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Decision **PROPOSED DECISION OF ALJ HYMES** (Mailed 10/28/2011)

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.	Application 11-03-001 (Filed March 1, 2011)
And Related Matters.	Application 11-03-002 Application 11-03-003

DECISION ADOPTING DEMAND RESPONSE ACTIVITIES AND BUDGETS FOR 2012 THROUGH 2014

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DECISION ADOPTING DEMAND RESPONSE ACTIVITIES AND BUDGETS FOR 2012 THROUGH 2014

1. Summary

By this decision, the Commission adopts demand response (DR) activities and budgets for Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (collectively, the Utilities) to conduct DR programs, pilots and associated activities for the years 2012 through 2014. We authorize a budget of $194,664,630 for PG&E, $63,067,177 for SDG&E and $186,182,650 for SCE.

We also approve DR customer incentives of $33.5 million requested by SDG&E in this application,[1] as part of the above authorized budget, and authorize PG&E and SCE to pay their DR response customers the incentives that we approved in other proceedings.[2] This proceeding is closed.

2. Background

The Commission broadly defines demand response (DR) as reductions or shifts in electricity consumption by customers in response to either economic or reliability signals. Economic signals come in the form of electricity prices or financial incentives and reliability signals present themselves as alerts during times when the electricity system is vulnerable to extremely high prices or

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[1] SGE-05 at Appendix A, Table A-3.

[2] PG&E received approval of $68.7 million in DR customer incentives through Decision (D.) 07-09-004 and $15.2 million in demand response customer incentives through D.07-05-029. SCE received approval of $252.9 million for demand response customer incentives through D.09-08-028, $8.5 million through D.10-12-047. SCE seeks approval of $199.3 million in demand response customer incentives through applications in A.11-03-001 and A.10-07-016.

reliability is compromised. We have generally categorized DR programs according to whether their purpose is to address spikes in market prices in the case of price-responsive programs or dynamic pricing or to relieve threats to system reliability in the case of reliability programs.

2.1. Procedural History

Commission D.09-08-027 adopted 2009-2011 DR activities and budgets for Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E) and Pacific Gas and Electric Company (PG&E), and required PG&E, SCE, and SDG&E (collectively, the Utilities) to file applications by January 30, 2011 for approval of DR activities and budgets for 2012-2014. D.10-12-024, which provides a consistent method for estimating the cost-effectiveness of DR activities among the Utilities, revised the deadline for filing of the applications to not later than March 1, 2011.

On March 1, 2011, the Utilities each filed an application for approval of their DR programs, activities, pilots, and budgets for 2012-2014 (Applications). Assigned Administrative Law Judge (ALJ) Kelly A. Hymes issued a ruling on March 30, 2011, consolidating the three applications into one proceeding, Application (A.) 11-03-001 et al., and setting a prehearing conference for May 3, 2011. Parties filed timely protests and responses to the Applications on April 1, 2011 and April 4, 2011.[3]

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[3] The assigned ALJ emailed the service list on March 31, 2011 clarifying that because of the consolidation of the three Applications, protests and responses would be due on April 4, 2011. North America Power Partners, Inc. and California Independent System Operator Corporation filed responses on April 1, 2011; Comverge, Inc., Enernoc, Inc., Energy Inc., California Energy Storage Alliance, and Ice Energy Inc. filed responses on

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In a related matter, ALJ Hymes issued a ruling on April 29, 2011[4] that incorporated by reference into the record of this proceeding the Statewide Joint Investor-Owned Utility Study of Permanent Load Shifting[5] (PLS Study) and its associated comments and reply comments.[6] The ruling provided further guidance to the Utilities for revising estimates of the cost-effectiveness of proposed PLS activities in the applications and directed the Utilities to serve the revised estimates on May 20, 2011.

On May 3, 2011, the ALJ held a prehearing conference to determine parties, scope, schedule and other procedural matters. Aside from the three utility applicants, thirteen parties actively participated in this proceeding: California Energy Storage Alliance (CESA), the California Independent System Operator (CAISO), California Large Energy Consumers Association (CLECA), CALMAC Manufacturing Corporation (CALMAC), Demand Response Aggregators (DR Aggregators), Direct Access Customer Coalition (DACC), the Alliance for Retail Energy Markets (AReM), the Division of Ratepayer Advocates (DRA), ICE Energy, Marin Energy Authority, North America Power Partners

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April 4, 2011; and the Division of Ratepayer Advocates and the Alliance for Retail Energy Markets filed protests on April 4, 2011.

[4] The April 29, 2011 ruling is available at http://docs.cpuc.ca.gov/efile/RULINGS/134347.pdf.

[5] The assigned ALJ in Rulemaking 07-01-041, issued a ruling on February 11, 2011placing the PLS Study into the formal record of that rulemaking. The PLS Study is available at http://docs.cpuc.ca.gov/efile/RULINGS/130717.pdf.

[6] The assigned ALJ issued a ruling on July 29, 2011 directing SCE to file and serve errata to the PLS Study. SCE filed and served the errata to the PLS Study on August 2, 2011.

(NAPP), The Utility Reform Network (TURN), and the Utility Consumers Action Network (UCAN).

Following the prehearing conference, the assigned Commissioner and ALJ jointly issued a scoping memo on May 13, 2010 (Scoping Memo) that set out the scope of the proceeding, which is discussed below. The Scoping Memo directed the Utilities to further revise the cost-effectiveness analyses using updated Load Impact Report data and consensus values. The scoping memo directed the Utilities to serve this set of revisions on May 27, 2011.

Parties served testimony on June 13, 2011 and rebuttals on July 11, 2011. During July 19 -22, 2011, parties participated in four days of evidentiary hearings. Following hearings, the parties received briefing guidance from the assigned ALJ in an August 1, 2011 Ruling. In this Ruling, PG&E was instructed to file a motion to late file versions of its DR Reporting Templates as late-filed exhibits. PG&E complied and the assigned ALJ issued a ruling on August 17, 2011 identifying and receiving the DR Reporting Templates into evidence.

On August 5, 2011, the assigned ALJ issued a ruling incorporating into the record of this proceeding responses by the Utilities to Energy Division data requests. An attachment to the ruling included questions from the Energy Division to the Utilities and the associated utility responses.[7] Parties provided comments to these responses on August 12, 2011.[8]

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7 PG&E did not respond to the data request in a timely manner. Due to time constraints of this proceeding, PG&E's responses were not included in the ruling attachment and thus are not a part of the record of this proceeding.

8 In comments to the August 5, 2011 ruling, DR Aggregators object to the "incorporation" into the record of this proceeding of the Utilities' responses to energy division data request. SCE objected to the omission of a reply opportunity but provided

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Parties filed briefs on August 21, 2011[9] and reply briefs on September 9, 2011. The assigned ALJ submitted the record of this proceeding on September 9, 2011.

2.2. Scope of Proceeding

The scope of this proceeding is a review of the three 2012-2014 DR applications for compliance and reasonableness. The assigned Commissioner and ALJ emphasized in the Scoping Memo that DR is an essential piece of the California energy policy framework and, thus, it is crucial that what we approve in the Applications takes into account not only the policies set in Commission energy proceedings, but the energy policies set across the state of California. Accordingly, DR programs and their associated budgets requested in the Applications have been reviewed in three categories: compliance, reasonableness, and meeting future energy needs, all of which will be discussed in further detail below. Other matters, such as fund shifting, revenue requirement and cost recovery are also included in the scope of this proceeding and addressed in this decision.

In addition to a review of the DR programs, parties brought to light several policy issues requiring attention by the Commission. Some of these issues affect more than one DR program such as cost-effectiveness, baseline methodology, dual participation and bilateral contracts with third party DR

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its reply in Opening Briefs. In comments to the ruling, SDG&E stated that it did not consent to the post hearing evidence being entered into the record. SDG&E has no objection to the inclusion of its data request responses in the record at this time for comment but not evidence. These objections are duly noted.

[9] By e-mail ruling, the ALJ revised the deadline, from August 19, 2011 to August 22, 2011, for parties to submit Opening Briefs.

providers. Other issues look to the future of DR. These include the coordination of DR with California energy policies, the integration of DR programs with CAISO energy markets, and DR market competition.

2.3. Factors Considered in the Review of Applications

As discussed above, the Scoping Memo directed that the programs and budgets requested in the three Applications be reviewed in terms of compliance, reasonableness and meeting future energy needs.

In regards to reviewing the Applications for compliance, the Scoping Memo directed that the Applications comply with any and all directives related to DR, including the August 27, 2010 Ruling (Guidance Ruling.)[10] The Scoping Memo cautioned that while the proceeding will focus on DR-specific directives including the emergency-triggered programs settlement, the analyses will also look to ensure compliance with related directives such as the Resource Adequacy rules. The Scoping Memo also noted that parties should be aware that Commission decisions containing references to DR in general may apply to these Applications, e.g., D.11-01-036 encouraged PG&E to improve the price trigger for its Air Conditioning (AC) cycling program in its 2012-2014 DR application. Furthermore, several Commission proceedings may contain potential overlap, e.g., A.10-09-002, the Dynamic Pricing Proceeding.[11] The Scoping Memo

[10] ALJ Jessica Hecht's August 27, 2010 Ruling (Guidance Ruling) required that: 1) the Utilities' Applications shall conform to the guidelines outlined in the Guidance Ruling, and 2) all requirements for the 2012-2014 Applications made in previous Commission orders, including any not mentioned in this Guidance Ruling, still apply.

[11] We will not, however, review dynamic rates themselves. The Guidance Ruling declares, on page 5, that the DR applications proceeding will focus on price-responsive

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cautioned parties that these proceedings would be monitored for any potential overlap with or impact on this proceeding. As discussed throughout this decision, the Commission is working to ensure that DR policies do not contradict policies in other areas of energy.

In addition, this proceeding will specifically look at the compliance of the cost-effectiveness measurements and inputs. We note that these Applications are the first to use Cost-Effectiveness Protocols (Protocols) developed and adopted by the Commission. Because this proceeding is a first test for the Protocols, it is prudent for us to take this into consideration and remain flexible in our approach to using these Protocols.

As described in the Scoping Memo, this proceeding will evaluate the reasonableness of program and portfolio design in terms of cost-effectiveness, track record, future performance, cost, flexibility and versatility, adaptability, locational value, integration, consistency across the Utilities' applications, simplicity, recognition, environmental benefits and consistency with general Commission policies[12] and policies affecting revenue allocation. We will discuss our review approach to using the Protocols in combination with these factors.

In regards to reviewing the Applications to meet future energy needs, we consider the evolving nature of DR as well as the impact of its evolution on both

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demand response, not dynamic rates. Footnote 5 accompanies this declaration, stating, "The authority to develop and recover costs associated with dynamic rates will be addressed in other proceedings." The Ruling notes that utilities should keep in mind that the proposals should complement dynamic pricing and/or respond to wholesale price signals.

[12] The Commission utilized these identical factors to analyze the 2009-2011 DR applications.

current and future applications. This proceeding considers the adequacy of the DR programs, looking at whether existing and proposed programs and pilots are sufficient to meet California energy goals in light of the changing nature of the energy grid and the 33 percent renewables' requirement.[13] Our review will speak to specific activities including CAISO market integration and DR market competition. In addition, because California energy policies are dynamic, we require continuous monitoring of other Commission and State agencies' energy policies and programs including the California Energy Action Plan[14] and the California Long Term Energy Efficiency Strategic Plan (Strategic Plan) so as to ensure coordination between these policies and DR policies. We discuss these policies in a subsequent section of this decision.

3. Motion of the Division of Ratepayer Advocates

Pursuant to Rule 11.4 of the Commission's Rules of Practice and Procedure, the DRA filed a motion on August 22, 2011 requesting the Commission for leave to file under seal the confidential Attachment A to DRA's Opening Brief. Pursuant to Public Utilities Code Section 583, PG&E designated the information contained in Attachment A as confidential. No party objected to the motion. In accordance with our Rules of Practice and Procedure, we find the motion to be reasonable. We grant DRA's motion to file under seal the confidential Attachment A.

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[13] On April 12, 2011, California Governor Jerry Brown signed Senate Bill X1-2, requiring all California utilities, public and private, to obtain 33 percent of their electricity from renewable sources by the end of 2020.

[14] *Energy Action Plan I*, California Energy Commission, California Public Utilities Commission and Consumer Power and Conservation Financing Authority, May 8, 2003. Available at: http://docs.cpuc.ca.gov/word_pdf/REPORT/28715.pdf

We affirm all other assigned Commissioner and ALJ Rulings in this proceeding. All motions not previously ruled upon or addressed in this decision are denied.

4. California Energy Policies

4.1. Ensuring Effective DR Programs

DR programs are an essential element of California's energy resource strategy. As such, the Commission recognized the need to evaluate and measure the effectiveness of DR programs. After opening a new rulemaking in January 2007, the Commission has since approved load impact protocols[15] and a cost-effectiveness methodology.[16] Currently the Commission is investigating modifications needed to DR programs in order to be eligible for participation in the CAISO wholesale energy market which is discussed in a subsequent section of this decision. However, there remain additional DR policy issues that the Commission must address in order for the DR programs to operate effectively.

4.2. The Strategic Plan

Understanding the need to effect lasting transformation in the market for energy efficiency, the Commission developed the Strategic Plan in September 2008.[17] The Strategic Plan set forth a roadmap for energy efficiency in California through the year 2020. Recognizing the importance of coordination and integration, the Strategic Plan includes, as one of its cross-cutting areas,

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[15] D.08-04-050, adopted by the Commission on April 24, 2008, approved load impact protocols for DR programs.

[16] D.10-12-024, adopted by the Commission on December 21, 2010, approved a cost-effectiveness methodology for DR programs.

[17] Adopted by the Commission on September 19, 2008 in D.08-09-040.

Demand Side Management (DSM) Coordination and Integration.[18] The vision of this cross-cutting area is that energy efficiency and DR (amongst others) are offered as elements of an integrated solution that supports California's energy and carbon reduction goals immediately. The Strategic Plan called for a shift away from single-product DSM approaches to more integrated approaches. These integrated approaches enable offerings of packages that maximize energy savings and improve utility program overhead efficiencies.

The goal of the Integrated DSM (IDSM) cross-cutting sector is to deliver integrated DSM options that include energy efficiency, DR, energy management, and self generation measures through coordinated marketing and regulatory integration. The Strategic Plan lays out three levels of integration: (1) comprehensive and coordinated marketing, (2) program delivery coordination, and (3) technology and systems integration. We used the IDSM portion of the Strategic Plan in our review of the Applications and to provide guidance of future DR applications.

4.3. California Energy Agencies' Policies

In September 2010, the Commission, the California Air Resources Control Board, the California Energy Commission (CEC), the California Environmental Protection Agency, and CAISO jointly unveiled a collaborative plan and vision for California, "*California's Clean Energy Future*." The plan outlines how California will meet its ambitious energy policies and goals for the future including the reduction of California electric consumption. The foundations for

[18] *The California Long Term Energy Efficiency Strategic Plan*, January 2011, can be found at: http://www.cpuc.ca.gov/NR/rdonlyres/A54B59C2-D571-440D-9477-3363726F573A/0/CAEnergyEfficiencyStrategicPlan_Jan2011.pdf.

this plan are the California Loading Order Policy, adopted by California energy agencies in the 2003 Energy Action Plan and reiterated in the Energy Action Plan II,[19] and the energy-sector measures articulated in the California Air Resources Control Board's Assembly Bill (AB) 32 Scoping Plan.[20] The Energy Action Plan II delineates the deployment of cost-effective energy resources to meet California's energy needs and ranks energy efficiency and DR programs first in the "loading order."[21] The Energy Action Plan II emphasized a need for DR programs that result in cost-effective savings and the creation of standardized measurement and evaluation mechanisms to ensure verifiable savings.

Given the extent and ambition of these statewide policies and goals, we reviewed the Utilities' Applications with an eye toward ensuring that the DR programs and policies we adopt today move us toward attainment of these goals.

4.4. CAISO's DR Markets

DR programs are now considered to be an increasing part of CAISO's wholesale market development. Since 2007, CAISO has engaged in substantial efforts to integrate retail DR programs with its wholesale markets. CAISO's

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[19] In 2005, a second Energy Action Plan was adopted by both the Energy Commission and the Commission to reflect the policy changes and actions of the ensuing two years.

[20] Also known as the *California Global Warming Solutions Act of 2006*, AB 32 is the state's roadmap to reach the greenhouse gas reduction of 1990 levels. Reducing greenhouse gas emissions to 1990 levels means cutting approximately 30 percent from business-as-usual emissions levels projected for 2020, or about 15 percent from today's levels.

[21] *Energy Action Plan II* at 3. See http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

efforts are referred to as the Market Redesign and Technology Upgrade (MRTU).[22] The Utilities have worked to develop modifications to their current DR programs to allow the DR programs to be compatible with the CAISO's market products.

In Rulemaking (R.) 07-01-041, the Commission stated that it would consider modifications to DR programs needed to support CAISO's efforts to incorporate DR into wholesale market design protocols.[23] The Commission has been actively working within the CAISO stakeholder process to that end. As part of those stakeholder efforts, CAISO endeavored to design market products where capacity represented by DR can be bid into wholesale markets just as generation resources would do thereby resulting in increased market competition and efficiency. CAISO developed two wholesale market products: (1) Proxy Demand Resource (PDR) and (2) Reliability Demand Response Product (RDRP). PDR enables DR participation as a single resource or an aggregation of resources in the wholesale day-ahead, and/or real-time energy markets as well as the Ancillary Services market. In July 2010, the Federal Energy Regulatory Commission (FERC) approved CAISO's PDR. RDRP enables emergency responsive DR resources to integrate into the CAISO market and operations. It is expected to be implemented by CAISO in 2012.

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[22] MRTU manages transmission congestion and dispatches generation based on a model that will accurately depict available capacity and constraints on the CAISO controlled grid across all market time frames to ensure that market outcomes are consistent with real-time operation of the transmission grid.

[23] http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/64245.pdf.

The Commission has encouraged the Utilities to participate in CAISO's PDR. In 2009, the Commission ordered the Utilities to modify existing DR programs such that at least 10 percent of their DR programs would comply with the requirements of PDR.[24] In December 2010, the Commission authorized the Utilities to operate pilot projects that could participate in PDR.[25]

The Commission has also been working to address another aspect of DR wholesale integration, direct participation in CAISO whole electricity markets. Direct participation is the ability of retail electric customers, either on their own or through an aggregator or third party DR provider, to bid DR directly into CAISO wholesale electricity markets. This is distinct from the efforts described above which had been focused on the Utilities' readiness to bid DR into wholesale markets. In 2009, the Commission opened Phase 4 of R.07-01-041[26] in response to FERC Order 719[27] which required CAISO to allow direct participation if state laws and rules do not prohibit such bidding.

As such, we reviewed the Utilities' Applications in terms of the compliance with Commission and Federal policies encouraging the integration of DR programs into the CAISO market.

5. Summary of the Applications

The Applications submitted by the Utilities include proposed DR activities and programs and lays out DR policies that serve as a foundation for the

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[24] D.09-08-027, Ordering Paragraph (OP) 25.

[25] D.10-12-036, OP 1.

[26] http://docs.cpuc.ca.gov/efile/RULINGS/109611.pdf

[27] *Wholesale Competition in Regions with Organized Electric Markets*, (FERC Order 719) issued October 17, 2008 in RM07-19 and AD07-7.

proposals. The Applications also include budgets for these activities. The following sections briefly describe the proposed Applications, including the budgets, while highlighting a few specific proposals for each utility.

5.1. PG&E (A.11-03-001)

PG&E proposes to continue most of its DR programs from the 2009-2011 budget years and update several of the existing DR programs to create compatibility with CAISO's PDR requirements. For example, PG&E requests modifications to its Base Interruptible Program to enable the program to be bid as a CAISO RDRP. PG&E also proposes to amend several other programs, most notably, combining the Demand Bidding Program with PeakChoice. With these programmatic proposals, PG&E estimates load impacts of 631 megawatts (MW) in 2012, 716 MW in 2013 and 730 MW in 2014.[28] PG&E's Application contains several pilot programs including one to using the Home Area Network (HAN) technology. Although all three utilities had Aggregator Managed Program (AMP) contracts with DR aggregators during the 2009-2011 program years, only PG&E requests a one-year extension of the existing AMP contacts and to issue a competitive solicitation for contracts during 2013 to 2017.

In addition to the above programmatic proposals, PG&E proposes administrative modifications ranging from revising the fund shifting rules to simplifying its cost recovery mechanisms. PG&E requests approval of a DR budget of $234,293,961 for years 2012-2014. PG&E also requests the

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[28] See Appendix B for the load impacts of each DR program.

authorization to provide $84 million in DR customer incentive costs which we approved in D.07-09-004[29] and D.07-05-029.[30]

5.2. SDG&E (A.11-03-002)

SDG&E proposes overarching changes to its DR programs including changing the current Capacity Bidding Program baseline from individual 10-in-10 baseline with an adjustment of a 20 percent cap to an aggregated 10-in-10 baseline with a same day adjustment of a 40 percent cap and prohibiting multiple program participation where both programs provide Resource Adequacy qualifying capacity. As a result of its proposals, SDG&E anticipates an ex ante load impact of 146 MW in 2012, 185 MW in 2013, and 194 MW in 2014.[31] While not requesting authorization for future AMP contracts, SDG&E requests authorization for program payment rates to be guaranteed to the Aggregators for a three-year period.

Administratively, SDG&E proposes that costs related to Information Technology (IT) upgrades for CAISO MRTU be recovered through its MRTU Memorandum Account. Additionally, SDG&E requests the ability to make adjustments to fund shifting rules to allow for greater flexibility. Overall, SDG&E requests a budget of $68,120,000 for years 2012-2014.[32]

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29 D.07-09-004 approved PG&E's customer incentives for the Base Interruptible Program.

30 D.07-05-029 approved PG&E's customer incentives for the AMP contracts.

31 See Appendix B for the load impacts of each DR program.

32 SGE-01, Table MG-3 at MFG-26.

5.3. SCE (A.11-03-003)

As with the other two utilities, SCE also proposes continuation of most of its DR programs from the 2009-2011 budget years with an eye toward incorporating many of these current programs into CAISO's PDR or RDRP requirements. To support CAISO market integration, SCE proposes an Ancillary Services tariff. SCE proposes a new price-responsive Residential Summer Discount Plan, for both legacy and newly enrolled customers. SCE also requests to launch a PLS program. With these programmatic proposals, SCE estimates to increase its load impacts from its current 1530 MW to 1824 MW[33] by 2014[34] with approximately 1,360 MW of its portfolio available to be bid in the CAISO markets with full locational dispatch capability. SCE's application proposes two pilot programs: Smart Charging Pilot and the Workplace Charging Pilot. SCE claims these two pilots facilitate the adoption of new technologies.

In addition to the above programmatic proposals, SCE requests funding in support of its Dynamic Pricing and IDSM programs. SCE requests approval of a DR budget of $229,037,000 for years 2012-2014.[35]

6. Overarching Issues

Before we can make a determination on the approval of DR programs, activities, and budgets requested in this proceeding, we must address several overarching issues. First we must look at utility proposals to decrease the number of DR budget categories and revise the fund shifting rules for those

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[33] See Appendix B for the load impacts of each DR program.

[34] SCE-05 at 19.

[35] SCE-05A, Table IV-21 at 51.

categories. We must also determine our approach to evaluating the cost-effectiveness of DR programs, whether we need to revise our rules for participating in more than one DR program, and whether our method for estimating energy usage is accurate.

6.1. Budget Categories and Fund Shifting Rules

6.1.1. Background

In D. 09-08-027, the Commission provided the Utilities the flexibility to shift funds authorized in the proceeding between DR programs, so that the Utilities could appropriately respond to unexpected events or changing conditions.[36] However, the Commission also said that major funding changes must be subject to Commission review and public comment.[37] Noting that the DR budget process would become meaningless if utilities were able to shift funds without reasonable parameters, the Commission developed rules that provided the flexibility needed by the Utilities without undermining the Commission's regulatory process.[38]

The Commission established ten budget categories for DR programs and activities: 1) Emergency Programs; 2) Price Responsive Programs; 3) DR Service Provider Managed Programs (Aggregators);[39] 4) DR Enabling Programs; 5) Pilots; 6) Statewide Marketing Programs; 7) Evaluation, Measurement and

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[36] D.09-08-027 at 211-212.

[37] *Ibid*.

[38] *Ibid*.

[39] Following the adoption of D.09-08-027, the Commission granted a Petition for Modification by PG&E to move the Capacity Bidding Program from budget category 2 to category 3 to enable a fund shift from the AMP Contracts to the Capacity Bidding Program. See D.10-12-033.

Verification (EM&V); 8) System Support Activities; 9) DR Core Marketing and Research; and 10) Integrated Programs.

Within each of the budget categories, the Commission allows the Utilities to shift up to 50 percent of a program's funds to another program, with appropriate monthly reporting. If a utility wants to shift more than 50 percent of a program's funds to a different program within the same budget category, the Commission requires the utility to first submit a Tier 2 Advice Letter.[40] The Commission also requires the Utilities to submit a Tier 2 Advice Letter if the fund shifting results in the elimination of a program. The Commission prohibits the elimination of any activity or program through multiple fund shifting for any reason without prior Commission authorization.

6.1.2. Utility Proposals

All three Utilities recommend continuing current fund shifting rules. However, the Utilities request the Commission to collapse the ten current budget categories into six categories as listed in the following table.

TABLE 6.1.2			
	Proposed Utility DR Program Categories (Approximate Funding Amount in Millions)		
	PG&E	SCE	SDG&E
Category 1	DR Programs: including reliability, price-responsive, and DR Provider-Managed	DR Programs: including reliability, price-responsive, and DR Provider-Managed	DR Programs: including reliability, price-responsive, and DR Provider-Managed

[40] If associated with the implementation of a new DR program, the fund shift must be requested in the application for approval of the new program.

TABLE 6.1.2			
	Proposed Utility DR Program Categories (Approximate Funding Amount in Millions)		
	PG&E	SCE	SDG&E
	programs ($49.3)	programs ($115.3)	programs ($21.5)
Category 2	Enabling Programs, Pilots, DR Integration Policy and Planning ($53.9)	Enabling Technology, Pilots and Emerging Markets and Technology($59.2)	Enabling Programs, Pilots, DR Integration Policy and Planning ($28.8)
Category 3	EM&V ($15.7)	Technology Integration and Support ($20.6)	EM&V ($5.1)
Category 4	System Support Activities ($41.5)	Measurement & Evaluation (M&E), Load Impacts and Cost Effectiveness ($9.0)	System Support Activities ($7.6)
Category 5	DR Core Marketing and Outreach ($25.3)	Marketing, Education and Outreach (ME&O) ($6.2)	DR Core Marketing and Outreach ($1.1)
Category 6	Integrated Programs ($14.6)	IDSM Programs and Pilots ($18.5)	Integrated Programs ($4.9)

SDG&E alleges that the current ten budget categories isolates programs and severely limits a utility's flexibility.[41] PG&E contends that reducing the number of budget categories from ten to six will provide flexibility between programs with similar goals and will allow utility response to changes in customer enrollment in the various DR programs.[42] By combining Reliability, Price-responsive and third party DR provider-managed programs into one

[41] SGE-01 at MFG-14.

[42] PGE-01 at Ch. 10-C.

budget category, PG&E alleges utilities will be able to transfer funds to programs with highest enrollment and participation, optimize portfolio value, and better align programs with Resource Adequacy rules and changing market needs.[43] SCE argues that the current category structure does not provide the flexibility to make reliability programs price-responsive as directed by the markets and the state's regulatory bodies.[44]

6.1.3. Parties' Positions

DRA, the only other party to provide comment on this issue, opposes the reduction in the number of budget categories. DRA specifically requests that the Commission maintain separate categories for reliability and price-responsive programs.[45] Furthermore, DRA recommends that the Commission categorize PDR and RDRP product programs in separate categories or simply prohibit fund shifting between the two types of programs.[46] DRA suggests that it may be possible to re-categorize some similar programs, if the Commission adopts new fund shifting rules and enhances current rules. For example, DRA proposes that the Commission require Utilities to submit a Tier 2 Advice Letter for approval to increase a DR program budget by more than 50 percent through fund shifting.[47]

6.1.4. Discussion

In D.09-08-027, the Commission addressed the fund shifting issue, including a request by PG&E to approve four budget categories. Recognizing

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[43] *Id.* at Ch. 10-C.

[44] SCE-05 at 49, lines 26-27.

[45] DRA-01 at 1-8.

[46] *Ibid.*

the evolving electricity market, the Commission concluded that some flexibility would be reasonable, so long as that flexibility was balanced with regulatory oversight and public review. Thus, we established the ten budget categories along with rules for fund shifting.

Three years later, the Commission and the Utilities have moved further along the path toward CAISO market transformation which includes transitioning reliability programs to price-responsive programs. While the Utilities continue to stress flexibility as vital to market transformation, the Commission finds oversight and public review equally important. During our review of the Applications, we encountered obstacles to determining the reasonableness of many funding requests. These obstacles emanate from a lack of budget transparency. We agree that flexibility is important to the Utilities, but too much flexibility endangers budget transparency. Such is the case when specific costs that should be located in obvious budget categories are instead sorted into multiple categories or when costs supporting DR programs are requested and approved in separate proceedings, making it difficult to track all DR costs. We also address these issues in greater detail during our discussion of cost-effectiveness.

The Utilities' proposed combination of DR programs and activities creates budget categories that would allow the transfer of millions of dollars between programs in the same category. For example, SCE's proposed "Demand Response Programs" category has a proposed budget of $115.3 million and its Save Power Day program has a proposed budget of $30 million. With SCE's

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[47] *Ibid*.

proposed category consolidation, SCE would be able to shift as much as $15 million from the Save Power Day program to another program listed in this category.

We remain concerned about the potential shifting of large amounts of funding from one program to another. We, therefore, reaffirm our findings in D.09-08-027 that major changes to the relative funding of specific programs must be subject to thorough regulatory review and party comment. The Utilities provide no new information or additional justification in these applications for us to change this general policy. Furthermore, we find that minor revisions of certain budget categories with additional safety provisions as recommended by the parties are reasonable. Therefore, we establish the following refinements to our budget categories and fund shifting rules.

First, we direct the Utilities to organize their DR programs within the following ten categories: 1) Reliability Programs;[48] 2) Price Responsive Programs; 3) DR Provider/Aggregator Managed Programs;[49] 4) Emerging and Enabling Technologies; 5) Pilots; 6) EM&V; 7) ME&O Activities;[50] 8) DR Systems Support; 9) Integrated Programs and Activities (to include Technical Assistance), and 10) Special Projects. We note that while the Commission previously authorized PG&E to categorize the Capacity Bidding Program to the DR Provider category, the purpose for the re-categorization was to allow PG&E to

[48] We renamed the "Reliability" Programs category to be consistent with the change from the term "Emergency."

[49] We previously authorized PG&E and SDG&E to categorize the Capacity Bidding Program in the DR Provider category.

[50] This category combines the Statewide Marketing and DR Core Marketing categories, but does not include IDSM ME&O.

shift funds from the AMP Contracts to the Capacity Bidding Program.[51] While we agree with the necessity of that particular shift, we find it no longer necessary to categorize these two programs together.

As has been Commission practice, Utilities may shift funds authorized in this decision within a category but shall not shift the funds between these 10 categories. We make one exception to this rule. Unlike PG&E and SCE, SDG&E included all DR customer incentives in the 2012-2014 DR Application. Because fund shifting rules in this proceeding are not applicable to PG&E's and SCE's customer incentives approved in other proceedings, we allow SDG&E additional flexibility for funds approved for customer incentives in this proceeding. For these funds only, we grant SDG&E the flexibility to shift the funds between categories through the submittal of a Tier 2 Advice Letter. This provides a level playing field between PG&E, SCE and SDG&E.

The Utilities may continue to shift up to 50 percent of a program's funds to another program within the same budget category, with proper monthly reporting. As recommended by DRA and agreed to by SCE, we require the Utilities to submit a Tier 2 Advice Letter before shifting more than 50 percent of a program's funds to a different program within the same budget category.[52] If a shift of more than 50 percent of a program's funds is necessary as part of the implementation of a new program, the fund shift should be included in the application for approval of the new program.

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[51] D.10-12-033 at 10-11.

[52] DRA-01 at 1-8, lines 19-24 and SCE Opening Briefs at 79.

The Utilities may not shift funds within the "Pilots" or "Special Projects" category without a Tier 2 Advice Letter submission. This will allow the Commission to properly monitor pilots and special projects to determine their efficacy and viability as a future full time program. The Utilities may shift funds for pilots in the Enabling or Emerging Technology category. The Utilities must continue to submit a Tier 2 Advice Letter to eliminate a program. As is the current policy, the Utilities may not eliminate a program through multiple fund shifting events or for any other reason without prior authorization from the Commission.

6.2. Evaluating Program Cost-Effectiveness

6.2.1. Background

In December 2010, following four years of workshops and multiple rounds of comment, the Commission approved D.10-12-024, adopting a method for estimating the cost-effectiveness of DR activities. Most of the parties participating in this proceeding also actively participated in the development of the Protocols. D.10-12-024 required the Utilities to use the Protocols for all future cost-effectiveness analysis of DR programs, including the 2012-2014 applications. The Commission directed the Utilities to use the DR Reporting Template to provide a cost-effectiveness analysis for any program "for which the Utilities are requesting a set budget and for which load impacts can be estimated using the load impact protocols."[53] [54] The Protocols were designed to be used to measure

[53] D.10-12-024 at 44.

[54] Funding for Integrated Demand Side Management activities requested in the 2012-14 app is exempt from cost-effectiveness analysis. The Commission noted that it may issue further guidance for calculating the cost-effectiveness of PLS activities.

the cost-effectiveness of both individual DR programs and a utility's overall DR portfolio.[55]

The Protocols require the Utilities[56] to use the defined versions of the four cost-effectiveness tests from the Standard Practice Manual (SPM)[57] The Protocols explain that "[t]he output of each test is based on the net present value of the costs and benefits, discounted over the lifetime of the relevant DR resource. Hence the costs and benefits are not simply added together to produce the SPM outputs."[58] The Protocols also define costs attributable to a DR program; use the Avoided Cost calculator developed by Energy and Environmental Economics, Inc. (E3)[59] to determine all avoided costs,[60] which are the primary benefits of DR programs; provide detailed instruction about how to determine the value of each cost and benefit; require a sensitivity analysis on specific key variables; and utilize public and transparent methods, models, and inputs. In addition to this

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55 *2010 Demand Response Cost Effectiveness Protocols* (*Protocols*) at 5.

56 The protocols are designed for the three Investor-Owned Utilities, but should be applicable to any Load Serving Entity.

57 The four cost-effectiveness tests are the Total Resource Cost (TRC) test (which measures cost-effectiveness from the point of view of society as a whole), the Program Administrator Cost (PAC) test (which measures cost-effectiveness from the point of view of the utility), the Ratepayer Impact Measure (RIM) test (which measures cost-effectiveness from the point of view of ratepayers) and the Participant Test (which measures cost-effectiveness from the point of view of a program participant).

58 *Protocols* at 14.

59 The E3 Avoided Cost Calculator is a spreadsheet tool developed by the consulting firm, E3, as part of the Distributed Generation Cost-Effectiveness framework.

