement directive to diligently transition customers to price responsive demand response.

C. 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.[26] The ISO also supports the emerging technologies, objectives and proposals. The ISO finds these efforts relevant, pertinent areas where further investigation and research must be conducted to elicit information to advance resource diversity and identifying demand resource shaping and firming opportunities.

D. The ISO Believes that SCE's Proposed Event Hours for Its CPB and DBP Programs are Too Limiting

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.[27] 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.

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[26] PG&E Testimony at Chapter 3 Section C 2 [*C&I Based Intermittent Resource Management Pilot 2*], pp3-17 to 3-30

[27] 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

E. SCE's Cost Estimate for the Telemetry and Metering Infrastructure Needs Under its Ancillary Services Tariff Appears too High; Other Workable Solutions are Available

(Witnesses: John D. Goodin; Jill E. Powers)

SCE's testimony discussing its Ancillary Services tariff implementation efforts states that SCE proposes to limit the scope of participating customers for its "Ancillary Services tariff" to those customers who can provide a minimum of 1 MW of load drop. The ISO understands SCE to be using its proposed size limitation in order to focus on those retail customers with relatively high energy usage who can tolerate relatively higher infrastructure costs. SCE's testimony relays a high per-resource cost of telemetry and metering associated with installation and ongoing operating costs for each customer, which SCE estimates *at $70,000 per meter*. Its 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."[28] The ISO does not believe that it is necessary to spend that much money to achieve workable metering and telemetry solutions, and that the use of less expensive solutions would widen the scope of potential customer participation from the mere 3 to 5 customers that SCE projects.[29]

The ISO has substantial experience with the mechanics and costs of metering. Nearly all large generating stations located in the IOU service territories have installed ISO-certified metering. Reviewing the cost information presented in SCE's testimony and comparing it against the ISO's own experience on the subject, it is ISO's opinion that Edison's $70,000 per meter estimate is overstated and needs to be substantiated. The ISO's preliminary reaction is that this estimate is extremely high.

Moreover, in connection with the ISO's proxy demand resource product development, the ISO has been working on cost effective telemetry solutions for more than two years now.

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

These efforts began in earnest in about 2009, when the ISO worked with the IOUs and other parties on the participating load pilot programs which were part of the last DR budget program application cycle. As part of the ISO's proxy demand resource activities, the ISO has conducted its own internal efforts to investigate and identify low cost telemetry solutions. Based on this experience and effort, the ISO believes that metering and telemetry functionality can be achieved at costs substantially lower than SCE's estimate.

In this regard, work that the ISO has been engaged in over the last three months with SDG&E and SDG&E's PDR pilot known as the Demand Response Wholesale Market Pilot is pertinent. At the conclusion of this ISO - SDG&E interaction, the parties were able to successfully test ancillary service capabilities of SDG&E's proxy demand resource. The ISO believes that if it works with SCE in similar fashion, the parties could also achieve less expensive telemetry and metering solutions that would reduce the per-customer installation costs and ongoing expenses for these functions.

In the ISO's opinion, the MW scope of eligible customers does not have to be as narrow as SCE has specified, and the scope can be comfortably broadened to include customers who can provide a load drop of 0.5 MW. The ISO believes that it would be better for SCE to select a load drop capability of 0.5 MW. This is the ISO's own eligibility requirement for demand response resource participation in the ISO ancillary services market.

(Witnesses: John D. Goodin)

F. SCE's Outdated Temperature-Based Triggers Should Be Phased Out Too

SCE's testimony reveals 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."[30]

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

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 market-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. Accordingly, price-triggers are a more appropriate match to the system needs.

Appendix A: Witness Qualifications

John D. Goodin
Jill E. Powers

<u>Qualifications of Witness JOHN D. GOODIN</u>

Q. Please state your name and business address for the record.

A. My name is John Goodin. My business address is 250 Outcropping Way, Folsom, California 95630.

Q. By whom and in what capacity are you employed?

A. I am employed in the Market Design and Regulatory Policy department for the California Independent System Operator Corporation as the lead for demand response issues and policies. The California Independent System Operator Corporation has been commonly known as the CAISO and is generally called by that name in CPUC proceedings and documents. In the last several years, the company has styled its name as the ISO rather than the CAISO in its own documents and pleadings.

Q. Please describe your educational and professional background.

A. I have been employed with the ISO since before the ISO commenced operations in 1998. I joined the ISO's client relations department (later renamed the external affairs department) in December 2007 as an account manager, serving key clients and leading special projects. In December 2005, I joined the Market and Product Development group as a Senior Market and Product Developer as lead staff engaged in the development of resource adequacy policy. In November 2007, I became the ISO lead for demand response issues. My responsibilities include work on the development of demand response policy and products for the ISO.

Prior to joining the ISO, I was employed by the Pacific Gas and Electric Company ("PG&E") for over nine years, and for a brief period, by PG&E Energy Services. I spent a majority of my tenure at PG&E working on demand-side management and load management related programs, both at the program management level and directly with retail customers. I have a B.S. degree in Mechanical Engineering from the California Polytechnic State University, San Luis Obispo.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of this testimony is to present the Commission with certain recommendations of the ISO in connection with Commission approval of the applications, portfolios and budgets of Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE).

Q. Was the material entitled TESTIMONY OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION RE: 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 prepared by you or under your supervision?

A. Yes. All portions of the document that are referenced as my testimony were prepared by me and/or under my supervision.

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

A. Yes, I do.

<u>**Qualifications of Witness Jill E. Powers**</u>

Q. Please state your name and business address for the record.

A. My name is Jill E. Powers. My business address is 250 Outcropping Way, Folsom, California 95630.

Q. By whom and in what capacity are you employed?

A. I am the manager of the Energy Measurement, Acquisition and Analysis group for the California Independent System Operator Corporation ("ISO"). My group is responsible for ensuring real time and revenue metering is installed and its data is accurate and available for use by grid operations and for the accurate settlement of ISO market transactions.

Q. Please describe your educational and professional background.

A. I have been with the ISO for over twelve years during which time I have held a variety of positions supporting grid operations and the design of energy markets facilitated by the ISO.

Prior to joining the ISO, I had 15 years experience in the gas and electric utility industry, which included working in the design development and marketing of energy conservation and management technologies, financial incentive programs, and time-of-use rates. During this time, I also founded a state certified women owned business (MWBE) that provided professional and technical engineering services to Northern California utilities.

I hold a Bachelor of Science in Mechanical Engineering and a Master of Science in Computer Information Systems.

Q. What is the purpose of your testimony in this proceeding?

A. To discuss metering and telemetry issues for demand response resources.

Q. Was the material entitled TESTIMONY OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION RE: 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 prepared by you or under your supervision?

A. Yes. All portions of the testimony where I am listed as a witness was prepared either by me and/or at my direction.

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

A. Yes, I do.