60 The Protocols allow the Utilities to specify five adjustment factors to the avoided costs. These adjust the avoided generation capacity cost for an individual DR program based on the following factors: "A" - availability of the program; "B" - notification times; "C" - trigger flexibility; "D" – distribution; and "E" – energy price.

quantitative analysis, the Protocols require the Utilities to provide a qualitative analysis of "optional" costs and benefits.

The Protocols do not define cost-effectiveness, rather they defer "[t]he means by which the Commission will use these protocols to determine whether to pursue various DR programs, activities or policies [to]other Commission proceedings,"[61] such as this proceeding. The Commission emphasized that it developed the Protocols with the understanding that DR is in a transitional period.

Our approach to using the Protocols in this proceeding will be flexible to capture the benefits of the emerging change.[62] In this section, we do not provide a final determination of approval of any particular program or activity. That determination will be provided in the chapters discussing the programs and activities. Instead, we discuss how we will use the Protocols in our review of DR programs.

6.2.2. Utility Reported Cost-Effectiveness Results

In its testimony, PG&E asserts that its 2012-2014 DR portfolio is cost-effective because it has a benefit-cost ratio of 1.1 using the TRC test. PG&E provided cost-effectiveness results for individual DR programs[63] and the portfolio using the four SPM tests. PG&E's DR portfolio cost-effectiveness analysis also includes costs attributable to its DR HAN Integration Project,

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[61] *Protocols* at 5.

[62] *Id.* at 4.

[63] PG&E's cost-effectiveness analysis includes the 2012 AMP, Base Interruptible Program, Capacity Bidding Program, PeakChoice (including Demand Bidding Program), SmartAC, and PLS.

Integrated Energy Audit Program, Integrated Technical Incentive Program and Time-of-Use Rates. PG&E provided two separate analyses using two cost-effectiveness models, one using the E3 methodology, and one using PG&E's Loss of Load Probability (LOLP).

SDG&E filed its cost-effectiveness analysis using the Protocols. SDG&E performed its cost-effectiveness analysis on a program-by-program basis, and on the portfolio which included ME&O; EM&V; and Technical Incentives costs. SDG&E provided an explanation of its assumptions for the five adjustment factors required by the Protocols.

SCE provided its cost-effectiveness analysis and asserts to be in compliance with the 2010 Protocols.[64] SCE explained its assumptions for each of the adjustment factors to the E3 inputs.

The following tables show the TRC, PAC and RIM results for each utility's DR programs, as provided by the Utilities. In the case of PG&E, the table includes the results from the E3 Model and PG&E's LOLP model.

TABLE 6.2.2

PG&E	**LOLP**			**Default**		
Program	**TRC**	**PAC**	**RIM**	**TRC**	**PAC**	**RIM**
AMP	1.17	0.99	0.98	0.49	0.42	0.42
Base Interruptible Program	1.45	1.19	1.18	0.90	0.73	0.73
Capacity Bidding Program day-of	1.53	1.38	1.32	1.11	1.00	0.95
Capacity Bidding Program day-ahead	1.01	0.93	0.92	0.73	0.67	0.66
Capacity Bidding Program	1.25	1.15	1.11	0.91	0.83	0.80
Demand Bidding Program	1.10	1.10	1.07	1.09	1.09	1.07
Demand Bidding Program with Peak Choice-Best day-ahead	0.89	0.87	0.85	0.47	0.46	0.45
PeakChoice-Commit day-of	0.66	0.59	0.59	0.34	0.31	0.30

[64] SCE-07 at KCM-1 and KCM 13-KCM-16.

PeakChoice-Commit day-ahead	0.73	0.69	0.67	0.39	0.37	0.36
PeakChoice-Best day-of	0.93	0.91	0.89	0.50	0.49	0.48
PeakChoice	0.72	0.66	0.65	0.38	0.35	0.34
SmartAC-Residential	1.06	1.03	1.03	0.68	0.67	0.66
SmartAC Non-Residential	0.40	0.37	0.37	0.25	0.23	0.23
Smart AC	0.98	0.95	0.95	0.63	0.61	0.61
PLS	0.68	1.84	0.80	0.69	1.86	0.80
Portfolio	0.99	0.92	0.88	0.63	0.58	0.55

SCE			
Program	**TRC**	**PAC**	**RIM**
Summer Discount Plan -- Non-Residential enhanced	1.39	1.13	1.10
Summer Discount Plan -- Non-Residential base	0.78	0.64	0.62
Summer Discount Plan -- Residential	1.26	1.02	0.99
Peak Time Rebate	1.26	1.20	1.08
Demand Bidding Program	0.74	0.71	0.66
Critical Peak Pricing	0.40	0.40	0.40
Capacity Bidding Program day-ahead	0.36	0.33	0.31
Capacity Bidding Program day-of	0.39	0.35	0.34
Base Interruptible Program	1.33	1.01	1.01
Agricultural Pumping Interruptible	1.12	0.88	0.88
Real Time Pricing	0.87	0.88	0.85
Ancillary Services Tariff	1.02	0.84	0.84
PLS	0.77	2.00	0.86
Portfolio	1.15	0.96	0.93

SDG&E			
Program	**TRC**	**PAC**	**RIM**
Base Interruptible Program	0.98	0.82	0.82
Capacity Bidding Program day-ahead	0.69	0.62	0.60
Capacity Bidding Program day-of	0.65	0.58	0.56
Small Customer Technology Deployment	0.62	0.64	0.62
Peak Time Rebate	3.92	5.29	3.60
PLS	0.42	1.45	0.91
Portfolio	1.20	1.22	1.10

Portfolio (without Peak Time Rebate)	0.62	0.60	0.57

6.2.3. Parties' Positions

DRA argues that the Commission should require the Utilities to demonstrate a need for any DR program before the Commission contemplates the cost-effectiveness of these programs. Once this threshold question is answered, DRA recommends that the Commission not approve any program where the TRC benefit cost ratio is less than 1.0, unless the cost structure of the program can be changed to bring the TRC benefit cost ratio to at least 1.0. To improve the cost-effectiveness of certain programs, DRA provides some specific cost-cutting measures and other program modification recommendations, including revising SDG&E's "A Factor"[65] so that it is based on 250 hours,[66] as recommended in the E3 default method. DRA requests that the Commission use PG&E's cost-effectiveness analyses that uses the E3 default method, rather than PG&E's LOLP, because 1) the LOLP was completed in 2006 and is therefore outdated, and 2) the LOLP does not conform with the Protocols because it is confidential and uses proprietary software.

CLECA contends that the Commission should determine the cost-effectiveness of a program using all applicable data. Asserting that the Commission should consider the value of stability in a DR program and balance the value of that stability with any cost-effectiveness variance over time, CLECA

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[65] The A Factor is intended to represent the portion of capacity value that can be captured by the DR program based on the frequency and duration of calls permitted. A program that can be "called" in every hour that a generation capacity constraint might be experienced by a utility would have an A Factor of 100 percent.

[66] SDG&E used an A Factor based on 100 hours.

claims that in the case of the Base Interruptible Program and the Demand Bidding Program, the policy of only counting a load once has a negative impact on the cost-effectiveness of these two programs because of the number of dually-enrolled customers. CLECA recommends several specific program modifications to improve cost-effectiveness, but notes that many inputs used to determine cost-effectiveness are out of the control of DR customers, i.e., weather and the economy. One recommendation is that SCE should amortize its Automated DR (ADR) program costs. CLECA also contends that the cost of transitioning some DR programs into CAISO markets is unknown, and thus the cost-effectiveness of certain programs such as the Demand Bidding Program and Peak Choice is unknown.

CAISO concludes that the Commission should require DR programs and activities to be "reasonable, competitive, and cost-effective on their own merits."[67] CAISO recommends that the Commission require the Utilities to adjust certain program aspects to ensure that each program is cost-effective. Furthermore, CAISO suggests that the Commission not permit bundling of programs with cost-effectiveness results of less than 1.0 with other programs in order to improve the overall cost-effectiveness results.

TURN's comments focus solely on SCE's Application. TURN contends that SCE failed to include in its cost-effectiveness analysis all costs associated with DR programs and the DR portfolio. By excluding the IT costs and amortized costs for several DR programs, TURN asserts that the Commission has

[67] CAISO Opening Briefs at 4.

incomplete data to review the cost-effectiveness of SCE's DR programs and portfolio.

6.2.4. Discussion

The Commission recognizes that this is the first time the Protocols are used in a DR application to evaluate the cost-effectiveness of DR programs. As stated in D.10-12-024 and in the Scoping Memo, the Commission will allow for a transition period for using these Protocols. But, as required by D.10-12-024, we use the Protocols in reviewing the 2012-2014 DR applications.

Below, we discuss the cost-effectiveness analysis models and inputs, as well as the degree of flexibility we should allow in approving DR programs. We then put forth our approach to how we will use the Protocols to review the 2012-2014 DR applications. We also address deficiencies in the Protocols.

First, however, we address DRA's contention that the Commission should require the Utilities to demonstrate a need for any DR program before the Commission contemplates the cost-effectiveness of the DR programs. The Energy Action Plan II states that cost-effective energy efficiency and DR are the primary way we will meet California's electricity demand. Furthermore, under Public Utilities Code Section 454.5(b)(9)(C) utilities are required to first meet their "unmet resource nees through all available energy efficiency and demand reduction resources that are cost-effective, reliable, and feasible." The Commission remains committed to the Energy Action Plan's loading order whereby energy efficiency and demand response are the preferred means of meeting California's energy needs. As such, we review the DR programs to ensure that the DR resources we approve in this decision are a more cost-effective alternative to the utility procurement of supply-side resources.

6.2.4.1. Models and Inputs to the Protocols

6.2.4.1.1. PG&E'S Use of Alternative LOLP Model

PG&E contends that the Commission should reject DRA's argument to use PG&E's default cost-effectiveness analysis (which uses the E3 model to determine the A factor and monthly capacity allotment), rather than PG&E's alternative cost-effectiveness analysis (which use PG&E's LOLP model to determine those quantities). DRA asserts that the LOLP model does not comply with the Protocols' requirement that the model be shared in the public domain and independently verifiable.[68] DRA also states that the Commission should consider PG&E's LOLP model outdated because of changes in generation capacity since the LOLP data has not been updated since 2006.[69]

Arguing against DRA's claim that using the LOLP violates the Protocols, PG&E maintains that the Protocols allow the Utilities to use their own LOLP models in addition to the E3 default model.[70] While DRA accepts that an alternate model is permitted, DRA contends that the Commission required such a model to have the ability to "be shared in the public domain, along with sufficient documentation of their derivation to allow them to be verified independently."[71] PG&E refutes this claim with the testimony of PG&E witness William H. Gavelis who testified that no party requested access to the model.[72] PG&E states that the fact that the parties did not ask to verify the model does not

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[68] D.10-12-024, Attachment 1 at 23.

[69] DRA-01 and DRA-01c at 2-6.

[70] PGE-08 at 9-4.

[71] D.10-12-024, Attachment 1 at 23.

[72] Tr. Vol. 1, 42:21-26 (PG&E/Gavelis).

indicate that the model is not verifiable. DRA counters PG&E's claim by stating that allowing any utility to use proprietary models would be contradictory to the Commission's efforts, as stated in the Protocols, to use consistent and transparent inputs for any cost-effectiveness analysis.

In opposition to DRA's claim that the LOLP model is dated, PG&E states "[i]ncreases in forecast capacity since 2006, combined with a decline in forecast load due to the recession would certainly push out the year when generation supply and system load would be in balance, i.e., the year that a new LOLP study would model."[73] However, PG&E asserts that "it is not obvious, *a priori*, that a newer LOLP study would increase the number of LOLP hours in a year, and thereby decrease DR cost-effectiveness, as DRA suggests."[74]

While we agree that PG&E's use of the LOLP model is consistent with the Protocols authorization of an alternate model in addition to the default E3 model, we note that PG&E provided no evidence that the LOLP model is more accurate than the default E3 model. PG&E argues that the Protocols call the utility LOLP studies "more theoretically robust" than the E3 Model.[75] Despite this statement, the Protocols consider the E3 approach one that "properly place[s] more emphasis on the hours of the year when system demands are the highest."[76] Furthermore, the Protocols conclude that in regard to the E3

73 PGE-08 at 9-3.

74 *Ibid*.

75 D.10-12-024, Attachment 1, 2010 Cost-Effectiveness Protocols at 23.

76 *Ibid*.

approach, "the advantage of simplicity and transparency outweigh[s] the advantages of proprietary traditional LOLE/LOLP models."[77]

We agree with DRA that the LOLP model used by PG&E is not in compliance with the Protocols because as the Protocols themselves point out the LOLP model is proprietary. Furthermore, we also agree that the LOLP model is out of date for use in this proceeding. PG&E testified at the hearings that they believe the LOLP results have not changed much since 2006, but it has not performed a complete analysis to justify this assertion.[78] While PG&E claims that there is no evidence that an updated LOLP analysis will result in lower LOLP, PG&E admits that changes have occurred since 2006 potentially impacting the outcome of an LOLP.[79] By definition then, the probability that the system will experience loss of load will likewise change.

We will continue to allow the use of alternate models as directed by the Protocols but require the Utilities to provide an analysis of why an alternate model is preferable over the default. For the reasons discussed, we will only consider the E3 model results when reviewing PG&E's cost-effectiveness analyses in this proceeding.

6.2.4.1.2. Costs Considered In DR Cost-Effectiveness Analysis

SCE disagrees with TURN's assertion that the DR Protocols require the Utilities to incorporate costs from other proceedings when performing a cost-effectiveness analysis on either a DR program or the DR portfolio. TURN

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[77] *Ibid*.

[78] Tr. Vol.1, at 88-89:12-28 and 1-17.

[79] *Ibid*.

states that the decision adopting the Protocols requires that the administrative costs of each program include all costs attributable to the program, including costs in a separate budget category.[80] SCE counters that the Protocols do not require the cost-effectiveness analysis to include related costs from other proceedings, explaining that if the Protocols required utilities to include all related costs from any proceeding, it would not have used the term "budget category."[81]

In amended testimony regarding the cost-effectiveness of the portfolio, SCE states that its DR cost-effectiveness analysis takes into account DR-related costs from other proceedings.[82] SCE also asserts that the benefit cost ratio for all of its programs will improve to make them cost-effective if the "external" costs such as ADR, EM&V, and ME&O, which the Commission ordered to be added to each of their DR programs' administration costs, are eliminated. We cannot eliminate these costs, because the Commission requires their inclusion. D.10-12-024 concluded that "it is reasonable…to ensure that all costs attributable to a program, including administrative and other costs that may not be captured in the program's budget, are included in the cost-effectiveness of each program.[83] We add that SCE failed to include ME&O costs and misallocated EM&V costs in its cost-effectiveness analysis. The ME&O costs were included in SCE's cost-effectiveness analysis of the portfolio, but not in the analysis of the individual programs.

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[80] D.10-12-024 at 22.

[81] SCE-07 at 10:18-28.

[82] SCE-05 at 45:17-21.

[83] Protocols D.10-12-024 at Conclusion of Law 11.

D.10-12-024 lists capital costs to utilities or participants as one of the major costs defined in the Protocols.[84] We disagree with SCE's interpretation of the Protocols requirement regarding costs and reaffirm that all costs directly attributable to a DR program or activity should be included in the cost-effectiveness program analysis, whether the cost is included in that program's budget or not. If the Commission allowed the Utilities to include and exclude the cost of an activity as they deem fit, we would never know the true costs of a program. We will utilize SCE's cost-effectiveness analysis that included all the costs attributable to each DR program, including the costs of activities such as ME&O, and IT costs approved in other proceedings, and the CLECA suggested amortization of ADR.[85] We note however, that SCE is correct in that these costs should be amortized over the lifetime of the investment, and the annual costs applied to those years that the cost-effectiveness analysis covers.[86]

6.2.4.2. Using the 2010 Protocols in Program Analysis

First, we note that the Utilities filed several versions of their DR Reporting Template spreadsheets, which contain their cost-effectiveness analyses. For each utility, we base our analysis upon the most recent version of the DR Reporting Template spreadsheets.[87] For the reasons discussed above, we rely upon PG&E's cost-effectiveness analysis using the E3 default method and SCE's cost-effectiveness analysis using the spreadsheet "CLECA+TURN".

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84 *D.10-12-024Id*. at 34.

85 Submitted as part of SCE-08, "SCE DR Reporting Template – TURN Scenario."

86 *Protocols* at 29.

87 PGE-18, SGE-12, and SCE-08, Spreadsheet "CLECA+TURN".

The Scoping Memo for this proceeding discusses the cost-effectiveness measurements and inputs as well as eleven other factors to consider when reviewing the DR applications.

> [T]his proceeding will specifically look at the compliance of the cost-effectiveness measurements and inputs. Scoping Memo at 7.
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> We "will evaluate the reasonableness of program and portfolio design, measured in terms of cost-effectiveness, track record, future performance, cost, flexibility and versatility, adaptability, locational value, integration, consistency across the Joint Applicants' applications, simplicity, recognition, environmental benefits, consistency with Commission policies and general policies affecting revenue allocation." Scoping Memo at 8.

SCE quotes the scoping memo's reference to other factors that should be considered in approving DR programs and activities.[88] DRA argues that several factors listed in the Scoping Memo are already taken into consideration using the Protocols: track record, costs, flexibility and versatility, locational value, and environmental benefits.[89] We agree with DRA that these factors are considered in the Protocols. In fact, we find that the Protocols also consider adaptability and consistency across the applications. Having included most of the factors in the adopted Protocols already; we will rely heavily on the Protocols in considering the reasonableness of a DR program and its proposed budget.

Parties provide several options for using the Protocols to determine whether DR programs should be approved. Both PG&E and SCE convey a belief that the Commission should approve an entire DR portfolio if the TRC is above 1.0. PG&E concludes that because the TRC benefit cost ratio for its DR Portfolio

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[88] SCE Opening Brief at 21.

[89] DRA Opening Brief at 5.

resulted in over a 1.0, the portfolio is cost-effective.[90] In comments, SCE contends that under D.10-12-024, its DR portfolio with a TRC result of 1.15 should be approved in total. SCE also argues in comments that the TRC should be the test when evaluating DR cost-effectiveness. Alternatively, DRA recommends that DR programs be reviewed individually and that the Commission consider rejecting funding for DR programs that are not cost-effective based on E3's 250-hour methodology.[91]

We reiterate that the Protocols do not dictate how the Commission should use the results of the cost-effectiveness tests to approve DR programs. While the Protocols require the Utilities to provide a cost-effectiveness analysis of the entire DR portfolio in addition to each DR program, neither D.10-12-024 nor the Protocols say that a DR portfolio with a TRC above 1.0 is deemed cost-effective and should be approved. We agree with DRA that we should review the cost effectiveness of each program individually, as was the practice in D.09-08-027.[92] Moreover, we found it difficult to define the parameters of the DR portfolio in this proceeding. Because there are a number of DR activities which are approved in separate proceedings, it is challenging to determine exactly what the DR portfolio contains. We reviewed the portfolio cost-effectiveness analyses only as a general guideline and advisory tool.

In a discussion regarding its intended use, the Protocols explain that approval of DR programs will include "all types – event-based and non-event

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[90] PGE-01 at 9-4.

[91] DRA Opening Brief at 2-7.

[92] D.09-08-027 at 18-19.

based, price-responsive and emergency, day–ahead and day-of."[93] Furthermore the Protocols may also be to determine the cost-effectiveness of a rate program, such as Critical Peak Pricing.[94] Thus we will review the cost-effectiveness of each individual DR program including subprograms.

The Protocols do not constrain the analysis of a program's cost-effectiveness to review only the TRC results. Otherwise, why would the Protocols require submission of the other tests?[95] In comments, SCE claims that it is Commission practice to use the TRC to determine cost-effectiveness. We disagree with SCE's claim. In D.09-08-027, the Commission stated that although the TRC is cited throughout that decision, all four tests were considered in the cost-effectiveness review.[96] In the current proceeding, we focus our analysis on the benefit to cost ratios for the TRC, PAC, and RIM, as each provide a valuable perspective.[97] Because participation in DR programs is voluntary, we do not consider the Participant Test in our analysis for this proceeding.

The Protocols state that "flexibility in the application of these protocols may be necessary to fully reflect the attributes of some DR programs.[98] We conclude that the Protocols allow us to be flexible in our approach to analyzing cost-effectiveness for DR programs. We have taken the parties' various options

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[93] *Protocols* at 5.

[94] *Ibid*.

[95] D.10-12-024 at OP 1.

[96] D.09-08-027 at 19.

[97] D10-12-024 at Conclusion of Law 8 states that "[t]he relative weight given to any Standard Practice Manual test in determining program approval or modification should be determined within the demand response budget proceedings."

[98] *Protocols* at 6.

into consideration, as well as an appropriate degree of flexibility given to us by the Protocols, and developed the following transitional approach for reviewing DR programs for the set of applications in this proceeding. Furthermore, we do not consider this transitional approach to be precedential for future DR application proceedings or any other proceedings that discuss cost-effectiveness.

First, for any program for which the three tests differ by more than 20 percent, we will examine the reason for this difference and determine which of the tests provides the most reasonable analysis of that program. We find that the flexibility called for by the Protocols gives us the ability to make this determination.[99]

As we previously explained, we reviewed the TRC, PAC, and RIM results for each of the DR programs. We found that nearly none of the DR programs have results equal to or greater than a 1.0 for all three of the tests. While we affirm that the Commission should approve cost-effect DR programs, we again acknowledge the flexibility called for in the Protocols and use the following criteria to evaluate the DR programs proposed in this proceeding:

1. Where at least two of the TRC, PAC, or RIM test results are 0.9 or higher, we consider these programs to be "cost-effective". We utilize a 0.9 result as opposed to a "perfect" 1.0 result to allow for flexibility and the recognition that the sensitivity analysis[100] contained in the Utilities' DR spreadsheets indicates that the benefit cost ratio would be greater than one with a reasonable error in the value of key variables. This also allows for a benefit of

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[99] *Protocoals* at 4.

[100] The sensitivity analysis on key variables provides a sense of the impact of any error in the calculation of the major inputs driving the final results of the analysis. See also D.10-12-024, Findings of Fact (FOF) 14.

the doubt during this first use of the Protocols without compromising the integrity of the Protocols.

2. Where at least two of the cost-effectiveness test results are between 0.5 and 0.9, we consider these programs to be "possibly cost-effective". These are programs that, given variations as shown by the sensitivity analyses or small program modifications, could be cost-effective. We discuss the "possibly cost-effective" programs under the appropriate program category. Within that discussion, we provide modifications to these programs to improve their cost-effectiveness. In most cases, the modifications consist of required or recommended budget decreases.
3. Where two or more of the test results fall below 0.5, we consider these programs to be "not cost-effective". We will discuss the consequences of these programs under the appropriate category.

6.2.4.3. Deficiencies in the Protocols

Because this is the first time that the Protocols are being used to determine the cost-effectiveness of DR programs, it is not surprising that our analysis uncovered several deficiencies in the Protocols. While the Commission was able to perform its review of the cost-effectiveness results, the deficiencies made it challenging. Correcting the deficiencies will improve the Protocols for the future. We describe these deficiencies below and direct the Energy Division to hold workshops to address and develop cures for the deficiencies.

First, the Protocols provide five factors to be used by the Utilities to adjust a DR program's avoided costs, based on specific program characteristics. The Protocols allow the Utilities flexibility in determining the exact level of those adjustments. However, the results are inconsistent and sometimes based on speculation. For example, for the statewide Capacity Bidding Program, PG&E uses 67 percent for the value of the A factor, SDG&E uses 42 percent, and SCE uses 39 percent. While we gave the Utilities flexibility in selecting the A factor, the wide differences in the A factor between the Utilities are unreasonable given that the Capacity Bidding Program is available the same number of hours for each utility. As a result of these differences, the Capacity Bidding Program is "possibly cost-effective" in SDG&E and PG&E's service areas, but "not cost-effective" in SCE's service area. The A factor should be more consistent across the three utilities. The Energy Division should work with the parties to review the five factors in the Protocols in order to provide better guidance to the Utilities in future applications.

Second, the Utilities were asked to allocate the budgets of supporting programs such as ME&O, EM&V, and IT etc. to each DR program, based on how those budgets are used to support programs or based on the total program budget. Each of the Utilities has a slightly different approach to this allocation and thus the allocations are not consistent across the Utilities. This inconsistency makes it challenging to analyze the allocations. The Commission provided prior guidance regarding our expectations for these allotments. The Utilities need clarification regarding budget allotment procedures.

Third, the Protocols require the Utilities to provide qualitative analysis of "optional" costs and benefits.[101] The Utilities did not comply with this directive. We remind the Utilities that a qualitative analysis will assist us in determining whether actual quantitative values for currently unquantifiable factors can or

[101] D.10-12-024 at 24-25.

should be included in potential future updates.[102] The Utilities require a better understanding of what the Commission expects in a qualitative analysis.

In a prior discussion above, we noted that it is difficult to define the DR portfolio. Because there are a number of DR activities which are approved in separate proceedings, it is challenging to determine the contents of the DR portfolio. The Protocols should be updated to include a definition of what is in the portfolio and the process to determine the costs and benefits of its contents.

As we explained in D.10-12-024, in order to ensure that the specific inputs and assumptions contained in the Protocols are accurate and current, the Energy Division should hold workshops to validate and update the models. We find that workshops are necessary to address the cost-effectiveness issues that we have discussed here as well as other issues that parties believe will result in improvements to the Protocols. We direct the Energy Division to solicit input from parties to determine an agenda for the Protocols workshops and hold workshops beginning in the first 60 days after the issuance of this decision to discuss these issues.

6.3. Dual Participation Rules

In D.09-08-027, the Commission revised its policy of not permitting participation in more than one DR program or dynamic pricing tariff. Recognizing that limiting such dual participation could also limit the amount of peak load reduction achieved, we adopted the following rules on dual participation:[103,104]

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[102] *Id* at 25.

[103] D.09-08-027 at 152-153 and OP 30.

a) Prohibit duplicative payments for a single instance of load reduction or drop. (In the case of simultaneous or overlapping events called in two programs, a single customer enrolled in those two programs shall receive payment only under the capacity program, not for the energy payment programs.)

b) Allow dual participation in up to two DR activities, if one provides energy payments and the other provides capacity payments.

c) Prohibit participation in two day-ahead programs or two day-of programs.

Currently, dual participation is permitted in up to two of the following programs: Base Interruptible Program and Critical Peak Pricing,[105] AMP and Demand Bidding Program or Capacity Bidding Program.[106]

In D.09-08-027, we anticipated that the Commission would re-evaluate these rules to determine their effectiveness in promoting program participation, increasing available DR load reduction, and avoiding instances of duplicative payments and gaming.[107]

6.3.1. Utility Proposals

PG&E proposes to simplify the current dual participation rules and reduce the number of programs available for dual participation from seven to

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[104] The Commission required the Utilities to implement theses rules between January 1, 2010 and May 1, 2010 pursuant to D.09-08-027 at 155.

[105] The Commission considers Critical Peak Pricing an energy payment program.

[106] PG&E provided its current dual participation matrix in Exhibit PGE-01, Appendix 2A.

[107] In its 2009-2011 DR budget application, SCE also recommended re-evaluating dual participation requirement in 2012 (A.08-06-001 et al., Exhibit 2. Also see D.09-08-027 at 141).

four: 1) Peak Day Pricing day-ahead (Energy), 2) Base Interruptible Program day-of (Capacity), 3) PeakChoice/Demand Bidding Program day-ahead (Energy), and 4) Optional Bidding Mandatory Curtailment Program.[108] PG&E contends that simplified rules will reduce implementation efforts and ratepayer costs. PG&E recommends the following rules in order for a customer to participate in two DR programs:[109]

a) One program must be a capacity-based DR program and one must be an energy-based DR program (as established in D.09-08-027);

b) One program must be a day-ahead DR program and one must be a day-of DR program (as established in D.09-08-027);

c) One program must be an emergency or reliability program and the other must be a price-responsive program; and

d) Both programs must be offered by the same DR provider.

Alleging that dual participation is not allowed in CAISO markets at this time, SCE proposes that the Commission wait to modify the current dual participation rules until after it finalizes the rules for direct participation in the CAISO markets. SCE expresses concern that if the current rules are eliminated, the "current dual participants in [the Demand Bidding Program] and [the Base Interruptible Program] would be forced to choose between [the Demand Bidding Program] and [the Base Interruptible Program]; which likely all would select [the Base Interruptible Program]."[110] However, in its General Rate Case (GRC) Phase

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108 PGE-08, Chapter 2, Table 2-1 at 2-8.

109 PGE-08, Chapter 2 at 2-7.

110 SCE-07, Chapter VI at 34, lines 17-18.

2 (GRC 2) application,[111] SCE proposes the prohibition for dual participation in its Summer Discount Plan and Save Power Day Incentive Program.[112] SCE claims that the administrative burden along with potential customer confusion outweighs the incremental impacts.[113]

SDG&E alleges that the frequency and magnitude of DR program overlap warrant a review of the dual participation rules. SDG&E notes that in 2009 it experienced a 50 percent overlap between default Critical Peak Pricing and Capacity Bidding Program day-of events and in 2010 it experienced a 100 percent overlap for the same events.[114] To alleviate this problem, SDG&E proposes two solutions. First, it recommends Critical Peak Pricing customers be precluded from participating concurrently in the Capacity Bidding Program or the Base Interruptible Program. Secondly, recognizing the economic burden this would place on third party DR providers, SDG&E offers an alternative to dual participation that it asserts creates "a viable business model" for third party DR providers. SDG&E suggests that Utilities offer third party DR providers who offer DR services to ADR-equipped Critical Peak Pricing customers both a monthly capacity payment and a Critical Peak Pricing day-of incentive. SDG&E contends this alternative would increase the available customer base for third party DR providers, provide a tool to maximize customers' Critical Peak Pricing benefits and minimize costs, and leverage the ADR technology for day-of events when needed. SDG&E surmises that these benefits are achievable without the

111 A.11-06-007 filed on June 6, 2011.

112 Previously known as Peak Time Rebate program.

113 SCE-07, Chapter VI at 34, lines 9-11.

114 SGE-01, Ch. 1 at MFG-7.

concern of double counting resource adequacy in resource plans or double payments for that capacity.[115]

6.3.2. Parties' Positions

CAISO opposes PG&E's proposed rules that allow dual participation in both the Base Interruptible Program and PeakChoice because both programs will be participating in the CAISO's RDRP product and PDR product.[116] As discussed above, under its current rules for PDR and proposed rules for RDRP, CAISO does not allow dual participation between PDR and RDRP and within PDR.[117]

DRA proposes the elimination of all current dual participation rules. DRA contends that the Commission should no longer permit dual participation for DR programs that are transitioning to the CAISO wholesale market, because CAISO does not allow dual participation of the same resource for its DR wholesale products.[118]

DR Aggregators oppose DRA's proposal of eliminating dual participation in DR programs. DR Aggregators contend that DRA's recommendation is flawed in that it is premature, inconsistent with Commission policy, fails to consider consequences to customers, increases market uncertainty, and may not accurately reflect how the Utilities intend to dispatch their retail programs to

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115 SGE-01, Ch.1 at MFG-8.

116 CAISO Protest at 7.

117 Pending FERC approval.

118 DRA-01, Chapter 1 at 1-16, lines 25-29.

participate in RDRP and PDR.[119] CLECA also opposes DRA's proposal because it maintains that CAISO does permit dual participation in RDRP.[120]

NAPP submits that "(t)he Commission's dual participation options adopted in D.09-08-027 should be expanded by permitting customers to participate in any combination of day-of or day-ahead programs subject to the limitation of one capacity and one energy program for a specified delivery period."[121]

6.3.3. Discussion

6.3.3.1. Compliance

All three utilities executed the dual participation rules by the summer of 2010. Thus, the Utilities are in compliance with D.09-08-027 for implementing dual participation.

6.3.3.2. Reasonableness

As previously discussed, we anticipated reevaluating the current dual participation rules to determine the effectiveness in promoting program participation, increasing available load reduction, and avoiding instances of duplicative payments and gaming. We note that neither the Utilities nor the parties provided explicit analysis on the effectiveness of dual participation in promoting customer participation. The Utilities' testimony implies that DR customers did not have to decide on one program over another under the current

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[119] DAG-02, Chapter II, at II-2, lines 8-14.

[120] CLE-01, Q&A 20 at 21-22 and CLE-02, Q&A 6 at 3.

[121] NAPP Opening Brief at 2.

dual participation rules. We find that, as was our intention, the rules have promoted customer participation.

SDG&E provided an analysis showing that dual participation did not effectively increase load reduction due to overlapping events between programs.[122] As we noted previously, all four SDG&E Critical Peak Pricing day-ahead events in summer 2010 overlapped with Capacity Bidding Program day-of events. PG&E also provided data that showed a test event for its Base Interruptible Program on August 24, 2010 partially overlapped with its Peak Day Pricing day-ahead event.[123] SDG&E and PG&E's experiences were contradictory to our previous understanding that day-of events generally do not overlap with day-ahead events. Although the Utilities complied with Dual Participation Rule a) and structured their tariffs in a way to avoid duplicative payments for the overlapping events, we find that this rule did not effectively increase load reduction.

We recognize that allowing dual participation in a capacity payment program and an energy payment program, as defined under the current dual participation rules, could result in both a loss of resource adequacy capacity value and double payment of resource adequacy resources. In our review of the Utilities' 2010 and 2011 load impact reports, we found that all three Utilities removed, from their resource adequacy counting, the incremental load impact from dual participants. The Utilities explicitly excluded the load impacts from dual participants in energy payment programs (e.g., Peak Day Pricing, Critical

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[122] SGE-01 at MFG-6, Table MFG-1.

[123] PGE-01, Appendix 8A-E, Table 2.

Peak Pricing, and the Demand Bidding Program), even though these programs have a capacity element and are eligible for resource adequacy. Customers in these energy payment programs receive the incentive payments in the non-overlapping events. Dual Participation Rule b) should eliminate potential double-counting when DR events overlap.[124] However, not counting these megawatts for resource adequacy would result in double payment of resource adequacy resources if the DR events for the two programs had not overlapped.

For example, SCE currently has customers dually enrolled in the Base Interruptible Program and the Demand Bidding Program.[125] SCE had nine Demand Bidding Program events in 2010[126] with an ex post load impact of 60.6 MW.[127] None of the Demand Bidding Program events overlapped with the Base Interruptible Program events.[128] SCE estimated about 71 MW for its Demand Bidding Program in 2012, but only counted 12 MW for its 2012 resource adequacy qualifying capacity.[129] SCE had excluded 59 MW to avoid potential double counting if the Demand Bidding Program and the Base Interruptible Program events had overlapped. Unless SCE pays its Demand Bidding Program

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124 It is difficult to predict whether future DR events will overlap, thus the Utilities remove the load impact from the energy payment program for resource adequacy counting purposes.

125 Base Interruptible Program has a capacity payment and Demand Bidding Program has energy payments. Both programs are eligible as resource adequacy.

126 SCE's 2011 April Load Impact Report, Table 4-1 at 16.

127 IOUs DR Program Workbook served on July 13, 2011 pursuant to the ALJ's request.

128 SCE did not call any events for Base Interruptible Program in 2010.

129 SCE's 2011 April Load Impact Report, Table B-2 at 36 and Table D-2 at 58.

customers an incentive based on avoided energy costs, SCE would have to procure resource adequacy resources for the 59 MW and simultaneously pay customers an incentive based on resource adequacy capacity value.

Dual Participation Rule b) which allows for energy and capacity payment dual participation, should address this concern because an energy payment program should only be based on avoided energy costs and not have any capacity value. Such a program would not provide any resource adequacy capacity value. We specifically categorized Critical Peak Pricing as an energy payment program versus a capacity payment program with the hope that it would increase customer participation and load reductions. SDG&E's experience shows that while such categorization may increase participation, it did not effectively increase load reduction. SDG&E proposes that the "Commission should prohibit multiple program participation where both programs provide resource adequacy qualifying capacity."

Rule b), as currently written presents two problems. If both program events overlap, dual participation does not effectively increase load reduction. If the events do not overlap, the utility could experience double payment and ultimately an impact to the cost-effectiveness of dual participation. While the purpose of dual participation is to promote customer participation and increase load reduction, we will not do so at the expense of cost-effectiveness. We agree with SDG&E that we should not allow dual participation in two DR programs where both programs provide resource adequacy qualifying capacity. An energy payment program that provides resource adequacy qualifying capacity has an embedded capacity element. The revision in the rules reinforces the current rule between capacity payment and energy payment programs.

6.3.3.3. Meeting Future Needs

As directed by the Scoping Memo, we have reviewed our Dual Participation rules to ensure coordination with other State Energy Agencies' policies to meet California Energy needs in the future.

Following adoption of the Commission's rules on dual participation, CAISO developed rules for its PDR and RDRP products, wherein it prohibits dual participation of one resource bidding into both products or within the two products.[130] We agree with DRA that the integration of the Utilities' retail DR programs into the CAISO market presents problems.

CAISO points out that PG&E's proposed dual participation for its Base Interruptible Program and PeakChoice violates CAISO's dual participation rules because the Base Interruptible Program will participate in RDRP and PeakChoice in PDR. We, therefore, reject PG&E's proposed modification requiring one program to be a reliability program and the other a price-responsive program. CAISO clarified that "PG&E's customers could participate in both the Base Interruptible Program and PeakChoice 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."[131] This would be complicated for customers in PG&E's PeakChoice program who dual participate in the Base Interruptible Program because PeakChoice participates in PDR and the Base Interruptible Program can be bid into RDRP. To resolve this, we revise our rules to allow dual participation

[130] With the exception of RDRP day ahead and Real Time markets.

[131] CAISO's Protest, April 1, 2011 at 7-8.

in a capacity and energy program if both programs are bid into the CAISO wholesale DR markets and dual participation is allowed by the CAISO rules.

To be further consistent with CAISO, we adopt PG&E's proposed modification that requires that dual participation can only occur in programs provided by the same provider. However, we will not eliminate dual participation completely because CAISO permits it between RDRP between day-ahead and day-of markets.

6.3.3.4. Revised Dual Participation Rules

To address the above issues, we adopt the following revised dual participation rules for cost-effective DR programs:[132]

a) Prohibit duplicative payments for a single instance of load drop. In the case of simultaneous or overlapping events called in two programs, a single customer account enrolled in the two programs shall receive payment only under the capacity program, not the energy payment program.

b) Allow dual participation in up to two cost-effective DR activities, if one provides energy payments *based on avoided energy costs without any explicit or implicit capacity elements* and the other provides capacity payments.

c) Prohibit participation in: 1) *two DR programs that provide resource adequacy qualifying capacity value with the exception of dual participation between the Base Interruptible and Demand Bidding Programs*; 2) *two DR programs that bid in CAISO's wholesale DR products that are prohibited under the CAISO rules*; and 3) two day-ahead DR programs or two day-of DR programs.

d) *Require that the two programs are offered by the same DR Provider.*

[132] Changes from the current rules are italicized.

We share the DR Aggregators' concerns regarding the potential impacts to customers who are currently enrolled in two DR programs after the Utilities implemented the dual participation rules only one summer ago. We will allow 2012 as a transition year for these customers to decide on which program they would like to stay. The new rules will apply to all new customers starting 2012 and existing customers in 2013. Furthermore, we direct Energy Division to include on the Protocols' workshop agenda, a review of the methodology to evaluate the cost-effectiveness of dual participation in DR programs.

We note that the Commission has issued proposed Direct Participation rules for comment in R.07-01-041.[133] As we previously discussed, Direct Participation is the ability of retail electric customers, either on their own or through an aggregator or third party DR provider, to bid DR directly into CAISO wholesale electricity markets. Direct Participation rules determine the specifics of how customers will participate in the CAISO markets. If necessary, we will further modify our Dual Participation rules to align with the final direct participation rules.

6.4. Baseline Methodology

Certain DR programs pay customers to reduce energy usage during DR events.[134] Utilities determine the amount of energy usage reduction by estimating the amount of energy the customer would have used if a DR event

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[133] The assigned ALJ issued a ruling on August 19, 2011 soliciting comments on the proposed rules.

[134] These programs are the Capacity Bidding Program, Demand Bidding Program, Optional Binding Mandatory Curtailment Optional Binding Mandatory Curtailment ProgramProgram, and PG&E's PeakChoice Program.

had not been declared. We refer to this estimate of energy usage as the "baseline."

In D.09-08-027, the Commission adopted an "*individual 10-in-10 baseline with an optional 20 percent cap day-of adjustment*" as the methodology to determine a customer's baseline. The methodology begins with the customer's average energy use during the ten previous non-event business days, adjusted up or down based on the day-of adjustment. The day-of adjustment is equal to the average load of the first three of the four hours prior to the event divided by the average load of the corresponding hours from the past 10 similar weekdays. The day-of adjustment is capped at 20 percent, meaning that the adjustment must be between 80 to 120 percent of the 10-day average load. In addition, customers may opt out of the day-of adjustment, in which case the baseline would be the average of the 10 previous non-event business days. The baseline is calculated individually for each customer, and then the cap is applied individually for each customer. Individual customer results are combined to determine aggregator totals.

6.4.1. Parties' Positions

In SDG&E's amended testimony,[135] SDG&E proposes to change the current Capacity Bidding Program baseline from "individual 10-in-10 adjusted baseline of a 20 percent cap" to an "aggregate 10-in-10 baseline with a same day adjustment of a 40 percent cap." SDG&E argues that the current baseline underestimates payments to aggregators. PG&E supports SDG&E's proposal to

[135] SGE-13 at LW\KS-25.

change the current baseline to an aggregated 10-in-10 baseline with a 40 percent cap.[136]

DR Aggregators recommend that the Commission remove the cap on the day-of adjustment, arguing that the cap undervalues customer performance.[137] CLECA agrees that the existing 20 percent cap understates load reductions, but contends that the analysis of the 40 percent cap shows that there is a substantial chance of overstating the load impact.[138] CLECA recommends that the Commission not eliminate the cap without further analysis.

SCE originally recommended that the Commission schedule a workshop to discuss alternative baseline issues.[139] During hearings, SCE indicated that it was analyzing different baseline caps and thus a workshop would no longer be necessary.[140] SCE agrees that a change in the 20 percent cap would be appropriate and supports SDG&E's proposal to implement an aggregated baseline with an optional 40 percent capped adjustment, but recommends continued examination.[141]

6.4.2. Discussion

The Commission encourages DR participation and considers an accurate customer baseline important to compensate customers for their actions. In the case of the Capacity Bidding Program, if customers achieve less than 90 percent

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[136] PGE-08, Chapter 8 at 8-2.

[137] DR Aggregators Opening Briefs at 14-21.

[138] CLE-02 at 11.

[139] SCE-07 at 29.

[140] Tr. Vol. 1 at 172.

[141] SCE Opening Briefs at 29.

of their nomination (the amount they agree to reduce), their payment is reduced by 50 percent and if they achieve less than 75 percent of their nomination, they receive no payment. An accurate baseline calculation helps determine the success of a DR program. Overestimation leads to overpayment, but underestimation could potentially lead to customer withdrawal from a DR program.

All three utilities agree that the aggregate 10-in-10 baseline with a same-day or day-of adjustment of a 40 percent cap is more accurate than the current 10-in-10 individual baseline with a 20 percent cap. SDG&E provided the results of an analysis that compared three baseline options (see table below). SDG&E suggests that the aggregated 10-in-10 baseline with a 40 percent cap is a more accurate baseline compared to the 20 percent cap, because it results in at least 91 percent of the 2010 M&E results, with a minor overestimation of 104 percent of the M&E results.

TABLE 6.4.2

	Settlement Baseline	Baseline Load Impact as a Percentage of the 2010 M&E Results		
Capacity Bidding Program day-of		July	August	September
	10-in-10 individual 20 % cap	71 %	89 %	68 %
	10-in-10 aggregated 20 % cap	83 %	100 %	75 %
	10-in-10 aggregated 40 % cap	**95 %**	**104 %**	**91 %**

Capacity Bidding Program day-ahead	Settlement Baseline	Baseline Load Impact as a Percentage of the 2010 M&E Results		
		July	August	September
	10-in-10 individual 20 % cap	85 %	95 %	96 %
	10-in-10 aggregated 20 % cap	94 %	101 %	104 %

	10-in-10 aggregated 40 % cap	**102 %**	**100 %**	**104 %**

DR Aggregators agree that SDG&E's proposal of the 40 percent capped adjustment is an improvement, but argue that it is not sufficient.[142] Based on the table above, DR Aggregators argue that using the 40 percent cap on the aggregated baseline load underestimates customer actual load. For example, July was 95 percent of the actual load. Despite the 40 percent cap overestimating the actual load in some instances, DR Aggregators argue that "ratepayers are totally protected on overpayments because they can never pay for more than 100 percent of the nominated load, whereas aggregators and customers are at dramatic risk of underpayment because of the penalty mechanism that reduces payments to 50 percent of nomination levels at a performance of 89 percent."[143]

DR Aggregators contend that the uncapped day-of adjustment is the most accurate mechanism because the vast majority of studies are based on an uncapped adjustment, which "implies the uncapped adjustment improves the accuracy of various baseline methodologies."[144] In its rebuttal testimony, CLECA argues that the cap should not be eliminated because of a lack of sufficient analysis.[145] CLECA acknowledges that DR Aggregators and SDG&E have made a case that the 40 percent cap has merit, but recommends that the Commission schedule workshops to further review the issue.[146] SDG&E asserts that the DR

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142 DAG-01 at III-12.

143 DAG-01 at III-13.

144 DAG-01 at III-10.

145 CLE-02 at 10-11.

146 CLECA Opening Brief at 13.

Aggregators did not provide an analysis comparing the DR Aggregator's "no cap" proposal to the 2010 M&E Capacity Bidding Program results.[147] SDG&E contends that without a comparison analysis, there is no understanding of the accuracy of the "no cap" baseline.[148]

We reaffirm our prior statement that an accurate customer baseline is important to compensate customers for its action. The goal of the Commission is to increase the accuracy of the baseline. We agree that a change to the 20 percent cap is needed.

SDG&E's analysis in its testimony[149] provides the most convincing evidence on record of which baseline is the most accurate. Using the 2010 M&E results as a reference point, SDG&E compares the 20 percent and the 40 percent baseline settlement result to the 2010 M&E result. The Commission agrees with SDG&E's method for determining the most accurate baseline for settlement, but questions whether the 40 percent cap is the most accurate for *all* utilities. Furthermore, none of the parties presented analysis in their testimony that compares the 30 percent, 35 percent, 50 percent and no cap results to the 2010 M&E results. Without a comparison analysis of other cap ranges, the Commission cannot determine which baseline is the most accurate.

On July 26, 2011, the Energy Division issued a data request to the Utilities asking for the baseline settlement result using both individual and aggregated baseline with 30 percent, 35 percent, 40 percent, 50 percent and no cap adjustment for Capacity Bidding Program day-ahead and Capacity Bidding

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147 SGE-14 at LW\KS-1.

148 *Ibid*.

Program day-of for the months of July, August and September 2010. Energy Division requested the Utilities to compare those 2010 baseline settlement results with the 2010 M&E results. On August 3, 2011, the Utilities responded to the Energy Division data request. The analysis is based on only those service accounts for whom the adjusted energy baseline option was selected in the nomination month. The assigned ALJ attached the responses to an August 5, 2011 Ruling allowing parties to comment on the responses.[150]

SDG&E, CAISO, and the DR Aggregators filed comments to the data response on August 12, 2011. CAISO finds the results of the Utilities' data responses to be inconclusive and recommends a study on the adjustment factors within a range of 20 percent and 50 percent, including a no-cap base, to be completed within the first quarter of 2012. CAISO recommends maintaining the existing 20 percent cap until there is more substantial data.[151] DR Aggregators request clarification on the basis and foundation for incorporating the data response into the records. Absent such clarification, the DR aggregators object to the incorporation of the data response into the record and if the data response is made part of the record, DR Aggregators recommend the information in the data response should be given little or no weight.[152] "SDG&E does not consent to the

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[149] SGE-13 at LW/KS 24-30.

[150] http://docs.cpuc.ca.gov/efile/RULINGS/140887.pdf.

[151] Comments of CAISO in response to August 5, 2011 ALJ Ruling, filed August 12, 2011.

[152] Comments of DR Aggregators in response to August 5, 2011 ALJ Ruling, filed August 12, 2011.

post hearing evidence being entered into the record."[153] More specifically, SDG&E does not object to the entry of the data response in the record for comment but not as evidence.[154]

The Commission finds the results of the Utilities data response to be of limited use. There is no clear evidence to determine the most accurate day-of adjustment that should be used for all the Utilities. More studies are needed to make an informed decision on baseline settlement.

We direct the Utilities to provide, as part of the Load Impact Annual Filing on April 1, 2012, an analysis of the Demand Bidding and Capacity Bidding Programs and the AMP contracts that compares their baseline settlement result using both individual and aggregated baseline with the following cap percentages 20, 30, 35, 40, 50 and no cap adjustment for the months of July, August, and September 2011. Further, we direct the Utilities to compare the 2011 baseline settlement results with the 2011 M&E results. The comparison analysis must include service accounts for whom the adjusted energy baseline option was selected in that nomination month. For additional data sampling, the analysis must also include a second set of service accounts, assuming all service accounts select day-of adjustment.

In addition, the Utilities are directed to address the baseline comparison analysis as part of the annual Load Impact workshop. Prior to the workshop, we direct the Utilities to solicit parties' input on improving the baseline comparison studies. This input may include a discussion of alternate accepted baseline

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153 Comments of San Diego Gas & Electric Company in response to August 5, 2011 ALJ Ruling, filed August 12, 2011 at 3.

154 *Ibid.*

methodologies. Forty-five days following the workshop, the Utilities must submit a joint Advice Letter addressing whether there is need to change the current baseline along with a proposed baseline comparison study for the following year. The baseline comparison analysis and the workshop should be conducted each year through 2014 when this program cycle ends.

SDG&E, PG&E, and the DR Aggregators have made a strong case that the 20 percent cap on the day-of adjustment for the 10-in-10 baseline understates load reduction, thus underpaying customers for their actions. Although the Commission agrees that more studies are needed, we find that the current 20 percent cap on the day-of adjustment for the Capacity Bidding Program day-of is underpaying customers. Customers should not bear these additional costs while we continue to study the issue. A 40 percent cap on the day-of adjustment provides a fair balance for all customers as an interim solution. For consistency and administrative ease, we also revise the baseline used for the Capacity Bidding Program day-ahead program to 40 percent for a morning of-adjustment while the Commission continues to study the issue.

We do not change the current individual baseline for customers enrolled in the Capacity Bidding Program through an aggregator.[155] We find that a customer's baseline calculation should be the same whether they enrolled in the Capacity Bidding Program through an aggregator or through a utility.

155 SDG&E, PG&E, and SCE proposed an aggregated baseline be used for the morning of adjustment.

7. DR Programs and Activities

7.1. Third Party DR Contracts

7.1.1. Current Aggregator Managed Programs

Following the aftermath of the 2006 California heat storm, PG&E held a competitive bidding process for DR contracts in order to increase the amount of DR available to California.[156] These PG&E contracts, now known as the AMP contracts, provide opportunities for third party DR providers,[157] to enroll and sign up retail customers including bundled service, Community Choice Aggregation, and Direct Access customers. The AMP contracts resulted in increased DR services beginning in June 2007.[158]

Three years later, D.10-12-033 approved modifications to two of the AMP contracts. That decision rejected a request from PG&E for a competitive bidding process for new contracts beginning in 2012. However, the Commission allowed PG&E the opportunity to request a one-year extension for the contracts "[i]f circumstances warrant."[159]

The current AMP contracts between PG&E and five individual DR providers, scheduled to expire on December 31, 2011, require the aggregators to provide a total of 200 MW of load reduction in 2011. The contracts are available for 50 hours annually and do not allow the 1,000 currently enrolled customers to

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[156] The Commission directed PG&E and SCE to hold solicitations for aggregated managed contracts via D.06-11-049.

[157] Also known as DR Aggregators.

[158] The Commission approved the first AMP contracts in D.07-05-029.

[159] D.10-12-033 at 9.

participate in the Capacity Bidding Program and the Base Interruptible Program.[160]

7.1.1.1. Utility Proposals

PG&E requests the Commission to extend the current four AMP contracts for one year, with no additional changes, pursuant to D.10-12-033. PG&E provided the following proposed contract levels, by aggregator, for 2012:

TABLE 7.1.1.1

	Company	MW
1	EnerNoc, Inc.	70
2	Alternative Energy Resources, Inc. (Comverge)	50
3	Energy Curtailment Specialist, Inc.	40
4	Energy Connect, Inc.	20
	Total	180

PG&E requests a budget of $1.2 million[161] for the administrative costs of its AMP contracts. PG&E contends that "extending existing AMP contracts through 2012 is needed to prevent a gap in the DR portfolio arising from PG&E's current lack of authorization by the Commission to hold a new AMP solicitation to

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160 SCE and SDG&E also have experience with aggregator contracts. SCE currently has contracts with five DR Aggregators; one of which will expire in 2011 and four which will expire in 2012. SCE's five contracts provide 105 MW in resource adequacy qualifying capacity. SDG&E contracted with one aggregator, but cancelled the contract in 2011.

161 The Commission authorized $2.7 million for the administrative costs in the 2009-2011 budget cycle.

replace the existing AMP contracts[162] and the inability for aggregators to directly participate in the CAISO market."[163]

SCE does not request the Commission to renew current AMP contracts that expire in 2012. SDG&E does not have AMP contracts at this time.

7.1.1.2. Parties' Positions

DRA objects to PG&E's request for the one-year extension to its AMP contracts. Citing a lack of justification by PG&E for the extension, DRA presents several arguments against the contract extension: the contracts are unnecessary because of anticipated excess capacity in 2012; the AMP contracts did not perform well between 2007 and 2010; the contracts are not cost-effective, and the contracts do not have reasonable safeguards to address any under-performance. DRA concludes that ratepayers will overpay if the Commission approves PG&E's extension request. Furthermore, DRA contends that one contract has a provision that, if the contract had been extended prior to October 31, 2010, would have significantly reduced the premium prices.[164] Ultimately, DRA recommends that the Commission should only consider new third-party DR provider contracts after it finalizes the direct participation rules in Phase IV of the DR Rulemaking (R.07-01-047).[165]

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162 In a related matter to be discussed in a latter section of this decision, PG&E requests to hold a competitive solicitation in 2012 seeking new AMP contracts effective 2013-2017.

163 PGE-08 at 2-2 – 2-3.

164 DRA-01, Chapter III at 1-20 to 1-26.

165 *Ibid.*

DR Aggregators maintain a need for renewed AMP contracts. DR Aggregators base this need on current barriers to DR provider participation in CAISO markets and insufficient information to determine the extent of future DR provider participation in the markets due to a lack of final direct participation rules. Pointing to the Commission approval of the current contracts, DR Aggregators argue that there is no comparable opportunity for DR providers to participate in CAISO in 2012. DR Aggregators conclude that it is essential to renew the AMP contracts for 2012.

7.1.1.3. Discussion

7.1.1.3.1. Compliance

In D.09-08-027, the Commission denied PG&E's request for an RFP without prejudice but allowed PG&E to "propose a similar RFP in the future, if appropriate based on market conditions."[166] In a subsequent decision regarding PG&E's Petition for Modification of D.09-08-027, we again denied PG&E's request to modify the previous decision and hold a competitive solicitation. We reiterated, "(i)f circumstances warrant and new aggregator contracts are not available in 2012, PG&E may request that its existing contracts be extended to continue for that year."[167] We conclude that PG&E's request for a one-year extension to its AMP contracts complies with the direction of D.09-08-027 and D.10-12-033.

[166] D.09-08-027 at 118.

[167] D.10-12-033 at 9.

7.1.1.3.2. Reasonableness

It has been two years since the last DR budget decision. We agree with PG&E and DR Aggregators that there is insufficient information to determine the extent of participation by DR providers in the CAISO's markets. Given the uncertainty of the CAISO's market condition, we agree that there is merit to maintaining the resource adequacy capacity resources provided by the AMP contracts.

We are not persuaded by DRA's argument that we should deny PG&E's request for the contract extension because of the high reserve margin. While, we share DRA's concerns regarding the excess capacity in PG&E's system, we want to have DR resources available for our use. We need to be consistent in enforcing the loading order in the Energy Action Plan II that the Utilities should not procure or build non-DR resources that the system may not need.

We also share DRA's concern that these contracts experience so few actual events compared to other DR programs.[168] According to DRA's testimony, there were very few actual events from 2007 to 2010.[169] Specifically, there were zero non-test events for the AMP contracts in 2009 & 2010.

Our main concern, however, is the cost-effectiveness of these contracts. We disagree with the DR Aggregators that we should approve the extension because we found these contracts cost-effective when we initially approved them. At that time, we had not adopted the Protocols and did not address the question of cost-effectiveness. Furthermore, the input assumptions would have

[168] For example, Capacity Bidding Program had 12 events.

[169] DRA-01, Chapter 1, Table 5 at 1-25.

been different today compared to five years ago. Since the adoption of the Protocols in 2010, we are now required to address cost-effectiveness.

PG&E's analysis shows that the AMP contracts have a benefit-cost ratio less than or equal to 0.5 for all three tests.[170] As we discussed in the cost-effectiveness chapter of this decision, we consider programs with ratios of 0.5 or lower in two or more of the three SPM tests to be "not cost-effective." Setting aside DRA's concerns regarding the under performance of the AMP contract, PG&E's cost-effectiveness template shows that none of the contracts would be cost-effective even assuming 100 percent performance. These contracts have limited availability (50 hours/year in summer) so the A factor, which is based on the program's availability, is only 30 percent, much lower than other DR programs that are available for more hours such as Capacity Bidding Program, which has an A factor of 67 percent. With cost-effectiveness ratios of 0.49 for the TRC, 0.42 for the PAC and 0.42 for the RIM, these contracts are far from being cost-effective.

We find it unreasonable to extend these contracts without addressing these issues. PG&E did not provide any analysis on alternative solutions, such as modifying the contract terms and conditions to make these contracts cost-effective. We cannot allow any extension without sufficient revisions to make the contracts cost-effective in the future. Thus, we direct PG&E to renegotiate the terms of the contracts to improve the cost-effectiveness so that at least two of the three cost-effectiveness tests attain at least a 0.9. For reasons we discuss in the next section of this decision, we allow the renegotiated contracts to be

[170] TRC, PAC, and RIM tests.

extended up to three years, through the end of 2014, contingent upon the contracts being cost-effective. Within 90 days from the issuance of this decision, PG&E should submit a Tier 2 Advice Letter that includes the renegotiated contracts, along with a revised cost-effectiveness analysis that provides the results of the three cost-effectiveness tests. We approve the request by DR Aggregators, and agreed to by PG&E, to enroll net energy metering customers in AMP. This should assist in improving the cost-effectiveness of the AMP contracts.

We recognize that there may not be sufficient time for PG&E and the AMP contractors to complete their negotiations, receive approval by the Commission of the new contracts, and then enroll customers into the new contracts by the beginning of the 2012 summer season. Thus, we allow the current AMP contracts to operate for one additional year. However, the authorization of the AMP extension and associated budget is contingent upon re-negotiated cost-effective AMP contracts for 2013-2014 received by the Commission as directed above. In order to be considered cost-effective, the AMP contracts must comply with the Protocols as well as all of the cost-effectiveness directives that we discuss in this decision, e.g., PG&E shall not use the LOLP model in its cost-effectiveness analysis.

We address the issue of meeting future energy needs in our discussion on future contracts.

7.1.2. Future Contracts

7.1.2.1. Utility Proposals

PG&E requests the Commission for authority to hold a competitive solicitation for new AMP contracts "that can be bid into the CAISO markets as PDR.[171] PG&E proposes that the five-year contracts would seek to provide 150-250 MW of new DR beginning in 2013. PG&E notes that the funding for these contracts is not included in this application.

SCE's current DR contracts expire in 2012. SCE received approval of the current DR contract capacity and administrative costs in prior Commission decisions.[172] In this application, SCE does not request renewal of its current contracts or authorization to solicit a new set of contracts. SCE considers it "prudent for the Commission to leave open the option for the future."[173] SCE concludes that the Commission expects third-party aggregators to participate directly in the CAISO market and will focus on facilitating the development of that market before approving new contracts.[174]

SDG&E notes in its application that it is in negotiations with successful bidders from its 2009 DR Request for Offer. SDG&E does not request any new contracts with DR providers. Based on experience with the deliverability of its

[171] PGE-01 at 2-28.

[172] D.08-03-017 and D.09-08-027. See also SCE-03 at 70.

[173] SCE Opening Brief at 78.

[174] SCE-01 at MFG-9.

previous DR contract, SDG&E recommends that the Commission revisit its policy on bilateral DR contracts and deny any future contracts.[175]

7.1.2.2. Parties' Positions

CAISO supports PG&E's proposal for a competitive solicitation of DR resources with the assumption that these resources are integrated into the CAISO market.[176] CAISO believes that the competitive solicitation should be the default procurement method for DR and, like generation procurement, should occur before the Utilities develop their own retail DR programs. CAISO recommends that "IOUs use competitive procurement to solicit DR designed to satisfy long term procurement and resource adequacy requirement for aggregators."[177]

DRA "urges the Commission to wait until the final rules for DR provider participation are adopted before considering the approval of new contracts. This will ensure that third-party aggregator contracts will not reduce DR provider's direct participation in the CAISO's wholesale market."[178] DRA also argues "current surplus capacity situation exposes ratepayers to substantial financial risk of paying for unneeded capacity"[179] if the Commission authorizes new contract solicitation. In addition, DRA questions the cost-effectiveness of PG&E current AMP contracts.

DACC/AReM supports the CAISO's position on the competitive procurement for DR resources that would provide a significant benefit of

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175 SGE-01 at MFG-9 and MFG-10.

176 CAISO Opening Brief at 23,.

177 ISO-1 at 11, lines 18-19.

178 DRA Opening Brief at 56.

179 *Ibid*.

transitioning away from utility-dominated DR markets and reduce ratepayer risks. As a general policy, DACC/AReM advocates for expanding DR market competition and eliminating participation barriers for non-utility DR providers.[180] DACC/AReM strongly argues that continuation of the utility monopoly provision of DR services ("business as usual") ensures only high cost programs and a failure to meet the Commission's policy goals.[181]

DR Aggregators support PG&E's request for new solicitation for AMP contracts that can bid into the CAISO market. DR Aggregators believe that the Commission's authorization is an important step to preserve and increase DR resources.[182] Supporting the need for bilateral contracts in 2012 and the foreseeable future, DR Aggregators note that the "volume of participants expected to engage in direct participation may be small."[183]

NAPP submits that the Commission must address the issue of the expiring bilateral contracts in order to provide regulatory certainty for DR providers. NAPP urges the Commission to require the Utilities to hold competitive solicitations for new contracts that qualify for Resource Adequacy and can be bid into the CAISO wholesale markets. NAPP suggests that the "contracts should be restructured to better address the regulatory risk associated with long-term contracts and improve the overall performance of the contracts."[184]

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180 DACC/AReM Opening Brief at 15.

181 DACC/AReM Reply Brief at 3.

182 DR Aggregators Reply Brief at 37.

183 DR Aggregators Opening Brief at 51.

184 NAPP Opening Brief at 2.

7.1.2.3. Discussion

The Applicants and parties all agree that the Commission should preserve the DR resources from current and future AMP contracts because they can be bid into the CAISO market. The point of disagreement is whether the current model for contracts be allowed to continue where the Utilities would bid the resources into the CAISO market or should the Utilities procure these resources similar to the way they procure other Resource Adequacy resources where third-party aggregators directly bid the resources into the CAISO market. The fundamental differences between the current and procurement models are 1) whether the Utilities or the third-party aggregators bid the resources into the CAISO market and 2) whether the contracts are integrated into the CAISO market.

CAISO believes that the procurement model shifts the risk of potentially expensive market integration IT costs from the ratepayer to the aggregators. CAISO argues that "the aggregator's IT costs are not transferred to rate base and to all ratepayers as are the [Utilities' costs]."[185] Further, DACC/AReM contends that the current model gives the Utilities' DR providers an advantage over non-utility DR providers because the Utilities recover all related costs from the ratepayers. We share CAISO and the DACC/AReM's concerns about the cost to ratepayers, especially since we found many of the DR programs not cost-effective.

With both models, DR resources reduce the resource adequacy requirements. However, the DR procurement model builds these resources directly into the resource adequacy portfolio. CAISO continues to emphasize a

[185] CAISO Reply Brief at 12.

market preference for DR resources that qualify for resource adequacy because of reliability and economic efficiency.[186] CAISO maintains that the Utilities should solicit DR resources the way they solicit generation resources. CAISO does not support third party aggregators delivering DR resources to the CAISO system that are not integrated with the wholesale market.[187]

SCE and SDG&E question whether the Commission should continue the current model for the AMP contracts under CAISO's new wholesale market for DR. SDG&E cancelled its AMP contract in early 2011, contending that "the unique attributes of SDG&E's service territory inhibits the success of Aggregator Managed Programs."[188] SDG&E expresses concern regarding the reshuffling of customers between SDG&E's DR programs and the AMP contract; thus providing no incremental benefits to SDG&E's customers.[189]

For the reasons discussed above, and consistent with our policy vision on integration into and direct participation of DR resources in the CAISO market, we deny PG&E's request for an RFP for new AMP contracts. Instead, we adopt the DR procurement model as proposed by the CAISO. The specifics of the DR procurement model will be further developed in the current DR Rulemaking proceeding, R.07-01-041, or its successor. We expect the Utilities to hold competitive solicitations for new PDR contracts as a part of their Resource Adequacy portfolio, once we have finalized the direct participation rules and implemented new Resource Adequacy rules for wholesale DR resources. We

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186 CAISO Reply Brief at 7-10.

187 CAISO witness' testimony, Transcript Vol. 4,493, lines 7 to 20.

188 SDG&E Reply Brief at 15.

189 SGE-01, Chapter II, MFG-9 to MFG-10.

require the Utilities to work closely with CAISO, Energy Division staff, and the Procurement Review Groups when developing the RFP requirements to meet future system needs, e.g., integration of renewable resources.

We recognize the issues raised by the Utilities and parties regarding the uncertainty of the CAISO market development and the direct participation rules. PG&E did not request funding for the AMP contracts in 2013 and 2014. To preserve the current AMP resources during the transition period of 2013 to 2014, we allow PG&E an extension of the current AMP contracts through 2014, but PG&E must negotiate revisions to make the contracts cost-effective as we previously discussed. We also permit but do not require SCE to submit, no later than April 1, 2012, applications for cost-effective, as defined herein, 2013-2014 third-party DR aggregator contract extensions.

7.2. Marketing, Education, and Outreach

In D.09-08-027, the Commission approved marketing budgets in three categories: Category 6 for Statewide DR Marketing, Category 9 for Local DR Marketing,[190] and Category 10, IDSM Marketing. We adopted 2009-2011 budgets of $6.4 million for PG&E, $4.94 million for SCE and $1.25 million for SDG&E for Statewide DR Marketing also known as Flex Alert.[191] We also authorized local

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190 In the 2009-2011 DR application, each utility used a different name for Category 9. SCE called Chapter 9, "Specialized Marketing, Education, and Outreach. PG&E called it "Core Marketing and Outreach." SDG&E called it "Customer Education, Awareness and Outreach. For the purposes of this decision, all marketing that is not Statewide or IDSM marketing will be referred to as Local ME&O.

191 *Id*. at 96.

DR marketing budgets of $10.7 million for PG&E, $9.38 million for SCE and $6.94 million for SDG&E.[192]

In D.09-08-027, we strongly encouraged the Utilities to move toward more coordinated ME&O, and reduce or eliminate program-specific budget requests for the 2012-2014 budget applications. We directed the Utilities to coordinate these activities with similar activities in energy efficiency and demand-side management programs. Additionally, in the Guidance Ruling, we required the Utilities to include proposals for bridge funding for IDSM marketing.

As previously addressed in the chapter on cost-effectiveness, in order to improve the cost-effectiveness of many DR programs, we direct the Utilities to decrease costs in some specific areas, including ME&O. We will discuss both the required and recommended decreases. Proposed and approved 2012-2014 budgets for the Statewide DR ME&O and Local DR ME&O will be discussed separately. We incorporate the IDSM ME&O budget as part of the IDSM discussion in Chapter 18.

7.2.1. Statewide DR Marketing / Flex Alert Campaign

The Commission created the Flex Alert campaign as a statewide marketing program that encourages residential customers to reduce their demand when CAISO calls a Stage I Emergency. In the 2009 DR decision, the Commission required that future DR statewide marketing strategies would be determined by the Strategic Plan.[193] The Strategic Plan provides several strategies to "create a consumer experience that offers an integrated set of DSM information and

192 D.09-08-027 at 98.

program options."[194] OP 34 of D.09-09-047 directs the Utilities to integrate DR Statewide Marketing with energy efficiency statewide marketing. Because the two proceedings, energy efficiency and DR, are on different budget cycles, the Utilities propose 2012 bridge funding in this DR application for statewide marketing.

Each utility has an individual budget for the statewide marketing program; these budgets are pooled together to fund one contract currently held by SCE. SCE requests $1,649,330 per year for each of years 2012 and 2013, to cover the costs of the statewide contract. PG&E requests $ 1,086,500 per year for years 2012 and 2013, to cover the cost of its portion of the program contract. SDG&E requests a budget of $210,000 for 2012 for its portion of the contract.

PG&E and SCE assert that because the energy efficiency program application cycle has been delayed an additional year, two years of bridge funding is necessary. We recognize that the energy efficiency application proceeding has been delayed another year. However, 2013 bridge funding for the entire energy efficiency portfolio will be needed to maintain the current programs. The Utilities will have an opportunity to request funding for the 2012 DR statewide marketing in the 2013 energy efficiency bridge funding request. We deny all DR statewide marketing funding requests for 2013 in this proceeding.

We have consistently encouraged the Utilities to coordinate and integrate ME&O messaging in order to deliver common messages. We address this

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[193] D.09-08-027, OP 17.

[194] Strategic Plan, Section 10 at 80.

further in our discussion on local ME&O. During the 2012 program year, we direct the Utilities to develop two statewide marketing efforts, one that focuses on emergency alerts, and one that focuses on a general awareness campaign regarding dynamic rates and the Peak Time Rebate program.

For DR budget years 2009-2011, we approved a total statewide DR ME&O budget for PG&E and SCE of $11.3 million. PG&E's and SCE request a budget of $5.4 million for years 2012 and 2013. We deny funding for 2013. However, in order to provide both the emergency alert campaign and the dynamic rates/Peak Time Rebate campaigns, we authorize the requested budget of $5.42 million to be spent in 2012 only.

SDG&E's DR statewide marketing budget request of $210,000 equals its DR statewide marketing budget authorization of 2011; we find this amount insufficient for SDG&E's portion of the statewide contract in 2012. SDG&E's DR statewide marketing budget for 2009 through 2011 equaled approximately $1.25 million.[195] We find two-thirds of SDG&E's 2009-2011 budget, or $836,000, to be a more appropriate amount for SDG&E's portion of both components of the DR statewide marketing.

[195] SGE-01 at MFG-26.

For the reasons discussed above, we authorize a 2012 Statewide DR ME&O budget for each utility as provided in the following table:

TABLE 7.2.1

Statewide DR ME&O Budgets		
Utility	**Total Requested (2012-2013)**	**Authorized Total (2012)**
SDG&E	$ 210,000	$ 836,000
PG&E	$ 2,173,000	$ 2,173,000
SCE	$ 3,298,659	$ 3,298,659

The Commission and the Utilities are working collaboratively to identify statewide marketing needs for the future. The Utilities should use the results of that collaboration to guide their statewide marketing implementation in 2012. While we authorize one year (2012) of bridge funding for this program in this proceeding, we will authorize any emergency alert budgets, if applicable, within future energy efficiency application proceedings. During the approval process of the energy efficiency program budget for 2013 and beyond, the Commission will determine the strategies for statewide campaigns.

7.2.2. Local DR ME&O

7.2.2.1. Utility Proposals

PG&E proposes a general DR marketing budget of $24.579 million during the 2012-2014 budget cycle. PG&E describes two categories of work within its marketing activities: "Continued Marketing, Education and Outreach" which includes research, outreach, awareness, and enrollment, support and retention in programs, and "Portfolio and Marketing Optimization" which includes strategic planning, customer targeting, program optimization and additional research.

In its Application, SDG&E proposes a $7.191 million budget for its Local DR Marketing which SDG&E allocates across several budget categories. SDG&E requests $1.158 million for a Customer Education, Awareness and Outreach program. SDG&E explains that the purpose of the Customer Education, Awareness and Outreach Program is to provide general information about DR to all of its customer classes. In addition, SDG&E requests that a portion of several DR program budgets be dedicated to marketing that individual program. SDG&E proposes $2.165 million to market its Base Interruptible Program, Capacity Bidding Program, Technical Assistance, Technical Incentive, PLS and the Small Technology Deployment Pilot. SDG&E also requests $3.868 million for Peak Time Rebate marketing materials to educate customers on 1) how DR and Peak Time Rebate are mutually beneficial, 2) rates and eligibility, 3) notification enrollment, 4) energy usage modification and 5) the installation of enabling technologies.

SCE recommends a Local DR Marketing budget of over $40 million which is separated into five areas: DR individual program marketing; Circuit Savers; DR ME&O; Peak Time Rebate; and Critical Peak Pricing marketing to small business customers.[196] SCE requests a total of $8.868 million for individual marketing budgets in many of its DR programs and activities that include the development of program materials and enrollment campaigns. SCE proposes to enhance its Circuit Savers program, a campaign that targets customers on load-constrained distribution circuits; and requests a budget of $2.5 million. In order to provide outreach to smaller business, agricultural, and water customers in DR

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[196] Customers with a demand of less than 200 kW.

programs, SCE proposes a budget of $3.6 million for its DR ME&O. SCE also requests $5.97 million to conduct marketing to small non-residential customers about Critical Peak Pricing. While already receiving approval of the program in D.08-09-038, SCE requests a budget of $20 million for Peak Time Rebate ME&O.

7.2.2.2. Parties' Positions

Only UCAN commented on utility Local DR Marketing budgets. UCAN opposes SDG&E's funding request to market Peak Time Rebate. UCAN provides several examples where ME&O budgets are excessive.[197] For example, UCAN considers the DR Local ME&O cost per customer to be excessive for a program in which a customer is automatically enrolled and participates voluntarily. UCAN argues that SDG&E should leverage the requested $28 million in its dynamic pricing application, A.10-07-009, to offer customers information about dynamic pricing and Peak Time Rebate.[198] Also, UCAN opposes SDG&E's Customer Education, Awareness and Outreach Program, calling it overly broad and targeted at the wrong customers.

7.2.2.3. Discussion

Over the past several years, the Commission has directed the Utilities to integrate all customer demand-side programs in a coherent and efficient manner.[199] In the Strategic Plan, we emphasized a coordinated approach to ME&O and directed the Utilities to develop marketing messages that offer

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[197] UCN-01 at 4-6.

[198] UCN-01 at 4.

[199] D.07-10-032 at 5.

bundles of DSM programs targeted to specific customer groups.[200] We further ordered the Utilities to coordinate all energy efficiency ME&O programs with DR ME&O programs to ensure integration across demand side management programs by the next portfolio cycle.[201] In D.09-08-027, we approved a total of three marketing budget categories and encouraged the Utilities to coordinate, reduce, or eliminate program-specific budget requests in the 2012-2014 DR applications. We find that the ME&O funding requests in the DR applications do not convey an adequate effort toward this policy. Our discussion below provides specific direction for coordination, reduction and, in some cases, elimination within the various Utilities' marketing funding requests.

The Utilities' applications contain as many as six separate marketing budgets not including specific line items within many individual programs. For example, SCE's and SDG&E's budgets for the Base Interruptible Program include a specific line item for marketing the program. In contrast to the goal of reducing costs and focusing on opportunities to engage customers through single points of contact, the Utilities continue to fragment their marketing into a greater number of categories. In addition to the multiple categories of marketing proposed in this proceeding, each Utility requests separate budgets for education in dynamic pricing proceedings or general rate cases.[202] While the Utilities have

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200 *Strategic Plan*, Section 10 at 80, September 2008.

201 D.09-09-047, OP 34.

202 PG&E requests $14.06 million for Peak Time Rebate in its 2010 Rate Design Window in A.10-02-028 at 5-6. SDG&E requests $13.7 million for dynamic rates for residential and small commercial customers in its application for Approval of Dynamic Pricing, A.10-07-009, Chapter 2 at 15. SCE requests $10 million for 2012-2014 Dynamic Rates in its 2012 GRC Phase II in A.10-09-002 at 14.

begun to use integrated marketing funding to streamline their messaging to customers, we consider the IDSM marketing category an interim measure toward complete integration. As the energy efficiency decision states, marketing should be integrated by 2013. Approving any more than the previously approved three marketing budgets in this proceeding is contradictory to past decision directives.

We reviewed the Utilities' requests for marketing individual DR programs. Both SCE and SDG&E recommend budgets to market their Reliability Programs. The Commission has capped the size of emergency-triggered DR that counts for resource adequacy. Although these programs remain open to new enrollment pursuant to the Settlement Agreement, the Commission has provided no direction to encourage enrollments in these programs, therefore these marketing budgets are not necessary and we deny such requests. SCE requests marketing funds for the Schedule Load Reduction and Optional Binding Mandatory Curtailment programs. We find it unreasonable to create marketing budgets for programs which have few, if any, customers. SCE and SDG&E also propose marketing budgets for their Capacity Bidding Programs, a program administered by third party providers. The Utilities have a combined total of one customer directly enrolled in this program. We find it unnecessary for the Utilities to market a program primarily administered by a third party. We deny requests for marketing funds for the Schedule Load Reduction, Optional Binding Mandatory Curtailment and Capacity Bidding Programs.

In comments, the Utilities expressed a concern that ME&O funding is not just for marketing, but also for educating and notifying customers. While we deny funding for marketing to Reliability program customers, we recognize a potential need to educate and communicate program changes to these customers. If a utility finds it necessary to target funds to educate and communicate with Reliability program customers, the Utilities can utilize funds from other DR programs within the ME&O category, so long as each DR program remains cost-effective. We also remind the Utilities that funding for customer notifications should be allocated from the DR Support Systems budget category. As we detail below, we decrease the overall 2012-2014 DR ME&O budget for two specific reasons: 1) historical ME&O under spending and over budgeting by the Utilities and 2) to make DR programs more cost-effective.

SCE and SDG&E requests funding for activities that the Commission has required to be integrated: Technical Assistance and Technology Resource Incubator Outreach.[203] Because the Utilities have been directed to integrate these programs, marketing for these activities should come from the IDSM marketing budget. We address these marketing requests in our discussion of IDSM in Section 7.9 of this decision.

Throughout our review, we found several instances where the funding requests for ME&O are excessive compared to recently reported utility spending. We note that, according to the Utilities' DR monthly reports for August 2011, all of the Utilities under spent their ME&O budgets. As of the end of August 2011, PG&E spent only 49 percent of their 2009-2011 ME&O budget, SCE spent only 30 percent, and SDG&E spent only 35 percent. Despite this under spending or over budgeting, we have found that certain DR programs such as AC cycling programs have exhibited a high per enrolled customer cost. SCE's marketing

[203] *Joint Assigned Commissioners' Ruling Providing Guidance on Integrated Demand-Side Management in 2009-2011 Portfolio Applications*, April 11, 2008.

and administrative costs per customer enrolled equaled $835 in 2009.[204] In 2009, PG&E enrolled 76,000 customers at a total program cost of $18.6 million averaging $ 245 per customer enrolled.[205] We take this past history into account in our review of utility requests for 2012-2014 ME&O funds.

SCE plans to enroll 196,000 customers[206] in its Summer Discount Plan by 2014. However, current enrollment levels from the September 2011 monthly report and the Enrollment Forecast table[207], estimates that SCE will only enroll 71,463 by 2014. Based on SCE's proposed budget of $6 million, this equals $93 per enrolled customer. As we noted above, SCE only spent 30 percent of its ME&O budget by October 2011. But, we also recognize that SCE spent 75 percent of its entire AC cycling budget which included ME&O and administrative costs. Thus while we decrease SCE's requested AC cycling budget, we do so only by 50 percent. We authorize SCE a budget of $3.4 million for it Summer Discount Program ME&O.

In comments, PG&E requested that its AC cycling budget reduction be limited to $ 3,722,278. PG&E explained that this would allow $5.8 million for Smart AC ME&O, $3.1 million of which would be used to enroll new customers and replace departing customers in order to maintain the current 174MW load impact. The remaining $2.75 million would be used, at a cost of $5 per customer annually, to retain the 209,000 plus customers currently enrolled in the program.

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204 DR monthly report December 2009.

205 DR monthly report December 2009.

206 SCE-03 at 30, lines 22-23.

207 SCE-05 at 11.

PG&E is proposing to enroll 51,843 customers by 2014[208] or $112 per enrolled customer.

All three Utilities state in comments that there is inadequate information on the record to determine whether Utilities' AC cycling budgets are excessive. We disagree and further find that several actions must be taken in the 2012-2014 program cycle to ensure that the Commission can properly evaluate whether currently authorized and future proposed marketing costs for AC Cycling and all other marketing are excessive. During the 2012 program evaluation of ME&O, we direct the Demand Response Measurement and Evaluation Committee (DRMEC)[209] to include a review of marketing costs per enrolled customer and determine the range of appropriate costs. The Utilities must work with the Energy Division to ensure that monthly DR reports provide proper and complete ME&O details.

PG&E's proposal to reduce its marketing budget for Smart AC to $ 5.8 million is approved.[210] SCE's Summer Discount Plan marketing budget is approved, but SCE must decrease its commercial Summer Discount Plan program to make it cost-effective.

We find SCE's $1 million requested increase for the Circuit Saver program to be unreasonable, given that SCE expanded this program while spending less than one-third of its approved 2009-2011 Circuit Saver budget as of March

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[208] DR September Monthly Report and PGE-01 at 8-6.

[209] The DRMEC oversees the evaluation of statewide demand response activities.

[210] PG&E Comments at 10.

2011.[211] Similarly, SCE proposes to expand its DR ME&O, but has used only a fraction of its budget in the current funding cycle. Unnecessary and excessive increases for specific marketing budgets are in stark contrast to our direction that utilities should reduce specific marketing budgets. We find it reasonable to reduce the requested budget for Circuit Saver and DR ME&O.

Our review found instances where the Utilities could take advantage of coordination and integration. SCE requests $20 million in marketing funds for Peak Time Rebate and SDG&E requests $3.8 million. For both utilities, this amount represents half of its total local marketing request. UCAN recommends that SDG&E use existing channels like email, direct mail and the SDG&E website to market to potential Peak Time Rebate customers. Both SDG&E and UCAN agree that once most customer email addresses are obtained, marketing costs should decrease.[212] However, neither SDG&E nor UCAN provide any estimates of cost savings.

The Commission directed SDG&E, as well as the other utilities, to make usage and cost information available to its customers online in anticipation of smart meter deployment.[213] Likewise, the energy efficiency proceeding requires the Utilities to develop online integrated audit tools for residential and small commercial customers.[214] Using all of these tools, as has been directed by the

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[211] SCE 2012-2014 DR Program Portfolio, Volume 2 at 115.

[212] SGE-06 at GMK-4:9-10.

[213] *Decision Adopting Rules to Protect the Privacy and Security of the Electricity Usage Data of the Customers of PG&E, SCE and SDG&E*, D.11-07-056, OP 5 and OP 6 at 164.

[214] *Decision Approving 2010-2014 Energy Efficiency Portfolio and Budgets*, D.09-09-047, OP 33.

Commission, should assist in fulfilling the Commission's goal of reaching customers through single points of contact while simultaneously decreasing the marketing budgets for these activities. Instead of doubling marketing budgets to provide information about one program, the Utilities should focus residential and small commercial marketing efforts on motivating them to use the My Account tool as well as other available online resources. We reduce the marketing funds for these activities accordingly.

While we reduce the Local DR ME&O funds for these programs, we recognize that there are similarities among each utility's designs for Peak Time Rebate and proposed dynamic rates. These similarities create opportunities for the Utilities to collaborate and provide general statewide messages about these two types of programs. As we discussed in the Statewide ME&O section, we increased funding so that the Utilities can provide two statewide campaigns, one of which will raise awareness about dynamic rates and the Peak Time Rebate program.

Unlike SDG&E and SCE, PG&E did not include marketing budgets within each of its program budgets. Instead, PG&E included all of its local marketing in its DR Core Marketing and Outreach line item. This is the model we expect the Utilities to use beginning with this budget. However, like SDG&E and SCE, PG&E's proposed ME&O budgets are excessive and not justified based on past expenditures. We reduce PG&E's Local ME&O budget accordingly.

In order for marketing funds to comply with our prior orders, we direct the Utilities to consolidate all marketing funding from the three categories previously approved in D.09-08-027 into two categories: ME&O and IDSM ME&O. We move the marketing budgets from the individual DR program funding requests to the ME&O category. The statewide marketing budget is now a line item within the ME&O category. Pursuant to the discussion on cost-effectiveness and our discussion above, we appropriately categorize all marketing funds, decrease funding for several programs and activities as discussed in this and the cost-effectiveness sections, and authorize the following overall budgets for Local DR Marketing.

TABLE 7.2.2.3 A			
Utility	**Total Approved Funds Local DR ME&O 2009-2011**	**Total Requested Funds allocated toward Local DR ME&O 2012-2014**	**Total Approved Funds Local DR ME&O 2012-2014**
SDG&E	$6,940,000	$6,929,000	$ 5,642,513
PG&E	$10,700,000	$24,579,000	$ 12,289,596
SCE	$9,380,000	$40,269,337	$ 16,324,906

Within 60 days of the issuance of this decision, the Energy Division shall hold a workshop on DR ME&O to more clearly define the roles for statewide and IDSM marketing, and to develop marketing plans for Local DR ME&O. Thirty days following the workshop, each utility shall submit a Tier 2 Advice Letter with a proposed Marketing Plan for their Local DR ME&O that provides an outline of intended activities which will be performed, categorized to provide details in the existing monthly DR reports to the Commission; the specific programs the ME&O activities will support; and marketing evaluation plans and schedules. The Marketing Plans will allow the Commission to better monitor ME&O expenses. Furthermore, the Marketing Plan should comply with the following policies:

a) Reliability Programs are capped. Until further notice, we prohibit the use of ratepayer funds to market these programs.

b) The Capacity Bidding Program is administered by third party DR providers. Marketing should be the role of the third party provider. We prohibit the use of ratepayer funds to market these programs.

c) Programs that have few to no customers enrolled, such as the Scheduled Load Reduction and Optional Binding Mandatory Curtailment Programs, do not require marketing funds. We prohibit the use of ratepayer funds to market these programs.

d) Marketing plans should focus on price-responsive programs and permanent load shifting activities.

e) Marketing efforts for residential and small commercial customers should focus on customer enrollment through "My Account."

f) Marketing for Peak Time Rebate should either be done online or through highly targeted campaigns only.

g) Marketing the concepts of Peak Time Rebate and dynamic rates should be delivered through statewide rather than local marketing campaigns.

The following Table shows the reductions we require to Local DR ME&O budgets for specific programs and activities:

SCE Local Marketing

TABLE 7.2.2.3 B			
Program/ Activity	ME&O Request	Reduction	Authorized ME&O amounts (to be categorized as Local DR ME&O)
Agricultural Pumping Interruptible	$44,500	$44,500	$0
Base Interruptible Program	$103,000	$103,000	$0
Optional Binding	$9,000	$9,000	$0

Mandatory Curtailment			
Scheduled Load Reduction Program	$9,000	$9,000	$0
Rotating Outages	$77,000	$77,000	$0
Ancillary Services	$5,000	$5,000	$5000
Capacity Bidding Program	$237,500	$237,500	$0
Demand Bidding Program	$302,400	$0	$302,400
Summer Discount Plan	6,714,000	$3,357,000	$3,357,000
Peak Time Rebate	$20,028,000	$9,999,000	$10,029,000[215]
Critical Peak Pricing > 200 kW	$297,900	$0	$0
Critical Peak Pricing <200kW	$5,639,000	$5,639,000	$0
Real Time Pricing	$489,500	$399,500	$0
PLS	$310,000	$0	$310,000
DR ME&O	$3,673,037	$2,453,778	$1,219,259
Circuit Savers	$2,599,822	$1,734,575	$865,247
Technical Incentives	$242,000	$0	$242,000
TOTAL	$40,780,659	$25,112,753	$16,324,906

[215] This amount equals one year of the funding requested by SCE to market this program. We consider this reasonable because SCE spent only 30 percent of its 2009-2011 Peak Time Rebate ME&O budgets by August of 2011, according to the SCE DR monthly report for August 2011.

PG&E Local Marketing

TABLE 7.2.2.3 C			
Program/ Activity	ME&O Request	Reduction	Authorized ME&O amounts (to be categorized as Local DR ME&O)
DR Local ME&O	$24,579,192	$12,289,596	$12,289,596[216]

SDG&E Local Marketing

TABLE 7.2.2.3 D			
Program	ME&O Request	Reduction	Authorized ME&O amounts (to be categorized as Local DR ME&O)
Base Interruptible Program	$165,000	$165,000	$0
Capacity Bidding Program	$15,000	$150,000	$0
Peak Time Rebate	$3,868,000	$928,320	$2,939,680[217]
Small Commercial	$1,639,000	$273,167	$1,365,833

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216 PG&E spent 49 percent of its 2009-2011 ME&O budget by August 2011, excluding Smart AC marketing, according to its DR monthly Report for August 2011.

217 This amount equals 55 percent of SDG&E's proposed marketing budget. SDG&E proposes to spend 55 percent of the total Peak Time Rebate budget in 2012, SGE-01 Table A-1. As of August 2011, SDG&E had only spent 35 percent of its marketing budget, according to its DR monthly report for August 2011.

Technology Deployment			
Customer Awareness, Education & Outreach	$1,158,000	$0	$1,158,000
PLS	$84,000	$0	$84,000
Technical Incentives	$95,000	$0	$95,000
TOTAL	$7,159,000	$1,516,487	$5,642,513

7.3. DR System Support Activities

In D.09-08-027, the Commission adopted the following budgets for DR infrastructure activities within Category 08 (System Support Activities): PG&E – $16.902 million, SDG&E – $0, and SCE - $13.158 million. Subsequently, D.10-12-047 approved a request of SCE to shift $3.525 million previously authorized in D.09-08-027. The Commission directed SCE to now use these funds for system improvements needed to support participation in PDR activities, in general, and, more specifically, SCE's Capacity Bidding Program and DR contracts.

7.3.1. Utility Proposals

7.3.1.1. PG&E

For 2012-2014, PG&E requests $41.5 million for DR Operations which is divided into three categories: DR Enrollment and Support ($15.787 million), Inter-Act/DR Forecasting Tool ($14.408 million) and Notifications ($11.328 million).[218]

[218] PGE-01 at 4-2.

- DR Enrollment and Support: As part of the CAISO market integration effort, PG&E proposes enhancements and increased labor costs to several DR enrollment systems including the Capacity Bidding Program operating system and Event Manager. In addition to the enhancements costs, PG&E requests funds for licensing fees and software maintenance costs.
- Inter-Act/ DR Forecasting: InterAct is PG&E's energy management and DR event notification application. PG&E requests funds for InterAct system updates, licensing fees, labor costs, and operational costs.
- Notifications: PG&E utilizes two notification systems for its DR programs: Varolli and Yukon. PG&E contracts with Varolli, a third party vendor, to provide notifications for PeakChoice, Peak Day Pricing, Demand Bidding Program, Base Interruptible Program, Schedule Load Reduction Program, Optional Binding Mandatory Curtailment Program and AMP Contractors. PG&E requests funds in this category for licensing fees, notification costs and labor costs. To provide SmartAC notifications, PG&E uses the Yukon system. Another CAISO integration project, PG&E plans to update Yukon to accommodate locational dispatch. PG&E requests funds for IT enhancements, notification and labor costs in the effort to revise Yukon for CAISO integration.

PG&E also proposes funds for PDR Risk Assessment and Review to capture PDR transactions; and for Meteorology Services Group to expand activities in support of Peak Day Pricing, Capacity Bidding Program, PeakChoice, SmartAC, day-ahead Demand Bidding, PDR and Load Research.

7.3.1.2. SCE

SCE recommends a budget of $20.6 million in the DR System Support Activities Category for DR system infrastructure expenses during the 2012-2014 program cycle.[219] In addition to these new expenses, SCE requests that the Commission allow SCE to carry over unspent CAISO integration funds authorized in D.10-12-047.[220] SCE explains that many of these previously authorized costs target the revision of SCE's retail DR programs to be compatible with CAISO wholesale products like PDR and RDRP. Despite receiving the 2009-2011 funds to update programs for PDR and RDRP integration, SCE only anticipates completing work by the end of 2011 that enables the Capacity Bidding Program and Demand Bidding Program to participate in PDR. However, if the Commission authorizes SCE to carry over the unspent CAISO funds, SCE alleges it will be able to complete the work necessary for SCE's DR programs to be compatible with RDRP by 2012.

SCE identified nine infrastructure items, equaling $12.4 million, to support DR programs during the 2012 – 2014 program cycle and beyond. The following table depicts the requested allocations for these expenses, including funds initially requested in D10-12-047. In addition to these expenses totaling $12.164 million, SCE has also identified $8.436 million in labor and non-labor expenses. SCE explains that the non-labor costs include $2.08 million in contracts, $100,000 in on-line training and approximately $79,000 for administrative overhead expenses.

TABLE 7.3.1.2
SCE'S SYSTEMS AND TECHNOLOGY BUDGET REQUESTS FOR 2012-2014

Infrastructure Expense	Activity	Amount Initially	Amount Newly requested in

219 SCE-02 at 147.

220 SCE-01 at 122. In D.10-12-047, the Commission authorized $3.535 million to fund CAISO-related PDR and RDRP integration costs.

SubCategory		Requested in D10-12-047	A.11-03-001
Customer Contact and Notification System ($1,125,000)			
	Outage Notification Communication		600,000
	System Enhancements for PDR/RDRP Geographic Dispatch	150,000	
	Event Notification System (ENS) Licensing Fees		345,000
	ENS CPP	234,000	
	ENS Save Power Day	957,000	
	FirstCall Interactive Licensing & Notification		180,000
Load Control and Dispatch Platforms ($6,864,000)			
	Alhambra FMRadio Communications System Licensing, Notification and System Enhancements		1,426,000
	Implementation of PDR/RDRP Geographic Dispatch	275,000	
	DR Automation Server Licensing, Software, & Enhancements	200,000	1,775,000
	APX Bidding & Event Dispatch Platform Licensing, Hosting, Security, & System Enhancements		2,163,000
	Advanced Load Control System (ALCS) Implementation of SEP IP		1,000,000
	ALCS Unanticipated Modifications with SCE Back Office		500,000
Load Control and Event Dispatch End User Technologies ($165,000)			
	Auto DR		40,000
	DR Gadgets		125,000
Customer Web Pages for Program Education and Event Notification ($1,160,000)			
	Ingrate Existing Energy Manager Suite w/Auto-DR Platform		100,000
	Update, Implement, & Modify Web Training Modules		60,000
	Unanticipated Projects		500,000
	Implement PDR/RDRP Geographic Dispatch	2,000,000	
	Modify Bidding & Settlement Systems for DBP	1,000,000	
	Develop, Modify, & Maintain Existing Customer Web Pages to Support DR Programs.		500,000
Customer Relationship Mgmt Systems / Reporting Environments ($2,000,000)			
	Develop and Maintain CRM		1,500,000
	Develop Integrated Systems to Manage Customer Enrollment		500,000
Billing and Event Settlement Dispatch Systems ($750,000)			
	Modify CSS central Billing System to Accommodate Dual Participation and Settlement Baseline		750,000
Technology/Software Needs ($100,000)			

	Activities and equipment to Support Dispatch/Measurement of DR Events		100,000
Total		$4,816,000.00	$12,164,000.00

7.3.1.3. SDG&E

SDG&E requests a budget of $5.4 million to implement all DR-related IT updates. SDG&E proposes funding for three specific IT projects: Customer Relationship Management System, Middleware, and CAISO Integration.

With full deployment completed in 2010, SDG&E plans to maintain its Customer Relationship Management System during the 2012-2014 period.[221] SDG&E requests a total budget of $1.259 million to cover the costs related to this system.

SDG&E proposes to implement a Middleware Infrastructure, a framework to interface between internal and external systems. Recommending a budget of $0.839 million to cover the cost of design, development and deployment of the Middleware Infrastructure, SDG&E also requests $1.8 million to fund additional hardware, software and interfaces necessary to synchronize program and event data across applications on this framework.

SDG&E proposes minor IT purchases that will enable its DR programs' participation in the CAISO wholesale market programs. Noting that CAISO uses varying automated systems to enable bidding, scheduling, dispatching, and settlement of standard generation resources, SDG&E points out that these systems were used for the SDG&E's 2009 Participating Load Pilot. Through this pilot, SDG&E identified potential functional interfaces to incorporate PDR-ready DR programs. SDG&E requests an initial budget of $1.5 million to fund CAISO

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[221] SDG&E states that it may update to a newer version of its Customer Relationship Management System but does not specifically request funding for the update.

MRTU IT infrastructure and system licenses and maintenance. SDG&E asserts that further MRTU Integration efforts will be recorded and recovered through its MRTU Memorandum Account.

7.3.2. Parties' Positions

TURN's testimony focuses on SCE's IT costs in relationship to program cost-effectiveness. TURN argues that several IT costs were not included in SCE's cost-effectiveness analysis and templates.[222] TURN contends that SCE omitted as much as $164 million in GRC-funded software project costs in its DR cost-effectiveness analysis.[223] In response, SCE submitted an alternative analysis with a cost-effectiveness spreadsheet that includes some of these GRC DR-related costs.[224] As a result, TURN urges the Commission to verify that the other two utilities have properly included all IT costs in DR cost-effectiveness analyses.[225]

On a related matter, TURN suggests that the Commission reconsider its requirement that 10 percent of the Utilities' DR portfolio be bid into the CAISO market as PDR. Highlighting the $36 million cost of a software system to support Dynamic Pricing, TURN recommends that the Commission "reconsider the push toward dynamic pricing."[226]

CAISO takes notice of PG&E's DR operations costs and argues that a shift toward a competitive procurement paradigm for DR will be a more efficient

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[222] TRN-01 at 3.

[223] TRN-01 at 9.

[224] SCE-08.

[225] TRN-01 at 4.

[226] TRN-01 at 3.

means of acquiring DR and relieve ratepayers of inordinate utility IT and infrastructure costs that will likely increase over time.[227]

7.3.3. Discussion

In the Commission's review of the Utilities' proposals for DR IT costs, we found three challenges that impacted our analysis. First, throughout the applications, the Utilities often include labor costs within the IT costs in addition to labor allocated separately for regulatory and other management support. The consolidation of these costs makes it difficult for the Commission to assess the reasonableness of DR proposals. Second, the Utilities do not provide adequate description or justification for most of their IT funding requests. Third, the Utilities do not adequately demonstrate what costs are being recovered in this proceeding, why they are distinct from costs requested in other proceedings and, why they do not represent a duplication of other efforts or costs. The following discussion provides multiple examples of the inadequacy of the Utilities' IT requests.

PG&E provides seven separate labor-related line items in workpapers for the DR Enrollment & Support portion of DR Operations. PG&E requests over $15 million for DR Enrollment & Support, $4 million of which is allocated to the Contracts and IT line item. Without more information to substantiate this request, it is not reasonable that nearly 30 percent of PG&E's DR Operations is attributable to labor costs not withstanding other labor costs from administration and overhead. Similar to PG&E, SCE's requested labor and administration costs do not include labor costs from administration and overhead. SCE projects

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[227] ISO-01 at 10-13.

$8.43 million in labor and administration costs for twelve SCE employees, representing nearly 40 percent of the total $20.6 million SCE requests. Based upon the record, none of the labor-related funding requests are reasonable.

SCE identifies $500,000 for unanticipated activities related to its Customer Web Pages for Program Education and Event Notification tasks and $500,000 for unanticipated modifications to SCE's back office systems. SCE has presented minimal information to justify these expenses. It is not reasonable to approve $1 million in costs that are neither justified nor properly documented.

While the Utilities argue that the CAISO integration requires these proposed IT changes, none provide adequate description and justification for these projects. The Utilities' Applications did not provide justification as to why a utility chose one IT solution from among other comparable solutions. SCE, for example, explains the intention of a proposed system and the impact on DR programs but neglects to explain the choices or provide the reasons for the ultimate selection. CAISO challenges SCE's proposed telemetry costs for its Ancillary Service Tariff, arguing that "Edison's meter estimate is overstated and needs to be substantiated."[228]

Relatedly, TURN's testimony presents $164 million in software costs that SCE requested in its 2011 GRC application.[229] The Commission must ensure that the Utilities are not recovering costs more than once for software and hardware systems to support DR programs. Again, the Utilities provide inadequate

[228] ISO-01 at 19.

[229] TRN-01 at 11.

information in their applications to fully explain and justify IT activities and the associated funding requests.

SDG&E's DR IT Systems budget request for 2012-2014 is reasonable. However, given the level of CAISO integration requirement costs, SDG&E's IT budget may be understated. Like PG&E and SCE, SDG&E co-mingles requested IT equipment costs with labor costs, and imbeds management labor costs in general administrative and overhead costs. In D.09-08-027, we denied SDG&E's IT budget because of a lack of description. For the 2012-2014 DR budgets, all three utilities present the Commission with the same situation.

In Section 6.2, we stated our expectation that the Utilities provide DR programs that are reasonably cost-effective. Because we have determined a need to decrease overall costs for most DR programs, and because the Utilities have not provided adequate justification for the specific requests in their DR Systems Support budgets, we find it reasonable to decrease the budgets in this category to improve the cost-effectiveness of the DR programs associated with the costs in DR Systems Support Activities.

In calculating the cost-effectiveness of a DR program or activity, the costs incurred from the DR Systems Support Activities budget are spread across each DR activity. Instead of proposing specific decreases to PG&E's and SDG&E's Systems Support budgets or additional cuts for SCE, we direct each utility to decrease overall program budget requests to make each program cost-effective. We allow the three Utilities to allocate the decreases across the DR Systems Support and ME&O budget categories and individual program administrative budgets to provide California with cost-effective DR programs. The Utilities may decrease either internal program costs (i.e., administrative or capital costs of the program) or external costs (e.g., marketing and IT budgets which were not requested as part of the program but were allotted to program costs in the cost-effectiveness analysis). The specifics of these decreases are addressed within the discussions of the individual DR programs. For certain programs, this requirement can be met by program modifications to increase the benefits of the program.

The Commission issued D.11-11-008 delaying, until November 2014, the implementation of PG&E's small and medium business customers defaulted to Peak Day Pricing. As a result, we reduce PG&E's budget request for Peak Day Pricing notifications to $1.339 million for notifications and $0.758 million for labor. In addition, we decrease SCE's overall Category 8 budget by $1 million. We find the two $500,000 requests for "unanticipated activities" to be unreasonable and unjustifiable and deny these requests.

7.4. Reliability-Based DR

Reliability or emergency-based DR programs are those programs triggered by the Utilities in response to an actual or imminent declaration by CAISO of a system emergency. The Commission directed the Utilities to transition its DR activities from reliability-based programs to price-responsive programs. In Phase 3 of R.07-01-041, the Commission approved a Joint Motion Settlement Agreement (Settlement Agreement) removing Commission-required enrollment caps on interruptible programs,[230] creating a new wholesale reliability market product called RDRP, and mandating that all utility emergency-triggered programs participating in RDRP continue to receive resource adequacy counting.

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[230] D.09-08-027 capped demand response emergency programs at then 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.

The Commission adopted, as part of the Settlement Agreement, the condition that the amount of emergency-triggered DR MW attributable to Resource Adequacy decreases from a cap of 3 percent of the CAISO all-time system peak in 2012 to 2 percent of system peak in 2014.

7.4.1. Utility Proposals

7.4.1.1. PG&E

PG&E currently maintains three reliability-based programs: Base Interruptible Program, Optional Binding Mandatory Curtailment Program,[231] and Scheduled Load Reduction Program.[232] For the 2012-2014 DR budget cycle, PG&E recommends changes solely to the Base Interruptible Program including the implementation of a pre-enrollment qualification process, retesting for non-compliant participants, limiting enrollment if the MW cap is approached, and allowing Base Interruptible Program participants to dual participate in PG&E's best effort day-ahead Peak Choice program. PG&E's proposed changes reduce the amount of reliability-triggered programs that count toward its resource adequacy requirements. PG&E notes that this is consistent with the terms of the Phase 3 Settlement Agreement, including the MW cap whereby PG&E's MW cap is 543.9 MW through 2016.

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[231] Both PG&E and SCE have Optional Binding Mandatory Curtailment programs which exempt qualifying customers from reduction of electric supply during scheduled rotating outages in exchange for a partial power reduction of their entire distribution circuit during every rotating outage when system and local emergencies occur.

[232] Schedule Load Reduction Program is subject to Public Utilities Code Section 740.10 and, despite a lack of customer participation, cannot be terminated without legislation.

7.4.1.2. SDG&E

As part of its policy to simplify its DR programs and reduce the reliance on reliability-based programs, SDG&E proposes to make the Base Interruptible Program its only reliability-based program. SDG&E requests to eliminate its Optional Binding Mandatory Curtailment Program and Critical Peak Pricing-Emergency programs. Although the Schedule Load Reduction Program is legislatively mandated and SDG&E will continue to offer the program, SDG&E proposes to minimize Schedule Load Reduction Program expenditures. With the Base Interruptible Program being its only reliability-based program, SDG&E recommends limited changes to keep below its 20 MW cap. SDG&E proposes to bid the Base Interruptible Program into CAISO's RDRP mechanism. As such, SDG&E requests the elimination of Option B of the Base Interruptible Program because the three-hour response time allowed in Option B does not comport with the 40-minute requirement in RDRP. SDG&E also requests to add a summer month rate premium. As previously discussed, SDG&E proposes to eliminate dual program participation in Base Interruptible Program.

7.4.1.3. SCE

In recognition of the transition of DR programs from reliability to price-responsive programs, SCE proposes to add a price-responsive component to its Summer Discount Plan.[233] The Summer Discount Plan will be reviewed and discussed under the price-responsive chapter of this decision. SCE requests to

[233] As part of the terms of the Phase 3 Settlement (D.10-06-034), SCE agreed to file an application to create a price-responsive option for SDP by the end of the second quarter of 2010 so that SDP could be bid into the CAISO market.

make minor changes to its Agricultural Pumping Interruptible[234] and Base Interruptible Programs[235] to transition them to wholesale RDRP. However, because the Agricultural Pumping Interruptible and Base Interruptible Programs are close to SCE's 2016 cap of 659 MW when combined, SCE plans to stop marketing the Base Interruptible Program unless measurable attrition provides sufficient headroom under the cap. To manage against rate subsidies if the MW cap is exceeded, SCE proposes to reduce the incentive payments for all interruptible programs covered by the MW cap requirement during the calendar year in which the oversupply is expected.

SCE requests a budget of $52,995 for its Schedule Load Reduction Program. SCE explains that in the Schedule Load Reduction Program, enrolled customers nominate a load reduction through one of three options where at least 15 percent of demand will be compensated on a per-kWh credit on their bills for the amount reduced. Despite no enrollment in the Schedule Load Reduction Program, SCE points out that the program is legislatively mandated and thus recommends continued funding at the minimal requested budget level.

SCE requests no changes to its Optional Binding Mandatory Curtailment or Rotating Outages Programs.

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234 Changes to the Agricultural Pumping Interruptible include modifications to align the program trigger with the requirements of the RDRP and to allow for geographical dispatch of events, and modifications to existing notification systems and event performance and tracking databases.

235 Changes to the Base Interruptible Program include modifications to existing notification systems, billing system, and event performance and tracking databases, and reprogram remote terminal units to allow for regional dispatch.

7.4.2. Parties' Positions

Only DRA and CLECA provided comments regarding the Utilities' Reliability programs. DRA recommends the Commission not approve PG&E's and SDG&E's Base Interruptible Program programs unless the programs' cost structures are changed to improve the TRC result to above 1.0. DRA supports PG&E's proposed mechanism to deter non-compliant Base Interruptible Program participants and recommends the Commission apply the same mechanism to SCE and SDG&E's Base Interruptible Program.[236] CLECA recommends retaining the Base Interruptible Program, but increasing PG&E's Base Interruptible Program operating hours from 120 to 180 hours to improve the program's cost-effectiveness,[237] which PG&E agrees to in its rebuttal testimony.[238] CLECA expresses concern with SCE's proposal on how to manage the cap limit because of the potential impacts to the participants.

7.4.3. Discussion

7.4.3.1. Compliance

As described earlier, the Commission adopted a Settlement Agreement in D.10-06-034 which has a significant impact on the Utilities' Base Interruptible Program. Among other things, the Settlement Agreement sets cap limits on the resource adequacy counting for these programs[239] and requires the Utilities to

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[236] DRA-01c, Chapter 3 at 3-5.

[237] CLE-01, Chapter II at 10.

[238] PGE-08, Chapter 2 at 2-11.

[239] PG&E' and SCE's AC Cycling programs are currently considered reliability-based programs pending Commission's decisions on the Utilities' applications to transition

Footnote continued on next page

address the oversupply if the total load impacts from these programs exceed the cap limits. The cap limit for 2012 Resource Adequacy compliance year is 1,659 MW for the three utilities combined, which will decrease to 1,005.4 MW in 2016. PG&E's and SDG&E's program load impacts from the reliability-based programs are well under the cap for 2012 as well as 2016.

In compliance with D.10-06-034, the Utilities provided testimony addressing the cap issues. We find the Utilities' cap proposals reasonable. Based on the Utilities' ex ante forecast as shown in their April 1, 2011 Load Impact reports and the Utilities proposals, we do not anticipate any oversupply issues pending the final decisions on the SCE's applications on transitioning the AC cycling programs to price-responsive programs.[240]

7.4.3.2. Reasonableness

Our examination of the Utilities' cost-effectiveness analyses of the Reliability programs included the statewide Base Interruptible Program and SCE's Agricultural Pumping Interruptible programs. The table below provides a list of these programs and the utility results of the cost-effectiveness tests.

TABLE 7.4.3.2				
Cost-Effectiveness Test Results of Utilities' Reliability Programs				
Program	TRC	PAC	RIM	Determination
SCE's Agricultural Pumping-Interruptible	1.12	0.88	0.88	Possibly Cost-Effective
PG&E's Base Interruptible	0.90	0.73	0.73	Possibly Cost-Effective

them into price-responsive programs in the Utilities' AC Cycling and this DR application.

[240] A.10-06-017, the assigned ALJ issued a proposed decision on September 19, 2011.

Program				
SDG&E's Base Interruptible Program	0.98	0.82	0.82	Possibly Cost-Effective
SCE's Base Interruptible Program	1.33	1.01	1.01	Cost-Effective

SCE's Agricultural Pumping-Interruptible cost-effectiveness analysis resulted in a TRC greater than 1, but with PAC and RIM results of 0.88. However, SCE's cost-effectiveness analysis did not consider $685,650 for ME&O and EM&V costs. We recalculated the cost-effectiveness analysis to include the ME&O and EM&V costs. In order for the Agricultural Pumping-Interruptible program to be cost-effective, we direct SCE to decrease $613,029 from the program budget in addition to the $44,500 costs we eliminated from the Local DR ME&O budget and the $50,739 we eliminated in the DR Systems budget.

As can be seen on the cost-effectiveness Test Results table, SCE's Base Interruptible Program cost-effectiveness analysis resulted in TRC, PAC, and RIM benefit cost ratios all above 1.0. As this meets our previously discussed criteria for cost-effectiveness, two tests ratios of at least 0.9, we approve funding for SCE's Base Interruptible Program during 2012-2014, minus any ME&O requested funds.

SDG&E's cost-effectiveness analysis of its Base Interruptible Program resulted in a TRC of 0.98 and a PAC of 0.82. Pursuant to our cost-effectiveness approach, we find this program to be possibly cost-effective. We approve programs in the possibly cost-effective category if the utility can improve the benefits or decrease costs of the program. We find that since SDG&E needs to slightly improve the result of the PAC test, a small decrease in costs will result in a cost-effective program. A budget decrease of $362,179 will improve the PAC result to our required 0.9. We have eliminated marketing funds for all Reliability programs. In order to operate its Base Interruptible Program in a cost-effective manner, we require SDG&E to decrease the administrative costs of Base Interruptible Program by $192,478.

We approve SDG&E's request to eliminate its Base Interruptible Program Option B in order to conform the rest of the Base Interruptible Program to CAISO's RDRP. The cost-effectiveness analysis provided by SDG&E included the requested addition of a summer month premium. Because the cost-effectiveness analysis with the budget decrease produced a "cost-effective" result, we approve the summer month premium.

PG&E's Base Interruptible Program cost-effectiveness analysis shows that in order for the Base Interruptible Program to be cost-effective, the PAC result must be increased to 0.9. Because this is such a large program, improvement in the PAC result would require a substantial decrease in funding or an increase in benefits. As recommended by CLECA, increasing the availability of the Base Interruptible Program from 120 to 180 hours per year will increase the benefits of the program and thus improve its cost-effectiveness results. SCE's Base Interruptible Program is available 180 hours a year and its A Factor is 68 percent.[241] Increasing PG&E's A factor to 68 percent for the program results in a TRC of 1.05, but only a 0.85 for PAC and RIM. In order for PG&E's Base Interruptible program to be cost-effective, we direct PG&E to increase its availability to 180 hours and decrease its budget for this program by $3.9 million, in addition to the $140,704 we eliminated from the ME&O budget allocated to the Base Interruptible Program. Because this amount is greater than the

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[241] SCE-08, DR Reporting Template, "Base Interruptible Program" tab, cell D40.

administrative costs requested for this program, we direct PG&E to decrease the budget of DR Enrollment and Support by $3,963,399.

By directing PG&E to increase the availability of its Base Interruptible Program from 150 to 180 hours per year, we recognize that some currently-enrolled program customers rely on operating backup generation (BUG) in order to provide the committed load reduction. The record of this proceeding does not include information regarding whether these customers have valid air quality permits to operate the BUG for the increased number of hours. D.11-10-003[242] requires the Utilities to collect customer data on the use of BUGs for DR load reduction. We require the Utilities to include this data in the annual load impact reports. Additionally, we require PG&E to collect data to determine whether the customers enrolled in the Base Interruptible Program are able to meet the increased number of hours without violating federal, state or local air quality rules. We will address this issue further in our DR Rulemaking, R.07-01-041.

SDG&E requests the Commission approve the removal of the BUG provision from its Capacity Bidding Program and Base Interruptible Program tariffs. As we discussed above, we will further address the issue of BUGs in R.07-01-041. At this time, we deny SDG&E's request without prejudice until we can further develop the record on BUGs.

PG&E also proposes several changes to its Base Interruptible Program including a pre-enrollment qualification process and retesting for non-compliant participants. DRA supports both of these revisions and recommends that the Commission adopt these changes for the other two utilities. SDG&E agreed to

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[242] D.11-10-003, adopted by the Commission on October 6, 2011, further refines the resource adequacy program regarding DR resources.

do so,[243] but SCE opposes the recommendation to adopt PG&E's proposal. SCE claims that it has similar procedures in place. We find SCE's procedures adequate. Unless otherwise noted herein, we approve PG&E's and SDG&E's requested revisions to their Base Interruptible Programs.

Although enrollment in Schedule Load Reduction Program is zero, we approve budgets as requested for each utility's Schedule Load Reduction program because the program is legislatively-mandated. No party provided comment on the Optional Biding Mandatory Curtailment program, SCE's Rotating Outages program, or SDG&E's proposal to eliminate its Critical Peak Pricing- Emergency program. Because the Optional Biding Mandatory Curtailment and Rotating Outages programs are small, we authorize the budget requests for the Optional Biding Mandatory Curtailment Program for PG&E and SCE, for Rotating Outages from SCE. We approve the request from SDG&E to terminate its Optional Biding Mandatory Curtailment and Critical Peak Pricing-Emergency Programs.

We reiterate our prior finding that because the Commission has capped the size of Reliability programs attributable to resource adequacy, and because the Commission has provided no direction to increase enrollments in these programs, we find no need for the marketing of these programs. Thus approval of the Reliability programs in this decision does not include any funds for ME&O. We previously noted that in comments, the Utilities expressed a concern that ME&O funding is not just for marketing, but also for educating and notifying customers. Again, we recognize the need for the Utilities to educate

[243] SGE-06 at GMK 13.

and communicate to Reliability program customers. As we previously directed, if a utility finds it necessary to target funds to educate and communicate with Reliability program customers, they can shift funds from other DR programs within the ME&O category, so long as the programs remain cost-effective. Furthermore, funding for customer notifications should be allocated to the DR Support Systems budget category.

7.4.3.3. Meeting Future Needs

As directed by the Commission, the Utilities are transforming more reliability programs to price-responsive programs. In this respect, we find that the Utilities' Reliability programs are meeting the future needs of California.

7.5. Price Responsive DR Programs

Price responsive programs are a key component of the Commission's DR policy.[244] Utilities trigger these programs based on the price of the wholesale market or when system conditions warrant and provide participating customers with pricing incentives in addition to a routine energy rate. The three Utilities in this proceeding offer two key price-responsive programs: Demand Bidding[245] and Capacity Bidding[246] programs. In some cases, the Utilities contract with

[244] D.09-08-027 at 30.

[245] The Demand Bidding Program is a program in which customers submit bids specifying the amount of energy usage they are willing to curtail during DR events in exchange for a fixed incentive rate in the case of PG&E or to receive bill credits in the case of SCE. SDG&E does not provide a Demand Bidding Program.

[246] Capacity Bidding Program is a bidding program where customers make a monthly commitment to provide load reduction when called upon during program events. Participating customers receive a monthly capacity incentive payment for their committed load reductions, as well as an energy incentive payment based on the actual

Footnote continued on next page

third party DR providers to offer a program. The Utilities' price-responsive program proposals are described below.

7.5.1. Utility Proposals

7.5.1.1. PG&E

PG&E intends to modify its price-responsive DR programs, with the goal of increasing customer enrollment and participation, program cost-effectiveness, and participation in the CAISO market. PG&E requests budgets for and revisions to several price-responsive programs: Capacity Bidding Program, a combined Demand Bidding Program and PeakChoice program, and SmartAC.

PG&E requests to continue to make its Capacity Bidding Program available through third party DR providers. Traditionally, PG&E has offered its Capacity Bidding Program between the months of May through October; but has only provided monthly capacity payments from June to September. PG&E requests to extend the capacity payments to include May and October in an effort to take advantage of these customers' load shed capabilities.

As part of the overall movement to enable utility programs to be bid into the CAISO markets, PG&E proposes to transition all of its Demand Bidding Program customers to PeakChoice during 2012. The Demand Bidding Program would then cease to exist no later than December 31, 2012. PG&E alleges that this will eliminate the need for costly system upgrades required in order for the Demand Bidding Program to be bid into the CAISO markets.

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amount of energy reduced during the event. PG&E, SDG&E and SCE provide a Capacity Bidding Program.

PeakChoice is a price-responsive DR program that provides customers with options that tailor DR participation to accommodate the customer's operational needs and DR capabilities. PG&E considers PeakChoice its retail platform for CAISO's PDR product. In addition to transferring the Demand Bidding Program customers to PeakChoice, PG&E recommends several modifications to PeakChoice to meet the goals listed above: add a 10-minute notification product, broaden time availability, allow for more flexibility in load reduction commitments, expand customer eligibility to include Direct Access and Community Choice Access customers, allow Base Interruptible Program participants to dual participate in Best Effort Day-ahead PeakChoice, and expand event triggers. With the proposed changes and the inclusion of the Demand Bidding Program into PeakChoice, PG&E requests a budget of $10.501 million for PeakChoice during the 2012-2014 budget cycle.

PG&E's SmartAC program is an air conditioning direct load control program for residential and small and medium business customers. Pursuant to an all party settlement approved by the Commission in D.11-01-036,[247] PG&E must decrease the number of SmartAC devices to be installed through this program, maintain a target of 174 MW, and add a price trigger at the bid cap of the CAISO beginning in 2012. PG&E proposes several non-program changes that are meant to directly improve the efficiency of the SmartAC program but are not directly attributable to the SmartAC program budget including day of notifications to customers, refined locational dispatching, and the use of and interaction with dynamic pricing and HAN-enabled devices. Largely due to the

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[247] *Decision Approving Pacific Gas and Electric Company's 2010-2011 SmartAC Program and Budget*, D.11-01-036, January 27, 2011.

settlement limitations, PG&E requests a 2012-2014 budget of $25.054 million for SmartAC, only one-third of the 2009-2011 approved budget.

7.5.1.2. SDG&E

SDG&E identifies two goals relevant in the development of the price-responsive portion of its Application: simplifying DR programs and enabling DR programs for integration into the CAISO market. SDG&E requests budget authority for its Capacity Bidding Program and its Peak Time Rebate program. As a side note, SDG&E provides a brief discussion of two price-responsive programs for which it does not seek funding in this Application: namely PeakShift and Summer Saver.

SDG&E considers its Capacity Bidding Program to be successful in terms of customer acceptance, enrollment and participation. Hence, it proposes to continue this program with only a few revisions. To further increase enrollment and participation, SDG&E proposes increased annual incentive payments for key months, but balanced with decreased payments for shoulder months. In order to integrate its Capacity Bidding Program into the CAISO market, SDG&E intends to establish a price trigger and bid the Capacity Bidding Program day-ahead program as a CAISO PDR product. SDG&E also recommends that the Commission remove the backup generation provision from its Capacity Bidding Program and prohibit the use of backup generation to achieve load reduction. The total recommended 2012-2014 budget for these proposals is $11.9 million which represents a "best case scenario" of customer enrollment.

SDG&E's Peak Time Rebate program is an incentive-based program developed and approved in SDG&E's 2008 GRC. Peak Time Rebate helps customers achieve load reduction during peak energy consumption periods. Customers receive a base incentive for reducing energy through manual means and a premium incentive for reducing energy through automated enabling technologies. Peak Time Rebate's final roll-out, expected to begin in 2011, is contingent upon eligible customers having a Smart Meter and SDG&E completing the required IT and billing and notification system modifications.

SDG&E included the initial funding for the customer communication and education in its Smart Meter proceeding. In this DR budget Application, SDG&E requests to transition Peak Time Rebate into the DR portfolio, and requests additional funding for administration and ME&O for the program and its 1.1 million customers. SDG&E proposes a budget of 4.4 million for these Peak Time Rebate activities during the 2012-2014 DR budget cycle.

7.5.1.3. SCE

SCE proposes to offer a panoply of price-responsive programs: Demand Bidding Program, Capacity Bidding Program, Ancillary Services Tariff, Summer Discount Plan and the Save Power Day[248] Program. SCE anticipates these programs to provide a significant portion of the price-responsive DR in the 2012-2014 program cycle. Additionally, SCE expects to bid the Capacity Bidding Program, Demand Bidding Program, and Summer Discount Plan into the CAISO markets and thus proposes modifications to meet the requirements of programs participating in the market.

SCE seeks faster customer enrollment and increased customer satisfaction with its Demand Bidding Program. As such, SCE requests to expand the Demand Bidding Program to include non-residential customers with loads under 200 kW, reduce bidding limits to a 1kW minimum bid and eliminate

[248] Formerly known as the Peak Time Rebate Program.

aggregated participation in this program. SCE also proposes to modify the Demand Bidding Program design and systems to allow geographical event dispatch for integration with CAISO's MRTU as PDR. SCE explains that D.10-12-047 approved a request to repurpose $3.5 million to support program modifications that enable participation as PDR. Thus, SCE requests that the proposed changes to the Demand Bidding Program be funded through D.10-12-047. For the 2012-2014 DR budget cycle, SCE requests $1.786 million to operate the Demand Bidding Program.

As noted above, SCE expects to integrate its Capacity Bidding Program into CAISO and thus recommends business process and system modifications. SCE also proposes to change the Capacity Bidding Program to a year-round program to provide additional hours for available dispatch. To cover both the proposed modifications and the operations of this program for 2012-2014, SCE requests a budget of $0.96 million.

As directed by D.09-08-027, SCE proposes the adoption of a limited enrollment tariff to comply with the 10-minute dispatch notification time requirement for participation in the CAISO's Ancillary Services market as either PDR or Participating Load. SCE's proposal recommends an Ancillary Services tariff for a 5-minute minimum and 30-minute maximum event dispatch. SCE suggests that customers on this tariff must also be ADR enabled and must install equipment and software that can interface CAISO to supply telemetry data. SCE proposes to limit the number of customers receiving complimentary equipment, but incur the cost of equipment installation. SCE anticipates no more than five service accounts would participate in this program and requests a budget of $0.743 million to operate the Ancillary Services tariff.

As previously discussed, SCE's Summer Discount Plan is currently a reliability-based program but SCE is requesting to transition it to a price-responsive program[249] that provides credit to customers who allow their air conditioning units to cycle off and on during curtailment events.[250] Participating customers receive a monthly credit on their electric bills from June to October. In 2012-2014, SCE proposes to transition the 330,000 current customers to the new price-responsive program and enroll new customers in accordance with the SmartConnect business case.[251] SCE also proposes to double the available event hours for the Summer Discount Plan from 90 to 180 and implement a new market-based trigger allowing the Summer Discount Plan to be bid into CAISO using the PDR product. SCE included the funding for transitioning current customers into the price-responsive Summer Discount Plan in its Transition application.[252] In this Application, SCE requests $71.1 million to support the enrollment of 196,000 new customers, maintain operations, perform customer education and awareness campaigns, and provide legacy customers with the option for an override technology function.

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[249] Pursuant to the settlement agreement in D.10-06-034, SCE agreed to submit an application introducing a price-responsive option for the Summer Discount Plan such that the program could be bid into CAISO's markets.

[250] SCE filed application A.10-06-017 on June 30, 2010 requesting to transition the residential Summer Discount Plan to a price-responsive resource that can be bid into and integrated with CAISO's markets.

[251] The SmartConnect business case was approved in 2008 pursuant to the settlement agreement in D.10-06-034, Appendix A, Attachment B. (PCT Program Decision Modifications and Revised Business Case Assumptions.)

[252] See A.10-06-017 at 1-2.

The Save Power Day Program[253] is an incentive program that offers residential customers bill credits for lower energy usage during certain peak usage periods throughout the year. Residential customers are defaulted to the Save Power Day Program once they receive an Edison SmartConnect meter. The Save Power Day Program was approved and funded as part of the SmartConnect business case. Costs incurred through 2012 are funded through the Edison SmartConnect Balancing Account. SCE requests Save Power Day Program funding for 2013-2014 to include ME&O, direct event notification, a rebate program for enabling technologies, and program management and administration. SCE requests a total budget of $24.7 million to administer and operate the Save Power Day Program.

7.5.2. Parties' Positions

Most parties commenting on price-responsive programs, focused on the cost-effectiveness of these programs. If a comment referenced a specific program or a specific change to a program to improve the program's cost-effectiveness, we discuss it here. Otherwise, we addressed the comment in our cost-effectiveness discussion and do not restate it here.

CLECA urges the Commission to continue the Demand Bidding Program for both bundled and direct access customers as it is a proven, cost-effective utility DR program. DRA recommends the Commission not approve PG&E's request to combine the Demand Bidding Program with PeakChoice. DRA asserts that no PeakChoice options are cost-effective, including those combining the Demand Bidding Program with PeakChoice. DR Aggregators recommend

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[253] Formerly known as the Peak Time Rebate Program.

that PeakChoice be expanded through the use of third party DR providers to facilitate customer participation.

UCAN recommends that the Commission condense SDG&E's Peak Time Rebate program. UCAN opposes most, if not all, of the $4.4 million Peak Time Rebate budget requested by SDG&E for two reasons. UCAN believes the cost is excessive and also asserts that the funding SDG&E is seeking in a separate proceeding could be leveraged to educate customers about dynamic pricing and Peak Time Rebate to customers.[254]

DRA expresses concern about the low cost-effectiveness results for all three utilities' Capacity Bidding Program, but offers no solution to improve the cost-effectiveness of this program. DRA recommends that the Commission deny funding for all Capacity Bidding Programs unless the Utilities can improve the cost-effectiveness results for the program. DRA also suggests that SDG&E did not correctly perform the cost-effectiveness analysis on its Peak Time Rebate program by not capturing all associated costs of Peak Time Rebate in the cost-effectiveness analysis.[255]

7.5.3. Discussion

In our previous discussion on cost-effectiveness, we described our approach to the review of a DR program and the approval or denial of a program's funding. In our discussions on ME&O and DR Systems funding, we determined that many DR programs need to be less costly in order to be cost-effective. We decreased the budgets in ME&O and DR Systems to move the

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[254] UCN-01 at 4 and SDG&E application 10-07-009 at http://www.sdge.com/regulatory/documents/a-10-07-009/Application.pdf.

[255] DRA-01 at 3-18.

programs closer to being cost-effective. The following discussion identifies the findings of our cost-effectiveness analysis regarding price-responsive programs and then addresses each price-responsive program along with any necessary modification to improve the cost-effectiveness.

TABLE 7.5.3		
Results of Program Review using Cost-Effectiveness Protocols and 3-Prong Approach		
PG&E Capacity Bidding Program day-of	Cost-Effective	Approved
PG&E E Capacity Bidding Program day-ahead	Possibly Cost-Effective	Approved w/Modifications
PG&E PeakChoice + Demand Bidding Program	Not Cost-Effective	Denied
PG&E Demand Bidding Program	Possibly Cost-Effective	Approved w/Modifications
PG&E PeakChoice	Not Cost-Effective	Denied
PG&E SmartAC residential	Possibly Cost-Effective	Approved w/ Modifications
PG&E SmartAC non-residential	Not Cost-Effective	Approved w/ Modifications
SDG&E Capacity Bidding Program	Possibly Cost-Effective	Approved w/ Modifications
SCE Capacity Bidding Program	Not Cost-Effective	Approved w/ Modifications
SCE Demand Bidding Program	Possibly Cost-Effective	Approved w/ Modifications
SCE Ancillary Services Tariff	Possibly Cost-Effective	Denied without Prejudice
SCE Save Power Day	Cost-Effective	Approved
SCE Summer Discount Program non-residential (enhanced)	Cost-Effective	Approved
SCE Summer Discount Program residential	Cost-Effective	Approved
SCE Summer Discount Program non-residential (base)	Possible Cost-Effective	Approved w/ Modifications

7.5.3.1. "Cost-Effective" & "Not Cost-Effective" Programs

As a result of our analysis and approach, we find the following programs "cost-effective": PG&E's Capacity Bidding Program (day-of), SCE's Save Power Day, SCE's Summer Discount Program non-residential enhanced, and SCE's Summer Discount Program residential. We approve these programs as requested and authorize budgets for these programs with no further modifications other than the ME&O and DR Systems budget decreases we previously discussed.

We find the following three programs to be "Not Cost-Effective:" PG&E's SmartAC non-residential, PG&E's PeakChoice with or without the Demand Bidding Program, and SCE's Capacity Bidding Program.

PG&E's SmartAC non-residential program performed very poorly on all the cost-effectiveness tests. Given the poor cost-effectiveness results and because there are other options available to non-residential customers who want to participate in DR programs (such as the Capacity Bidding Program, Demand Bidding Program and dynamic rates), our initial response is to deny funding for the non-residential SmartAC program and direct PG&E to terminate the program. In comments, PG&E asks to continue to operate its non-residential SmartAC program with its existing non-residential customers and decrease the overall SmartAC budget by $5,559,854.[256] This decrease, along with the required $3.7 million ME&O budget decrease, makes both the residential and non-residential portions of PG&E's SmartAC program cost-effective. We permit

[256] PG&E Comments at 10.

PG&E to continue to operate the non-residential portion of its SmartAC program with its existing customers and a limited budget.

Peak Choice, with or without the Demand Bidding Program, is not cost-effective. While the "Best Effort" options performed slightly better,[257] none of the other four Peak Choice options received cost-effectiveness results that could be considered "Possibly Cost-Effective" (attaining at least 0.5 in two or more cost-effectiveness tests). PG&E's analysis of the Peak Choice Best Effort day-ahead option without the Demand Bidding Program[258] may be in the "possibly cost-effective" range, but PG&E admits that this analysis is an approximation.

PG&E recommends that the Commission consider factors other than cost-effectiveness when determining the reasonableness of PeakChoice including future performance, flexibility and versatility, adaptability, locational value, and consistency with Commission policies.[259] PG&E asserts that PeakChoice successfully measures up to these factors. PG&E contends that PeakChoice provides multiple choices in multiple program characteristics thereby providing versatility.[260] DRA contends that PG&E's Peak Choice Best Efforts day-ahead is essentially the same program as the Demand Bidding Program.[261] PG&E emphasizes that PeakChoice is ready for the CAISO market since it can be

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257 PeakChoice Best Effort day-ahead attained results of 0.72 for the TRC, 0.72 for the PAC, and 0.69 for the RIM.

258 ALJ Ruling, August 5, 2011, Appendix: DR Cost Effectiveness Related Data. Available at http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm.

259 PG&E Opening Brief at 19.

260 PGE-01, Appendix 2B at 1-4.

261 DRA Opening Brief at 30.

locationally called and, compared to most of PG&E's other programs, already has the necessary software upgrades. We agree that it is an advantage for PeakChoice that it can be locationally called. However, we dispute PG&E's argument regarding software. Resolution E-4127[262] which approved PeakChoice states, "In its responses to Energy Division's data request, PG&E indicated that the IT system developed for the CSM[263] could be used to manage and operate current and future DR programs. Given the high costs of the IT system we explicitly direct PG&E to design and develop this system to be sufficiently flexible to allow it to be used for purposes of managing and operating current and future DR programs, as well as allow for potential modification to the options provided to customers, and allow for the potential future participation of aggregators. We believe this is critical in safeguarding ratepayer expenditure by mitigating the risk of stranded costs in the event the CSM program as approved herein is discontinued or significantly altered at some later date."

Setting aside the cost-effectiveness of this program, PeakChoice has not lived up to the potential PG&E has asserted. In a 2007 Advice Letter seeking approval for this program, PG&E predicted 42 MW by the end of 2008.[264] PG&E's 2009-11 Application predicted load impacts of 31, 117, and 292 MW for 2009, 2010, and 2011, respectively.[265] PG&E points out in comments, the 2009-2011 forecasts included the MW anticipated from a requested integration with

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262 The Commission adopted Resolution E-4127 on February 28, 2008.

263 PG&E initially referred to PeakChoice as the Cafeteria Style Menu (CSM) program.

264 PG&E Advice Letter 3085-E, July 13, 2007 at 6.

265 A.08-06-003, 2009-2011 DR application, Amended PG&E Testimony, Table 5-4 at 5-16, September 19, 2008.

the Base Interruptible and Demand Bidding Programs which the Commission denied.[266] In April 2011, PG&E's monthly reports shows load impacts of 25 MW.[267] PG&E's Application forecasts only 27 MW for 2012 and shows no increase through 2014.[268] Despite these expectations and given the past resignation of the Commission, PeakChoice simply has not achieved the results that PG&E anticipated.

Because PeakChoice fails most of the reasonableness factors discussed in the scoping memo, and performed dismally in all three cost-effectiveness tests, we deny funding for PeakChoice. In comments, PG&E and CAISO expressed concern about an abrupt end to PeakChoice.[269] Thus, while we require PG&E to terminate the program, transition its customers to other DR programs such as the Capacity Bidding Program and Demand Bidding Program, and adapt the IT system developed for it to PG&E's other DR programs, we recognize that this should be done in a thoughtful way. PG&E shall begin to migrate its customers to other DR programs in order to meet the following termination goals: 50 percent of its customers migrated to other programs by May 1, 2012 and the final 50 percent of customers migrated by the end of 2012. The specifics and schedule of this transition plan, including the details to adapt the IT system from PeakChoice to other DR programs and a revised plan to meet the 10 percent

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266 PG&E Comments at footnote 12.

267 PG&E Monthly Report on Interruptible Load and Demand Response Programs, April 2011.

268 PGE-01 at Table 8-5 at 8-7.

269 PG&E Comments at 9 and CAISO Comments at 11-12.

PDR requirements, shall be submitted in a Tier 2 Advice Letter no later than 90 days following the issuance of this decision.

Because we direct PG&E to terminate PeakChoice, we find no need to address DR Aggregators' recommendation to open PeakChoice to aggregators.

SCE requests to continue its Capacity Bidding Program but extend it to a full-year operation. SCE provided no details of this modification; nor did it include a cost-effectiveness analysis for a full-year operation. The Capacity Bidding Program is a state-wide program that is primarily administered by third party DR providers. Our analysis of PG&E and SDG&E's Capacity Bidding Program shows these programs to be "Possibly Cost-Effective." However, our analysis of SCE's program generates a "Not Cost-Effective" outcome. We compared the three utilities' Capacity Bidding Program programs to understand why a statewide program could have such a wide variation in cost-effectiveness, and why the A factors for this program differ so widely among the three utilities. Our review produced no conclusive answers to explain the differences in cost-effectiveness results.

SCE requests $237,500 for to market the Capacity Bidding Program, as they have only one directly-enrolled customer. As stated in the ME&O section of this decision, we expect that SCE requires little, if any, funding for marketing this program. The elimination of the Capacity Bidding Program marketing budget improves the program's TRC, PAC and RIM benefit cost ratios to 0.52, 0.45, and 0.43, respectively. However, even with this budget decrease, the Capacity Bidding Program remains in the non cost-effective category.

As we discussed earlier, SCE did not correctly perform the cost-effectiveness analysis of this program, incorrectly allocating EM&V and ME&O funds. To make the Capacity Bidding Program cost-effective, we would require an additional $5 million to be eliminated from the Capacity Bidding Program budget for the 2012-2014 budget cycle. A decrease of this magnitude may not permit SCE to adequately operate the Capacity Bidding Program. It is not reasonable to authorize a program with an inadequate budget nor is it reasonable to eliminate a statewide program in one part of the state.

Therefore, we allow SCE to maintain its Capacity Bidding Program, with the marketing budget of $141,500 eliminated but we also require SCE to decrease the program budget by an additional $2 million. Furthermore, we require SCE to increase the benefits of this program or further decrease the budget to make this program cost-effective.

To ensure improvement in the cost-effectiveness of the Capacity Bidding Program, we require SCE to perform an in-depth analysis of its program to (1) propose details of how the full-year Capacity Bidding Program would work, including additional incentive costs, forecasted load impacts, and an updated cost-effectiveness analysis for both the day-of and day-ahead options; (2) analyze the differences between PG&E, SDG&E and SCE's Capacity Bidding Program to determine why SCE's program is so much less cost-effective that the other utilities' program; and (3) provide a plan for improving the Capacity Bidding Program cost-effectiveness to 0.75 in 2013 and to 0.9 in 2014.[270] We direct SCE to submit this analysis in a Tier 2 Advice Letter to the Energy Division no later than 180 days following the issuance of this decision.

In the interim, we approve a budget of $661,287 for the Capacity Bidding Program, a decrease of $300,000 from the requested budget. In addition, we

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[270] At least two of the SPM tests must be at these levels.

eliminate $1.7 million from SCE's DR Systems budget to reflect the majority of the $1.9 million allocated to the Capacity Bidding Program. As we addressed in a prior discussion on BUGs, we deny without prejudice SDG&E's request to revise its Capacity Bidding Program tariff to prohibit BUGs.

7.5.3.2. "Possibly Cost-Effective" Programs

As a result of our cost-effectiveness analysis, we find the remaining price-responsive programs to be "possibly cost-effective" as shown in the tables below. As we addressed in our cost-effectiveness discussion, these programs become cost-effective (results of at least 0.9 in two or more of the cost-effectiveness tests) with increases in benefits and/or decreases in costs. The following table provides a list of the programs we have determined to be "possibly cost-effective" and the budget decreases required, in addition to decreases in the ME&O and DR System budgets that we previously discussed, in order for the programs to be considered cost-effective and approved. Unless otherwise stated, programmatic revisions requested by the Utilities in their applications for these programs are also approved.

TABLE 7.5.3.2 A Budget Cuts Needed for PG&E's Possibly Cost-effective Programs			
Program	**Budget Decrease Required for Cost-Effectiveness**	**DR Core M&O Budget Decrease**	**Remaining Budget Decrease**
Capacity Bidding Program Day-Ahead	*$2,721,415*	$1,500,750	$1,220,665
Demand Bidding Program	*further analysis must be provided by PG&E*		
SmartAC residential	$6,887,565	$3,722,278	$3,165,287
TOTAL			**$4,385,952**

TABLE 7.5.3.2 B
Budget Cuts Needed for SDG&E's Possibly Cost-effective Programs

Program	**Budget Decrease Required for Cost-Effectiveness**	**Program ME&O Budget Decrease**	**Remaining Budget Decrease**
Capacity Bidding Program	$4,304,607	$150,000	$4,154,607
TOTAL			**$4,154,607**

TABLE 7.5.3.2 C						
Budget Cuts Needed for SCE's Possibly Cost-effective Programs						
	Budget Decrease Required for Cost-Effectiveness	**Program ME&O Budget Decrease**	**DR IT Systems Budget Decrease**	**Omitted ME&O Budgets**	**Omitted Evaluation Budget**	**Remaining Budget Decrease**
Summer Discount Plan non-res. Base	$1,734,172	$123,368	$7,386	$14,641	$82,699	$1,700,758
Demand Bidding Program	$1,571,549	$0	$51,132	$11,200	($866,274)	$665,343
TOTAL						$2,366,101

The above requirements are mostly self-explanatory and unless otherwise stated herein, we approve these programs as requested and authorize budgets with the revisions listed above. There are a few exceptions as follows.

As previously discussed, we approve PG&E's request to decrease its SmartAC budget by $5.6 million in lieu of eliminating the non-residential portion of the program because the decrease makes the entire SmartAC program cost-effective. We also approve the request by DR Aggregators and agreed to by PG&E to enroll net energy metering customers in SmartAC.

In its Application, PG&E requested to combine the Demand Bidding Program with PeakChoice. Because we require PG&E to terminate PeakChoice, we deny PG&E's request to combine these two programs.

In its testimony, PG&E provided a combined cost-effectiveness analysis of its Demand Bidding Program with PeakChoice. Upon request, PG&E provided Energy Division an approximation of its Demand Bidding Program cost-effectiveness analysis.[271] PG&E's analysis indicates that the Demand Bidding Program is cost-effective. However, because the analysis is an approximation, we tentatively consider the Demand Bidding Program "possibly cost-effective". We require PG&E to perform an updated cost-effectiveness analysis and submit it along with a recalculated budget in a Tier 2 Advice Letter no later than 60 days from the issuance of this decision. If, however, the results indicate less than cost-effective, we will direct PG&E to further revise its Demand Bidding Program budget. We approve PG&E's Demand Bidding Program contingent upon the receipt and approval of the Advice Letter. We authorize PG&E a budget of $3.216 million for its 2012-2014 Demand Bidding Program, equal to the authorized amount for this program during 2009-2011.

We have decreased PG&E's Capacity Bidding Program budget by $1.5 million through our directives in the Local DR Marketing Category, as discussed in Chapter 11.2. Because the Capacity Bidding Program is administered by third party aggregators, we do not consider marketing by the Utilities necessary and we, therefore, eliminate its marketing budget completely. We are concerned that the budget for the day-of option of this program should be decreased by $1.22 million to be cost-effective. In comments, PG&E notes that because most PeakChoice customers are expected to migrate to the Capacity Bidding Program, the cost-effectiveness results will improve. At this time, we

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[271] ALJ Ruling, August 5, 2011, Appendix.

authorize the requested budget for the day-of option of the Capacity Bidding Program minus the requested marketing funds, contingent upon an additional Tier 2 Advice Letter submission in 45 days that shows the program is cost-effective without the additional $1.22 million budget decrease. Lastly, we approve the request by DR Aggregators and supported by PG&E to enroll net energy metering customers in the Capacity Bidding Program.

SCE must decrease the non-residential base budget of its Summer Discount Plan budget by a total of $1.734 million for the Commission to consider the program cost-effective.

Our review of SDG&E's Capacity Bidding Program shows that in order to be cost-effective, SDG&E must decrease its budget by over $4 million. In comments, SDG&E contends that such a large decrease would make it impossible to continue to operate the program. Instead, SDG&E proposes to increase the programs availability to make it cost-effective. We will allow SDG&E to submit a Tier 2 Advice Letter within 45 days showing that the increased availability will make this program cost-effective. The authorization of the funding for SDG&E's Capacity Bidding Program is contingent upon a cost-effective result.

SDG&E's analysis of its Peak Time Rebate program results in a "cost-effective" program. However, SDG&E did not perform the cost-effectiveness analysis correctly because they failed to include the per kW incentive provided to customers.[272] Our cost-effectiveness analysis included a per customer

[272] ALJ Ruling, August 5, 2011, Appendix.

incentive of $0.75 /kWh. The following table shows SDG&E's cost-effectiveness results for the Peak Time Rebate and the results that included the incentives.

TABLE 7.5.3.2 D		
Cost-Effectiveness Analysis of Peak Time Rebate		
	net benefits	benefit/cost
TRC	$19,298,279	3.92
PAC	$21,018,290	5.29
RIM	$18,724,942	3.60

TABLE 7.5.3.2 E		
Cost-Effectiveness Analysis of the Peak Time Rebate with the per customer incentive of $0.75/kWh		
	net benefits	benefit/cost
TRC	$12,685,107	1.96
PAC	$12,200,727	1.89
RIM	$9,907,379	1.62

The results of the analysis that includes the customer incentives show a "cost-effective" program. We do not require any further program modifications at this time, other than a decrease in the Local DR ME&O budget as discussed below. We require SDG&E to recalculate the cost-effectiveness analysis of the Peak Time Rebate program to include the customer incentives.

Our discussion in the ME&O section of this decision directs SDG&E to rely on online marketing for its Peak Time Rebate program. Consistent with our policy that the Utilities shall integrate, coordinate, and reduce ME&O, we re-categorize SDG&E's ME&O budget for its Peak Time Rebate program to the Local DR ME&O budget subcategory and reduce the budget by 24 percent.

We approve SDG&E's Peak Time Rebate program and authorize a budget of $0.485 million to administer the program. We direct SDG&E to submit a Tier 2 Advice Letter with its recalculated cost-effectiveness analysis within 60 days of the issuance of this decision.

We re-categorize the ME&O budget in SCE's Save Power Day program to the Local DR ME&O Category and decrease SCE's ME&O budget for this program by 50 percent. We approve SCE's Save Power Day program and authorize the remainder of the program's budget.

SCE proposes the Ancillary Service Tariff pursuant to OP 26 of D.09-08-027 which required the Utilities to file a proposal for at least one DR program that can participate in CAISO's Ancillary Service market. SCE requests $743,353 for its Ancillary Service Tariff program. We consider this program to be "possibly cost-effective" and may even be cost-effective with budget cuts. While SCE's cost-effectiveness analysis included the estimated $2.7 million in customer incentives, SCE failed to include a request for the estimated $2.7 million in customer incentives required for this program in its Application. SCE states that it "is currently developing the capacity credit amount for this [Ancillary Services] product and that a "final amount will be submitted with the tariff in the Advice Letter seeking authorization."[273] An Advice Letter is not the proper vehicle for funding requests. SCE should have requested the needed funding in this Application. Thus, we deny SCE's request for an Ancillary Services Tariff program without prejudice. SCE should propose a fully developed Ancillary Service Tariff program with a complete budget (including the administrative and

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[273] SCE-05 at 22, lines 10-11.

incentive costs as well as local marketing costs) through a Petition for Modification. As part of its filing, SCE should provide a cost-effectiveness analysis, which shows that the program meets the cost-effectiveness criteria in this decision.

7.6. Dynamic Pricing Program Budget Requests

The Utilities developed Dynamic Pricing programs in an effort to provide electric rates that reflect wholesale market conditions. Dynamic Pricing programs available to customers include Critical Peak Pricing and Real Time Pricing. Critical Peak Pricing imposes a short-term rate increase on customers during critical conditions. Real Time Pricing programs charge customers rates similar to actual hourly wholesale energy prices.

7.6.1. Utility Proposals

7.6.1.1. PG&E

PG&E contends that its Peak Day Pricing program, a dynamic pricing program, motivates participants to reduce demand in response to higher retail rates triggered by increases in the system-wide temperature.[274] While noting that dynamic rates programs are approved in rate-setting proceedings, PG&E requests approval of funds in this proceeding to support Peak Day Pricing. Specifically, PG&E requests funding to cover the costs of 1) measurement and evaluation efforts, and 2) personnel to support the notifications for Peak Day Pricing during 2014.[275] PG&E explains that these costs have not been covered in

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[274] PGE-01 at 2-31.

[275] *Ibid.*

other Peak Day Pricing proceedings.[276] We discuss the requested budgets for these efforts in the EM&V and DR Support sections of this decision.

7.6.1.2. SCE

In its 2012-2014 DR Application, SCE requests funding for two rate-based programs: Critical Peak Pricing and Real Time Pricing.

SCE conveys that, in D.09-08-028,[277] the Commission directed SCE to file applications for optional dynamic pricing rates and mandatory Time of Use rates. In A.10-09-002, SCE filed to extend its default Critical Peak Pricing/Time of Use tariff to 600,000 Commercial and Industrial customers with less than 200 kW demand and 1,200 Agricultural customers with equal to or greater than 200 kW demand. SCE also proposed to retain the Real Time Pricing-2 tariff structure and adapt it to all non-residential rate groups. The Commission directed SCE to seek cost recovery in either this DR application or the upcoming GRC.

Critical Peak Pricing is a summer season tariff whereby SCE offers participants lower energy rates during non-events in exchange for shifting or reducing electricity use during critical peak events when rates are higher. There are two Critical Peak Pricing programs, one for customers with loads equal to or greater than 200kW and one for customers with demands less than 200 kW.

For customers with demands equal to or greater than 200 kW, SCE offers a Critical Peak Pricing tariff of a 60 percent rate reduction for demand charges

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276 *Ibid.*

277 *Decision Adopting Settlements On Marginal Cost, Revenue Allocation, And Rate Design*, adopted by the Commission on August 20, 2009. http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/106088.pdf.

during non-event days. Energy charges during non-event days are equal to the Time of Use base rate. SCE proposed changes to the Critical Peak Pricing in A.10-09-002 including transitioning Critical Peak Pricing to a year-round program, applying demand credits only during the summer, and dispatching events year-round. SCE did not include marketing, education, and outreach funding in A.10-09-002 and thus, requests that funding in this DR Application. SCE proposes ME&O activities to continue ME&O efforts to defaulted Critical Peak Pricing customers, generate program awareness, and develop sales support materials. SCE requests a total budget of $2.67 million to implement and administer the Critical Peak Pricing for customers with demands greater than or equal to 200 kW.

For customers with demands less than 200 kW, SCE provides credits to either energy usage charges during a non-event or to time-related demand charges. Additionally, SCE bills the customer an increased energy charge during a Critical Peak Pricing event. In A.10-09-002, SCE proposes to default to Time of Use/Critical Peak Pricing rates those commercial and industrial customers with demands less than 200 kW and for agricultural customers with demands greater than 200 kW. SCE recommends these customers be given the option to opt out of this program. SCE requests funding to transition the 600,000 non-residential and 1,200 agricultural and pumping customers to the Critical Peak Pricing default rates. SCE recommends a budget of $7.63 million to include ME&O, event notifications, and program administration.

Real Time Pricing is a dynamic, Time of Use pricing tariff for Commercial and Industrial customers with demand greater than or equal to 500 kW. SCE bills participants for electricity based on temperature-driven prices. Because of the complexities of Real Time Pricing, SCE proposes to develop customer awareness through marketing and education efforts. SCE did not include the costs of this effort in A.10-09-002 and thus requests funding in this Application. SCE plans to integrate marketing efforts for Real Time Pricing with other DR programs. SCE requests a budget of $1.115 million to implement, administer and market the Real Time Pricing program.

7.6.1.3. SDG&E

SDG&E does not request funding for dynamic pricing programs.

7.6.2. Parties' Positions

DRA contends that the Commission should direct the Utilities to request funding related to dynamic pricing or rate-related programs in Phase I of GRCs. DRA argues that if the Commission reviews these programs in this proceeding, the results of the cost-effectiveness tests should be thoroughly examined. DRA points out that the results of the cost-effectiveness tests show that SCE's rate-based program, Critical Peak Pricing, is not cost-effective.

7.6.3. Discussion

Aside from PG&E's Peak Day Pricing program, the budget requests for rate-based programs are heavily focused on ME&O efforts. ME&O efforts for rate-based programs equal over $26 million for SCE and 3.8 million for SDG&E. As we discussed in the ME&O section, over the past several years the Commission has directed the Utilities to integrate, coordinate, reduce, and in some cases eliminate ME&O efforts. This decision puts the Commission and the Utilities back on course.

PG&E requests funding for its Real Time Pricing program for Evaluation, Measurement and Verification and for personnel to support the notifications for PDP. We address these requests in the EM&V and DR Systems Support sections of this decision.

SCE requests over $11 million for its Critical Peak Pricing program: $7.63 million for its program for customers with demand less than 200kW and $2.671 million for its program for customers with demand greater than or equal to 200 kW, and $1.115 million its Real Time Pricing program. SCE proposes that most of the funds be used for ME&O.

SCE explains that it did not include ME&O funding in its Application to implement the Critical Peak Pricing geared to customers with demand greater than or equal to 200 kW and, thus, requests that funding in this DR Application.[278] SCE proposes ME&O activities to continue ME&O efforts to defaulted Critical Peak Pricing customers, generate program awareness, and develop sales. SCE estimates that by 2014, this program will have fewer than 3,000 customers enrolled, but notes that the eligible population is 12,000.[279] For its Critical Peak Pricing program for customers with demand greater than 200 kW, SCE is requesting nearly $4 million solely to conduct ME&O activities. SCE filed a Dynamic Pricing Application for funding for the overall Critical Peak Pricing program for customers with demand greater than 200 kW, but did not include the funding for ME&O, event notification and program management and administration.[280]

The cost-effectiveness analysis of Critical Peak Pricing results in TRC, PAC, and RIM ratios of 0.4. SCE did not provide separate analysis of the two Critical Peak Pricing sub-programs. SCE's Critical Peak Pricing program is "not cost-effective". Because dynamic rate programs are in the purview of GRCs or

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[278] SCE-03 at 42-43.

[279] *Id*. at 44.

dynamic rate proceedings, we do not make program modifications in this proceeding. If we were to make changes, we would begin with the elimination of the marketing budgets which we find to be unreasonable. Instead, we deny SCE's request for funding for the Critical Peak Pricing program and direct SCE to request this funding in their 2012 GRC.

As was the case with Critical Peak Pricing, SCE states that it did not include funding in its Dynamic Pricing Application[281] for Real Time Pricing to support increased ME&O efforts.[282] Again, we deny this funding as it should have been included in its Dynamic Pricing Application. If SCE finds this funding to be necessary, we direct SCE to file a Petition for Modification within A.10-09-002.

7.7. Emerging and Enabling Technologies

7.7.1. Auto DR/Technology Incentives

Automated DR (Auto DR or ADR) refers to automated technologies that allow a customer's equipment or facilities to reduce demand automatically in response to a DR event or price signal, without the customer taking individual action. Limited data suggests that ADR customers have a higher participation

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[280] *Id*. at 46.

[281] Application 10-09-002.

[282] *Id*. at 39.

rate in DR programs[283] and provide better load shed.[284] Data also suggests that customers on dynamic rates perform better with ADR.[285]

In D.09-08-027, the Commission authorized over $20 million for ADR during 2009-2011 and ordered the DRMEC to evaluate ADR's load impacts, cost-effectiveness, predictability of load reduction, potential for expansion, and integration with CAISO markets.[286] In addition, the Commission also required the Utilities to include proposals for funding and incorporating ADR into DR programs for the next program cycle.[287] In September 2010, the Utilities submitted the results of the evaluation report.[288]

In the current applications, the Utilities have consolidated their Technology Incentive budgets to provide incentives only for ADR technologies (in the last cycle, incentives were offered for Non-ADR enabling technologies as well). The Utilities request a combined $71.2 million (PGE/$26.3 million, SCE/$35.8 million, and SDGE/$9.1 million) for Technology Incentives limited to ADR. Although the requested total budget for Technology Incentives is less than

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283 ALJ Ruling of August 5, 2011, Appendix at 21 and 29.

284 PGE-01 at 3-6, lines 14-15.

285 ALJ Ruling of August 5, 2011, Appendix at 29.

286 In September 2010, the Utilities submitted a report subsequent to a workshop to solicit input from stakeholders on proposals for the 2012-2014 DR program cycle.

287 D.09-08-027 at 93.

288 2009 Loan Impact Evaluation and Cost Effectiveness Tests of California Statewide Automated Demand Response Programs, Christensen Associates Energy Consulting, September 27, 2010 available at www.sdge.com/regulatory/documents/a-08-06-022/reports/AutoDR.pdf

the previous cycle of approx $73.23 million,[289] it is substantially larger than the $20 million amount budgeted for ADR last time.

7.7.1.1. Utility Proposals

The Utilities propose conceptually similar ADR program with differences in certain details (incentive levels, verification methods, eligible DR programs, allowed technologies, etc.). The Utilities recommend changes, motivated by the DRMEC evaluation report, to improve customer performance and cost-effectiveness. These changes include the following:

- Divide the incentive payment
  - 60 percent upon project completion and
  - 40 percent after one year, based on a customer's actual performance in a DR program. Currently, customer enrollment is sufficient; no performance is required.
- Require a three-year enrollment into the DR program by the customer. SDG&E proposes a one-year enrollment. Currently all utilities require one-year enrollment.

The incentive payments, ranging from $250/kW to $300/kW, are targeted to medium & large non-residential customers; however, both SCE & PG&E propose to expand eligibility to smaller customers.[290,291] PG&E proposes to make some funds available to small commercial customers at the rate of $450/kW. PG&E's proposal includes additional incentives to encourage the use of certain higher-cost emerging technologies, but is potentially more rewarding from a

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[289] In D.09-08-027, the Commission authorized budgets of $50.26 million for SCE Technical Assistance and Technology Incentives, $12.66 million for SDG&E TI and $10.31 million for PG&E TI for the 2009-2011 budget cycle.

[290] SCE-01 at 76, lines 10-12.

[291] PGE-01 at 3-13, Table 3-3, line 7.

load shed perspective, ranging from $50/kW to $150/kW.[292] SDG&E recommends additional incentives to aggregators[293] to motivate Critical Peak Pricing-D customers to install enabling technologies and encourage customers to perform during DR events.

The Utilities did not perform a cost-effectiveness analysis for the ADR budgets pursuant to the Guidance Ruling which considered ADR an enabling technology program. However, in the Utilities' cost-effectiveness analysis of DR programs, ADR budgets are allocated as costs to respective DR programs in proportion to expected customer enrollment.

7.7.1.2. Party Positions

CLECA supports targeting ADR as an enabling technology,[294] and agrees with PG&E and SCE's recommendation to require participating customers to enroll in DR for at least three years. As a supporter of targeting Technology Incentives to technologies that support open-ADR,[295] CLECA recommends that the Commission limit these incentives to technologies that use open-ADR.[296]

DR Aggregators consider the changes to ADR proposed by SDG&E and SCE to be unjustified and onerous, and claim that the changes will decrease incentives to customers.[297] DR Aggregators argue that the requirement to carry 40 percent of the cost of the technology is a substantial financial liability for

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[292] PGE-01 at 3-13, Table 3-3.

[293] SGE-01 at GMK-48, line 7.

[294] CLE-01 at 31.

[295] CLE-01 at 31-38.

[296] CLECA Opening Brief at 15.

[297] DR Aggregators Opening Brief at 28.

customers, equipment vendors or aggregators.[298] NAPP also opposes the 40 percent payment deferral, arguing that this could result in fewer customers willing to install ADR technology.[299]

Additionally, DR Aggregators request that the Commission require PG&E to revise its ADR program to allow enrollment by customers participating in bilateral contracts with third party DR aggregators.[300] NAPP agrees with DR Aggregators adding that the Commission should promote consistency among the Utilities and require PG&E to provide a similar offering.[301]

7.7.1.3. Discussion

In its evaluation study, the DRMEC found that customer load shed underperformed compared to the anticipated performance level of the equipment design. We find the Utilities' proposal to divide the payment into an initial 60 percent payment upon project completion and a 40 percent payment a year later predicated on the customer performance demonstration to be consistent with DRMEC's recommendation to address this issue. Moreover, the partial payment enhances the cost-effectiveness of the DR program by motivating the customer to demonstrate load shed performance at the level the equipment was designed to achieve.

We acknowledge that the additional 40 percent investment requirement could pose a financial liability to customers. However, we consider the one-year investment to be a minor inconvenience in comparison with the improved cost-

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[298] DAG-01 at V-2.

[299] NAPP Opening Brief at 13-14.

[300] DR Aggregators Opening Brief at 28.

effectiveness the programs experience. We reject DR Aggregators' recommendation to require the Utilities to provide customers 100 percent of the incentive amount upon project completion. In comments, several parties informed the Commission of a U.S. Department of Energy grant to equipment vendors to implement ADR.[302] This program provides customers federal grants for up to 50 percent of the costs of equipment needed to participate in the ADR program. However, the recipients of the federal grants must pay, up front, their matching half of the costs. The federal grant program expires at the end of 2012. Therefore during 2012, we will allow an exception to the 60-40 split discussed above for any customer enrolled in the federal ADR grant program.

Regarding DR Aggregators' request to revise its ADR program to allow enrollment by customers participating in bilateral contracts with third party DR aggregators, PG&E opposes this revision in ADR. PG&E states that its proposal to extend the existing third party contracts by one year, if approved, would not allow customers to participate in ADR. PG&E argues that "it would not be a good use of ratepayer funds to open ADR to AMP customers at this time when there is, at most, only a year left on their contracts."[303] We require PG&E to renegotiate the AMP contracts such that the contracts meet our cost-effectiveness requirements. We also allow PG&E to extend the renegotiated cost-effective contracts for a period not to exceed 2014. We agree with the DR Aggregators

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301 NAPP Opening Brief at 4.

302 Grant No. DE-OE0000314: see also Awards Summary at http://www.recovery.gov/Transparency/RecipientReportedData/pages/RecipientProjectSummary508.aspx?AwardIdSur=111472.

303 PGE-08 at 3-B-1.

that PG&E should open ADR to include AMP customers and require PG&E to revise its ADR program to include AMP customers once the AMP contracts are deemed cost-effective.

The Scoping Memo lists "consistency across utility programs" as one of the factors in determining the reasonableness of a program. We agree with CLECA's recommendation to align SDG&E with SCE and PG&E and see no reason for SDG&E to deviate from the practice of requiring ADR customers to enroll in some DR programs for a minimum of three years.

On a related matter, we note that the three ADR programs are conceptually similar but differ in many implementation details (incentive levels, verification methods, eligible DR programs, qualified technologies, application processes, etc.). By the end of the 2012-2014 DR program cycle, the Utilities will have had more than six years experience in managing ADR programs. We expect that by that time, the Utilities should be converging on a core set of best practices. In keeping with this policy of increasing consistency across utilities to reduce transaction and program costs, we direct the Utilities to collaborate on the development of a statewide ADR program with common program rules and incentive levels and present a proposal to Energy Division no later than October of 2013. We anticipate the 2013 proposal to be a precursor to any ADR proposal in the 2015-2017 DR Application.

We approve the utility ADR programs as requested but with the discussed modifications and direct the Utilities to fund ADR technologies that interoperate using generally accepted industry open standards or protocols. We authorize the ADR budgets as requested for 2012-2014.

7.7.2. Emerging Technology

Emerging Technology programs provide funding to research studies of new and emerging technologies and equipment, processes, and products. In D.08-09-027, the Commission authorized the following budgets for Emerging Technology: PG&E - $2.4 million, SDG&E - $2.1 million, and SCE - $9.24 million. We concluded that it would be helpful to develop guidance on the use of DR-related research and development funds including the types of projects to be funded and reasonable funding amounts. At this time, the Commission has not developed such guidance.

7.7.2.1. Utility Proposals

PG&E proposes evaluations in four emerging technologies: Open ADR-based commercial and public Plug-In Electric Vehicle charging systems, energy storage technologies, technologies that facilitate real-time feedback of DR resources, and technologies and controls that facilitate DR resources to provide new capabilities including ancillary services. PG&E requests a budget of $3.7 million to perform these evaluations.

SCE plans to leverage current collaborations while seeking out new ones in order to advance DR as it relates to codes and standards, the expansion of residential DR, and commercial and industrial customer solutions. SCE proposes several activities that explore the technical aspects of whole market integration: telemetry deployment, improving the quantification of performance, and technologies that support IDSM. SCE requests the Commission to authorize a budget of $7.3 million for its Emerging Technology projects.

SDG&E will focus on four categories of emerging technologies: heating ventilation and air conditioning (HVAC), energy storage, advanced controls, and electric vehicles. SDG&E proposes to evaluate and discuss barriers, risks, merits and cost-effectiveness for projects in these categories. SDG&E requests $2.1 million to cover the costs of proposed evaluations and demonstrations.

7.7.2.2. Discussion

Parties provided few comments regarding the Utilities' proposed programs and budgets for Emerging Technology.

In D.08-06-027, the Commission determined that given the continuing evolution in DR techniques, enabling technologies, and evaluation methods, California benefits from investing in research and development that will encourage the adoption of cost-effective DR. We find it reasonable to continue funding Emerging Technology projects for all three utilities. Our review of utility Emerging Technology proposals indicates that the programs address appropriate technologies needing evaluation and appear reasonable in terms of budget requests. Unless otherwise noted herein, we approve the Emerging Technology proposals as requested. We authorize the proposed 2012-2014 Emerging Technology budgets as requested for each utility.

As in D.08-06-027, we continue to emphasize the importance of ensuring that the research and development undertaken is understood by this Commission and can be shared with other research entities. We require the three utilities to provide semi-annual reports regarding their Emerging Technology projects to the Commission's Energy Division. These reports shall summarize each project, the potential benefits of the technology or technique, the activities undertaken as part of the project, and provide any available data and results. The Utilities shall follow the reporting format previously developed by staff for this purpose (and as modified by staff in the future), and provide reports on the previous year's Emerging Technology activities to the Director of the Energy Division by March 31 and September 30 of each year.

7.7.3. Permanent Load Shifting

Permanent Load Shifting (PLS) refers to the shifting of energy usage from one time period to another on a recurring basis. Generally speaking, PLS involves storing electricity produced during off peak hours and using the stored energy during peak hours to support loads. Examples of PLS technologies include battery storage and thermal energy storage. Thermal energy storage uses electricity during off peak hours to store thermal energy in ice, chilled water or eutectic solution that can be used during the day to cool buildings.

In D.06-11-049, the Commission directed the Utilities to initiate a process to solicit proposals from third parties for PLS programs. The utilities subsequently issued bilateral contracts and implemented a pilot program involving various PLS technologies. For the 2007-2011 period, sometimes referred to as the pilot period, the Commission approved approximately $24 million (PG&E/$10 million,[304] SCE/$10 million,[305] SDG&E/$4 million) for PLS programs to fund approximately 20 MW of PLS capacity (PG&E/8 MW,[306] SCE/11 MW,[307] SDG&E/1 MW).

D.09-08-027 ordered the Utilities to conduct a joint study of PLS cost-effectiveness, market potential, and strategies to encourage adoption of PLS. The Guidance Ruling directed the Utilities to include "proposals to expand the use of

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304 PGE-01 at 3-2, line 14.

305 SCE-013 at 80-82.

306 PGE-01 at 3-2, line 13.

PLS that are informed by the December 2010 [Statewide Joint Utility PLS] study [referred to as the PLS Study hereafter]". The Utilities completed the study on December 1, 2010 and used it as the basis for the currently filed utility proposals for PLS. The April 29, 2011 ALJ Ruling provided guidance to the Utilities to revise their cost-effectiveness analysis of proposed PLS programs, previously filed on March 1, 2011.

7.7.3.1. Utility Proposals

In the 2012-2014 DR applications, the Utilities propose PLS programs for combined budget requests of approx $32 million (PG&E/$15 million, SCE/$14 million and SDG&E/$3.4 million) to install approximately 50 MW (PG&E/27 MW, SCE/19 MW, SDG&E/3.6 MW) of PLS storage. All three utilities propose to revise the administrative framework of the programs to a standard offer contract instead of the Request for Proposal process used during the pilot phase.

PG&E and SDG&E propose to fund only mature technologies. SCE recommends allocating $3 million of its budget request for emerging technologies. SCE and SDG&E propose an incentive of approximately $500 per kW of installed PLS capacity as a standard offer for mature PLS technologies. PG&E provides a sliding scale for incentive levels as its standard offer, ranging from $250 per kW for a 4 to 6 hour shift up to $500 per kW for a 10 hour shift; the incentives are limited to mature technologies. SCE proposes an incentive of $3000 per kW as a standard offer for emerging PLS technologies.

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[307] SCE-03 at 80, line 14.

7.7.3.2. Parties' Positions

ICE Energy, CALMAC, and CESA oppose the utility proposals and recommend the following changes:

- Increased budgets, specifically $120 million total for all three utilities, divided equally among mature and emerging technology programs;
- Standardized program design across all utilities; and
- Increased incentive levels.

ICE Energy also objected to the cost-effectiveness analysis performed by SCE and asserts that the actual TRC is 1.0.

7.7.3.3. Discussion

The Aug. 27, 2010 Ruling directed the Utilities to include "proposals to expand the use of PLS that are informed by the December 2010 study."[308] This guidance, in turn, is motivated by state policies regarding the loading order as described in the Energy Action Plan set by California Public Utilities Code Section 454.5(b)(9)(C): "The electrical corporation will first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."

Earlier in this decision, we laid out an approach to how we would use the Protocols in our review of the DR programs. We determined that we will focus our analysis on the TRC, PAC and RIM tests, as they each provide valuable perspectives. We also noted that we would not eliminate the consideration of

[308] Guidance Ruling at 17.

any one of these three tests.[309] However, we consider PLS to be different from other DR programs because PLS shifts energy usage on a permanent basis instead of merely decreasing energy usage during certain times. Furthermore, the Protocols indicate that "these protocols may not be fully applicable to permanent load-shifting programs."[310] Because of this difference, we find it necessary and reasonable to review PLS and its cost-effectiveness analyses differently from the other DR programs.

As calculated by the Utilities, the PLS programs appear "possibly cost-effective" with PAC tests ranging from 1.5 to 2.0 and RIM test ranging from 0.8 to 0.9. The PLS programs do not perform as well on the third test with TRC ratios of 0.69 for PG&E, 0.77 for SCE, and 0.45 for SDG&E.

We agree that the cost-effectiveness analysis submitted by the Utilities for the PLS programs indicates that the TRC ratio is low. However, we are not convinced that the TRC ratio as calculated by the Utilities is the appropriate test to evaluate the cost-effectiveness of a program where large capital investment is required on the part of the customer, such as for PLS systems.

In the case of the proposed PLS programs, the Utilities added full equipment expenses to the cost side of the TRC test but did not add any offsetting customer benefits beyond bill savings to the other side. While customer benefits are difficult to quantify, the Protocols provide the Utilities with the option to estimate a value for difficult-to-quantify inputs and require

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[309] D10-12-024 at Conclusion of Law 8 states that "[t]he relative weight given to any Standard Practice Manual test in determining program approval or modification should be determined within the demand response budget proceedings."

[310] *Protocols* at 5.

that the Utilities include a qualitative discussion of those unquantifiable inputs. The Utilities did not include this qualitative analysis for the PLS program or for any other program in the DR portfolio. However, SCE acknowledges the importance of non-energy/monetary benefits to PLS customers and states that, "[w]hile non-energy/monetary benefits are important elements in customer's decision to install PLS equipment, the quantifiable benefits probably remain the major factor in their decision making process. In addition, non-energy/monetary benefits are difficult to quantify, so it is challenging in assessing such values."[311] The omission of a qualitative analysis is problematic for PLS programs when evaluating the TRC, since there are customer-perceived non-energy/monetary benefits of PLS.

We have other concerns with the PLS cost-effectiveness analyses submitted by the Utilities. The cost-effectiveness analyses only consider a three-year window of PLS amortized cost and benefits. While the three-year window is used in cost-effectiveness analyses of other DR programs, it is problematic to use for PLS given the substantial financial investment of PLS. Also, the Utilities did not comply with the guidance requiring them to use different consensus values for project costs and lifetimes for different technologies in determining cost-effectiveness. Instead, the Utilities used a consensus value of 15 years as a global average for PLS technologies and average project costs which are slightly different for each utility, ranging from $2,200 per kW to $2,300 per kW. Because the Utilities used different values for these factors, the Commission finds it difficult to compare the ratios across utilities.

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[311] ALJ ruling of August 5, 2011 at 49, Response to Q#7.

Returning to other aspects of the Utilities' cost-effectiveness analyses, the PLS PAC ratios are all greater than 0.9 (PG&E/1.84, SCE/2.0, SDG&E/1.48). Except in the case of SDG&E, the PLS RIM ratios are slightly less than 9.0 [PG&E/0.80, SCE/0.86, SDG&E/0.92). If we perform the cost-effectiveness analyses using a 15-year amortization period, all three RIM ratios are greater than 0.9. Thus, two tests (PAC & RIM) exceed 0.9 for all three utilities, deeming the PLS proposals cost-effective pursuant to our adopted approach. The following table depicts the Utilities' cost-effectiveness results compared to our cost-effectiveness results.

TABLE 7.7.3.3							
Utility	**SCE**		**PG&E**			**SDG&E**	
	Total Program	**Mature Tech Only**					
	Utility Submitted	**Commission Analysis**	**Utility Submitted**	**Commission Analysis**		**Utility Submitted**	**Commission Analysis**
AMORTI-ZATION PERIOD =>	**3 years**	**15 years**	**3 years**	**3 years**	**15 years**	**3 years**	**15 years**
TRC	0.77	0.6	0.68	0.8	**1.0**	0.45	0.8
PAC	**2.00**	**2.5**	**1.84**	**1.8**	**3.9**	**1.48**	**2.5**
RIM	0.86	0.9	0.80	0.8	**1.0**	**0.92**	**1.2**
PCT	0.83	0.7	0.78	**1.0**	**1.0**	0.26	0.5

CESA, CALMAC, and ICE contend that PLS has substantial potential and the program budgets should be larger, specifically $120 million for the three utilities combined,[312] divided equally among mature and emerging technology programs.[313] SCE rebuts that the likely effect of the larger budget on "SCE's

[312] CESA Opening Brief at 8.

[313] *Ibid* at 7.

ratepayers would be an approximately $7 million per year increase in rates;"[314] hence, a larger budget isn't reasonable. Further, PG&E argues that its program to date "is not fully subscribed"[315] and that the "PLS program has a benefit-cost ratio of less than one…Given [this], it will not be prudent to increase the program size."[316]

As we have shown, PLS programs are cost-effective. We further conclude that investing in utility programs to encourage adoption of customer-owned PLS resources is good policy as described in the Energy Action Plan and set by California Public Utilities Code Section 454.5(b)(9)(C). In this context, we agree with CESA, CALMAC, and ICE that the utility proposed budget levels of $32 million combined are not consistent with previous Commission guidance on expanding the use of PLS resources. However, we acknowledge that there are still many unknowns as to what a wider implementation of a successful PLS program entails. We find that a larger combined budget of $50 million for mature technologies represents a reasonable expansion of PLS, relative to the $24 million budget allocated during the 2007 to 2011 pilot phase. We direct each utility to increase its budget for PLS, $25 million for PG&E, $20 million for SCE, and $5 million for SDG&E), leading to an increased combined budget of $50 million.

In regards to the argument by CESA/ICE for a much larger emerging technology program, we emphasize that the Commission has already adopted a

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314 SCE-07 at 44, line 10.

315 PGE-08 at 3A-1, line 23.

316 *Ibid*, line 29.

decision to fund emerging storage technologies in the Self-Generation Incentive Program[317] and we find that providing a similar program in the DR portfolio would be redundant. Hence, we reject CESA/ICE's proposal to allocate funding to PLS emerging technologies and deny SCE's request for a PLS emerging technology program.

The Guidance Ruling directed the Utilities to include in their DR applications proposals to expand the use of PLS, as informed by the PLS Study. The proposals should include a discussion of the most effective ways to encourage an increase in cost-effective PLS. Because the Scoping Memo directs that the DR programs be evaluated in terms of cost-effectiveness and future performance, among other factors, we find it important to ensure that the incentive levels proposed by the Utilities are cost effective, but also encourage customer adoption of PLS.

CESA, ICE, and CALMAC argue that the PLS incentives should be increased to a range of $1000/kW to $2000/kW. As rationale for the higher incentive, ICE finds that "its PLS resource passes a 1.0 TRC benefit/cost ratio assuming incentive levels of $2000/kW."[318] And CALMAC asserts that proposed incentive levels "will not drive the market to install load-shifting equipment."[319]

We have determined that we will not rely upon the TRC in our review of PLS cost-effectiveness analyses. To evaluate the reasonableness of proposed incentive levels, it is more important to examine the impact on ratepayers via the

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[317] R.10-05-004 (http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/143459.htm).

[318] ICE Energy Opening Brief at 6.

RIM test. ICE's own analysis shows the RIM ratio to be 0.73,[320] a result substantially worse than ratepayer neutral suggesting that ICE's proposed incentive levels amount to a significant subsidy of the PLS customer by ratepayers.

The PLS Study finds that "using this new PLS cost-effectiveness framework, the lifecycle value of the avoided cost benefits of PLS technologies is in the range of $500/peak kW to $2500/peak kW, depending on the number of hours the PLS system can shift load, and what hour the load shifting starts."[321] Relative to the above range for avoided cost benefits of PLS, the PLS Study finds that: "When modeling specific [utility] rates, the rate payer neutral incentive levels range [assuming zero program administration costs] from roughly $800/peak kW to $1600/peak kW."[322] In comparison to the above range for ratepayer neutral incentive, the PLS Study finds that: "Numerous stakeholders provided consistent input that the end-user's financial hurdle for adoption is a minimum 3- to 5-year payback."[323] The PLS Study finds that the required incentive levels for the thermal storage installations range from about $660 to $3,030/kW to achieve a 5-year payback for the end user.[324]

Based on these findings of the PLS Study, we observe that the required incentive levels to allow customers to achieve a 5-year payback levels overlap the

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[319] CMC-01 at 17.

[320] ICE-01 at 10, Table 7.

[321] *PLS Study* at 7.

[322] *Ibid*.

[323] *Ibid* at 10

[324] *Ibid* at 11.

ratepayer neutral incentive levels estimated by the PLS Study. Furthermore, the utility proposed incentive levels ($250 to $545 per installed peak kW), which were designed to be approximately ratepayer neutral, are lower than both the customer required level or the ratepayer neutral level estimated by the PLS Study. We direct the Utilities to revise the cost-effectiveness analyses using incentive levels up to $1000/kW, subject to input from the Energy Division.

The DR PLS incentives approved in this decision apply to mature thermal energy storage technology and are therefore not eligible for incentives under the Self-Generation Incentive Program pursuant to the guidelines adopted in D.11-09-015.

The Scoping Memo outlined a framework for evaluating "the reasonableness of program" "in terms of…consistency across the Joint Applicants' applications, [and] simplicity…[among other factors]."[325] Based on the review of the submitted proposals, there are several differences between the Utilities' proposed programs. SCE & SDG&E have flat customer incentive rates per installed kW of peak load shift, whereas PG&E has a sliding scale that varies depending upon the number of hours of load shift provided by customer's PLS technology. The Utilities have different levels of customer incentives, ranging from $250 to $545 per installed kW of peak load shift; all of which are designed to be approximately rate-payer neutral. SDG&E proposes to cap incentive payments at 15 percent of project cost[326] and PG&E at 50 percent of project

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325 Scoping Memo at 8.

326 SGE-06, Appendix B at 57.

cost,[327] while SCE did not specify a cap. Other program details are not described or clear such as eligible technologies; the process for vendors and technologies to become qualified for funding; the application process to receive incentives; the verification process to determine incentives; and the incentive payment process, terms, and timing, etc. We find that the Utilities did not include sufficient details in their filings regarding the design and operation of the PLS programs.

Regarding program standardization, SCE states: "The IOUs will continue to work together on creating a consistent PLS Program, but SCE will not adopt a program decision just for the sake of consistency with the other IOUs if it does not meet the needs of our customers." "Standardizing incentives amongst the IOUs would not be ideal for customers because each utility has its own costs and benefits. Our rate structures are created based on SCE-specific costs and benefits and not that of PG&E and SDG&E."[328]

CESA argues that "Program simplicity and consistency across utility service territories is critical to minimizing transaction cost and to developing best practices in program administration."[329] CESA recommends that the Commission require PLS program uniformity and suggests that consistent program components should include technology eligibility, incentive structure, EM&V requirements, program criteria, application process and rules, and reporting. CESA contends that it may be reasonable to allow some differences between utility service territories to reflect differences in load shapes and

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[327] PGE-01 at 3-4.

[328] ALJ Ruling of August 5, 2011 at47, Response to Q#5.

[329] CESA Opening Brief at 10.

electric.[330] ICE Energy and CALMAC agree with this position. The PLS Study also identifies three factors critical to a PLS program's effectiveness in encouraging customer adoption of PLS: program consistency, program simplicity, and adequate education and training about PLS technologies.[331]

We see broad alignment between the parties and the PLS Study regarding the Commission's goals of program simplicity and consistency across the Utilities' territories, while allowing for appropriate differences. We discovered differences in program design inconsistent with these goals. For example, the differences in proposed incentive caps at a percentage of project cost appear to have little justification in terms of utility costs or customer needs. Because many program details are yet to be determined by the Utilities, we cannot assure program consistency when appropriate.

To achieve program consistency, we direct the Utilities to work collaboratively to develop and propose a standardized, statewide PLS program based on standard offer with common design and rules, and with differences limited to 1) incentive levels, 2) timing and duration of peak load shift, and 3) considerations specific to customer needs unique to a utility territory. The Utilities shall jointly submit the proposal to the Energy Division within 90 days of issuance of this decision. The proposal should include the updated cost-effectiveness analyses as previously discussed and a breakdown of the authorized budget such as administration, incentives, etc. We direct Energy Division to hold workshops to seek feedback from interested parties and

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[330] CESA Opening Brief at 10.

[331] *PLS Study* at 13, Table 2.

facilitate a consensus process for the Utilities to finalize the statewide program design and rules. Within 30 days after the final workshop, the Utilities should submit the final proposal of the statewide PLS program in a Tier 2 Advice Letter to the Energy Division.

7.7.4. PG&E's DR Home Area Network (HAN) Integration

In D.09-03-026, the Commission approved PG&E's request to upgrade its Advanced Metering Infrastructure deployment plan to include HAN-capability, pending development of suitable standards and HAN devices for use inside customer premise. In the Smart Grid Privacy decision,[332] the Commission directed the Utilities and Commission staff to collaborate to develop HAN implementation plans with details and a timeline focused on making HAN functionality & benefits generally accessible to customers.

7.7.4.1. PG&E'S Proposals

PG&E requests a budget of $30.7 million for two HAN-related activities:

1) $27.5 million: DR-HAN Integration project, consisting of two components:
   - IT integration to establish back-end HAN-based DR capabilities to support both pilot and general deployment of HAN-based DR program, and
   - "Evaluation Project"- Small-scale initial rollout or pilot of HAN-based DR program to 2000 homes & small and medium business customers equipped with PG&E provided load-control devices.
2) $3.2 million: Lab Work to test HAN devices & preparatory work for both DR-HAN integration project & EV pilot

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[332] D.08-12-009 at OP 9.

7.7.4.2. Parties' Positions

CLECA opposes the HAN project and considers it expensive and perhaps not implementable.

7.7.4.3. Discussion

PG&E asserts that the funds requested for these two projects are incremental to the basic HAN capability authorized and funded in D.09-03-026. Furthermore, PG&E argues that D.09-03-026 deferred the costs associated with the incremental work because of a delay in the HAN-based Title 24 PCT DR program due to a lack of suitable PCT devices at the time. The Commission adopted conservation and DR benefits from HAN-enabled programs in D.09-03-026.[333] Determining that "[t]here is significant uncertainty as to when this program will begin, and we prefer not to authorize related costs at this time,"[334] the Commission directed that "[t]hose costs will have to be recovered in a separate proceeding. PG&E should seek recovery of the *related IT* [emphasis ours] costs at the same time."[335]

PG&E considers this project to be "incremental to the work executed as part of the HAN Enablement project funded by the SmartMeter program."[336] PG&E asserts the additional capabilities gained through the DR-HAN Integration project will enable PG&E to reach new residential and small and medium business customers with DR programs envisioned in D.09-03-026.

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[333] D.09-03-026 at 153.

[334] *Id*. at 71.

[335] *Ibid*.

[336] PGE-01 at 5-5 line 19-21.

We accept PG&E's rationale and agree that the DR-HAN Integration project is incremental to the basic HAN functionality funded in D.09-03-026. We further find PG&E's current request to be consistent with Commission's direction in D.09-03-026 to seek recovery of IT costs for the incremental functionality in a later proceeding.

However, this rationale does not apply to the request of $3.2 million for HAN-related lab work. In its Application, PG&E describes this work as involving the "technology assessment of HAN-enabled end-use devices in a HAN laboratory or test environment before implementing approaches and programs at the production scale."[337] However, in D.09-03-026, the Commission approved $21.4 million for "technology assessment"[338] that included the following items:

- $6.4 million for "pilot testing to ensure that the proposed network can be integrated into the (Advanced Metering Infrastructure) AMI and will work as intended;"[339]
- $6 million (with 50 percent matching vs. $12.5M requested) for HAN related "laboratory testing and product demonstrations;"[340] and
- $5 million for "labor for HAN standards support."[341]

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337 PGE-01 at 5-3 line 16-18.

338 D.09-03-026 at 84-86.

339 *Id*. at 85.

340 *Ibid*.

341 *Id*. at 86.

There is no discussion in D.09-03-026 that suggests that the approved costs for technology assessment are specific to HAN-enabled conservation but not HAN-enabled DR. Thus, we conclude that the approved technology assessment funds apply to both conservation and DR related HAN capabilities. Since the Lab Work is intended for technology assessment to support HAN-related DR capabilities, we conclude that this is duplicative of work already approved by the Commission and reject the request of $3.2 M for Lab Work.

The IT costs that PG&E originally requested, but the Commission deferred in D.09-03-026, equaled $14.8 million, $12.7 million less than the $27.5 million being requested in the current proposal. We acknowledge that the HAN field has been rapidly evolving and the technology landscape today could be very different from that contemplated during the D.09-03-026 proceeding. Hence, a certain amount of increase in the cost estimate is reasonable. While PG&E contends that the scope of the current project is broader than that approved in D.09-03-026, PG&E once again provided limited information in its application to explain the differences between the projects and the reasons for the requested increased budget. Thus we limit the increase to 15 percent in addition to the original cost of $14.8 million.

We note that PG&E's request includes a small-scale initial pilot[342] of a HAN-based DR program to 2,000 residential and small and medium business customers equipped with PG&E provided load control devices[343] with no specified funding allocated to it. The pilot cost was not included as part of the

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[342] PG&E refers to this as an "evaluation project".

[343] PGE-01 at 5-7.

costs authorized in D.09-03-026. It is prudent for PG&E to pilot a new technology-based DR program. Considering SDG&E's budgets for its HAN-based pilot and programs (Residential Automation Technology) and PG&E's budget request for its HAN-based EV pilot, we authorize $3 million for PG&E to conduct its evaluation project.

We approve PG&E's request for its HAN Integration project including the $3 million for the evaluation project. However, we decrease its overall budget by $7.48 million, and authorize a budget of $20.02 million for the IT Integration and the evaluation projects. Furthermore, we require the HAN project to be categorized in budget category 11, Special Projects. Fund shifting within this category must be requested through a Tier 2 Advice Letter.

PG&E provides no schedule for when the pilot included in the DR HAN Integration project will be executed. PG&E states that the schedule is dependent on 1) the "development of applicable standards…SEP2.0"[344] and 2) the availability of suitable, standards-compliant HAN devices from third parties.[345] But PG&E notes that the schedule is "uncertain"[346] and that "delays in the schedule for HAN enablement activities may cause a change in PG&E's plans for any of the HAN-dependent projects and programs."[347]

We acknowledge the fast-changing nature of the HAN field. It is likely that PG&E may be re-evaluating its HAN-related implementation plans in

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344 PGE-01 at 5-6, lines 10-11.

345 *Id*., lines 15-16.

346 *Id*., line 14.

347 *Id*., lines 17-19.

response to D.11-07-056, related to HAN deployment[348] in the Smart Grid OIR proceeding (R.08-12-009). Hence, we direct PG&E to submit a Tier 2 Advice Letter with clear descriptions for this pilot, including a detailed schedule for the IT work and pilot execution, in order to release the $20.2 million allocated for this item. The descriptions should follow the guidelines for "Pilots" described later in this decision. This Advice Letter should be filed no later than June 30, 2012.

7.7.5. Small Customer Technology Deployment

7.7.5.1. SDG&E's Proposal

SDG&E proposes a new technology enabling program, called Small Customer Technology Deployment, and requests $13 million for its implementation. SDG&E explains that the launch of the Small Customer Technology Deployment program is contingent upon approval of a detailed implementation plan as informed by the results of an in-progress 2009-2011 Residential Automated Control Technology pilot, expected to conclude in the first quarter of 2012. SDG&E anticipates that the program will offer professionally installed HAN-based ADR enabling technologies at no cost for up to 15,000 residential customers and 3,000 small commercial customers participating in DR programs. Potential end-use loads targeted through this program include air conditioning, refrigeration, lighting, pool pumps, and electric water heaters.[349] SDG&E explains that the Small Customer Technology Deployment program will give participants "the ability to manage various end-

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[348] D.11-07-056, OP#11.

[349] SGE-05 at 50.

use electric loads year-round through utility tested and certified enabling technology."[350]

7.7.5.2. Parties Positions

UCAN initially raised concerns about the excessive cost of this program[351] but no longer seemed concerned about the cost during evidentiary hearings, and instead proposed that SDG&E use certain types of HAN devices.

DRA raised concerns about the cost-effectiveness of Small Customer Technology Deployment and that the timing of the program Advice Letter depended on the completion of the Residential Automated Control Technology pilot after this decision.[352]

7.7.5.3. Discussion

The Small Customer Technology Deployment is not cost-effective. However, the program is a technology enabling program, and thus does not require a separate cost-effectiveness analysis. Furthermore, given the early stage of the HAN market, using a behind-the-meter device may be the best current tool to motivate customers to use HAN capability. We approve the Small Customer Technology Deployment program with the following conditions.

First, 30 days following the completion of the Residential Automated Control Technology Pilot, SDG&E must submit a Tier 2 Advice Letter to include updated program details informed by the results of the pilot. Energy Division

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[350] *Id*., Appendix B at 33.

[351] UCN-01 at 6.

[352] DRA-01 at 3-17.

must review these results as a condition to release the authorized budget for the Small Customer Technology Deployment program.

We previously authorized SDG&E to deploy a limited number of HAN-based devices to small commercial customers in its AMI proceeding. To avoid duplication, we direct SDG&E to target the Small Customer Technology Deployment program to residential customers only and we reduce the budget accordingly to S10.83 million. This also improves the program's cost-effectiveness.

Because the program targets Peak Time Rebate customers, we direct SDG&E to (1) limit participation in the Small Customer Technology Deployment program to Peak Time Rebate customers only;[353] (2) combine the two programs, and (3) include an updated cost-effectiveness analysis of the combined programs in its required Peak Time Rebate Advice Letter submission. As discussed in the ME&O chapter of this decision, we also reduce the marketing budget to $982,538. SDG&E should utilize this budget number in the updated cost-effectiveness analysis.

If the Small Customer Technology Deployment Program is successful, we would consider it to be a major step forward in achieving the long-term vision of enabling wide-scale residential DR through customer managed automated technologies seamlessly integrated with utility AMI systems. We expect the program to drive the market to develop HAN-related devices that are easy to self-install and available at a reasonable cost to the average customer. We also expect this program to encourage third party providers to offer HAN-based

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[353] Note that this does not preclude customer participation in other DR programs, such as dynamic pricing programs, which are not part of this application.

devices to customers. We direct SDG&E to include in its Advice Letter a proposal for how the Small Customer Technology Deployment Program could drive this market transformation.

7.8. Evaluation, Measurement and Verification

The Commission depends upon EM&V studies to provide valuable insight on the effectiveness of DR programs. Information on DR program attributes, including customer acceptance and load impact, improves the design, operation, and maintenance of DR programs. In D.08-04-050, the Commission directed the Utilities to use the Load Impact protocols[354] to develop program evaluations and prepare and evaluate future budget applications. The Load Impact protocols are a necessary tool in the analysis of DR cost-effectiveness and for long term resource planning.

Traditionally, the Utilities perform DR program evaluations on statewide programs, activities such as marketing, and on dynamic rate tariffs available throughout the state. The statewide program evaluations are overseen by the DRMEC.[355] D.09-08-027 authorized DRMEC to perform evaluations of individual DR activities, programs and dynamic tariffs.

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[354] In R.07-01-047, the Commission developed and adopted protocols for estimating the impact of DR programs on the electric load.

[355] The DRMEC is composed of members from the California Public Utilities Commission, the California Energy Commission, and a representative from each of the three utilities. Previous Commission decisions created the DRMEC and authorized it to oversee the evaluation of statewide demand response activities; this authority was confirmed in D.06-11-049 and again in D.08-05-027.

In D.08-06-027, the Commission approved EM&V budgets of $9.062 million for PG&E, $4.106 million for SDG&E, and $7.075 million for SCE, noting that the budgets were for the most part reasonable.[356]

Subsequent to the adoption of the 2009-2011 DR program and budgets, the Commission adopted energy efficiency programs and budgets for 2009-2011. In D.09-09-047, the Commission determined that to provide proper oversight of the energy efficiency portfolio, EM&V activities should be jointly planned by the Utilities and the Commission and implemented to achieve five core objectives: Savings Measurement and Verification, Program Evaluation, Market Assessment, Policy and Planning Support, and Financial and Management Auditing.

7.8.1. Utility Proposals

The Utilities request a total EM&V budget of $31.5 million for the 2012-2014 DR program cycle to perform both statewide and individual program evaluations: PG&E requests $15.7 million, SDG&E requests $6.7 million and SCE requests $9.1 million. The Utilities propose to conduct specific load impact studies, process evaluation, and research studies with this funding.

PG&E requests funding to conduct local load impact studies of PLS, PeakChoice, Peak Time Rebate, Real Time Pricing, SmartAC, Time-of-Use Rates, and DR Pilots.[357] SCE plans to conduct a local load impact evaluation on Critical Peak Pricing /Time of Use, Base Interruptible Program, Aggregator Programs

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[356] The Commission decreased EM&V budgets slightly to reflect programs where EM&V funding had been requested, but the Commission had ultimately not approved the program.

[357] PGE-01 at 8-13.

(Capacity Bidding Program and DR Contracts), Auto-DR, Agricultural Pumping Interruptible, Save Power Days, Real Time Pricing, and Summer Discount Plan for year 2012-2014.[358] Because it anticipates that over 5 million electric meters will be replaced by Edison SmartConnect meters by the end of 2012, SCE proposes to evaluate related programs and tariffs as part of its SmartConnect Impact evaluation.[359] SDG&E also proposes to perform local load impact evaluations of several DR programs.[360]

All three utilities plan to conduct process evaluations. PG&E proposes process evaluations for its AMP, Base Interruptible Program, Capacity Bidding Program, Peak Day Pricing, PeakChoice, PLS, SmartAC, Peak Time Rebate, Pilot programs, Technology Incentive, ADR, demand-side program integration efforts and public campaign.[361] SDG&E plans process and marketing evaluations for new or revised programs including Critical Peak Pricing -Default, Peak Time Rebate, Peak Shift at Work,[362] Peak Shift at Home,[363] and Small Customer Technology Deployment. SDG&E recommends no process evaluations for established programs.[364] SCE states a need to conduct a process evaluation and marketing survey, but does not provide any details.[365]

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[358] SCE-05 at 3.

[359] *Id*. at 4.

[360] SGE-13 at LW\KS-22.

[361] PGE-01 at 8-13.

[362] Peak Shift at Work rate is a default critical peak pricing program for small commercial customers.

[363] Peak Shift at Home rate is a critical peak pricing program for residential customers.

[364] SGE-13 at LW\KS-22.

[365] SCE-05 at 5.

PG&E proposes to conduct a statewide study on demand-side program integration efforts and public awareness campaign. Other research studies may include the integration of DR into the CAISO market and general research studies. SCE did not request funding for any other research studies. SDG&E requests funding to conduct other customer research studies, forecast application development, and end-use meter.[366]

In addition to budget requests, SDG&E recommends clarifying language related to DRMEC activities. SDG&E expresses concern regarding potential accusations of anti-trust violations where the Commission has ordered utilities to work together on issues, such as the DRMEC. SDG&E requests the Commission to explicitly state that "implementation of required statewide DR activities…represents a state policy goal and that the Commission intends the Joint IOUs to work collaboratively as described to achieve this goal."[367] SDG&E, representing all three utilities, requests that the Commission explicitly authorize the Utilities to engage in DRMEC activities necessary to collaboratively implement the Commission-ordered DR statewide activities.[368]

7.8.2. Other Parties' Comments

Only DRA provided comment on the Utilities' requested EM&V budgets. DRA urges the Commission to consolidate all funding requests for dynamic

[366] SGE-13 at LW\KS-23.

[367] SGE-01 at MFG-13 to 16.

[368] *Ibid.*

pricing into a single proceeding under Phase 1 of a GRC,[369] which includes funding for the EM&V budget to evaluate dynamic pricing.

7.8.3. Discussion

This decision authorizes the DRMEC to continue to perform evaluations of both statewide and individual DR activities, and to continue reporting its findings in annual public workshops. We direct the DRMEC to ensure that EM&V activities are jointly planned and implemented to achieve the core objectives as adopted in D.09-09-047: 1) Load Impact Evaluations; 2) Process Evaluations; 3) DR Potential, Market Assessment and Technology Studies; 4) Policy and Planning Support; and 5) Financial and Management Audits.

Throughout this decision, we have made several design changes to DR programs. Measuring the load impact of each of these DR programs will provide valuable insight on the effect of these changes. Given that the Utilities are required to file load impact estimates of all their DR programs annually on April 1, it is reasonable to approve funding for impact evaluations in this decision. While we approve the funding for impact evaluations as requested, we direct the Utilities to conduct statewide impact evaluations whenever possible in order to provide synergies in the analysis and cost savings.

The process evaluation plans that the Utilities provided in their applications vary greatly. PG&E's process evaluation plan includes long-standing DR programs, while SDG&E's evaluation plan focuses on new programs and programs with design changes. Additionally, the Utilities fail to provide adequate description of their process evaluation plan. Process

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[369] DRA-01 at 1-12.

evaluations provide the Commission with insight on how the Utilities administer their DR programs. Process evaluations are especially valuable for new DR programs, but unnecessary for every DR program. Given the lack of detail provided by the Utilities, it's difficult to determine which DR programs require a process evaluation. Therefore, the Commission directs the DRMEC to submit a detailed process evaluation plan that lists all DR programs to be evaluated during 2012-2014 along with an explanation of the necessity of each evaluation.

The process evaluation plan should provide details that were omitted in the DR applications, including timing and funding. The plan should also include a list of what DR programs will not be evaluated and an explanation of why these programs will not be evaluated. This will ensure that process evaluations are performed when necessary, but that no program is inappropriately overlooked. When appropriate, the DRMEC should consider state-wide process evaluations. Because statewide evaluations are not always feasible, the plan should provide a process for maintaining oversight of non-statewide evaluations.

We direct the DRMEC to submit the process evaluation plan to the Energy Division no later than 45 days following the issuance of this decision. Following review and approval of the plan by Energy Division staff, the Utilities shall work with the DRMEC to implement the evaluation plan. If adjustments are needed throughout the three-year cycle, the Utilities may submit a revision of the plan to the Energy Division.

PG&E requests $15,721,000 to conduct EM&V during 2012-2014,[370] $2.7 million of which is attributed to PG&E's labor cost.[371] Upon review, we find PG&E's EM&V budget request reasonable. For 2012-2014, SCE proposes a budget of $9,093,654 for EM&V.[372] Thirty-three percent, or $3,035,428, of this amount is attributed to labor costs. SCE did not provide adequate information to explain its labor allocation. We find SCE's EM&V labor cost unreasonable. We reduce SCE's EM&V labor budget to $1.54 million. SDG&E requests $5.1 million for EM&V during the 2012-2014 program cycle,[373] with over $700,000 allocated to two full time employees. We find this amount to be reasonable in comparison with the other two utilities. In comments, SDG&E states that its budget request did not include any funding for research. We thus authorize a total EM&V budget of $5.715 million for SDG&E to include the $600,000 for research funding.

The Commission considers the DR Potential, Market Assessment and Technology Studies, and the Policy and Planning Support Studies important to the success of DR programs. Because these studies (frequently referred to as Research Studies) inform Commission policies on DR programs, we direct that these studies be overseen directly by the Commission. We authorize a budget of $3 million to be divided among the Utilities as follows: PG&E - $1.2 million, SCE - $1.2 million, and SDG&E - $0.6 million.

We authorize the Commission Executive Director to hire and manage one or more contractors to perform DR Research Studies, as described in this

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[370] PGE-01 at 8-2.

[371] SCE comments at 21.

[372] SCE-5 at 6.

[373] SGE-13 at LW\KS-24.

decision for the purpose of advancing the goals of the Commission. Costs shall be limited to work performed during the 2012-2014 budget cycle and shall not exceed $3 million based on the allocation described above.

The Commission authorizes the following total budgets as allocated for the 2012-2014 EM&V program:

TABLE 7.8.3		
	Requested Budget 2012-2014	**Authorized Budget 2012-2014**
PG&E	$15,721,000	$15,721,000
SCE	$9,093,654	$7,604,147
SDG&E	$5,115,000	$5,715,000

7.8.4. Anti-Trust Issue

In D.09-08-027 the Commission ordered the Utilities to implement statewide DR programs and activities in a collaborative fashion. In its Application, SDG&E requests the Commission to address a legal issue regarding joint-utility cooperation posed by the antitrust laws. SDG&E, speaking for all three utilities, contend that agreements among the Utilities concerning core elements of the competitive process could be viewed as unlawful under the antitrust laws.[374] This could result in ratepayers or shareholders bearing the costs of defending an antitrust lawsuit. To mitigate against these potential risks we find that[375] a State Action Doctrine defense to an antitrust action exists where: (a) the challenged conduct is a result of directions clearly articulated and affirmatively expressed as state policy; and (b) there is continued active

[374] SGE-03 at MFG-15.

[375] These findings are consistent with D.10-06-009 modifying D.09-12-024 and more recently D.10-12-054 modifying D.09-09-047.

supervision of the Utilities activities in this regard. Further, implementation of required statewide DR activities as called for in the Commission's final decision regarding the approval of the Utilities 2012-2014 DR activities represents a state policy goal which, for clarity, the Commission now affirmatively states that such policy provides and includes that the Utilities work collaboratively to achieve this goal. We therefore authorize the Utilities to engage in certain specific activities necessary to collaboratively implement the DR statewide activities as ordered by the Commission.

7.9. Integrated Demand Side Management (IDSM)

7.9.1. Background

The DSM Coordination and Integration chapter of the Strategic Plan envisions that DSM options including DR be offered as elements of an integrated solution that supports energy and carbon reduction goals immediately.[376] Through the Guidance Ruling,[377] the Commission provided direction to the Utilities regarding the IDSM portion of their DR Application. In an effort to align DR and energy efficiency funding for IDSM activities, we directed the Utilities to use 2012 as a bridge year for DR IDSM funding.[378] The Guidance Ruling noted that it makes sense to consolidate the Commission's review of these integrated activities in one proceeding.[379]

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[376] *Strategic Plan*, September 2008 at 71.

[377] http://docs.cpuc.ca.gov/efile/RULINGS/122575.pdf.

[378] The energy efficiency portion of the activities is funded through the end of 2012.

[379] Guidance Ruling at 14.

The Guidance Ruling instructed the Utilities that the 2012-2014 DR budget applications should include proposals and budget requests for two types of IDSM activities: 1) IDSM Strategic Plan activities; and 2) traditional DR activities with an integration component that previously had been integrated in the 2009-2011 budget cycle. Examples of this second group include Technical Assistance and Technology Incentives,[380] Emerging Technologies, and local marketing. The Ruling directed that 2012 funding would be bridge funding and beyond 2012 all IDSM activities would be proposed and approved through the energy efficiency proceeding.

Due to a delay in the energy efficiency proceeding, the Utilities consulted with Energy Division regarding a second year of IDSM bridge funding. Energy Division instructed the Utilities that they could "propose" IDSM funding for 2012 and 2013.[381] Energy Division described 2012 bridge funding as 2011 funding for 2011 activities.

7.9.2. Utility Proposals

7.9.2.1. PG&E

PG&E proposes eight IDSM activities: 1) Integrated Marketing & Outreach, 2) Integrated Education and Training, 3) Integrated Sales Training, 4) Flex Alert,[382] 5) Integrated Energy Audits, 6) Technology Incentives, 7) Integrated Emerging Technology, and, 8) PEAK. PG&E requests budgets of $6.25 million

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[380] Technical Assistance/Technology Incentives provides on site audits and financial incentives for customers to implement enabling technologies.

[381] SCE-24.

[382] Flex Alert is removed from this category and addressed in the ME&O chapter of this decision.

for year 2012 and $6.25 million for year 2013. PG&E asserts that it conducted all of these activities during the 2009-2011 budget cycle.

7.9.2.2. SCE

SCE proposes twelve IDSM activities with budgets for 2012 and 2013: Technical Assistance/Technology Incentives, Flex Alert,[383] Energy Leaders Partnership, Federal Power Partnership, IDSM Marketing, Commercial New Construction Pilot, IDSM Food Processing Pilot, a pilot for Institutional Partnerships, Residential New Construction Pilot, DR Technology Resource Incubator Outreach, Statewide IDSM, and Workforce Education and Training. SCE asserts that all of these activities were part of its 2009-2011 DR portfolio.

SCE identifies a need for funding to integrate the Technical Assistance portion of Technical Assistance/Technology Incentives, but not technology incentives. SCE requests $848,006 for 2012, and $625,192 for 2013 to integrate the audits that comprise the Technical Assistance program. SCE requests a total IDSM budget of $7.889 million for 2012 and $7.358 million for 2013.

7.9.2.3. SDG&E

SDG&E proposes four IDSM activities: Technical Assistance, Microgrid, Education and Outreach, and Flex Alert. Unlike PG&E and SCE, SDG&E did not include an IDSM Chapter in its previous DR and energy efficiency applications, so SDG&E did not have a 2011 DR budget for Microgrid or Education and Outreach to use as a reference to approve bridge funding for 2012. SDG&E's requests $3.2 million for its Technical Assistance program.

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[383] See footnote 4.

SDG&E is requesting $1.269 million for IDSM Education and Outreach. The utility proposes to use the funding to conduct research, develop an umbrella DSM campaign and use interactive media to target all of its customer classes. SDG&E proposes to transition the integrated marketing activities to the statewide campaign beginning in 2013. SDG&E requests a total of $4.711 million to fund its IDSM budget in 2012.

7.9.3. Parties' Positions

DRA recommends that the Commission consider only one year of bridge funding, 2012, for IDSM activities. No other party commented on IDSM activities.

7.9.4. Discussion

The Utilities' IDSM proposals do not provide detailed information about what they have accomplished in the 2009-2011 DR cycle, but rather the Utilities focus on what they propose to do in the future. The Scoping Memo lists past achievements as a measurement to determine the reasonableness of a program. The Utilities fail to demonstrate that they have effectively used existing budgets to achieve Commission objectives to integrate DSM. We recognize that delays in the energy efficiency program created obstacles to DR IDSM activity implementation during 2009.[384] We find that the DR IDSM implementation delay may have led to the lack of description regarding past achievements in the IDSM. However, given that the Utilities do not have adequate information about IDSM successes, we find that it would not be prudent to increase the scope of activities, as SDG&E and SCE request, or the funding.

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[384] The utilities did not implement most IDSM activities until 2010.

The Guidance Ruling specifically directed the Utilities to request authority to continue existing integrated activities for one year (2012). Furthermore, the Ruling explained that 2012 will serve as a bridge funding year for integrated activities that were approved in D.09-09-047. It is reasonable to authorize funding for 2012 so that the Utilities can continue with the existing scope of activities. If an activity has been operating within its scope during 2009-2011, we will consider the continuation of that activity.

In directing the Utilities to propose bridge funding for 2012, the Guidance Ruling noted that future authority and funding for IDSM activities will be considered in future energy efficiency proceedings beginning with 2013-2015 energy efficiency applications. We recognize that the energy efficiency proceeding has been delayed another year and, pursuant to the instructions of Energy Division, PG&E and SCE requested bridge funding for years 2012 and 2013. We find that PG&E and SCE complied with the Energy Division instructions. It is reasonable to anticipate that the energy efficiency proceeding will require bridge funding for its overall portfolio in 2013. Because the Guidance Ruling directed that IDSM activities will be considered in future energy efficiency proceedings, we direct the Utilities to request funding for post-2012 IDSM activities as part of their request for energy efficiency bridge funding. Furthermore, when the Utilities file the request for 2013 energy efficiency bridge funding, they should include a discussion of the achievements of each IDSM activity to justify the bridge funding request. We require the Utilities to serve the energy efficiency bridge funding applications to the DR service list because we anticipate the Utilities to request DR IDSM funding.

PG&E requests the same programs and budgets in 2012 as it requested in 2011. Pursuant to our discussions above, we approve PG&E's IDSM budget for

2012 as requested. For the reasons we provide above, we deny PG&E's request for 2013 IDSM funding in this proceeding.

SCE's Energy Leaders Partnership Program (Partnership Program) provides a prime example that requested increases to SCE's IDSM 2012 budgets are unnecessary. The Partnership Program successfully introduced customers to DR and energy efficiency simultaneously. Twenty-six cities enrolled in DR programs and developed event curtailment plans. The integrated approach led to over 155 integrated audits. SCE accomplished this by spending only 15 percent of the authorized budget for the Partnership Program. However, SCE requests 2012 bridge funding of $935,343,[385] a significant increase over the $413,000 spent in 2009-2010. We agree with SCE that the Partnership Program is successful, but we deny increased funding, because the Partnership Program succeeded with less than its authorized budget.

We approve SCE's 2012 Partnership Program and authorize a budget of $868,031, one third of its 2009-2011 budget. For 2012, we approve SCE's Technical Assistance budget of $839,506.[386] For each of the other requested IDSM programs, we approve an amount equal to one-third of the 2009-2011 budgets, for a total of $4.052 million. We deny all funding for 2013 for the reasons we discussed above.

We approve SDG&E's Technical Assistance IDSM budget as requested, but deny SDG&E's request for the funding of its Microgrid project. SDG&E's 2009-2011 IDSM funding did not include funding for the Microgrid.

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[385] SCE-04 at 12.

[386] This amount reflects the redaction of $8,500 for SCE's local ME&O budget.

Furthermore, SDG&E's status reports about Microgrid in its IDSM quarterly reports shows no evidence that the $119,000 funding request will improve this program. SDG&E's 2009-2011 authorized DR budget did not include a budget for IDSM ME&O. Thus we have no direct comparison in reviewing SDG&E's 2012-2014 request for $1.269 million. We rely upon SCE's approved amount in 2009-2011, which equals $2.95 million. We, therefore, approve one-third of this amount, or $994,359 for SDG&E's 2012 IDSM ME&O budget. We authorize a total IDSM 2012 budget of $4.305 million for SDG&E.

7.10. Utility Pilots

7.10.1. PGE's Proposed Pilots

PG&E requests that the Commission authorize PG&E to perform three pilots: Commercial and Industrial Based Intermittent Resource Management Pilot 2 (IRM 2), Transmission & Distribution (T&D) Pilot, and Plug-In Electric Vehicle (EV) Pilot. PG&E recommends budgets of $2.48 million each for the IRM2 and the T&D pilots, and $3 million for the Plug-In-EV pilot.

PG&E describes IRM 2 as a continuation of the field study and demonstration of other demand-side storage capabilities begun through a collaborative effort between PG&E, Lawrence Berkeley National Laboratory, and CAISO.[387] In IRM 2, PG&E will develop models and scenarios to 1) create best

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[387] During the 2009-2011 DR budget cycle, the collaboration explored and produced a field demonstration framework to address ways to mitigate intermittence of renewable resources. Phase 1 of this collaboration produced an assessment of various end-use loads and equipment to be considered in the field demonstration. Phase 2 performed field demonstrations to observe whether a properly controlled demand side resource can respond appropriately to CAISO needs and provide real-time 5-minute energy services.

practices for assembling DR products to achieve best-in-class results and 2) inform the construction or modification of new or existing DR resources. Leveraging the work done in the previous IR pilot, PG&E proposes to use the same customers to participate in this pilot but may recruit additional customers for diversity. Working with CAISO, PG&E will determine how best to bid these new or revised DR resources into the CAISO market. PG&E contends that the results of IRM 2 "will provide further insight on the use of demand-side resources to integrate IRR."[388]

In the future, PG&E envisions using demand side resources to assist with T&D operations. As such, PG&E has studied the integration of wholesale and retail DR into T&D. With the T&D Pilot, PG&E proposes to explore and demonstrate the feasibility and viability of applying current and future demand-side capabilities to provide services that assist T&D operations and planning. PG&E contends that the T&D pilot will identify the characteristics of resources needed for T&D operations as well as the demand-side resources to fulfill those needs.[389] Additionally, PG&E proposes that the pilot evaluate or develop optimization and forecasting tools. Using a two-phased approach for the pilot, PG&E explained that the first phase includes a scoping study and the second phase would deploy a field demonstration of incorporating DR resources in T&D operations. PG&E predicts that the pilot will use SmartAC and select AutoDR enabled Commercial and Industrial resources for the field demonstration, as

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[388] PGE-01 at 3-20.

[389] *Id*. at 3-21.

these resources have operational characteristics that may meet T&D operational needs.[390]

In addition to the DR-HAN Integration Project previously described, PG&E requests authorization to perform a HAN-based EV Pilot to demonstrate and analyze the technical capability for providing two-way communication to the EV Supply Equipment over the AMI network using the HAN gateway. Additionally, PG&E proposes to study an EV Supply Equipment's response to load control signals; requirements for a scalable system; customer behavior, etc. in regard to Plug-In EV charging; and the benefits of EVs to the utility and customers.[391] PG&E contends that this pilot is another step toward the development of a commercially-viable technology based on a collaborative effort between the Utilities, customers, automakers, and third-party EV Supply Equipment providers.[392]

7.10.2. SCE's Proposed Pilots

SCE requests authorization and funding to perform two pilots: 1) Smart Charging Plug-In EV Pilot, and 2) Workplace Charging Pilot. In R.09-08-009, SCE proposed including these two pilots as part of the 2012-2014 DR budget Application. The Commission responded by requesting the Utilities to "consider Alternative-Fueled Vehicle Tariffs, Infrastructure and policies to support

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390 *Id*. at 3-22.

391 *Id*. at 5-11.

392 PG&E also contends that the EV Pilot builds upon lessons learned in a Plug-In EV DR Pilot performed during the 2009-2011 DR budget cycle.

California's Greenhouse Gas Emissions Reductions Goals"[393] including the impact of EVs on California's grid and action needed.

SCE proposes a Smart Charging Plug-In EV Pilot to better understand the related issues and impact of Plug-In EV charging with DR. SCE explains that the pilot will test the related charging equipment, its ability to provide DR, as well as customer behavior. While testing and evaluating both EV Supply Equipment and Plug-In EVs in a controlled environment, SCE proposes to investigate the compatibility of the communication between smart meters and or utility Wide Area Networks or WANs. SCE anticipates deploying smart charging equipment at both controlled and non-controlled locations to determine the most appropriate technology needed for success. SCE will use the information garnered from this pilot to refine the Plug-In EV Smart Charging Program design as well as its related processes and systems. SCE argues that this pilot is different from other utility pilots on Plug-In EVs in that no other pilot involves residential, public and fleet charging scenarios.[394] SCE requests $600,000 to establish the Plug-In EV Smart Charging Pilot.

As suggested by the Commission, SCE proposes a Workplace Charging Pilot to analyze the impacts of Plug-In EV workplace charging on California's power system. SCE explains that its objective is to ascertain how to make Plug-In EV charging more convenient and accessible for both customers and suppliers. SCE plans to deploy up to 233 Plug-In EV charging stations at SCE facility parking lots. SCE will collect and analyze data from these charging

[393] SCE-03 at 103.

[394] *Id*. at 109.

stations in order to analyze load impacts on electric circuits and determine the effectiveness of various pilot DR strategies.[395] Serving as a proxy for larger workplace charging models, SCE anticipates this pilot to provide information that will enable SCE to advise and assist in developing future charging strategies. As justification for this pilot, SCE contends that no other workplace charging pilots include options such as flat rates, interruptible options and various Time of Use scenarios.[396] SCE requests a budget of $1.2 million to perform this pilot.

7.10.3. SDG&E's Proposed Pilots

SDG&E requests authorization to conduct two pilots during the 2012-2014 DR budget cycle: Locational DR (LDR) Pilot and New Construction DR (NCDR) Pilot. SDG&E proposes budgets of $433,000 and $1.1 million, respectively, for these two pilots over the three-year cycle.

Despite only having one local capacity area, SDG&E seeks authority to embark on the LDR pilot, anticipating that it will assist in determining whether LDR at the circuit level can provide adequate load drop to justify a full fledge program. SDG&E contends that an LDR program targeting strained circuits could be a cost effective alternative to immediate system upgrades. Leveraging existing energy efficiency, DR enabling technology and PLS programs, SDG&E proposes to use marketing efforts coupled with premium, locational incentives to create load impacts. SDG&E asserts that the LDR, in collaboration with the

[395] *Id*. at 110.

[396] SCE-01 at 113.

direct install energy efficiency program, will reduce energy consumption and power demand.[397]

Integrated into its existing new construction energy efficiency programs, SDG&E intends the NCDR pilot to be an enabling technology deployment pilot for the new construction market. SDG&E proposes to offer financial incentives and design assistance to gain participation in the pilot. SDG&E alleges that the enabling technologies installed during the course of the pilot will not only lead to load reduction but will provide customers with dynamic pricing information.[398] SDG&E notes that installation during construction is preferable to retrofits, and asserts that the NCDR pilot "is uniquely positioned to investigate and affect DR opportunities during building construction."[399] Focusing on design assistance, workforce education and training, and marketing support, SDG&E intends the NCDR pilot to provide education and outreach to new audiences. SDG&E plans to use the NCDR pilot to target five building types: multifamily, single family, grocery, office building, and small retail/mixed use. SDG&E requests $1.1 million to perform this pilot over the three-year budget cycle.

7.10.4. Discussion

No party provided substantive comments on the proposed pilots.

The Utilities submitted minimal information regarding the proposed pilots. Although we find the concept of each pilot valuable, the Utilities did not provide adequate details or justification to allow us to authorize the budgets as

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[397] SGE-05 at GMK-53.

[398] *Id*. at GMK-54.

[399] *Ibid*.

requested. However, we do not want to lose an opportunity to gain knowledge from the results of these pilots, given that we agree that the concepts are valuable. As such, we implement a framework for the consideration of these and future pilots within the DR portfolio and require the Utilities to provide pilot plans for each pilot. The framework is similar to established guidance for the submission, implementation and evaluation of energy efficiency pilot projects in D.09-09-047.

The purpose of a pilot is to test a new concept or program design that is intended to address a specific area of concern or gap in existing DR programs. Pilots can also be launched to advance a new DR policy or operational requirement. Pilots should be limited in scope and duration so that the results are available in a specified timeframe and limited in budget so that unsuccessful programs have a limited impact on the overall portfolio. Results of pilots should be shared widely amongst all utilities and with stakeholders impacted by the pilot. Pilot results should provide a plan and timeframe to transition the pilot program, if determined successful, into utility-wide and hopefully statewide use.

We make a distinction between demonstration projects and pilots. Demonstration pilots are intended to explore a new concept or technology capability, and the costs, schedule, expected performance or outcomes may be unknown or uncertain. Pilots test a new concept or program design intended to address a specific area of concern, but can advance a new DR policy or operational requirement.

Pilots may also expand upon already completed demonstration projects but are designed to validate or evaluate assumptions or expected performance or outcomes of new concept or technology or program design in a limited field deployment, with the intention of using the results and experience to develop a program suitable for general deployment. A pilot may be the pre-deployment phase or the initial phase of a yet to come general deployment of a program, but could also lead to no program if results prove the pilot to be unsuccessful. Demonstration projects are designed to examine new ideas and should have flexibility in budgeting to account for unexpected conditions. Pre-deployment pilots, in contrast, have already been tested on a limited basis and thus have a foundation for forecasting budgets and schedules with a reasonable confidence level.

For the pilots requested in this Application and all pilots requested in future DR applications, each utility should provide a proposed Pilot Plan. Each Pilot Plan should contain the following elements:

1. New and innovative program design, concepts or technology that have not yet been tested or employed;
2. A specific statement of the concern, gap, or problem that the pilot seeks to address and the likelihood that the issue can be addressed cost-effectively through utility programs;
3. Whether and how the pilot will address a DR goal or strategy;
4. Specific objectives and goals for the pilot;
5. A clear budget and timeframe to complete the pilot and obtain results within a portfolio cycle. Pilots that are continuations of pilots from previous portfolios should clearly state how the continuation differs from the previous phase;
6. Information on relevant standards or metrics or a plan to develop a standard against which the pilot outcomes can be measured;
7. Where appropriate, propose methodologies to test the cost-effectiveness of the pilot;
8. A proposed EM&V plan; and

9. A concrete strategy to identify and disseminate best practices and lessons learned from the pilot to all California utilities and to transfer those practices to resource programs, as well as a schedule and plan to expand the pilot to utility and hopefully statewide usage. Pilot results shall be reported at the public DRMEC spring or fall meeting on load impact or process evaluation results.

We direct each utility to submit a Tier 2 Advice Letter that includes a Pilot Plan as described above for all DR pilots no later than six months before the start of the pilot or 60 days after the issuance of this decision. All future DR applications should include a Pilot Plan for every DR pilot.

We authorize the following budgets for DR pilots, contingent upon the submittal and approval by Energy Division of the required Pilot Plan: $7.96 million for PG&E, $1.8 million for SCE, and 1.5 million for SDG&E.

8. Forward Looking Issues

8.1. Integration with California Energy Policies

We end this decision where we began, with a discussion of California energy policies and the integration of DR programs with these policies. California is witnessing the evolution of its electrical grid as technological improvements change the fundamental nature of how electricity is generated, transmitted, distributed and used. Simultaneously, the Commission has been working with the CEC and other entities to create improved and integrated energy efficiency and DR programs to decrease California's energy usage. However, the single largest change affecting the grid is the increased use of renewable generation technologies, which are now required by law to reach 25 percent of generation by 2015 and 33 percent by 2020. A majority of this renewable generation is intermittent in that the amount of energy is dependent on unpredictable weather conditions.

This evolution presents new opportunities for DR, as well as new challenges. Large amounts of intermittent generation create operational complexities for the grid operator. DR and energy storage should be available for ramp up and ramp down, compensation for over-generation, and balance of the system. Existing DR products may need to be reconfigured and new products developed to meet CAISO market requirements. The Scoping Memo stated that we would review DR program to determine whether the programs are sufficient to meet California's energy goals in light of these new opportunities and challenges.

PG&E asserts that its DR programs promote the key objectives of California's energy goals, including initiatives such as the Energy Action Plan II and the Strategic Plan.[400] CAISO contends that the Utilities' 2012-2014 DR proposals may not be broad enough to address the impacts of the 33 percent renewables requirement.[401] The Utilities have made efforts to meet these goals, but the current efforts may not be sufficient, either in terms of timing or breadth. While no one has determined the exact nature of the challenges that the grid will face, various scenarios can and are being developed which describe the potential challenges the grid is likely to face. It is critical to determine how we will meet these challenges.

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[400] PG&E Opening Brief at 53-54.

[401] Tr. Vol 4 at 523-524.

8.2. Integration with CAISO Markets

The Scoping Memo stated that we would review the DR applications to address the CAISO Market Integration.[402] The integration of retail DR programs with California's wholesale electricity markets has been an on-going effort by the Commission, the CAISO and the Utilities for the past five years. Generally, the Utilities have complied with earlier Commission directives to integrate their programs with CAISO wholesale market products, but are careful to lay out several caveats with respect to timing, costs and feasibility.

PG&E proposes a phased approach for most of its DR programs, but cautions that it intends to request funding for most of the costs of integration after it is fully informed of market requirements and can make a judgment on what is cost-effective for ratepayers. PG&E will make a consolidated funding request at the conclusion of R.07-01-041, Phase 4, Part 2.[403]

Like PG&E, SCE states[404] that full implementation and integration of DR programs with CAISO's wholesale market products is dependent on the final set of policies and rules under development in the Commission's direct participation proceeding.[405] SCE cautions that it may request additional DR funding depending upon the rules adopted for direct participation.[406] SCE currently anticipates over $15 million is necessary to implement the systems and programs for PDR and RDRP.

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402 Scoping Memo at 8.

403 PGE-01 at 7-6 and 7-7.

404 SCE-01 at 7.

405 R.07-01-041, Phase 4.

406 SCE-01 at 122.

SDG&E makes only brief mention of its intention to integrate its programs with wholesale markets in this Application. SDG&E's budget for wholesale market integration appears to be limited to a portion of the IT costs.

CLECA points out that the Commission previously concluded that we must weigh the benefits of the changes we make with the costs of the changes.[407] PG&E agrees with CLECA that policies to promote the integration of DR with CAISO must be justified with reasonable levels of feasibility and cost-effectiveness.[408]

SDG&E and SCE claim to be moving toward CAISO market integration. However, SDG&E recommends a bifurcated approach in that only some utility-provided DR programs be bid into CAISO markets[409] while SCE recommends full integration.[410] CAISO points out the potential cost of wholesale market integration that the Utilities will pass on to ratepayers if the Commission continues to rely on the utility-centric model for DR.[411]

While the Utilities' cautious approach toward integration is disconcerting, a slow, deliberative approach could provide the Commission with the time to consider the costs of continuing down the utility-centric path. PG&E raises the specter of additional costs it will seek in order to continue its role as a DR provider and integrate all of its programs with the CAISO market. CAISO raises a valid point that IT costs in particular tend to be larger than expected. CAISO

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407 CLECA Opening Brief at 18.

408 *Id*. at 55.

409 SGE Opening Brief at 20.

410 SCE Opening Brief at 72.

411 ISO-01 at 10-13.

strongly advocates the Commission to move toward a market-based model that could avoid huge ratepayer-subsidized DR infrastructure.

8.3. DR Market Competition

Competition in the emerging market for DR services has become a controversial issue. Historically, DR programs were interruptible programs targeted to large commercial and industrial customers and air conditioner cycling programs for residential customers. Today, we also have price-responsive programs and dynamic rates. In addition to new programs, we also have new players. The DR providers or aggregators, non-utility Load Serving Entities such as Energy Service Providers, and Community Choice Aggregators have created or intend to create DR products and services similar to those offered by the Utilities and want the opportunity to participate in California's DR marketplace.

Past Commission decisions support a model that places the Utilities at the center of DR programs and services. The Commission has allowed third party DR providers to play a role in the DR market through limited term contracts with utilities. In addition, Energy Service Providers currently offer a variety of services to Direct Access customers that go beyond the sale of electricity to include DR products and services.[412] Arguments are being proposed that, if adopted, would signal a departure from current Commission policy regarding DR programs and the role of the Commission itself. The changing nature of the electrical grid, which we previously discussed, has generated additional requirements that call into question whether a utility-centric model for DR

[412] DAC-01 at 6.

programs and services can meet current and future needs. This in turn would impact the roles of the DR providers, Load Serving Entities, and the Utilities as well as the future needs of the California electricity grid.

In their opening testimony, DACC/AReM promote the idea that DR programs are, in large part, competitive services and, as such, the Utilities should not be allowed to offer rate regulated DR services when those same services can be provided through competitive markets.[413] Furthermore DACC / AReM state that the Commission should facilitate a transition to broader competition in the DR markets beginning with the determinations made in this proceeding.[414]

CAISO suggests giving the Utilities a supporting rather than a central role in California's market. CAISO recommends that the Commission consider transitioning DR resources from a utility-delivered resource to a competitively-procured resource.[415] CAISO's testimony indicates that the Commission should direct the Utilities to use competitive procurement to solicit DR designed to satisfy long-term procurement and resource adequacy requirements from aggregators.

The Commission is currently developing market rules to govern the activity of DR providers in California. Furthermore, details regarding the federal directives for market integration are emerging on an ongoing basis. The uncertainty places the Commission in the position of not having enough information at this time to make a decision on how best to proceed.

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[413] *Id*. at 8.

[414] *Id*. at 2.

[415] ISO-01 at 11.

8.4. Next Steps

The Scoping Memo in this proceeding stated that we would review issues intersecting the DR programs and activities with CAISO market integration including DR market competition. However, we noted that policies addressing these activities may be revised or further developed either in this proceeding or in the associated rulemaking on DR (R.07-01-041).[416]

Dismantling of the utility-centric model, as suggested by some parties in this proceeding, requires thought and deliberation beyond the time provided in the current proceeding. Furthermore, the issues go beyond the three-year cycle of a DR Application and are more appropriately addressed in the DR rulemaking. The Commission must determine the future goals and policy objectives for DR before addressing these issues. At this time, however, the most prudent path forward is to continue to gather information to develop a better record before making lasting changes to the current structure. We will address these issues in the DR rulemaking proceeding, R.07-01-041 or its successor.

We note that the DRMEC has embarked upon a study to determine how current DR programs respond to challenges posed by intermittent generation. This study will be a first step in gathering additional information to determine the future course of DR.

9. Approved Budgets and Authorized Expenses

We approve the following budgets for the Utilities' 2012-2014 DR programs:

[416] Scoping Memo at 8.

Table 9 A

2012-2014 Demand Response Program Budgets - PG&E

Funding Categories	Total Authorized for 2009-2011	Total Requested for 2012-2014	Total Authorized for 2012-2014	Change	% change
Category 1 - Reliability Programs					
Base Interruptible Program	$800,000	$666,349	$666,349	$0	0%
Optional Binding Mandatory Curtailment/Scheduled Load Reduction	$138,000	$413,532	$413,532	$0	0%
Category 1 Total	**$938,000**	**$1,079,881**	**$1,079,881**	**$0**	**0%**
Category 2 - Price-Responsive Programs					
Demand Bidding Program	$3,216,000	-	$3,216,000	$3,216,000	-
Capacity Bidding Program	$5,371,076	$11,563,485	$10,342,820	-$1,220,665	-11%
PeakChoice	$9,000,000	-	$1,750,000	$1,750,000	-
PeakChoice with Demand Bidding Program		$10,500,921	$0	-$10,500,921	-100%
AC Cycling: Smart AC	$74,244,895	$24,994,094	$19,353,335	-$5,640,759	-23%
Category 2 Total	**$91,831,971**	**$47,058,500**	**$34,662,155**	**-$12,396,345**	**-26%**
Category 3 - DR Provider/Aggregator Managed Programs					
AMP	$5,083,998	$1,187,700	$1,187,700	$0	0%
Business Energy Coalition - 2009 Only	$2,311,998	-	-	-	-
Category 3 Total	**$7,395,996**	**$1,187,700**	**$1,187,700**	**$0**	**0%**
Category 4 - Emerging & Enabling Technologies					
Auto DR	$19,117,000	$26,297,459	$26,297,459	$0	0%
DR Emerging Technology	$2,421,000	$3,749,238	$3,749,238	$0	0%
Category 4 Total	**$21,538,000**	**$30,046,697**	**$30,046,697**	**$0**	**0%**
Category 5 – Pilots					
IRR Phase 2	-	$2,458,336	$2,458,336	$0	0%
T&D DR	-	$2,458,336	$2,458,336	$0	0%
Plug-in Hybrid EV/EV (incl. HAN-EV)	$1,010,000	$3,000,000	$3,000,000	$0	0%
2009-2011 Pilots	$5,367,000	-	-	-	-
Category 5 Total	**$6,377,000**	**$7,916,672**	**$7,916,672**	**$0**	**0%**
Category 6 - Evaluation, Measurement and Verification					
DRMEC	$9,062,000	$15,720,981	$14,520,981	-$1,200,000	-8%
DR Research Studies	-	-	$1,200,000	$1,200,000	-
Category 6 Total	**$9,062,000**	**$15,720,981**	**$15,720,981**	**$0**	**0%**
Category 7 - Marketing, Education and Outreach					
Statewide Marketing	$6,405,000	$2,172,510	$2,172,510	$0	0%
DR Core Marketing & Outreach	$9,339,000	$24,579,192	$12,289,596	-$12,289,596	-50%
Education and Training	$1,368,000	$771,993	$771,993	$0	0%
Category 7 Total	**$17,112,000**	**$27,523,695**	**$15,234,099**	**-$12,289,596**	**-45%**
Category 8 - DR System Support Activities					
InterAct/DR Forecasting Tool	$10,413,000	$14,407,887	$14,407,887	$0	0%
DR Enrollment & Support	$6,489,000	$15,787,400	$11,824,001	-$3,963,399	-25%
Notifications	-	$11,327,715	$7,427,715	-$3,900,000	-34%
DR Integration Policy & Planning	-	$3,893,342	$3,893,342	$0	0%
Category 8 Total	**$16,902,000**	**$45,416,344**	**$37,552,945**	**-$7,863,399**	**-17%**
Category 9 - Integrated Programs and Activities (Including Technical Assistance)					
Technology Incentives - IDSM	$7,310,000	$7,089,939	$3,538,000	-$3,551,939	-50%
PEAK	$1,639,000	$1,119,659	$560,000	-$559,659	-50%
Integrated Marketing & Outreach	$1,000,000	$608,510	$304,500	-$304,010	-50%
Integrated Education & Training	$200,000	$121,702	$61,000	-$60,702	-50%
Integrated Sales Training	$250,000	$152,128	$76,000	-$76,128	-50%
Integrated Energy Audits	$2,942,000	$2,528,037	$1,264,000	-$1,264,037	-50%
Integrated Emerging Technology	-	$879,661	$440,000	-$439,661	-50%
IDSM Clearinghouse	$500,000	-	-	-	-
Category 9 Total	**$13,841,000**	**$12,499,636**	**$6,243,500**	**-$6,256,136**	**-50%**
Category 10 - Special Projects					
DR-HAN Integration (excl. HAN-EV)	-	$30,714,000	$20,020,000	-$10,694,000	-35%
Permanent Load Shifting	$138,000	$15,129,846	$25,000,000	$9,870,154	65%
Category 10 Total	**$138,000**	**$45,843,846**	**$45,020,000**	**-$823,846**	**-2%**
Dynamic Pricing (Not Funded in This Decision)					
Critical Peak Pricing	$1,758,000	-	-	-	-
Total Dynamic Pricing	**$1,758,000**	-	-	-	-
TOTAL DR Portfolio	**$186,893,967**	**$234,293,961**	**$194,664,630**	**-$39,629,331**	**-17%**

[1] Source for PG&E's 2009-2011 Adopted and 2012-2014 requested budgets: PG&E-1A, Table 10A-6.

[2] Changes reflect the program specific adjustments adopted in this decision.

Table 9 B

2012-2014 Demand Response Program Budgets - SDG&E

Funding Categories	Total Authorized for 2009-2011	Total Requested for 2012-2014	Total Authorized for 2012-2014	Change	% change
Category 1 - Reliability Programs					
Base Interruptible Program	$1,475,423	$4,179,000	$3,816,821	-$362,179	-9%
Emergency Critical Peak Pricing	$328,541	-	-	-	-
Category 1 Total	**$1,803,964**	**$4,179,000**	**$3,816,821**	**-$362,179**	**-9%**
Category 2 - Price-Responsive Programs					
Capacity Bidding Program	$6,426,173	$11,939,000	$7,634,393	-$4,304,607	-36%
Peak Time Rebate	-	$4,353,000	$485,000	-$3,868,000	-89%
Demand Bidding Program and Peak Day Credit	$820,000	-	-	-	-
Category 2 Total	**$7,246,173**	**$16,292,000**	**$8,119,393**	**-$8,172,607**	**-50%**
Category 3 - DR Provider/Aggregator Managed Programs					
DemandSmart (DR contract)	Confidential	-	-	-	-
Category 3 Total	**-**	**$0**	**$0**	**$0**	**-**
Category 4 - Emerging & Enabling Technologies					
DR Emerging Technology	$2,142,495	$2,111,000	$2,111,000	$0	0%
Small Customer Technology Incentives	-	$13,009,000	$9,464,167	-$3,544,833	-27%
Technology Incentives	$12,662,841	$9,068,000	$8,973,000	-$95,000	-1%
Category 4 Total	**$14,805,336**	**$24,188,000**	**$20,548,167**	**-$3,639,833**	**-15%**
Category 5 – Pilots					
Locational DR	-	$433,000	$433,000	$0	0%
New Construction DR	-	$1,126,000	$1,126,000	$0	0%
2009-2011 Pilots	$5,445,671	-	-	-	-
Category 5 Total	**$5,445,671**	**$1,559,000**	**$1,559,000**	**$0**	**0%**
Category 6 - Evaluation, Measurement and Verification					
DRMEC	$4,105,832	$5,115,000	$5,115,000	$0	0%
DR Research Studies	-	-	$600,000	$600,000	-
Category 6 Total	**$4,105,832**	**$5,115,000**	**$5,715,000**	**$600,000**	**12%**
Category 7 - Marketing, Education and Outreach					
Statewide Marketing - FlexAlert Network	$1,253,886	$210,000	$835,924	$625,924	298%
Customer Education and Outreach	$6,029,000	$1,158,000	$1,158,000	$0	0%
Other Local Marketing		$0	$4,484,513	$4,484,513	100%
Subtotal: Local Marketing			*$5,642,513*		
Category 7 Total	**$7,282,886**	**$1,368,000**	**$6,478,437**	**$5,110,437**	**374%**
Category 8 - DR System Support Activities					
Regulatory Policy & Program Support	-	$2,231,000	$2,231,000	$0	0%
IT Infrastructure & System Support	-	$5,410,000	$5,410,000	$0	0%
Customer Relationship Management	$1,140,000	-	-	-	-
Category 8 Total	**$0**	**$7,641,000**	**$7,641,000**	**$0**	**0%**
Category 9 - Integrated Programs and Activities (Including Technical Assistance)					
Technical Assistance	$10,011,326	$3,321,000	$3,289,000	-$32,000	-1%
Residential Microgrid Program	-	$119,000	$0	-$119,000	-100%
Customer, Education, and Outreach - IDSM	-	$1,269,000	$984,359	-$284,641	-22%
Category 9 Total	**$10,011,326**	**$4,709,000**	**$4,273,359**	**-$435,641**	**-9%**
Category 10 - Special Projects					
Permanent Load Shifting	$3,308,000	$3,069,000	$4,916,000	$1,847,000	60%
Category 10 Total	**$3,308,000**	**$3,069,000**	**$4,916,000**	**$1,847,000**	**60%**
Dynamic Pricing (Not Funded in This Decision)					
Critical Peak Pricing	-	-	-	-	-
Total Dynamic Pricing	-	-	-	-	-
TOTAL DR Portfolio	**$55,150,000**	**$68,120,000**	**$63,067,177**	**-$5,052,823**	**-7%**

[1] Source for 2009-2011 approved budget: D.09-08-027, pp. 202-203.
[2] Source: SGE-1, Table MG-3 at MG-26 & SGE-13-1, Table KS-9 for EM&V budget.
[3] Program specific adjustments adopted in this decision.

Table 9 C

2012-2014 Demand Response Program Budgets - SCE

Funding Categories	Total Authorized for 2009-2011	Total Requested for 2012-2014	Total Authorized for 2012-2014	Change	% change
Category 1 - Reliability Programs					
Agricultural Pumping Interruptible	$1,400,000	$1,587,552	$930,023	-$657,529	-41%
Base Interruptible Program	$4,702,374	$2,510,226	$2,407,226	-$103,000	-4%
Optional Binding Mandatory Curtailment	$197,994	$46,475	$37,475	-$9,000	-19%
Rotating Outages	$408,738	$398,658	$321,658	-$77,000	-19%
Scheduled Load Reduction	$52,995	$24,000	$15,000	-$9,000	-38%
Category 1 Total	**$6,762,101**	**$4,566,909**	**$3,711,380**	**-$855,529**	**-19%**
Category 2 - Price-Responsive Programs					
Ancillary Service Tariff	-	$743,353	$0	-$743,353	-100%
Capacity Bidding Program	$812,299	$961,287	$661,287	-$300,000	-31%
Demand Bidding Program	$259,939	$1,786,086	$818,343	-$967,743	-54%
AC Cycling: Summer Discount Plan	$30,334,000	$71,105,768	$62,691,010	-$8,414,758	-12%
Peak Time Rebate / Save Power Day	-	$24,735,515	$4,707,515	-$20,028,000	-81%
Energy Options Program	$5,703,864	-	-	-	-
Category 2 Total	**$37,110,102**	**$99,332,009**	**$68,878,155**	**-$30,453,854**	**-31%**
Category 3 - DR Provider/Aggregator Managed Programs					
DR Contracts	$38,773,160	-	-	-	-
Category 3 Total	**$38,773,160**	**$0**	**$0**	**$0**	-
Category 4 - Emerging & Enabling Technologies					
Automated DR / Technology Incentives	$4,302,881	$35,818,277	$35,576,277	-$242,000	-1%
Emerging Markets & Technologies	$9,244,405	$7,303,969	$7,303,969	$0	0%
Agriculture Pump Timer Program	$126,018	-	-	-	-
Technical Assistance/Technology Incentives	$50,262,525	-	-	-	-
Category 4 Total	**$63,935,829**	**$43,122,246**	**$42,880,246**	**-$242,000**	**-1%**
Category 5 – Pilots					
Smart Charging Pilot	-	$600,000	$600,000	$0	0%
Workplace Charging Pilot	-	$1,243,125	$1,243,125	$0	0%
2009-2011 Pilots	$4,950,424	-	-	-	-
Category 5 Total	**$4,950,424**	**$1,843,125**	**$1,843,125**	**$0**	**0%**
Category 6 - Evaluation, Measurement and Verification					
DRMEC	$7,074,990	$9,093,654	$6,404,147	-$2,689,507	-30%
DR Research Studies	-	-	$1,200,000	$1,200,000	-
Category 6 Total	**$7,074,990**	**$9,093,654**	**$7,604,147**	**-$1,489,507**	**-16%**
Category 7 - Marketing, Education and Outreach					
Statewide Marketing - Flex Alert/Engage 360	$4,947,991	$3,298,659	$3,298,659	-	0%
Circuit Savers Program	$1,529,188	$2,599,822	$865,247	-$1,734,575	-67%
DR Marketing, Education, & Outreach	-	$3,673,037	$1,219,259	-$2,453,778	-67%
Agriculture and Water Outreach	$489,069	-	-	-	-
Income Qualified Customer Outreach	$120,768	-	-	-	-
Other Local Marketing	-	$0	$14,240,400	$14,240,400	100%
Subtotal: Local Marketing	-		*$16,324,906*		
Category 7 Total	**$7,087,016**	**$9,571,518**	**$19,623,565**	**$10,052,047**	**105%**
Category 8 - DR System Support Activities					
DR Systems & Technology	-	$20,600,032	$17,900,032	-$2,700,000	-13%
DR Forecasting, Resource Portal & Sys. Infra.	$13,158,420	-	-	-	-
Category 8 Total	**$13,158,420**	**$20,600,032**	**$17,900,032**	**-$2,700,000**	**-13%**
Category 9 - Integrated Programs and Activities (Including Technical Assistance)					
Integrated IDSM Marketing	$2,953,077	$2,721,193	$984,359	-$1,736,834	-64%
Statewide IDSM	$88,785	$1,067,162	$29,595	-$1,037,567	-97%
DR Institutional Partnership	$327,003	$417,491	$109,001	-$308,490	-74%
DR Technology Resource Incubator Outreach (TRIO)	$310,401	$283,011	$96,467	-$186,544	-66%
DR Energy Leaders Partnership	$2,604,093	$1,865,314	$868,031	-$997,283	-53%
Federal Power Reserve Partnership	$1,685,269	$2,844,304	$561,756	-$2,282,548	-80%
Technical Assistance	-	$1,473,198	$839,506	-$633,692	-43%
Commercial New Construction Pilot	$831,674	$634,203	$277,225	-$356,978	-56%
IDSM Food Processing Pilot	$291,628	$358,408	$97,209	-$261,199	-73%
Residential New Construction Pilot	$417,066	$350,870	$139,022	-$211,848	-60%
Workforce Education & Training Smart Students	$149,485	$3,232,760	$49,828	-$3,182,932	-98%
Category 9 Total	**$9,658,481**	**$15,247,915**	**$4,052,000**	**-$11,195,915**	**-73%**
Category 10 - Special Projects					
Permanent Load Shifting	-	$14,243,195	$19,690,000	$5,446,805	38%
Category 10 Total	**-**	**$14,243,195**	**$19,690,000**	**$5,446,805**	**38%**
Dynamic Pricing (Not Funded in This Decision)					
Critical Peak Pricing < 200 kW	-	$7,629,868	$0	-$7,629,868	-100%
Critical Peak Pricing >= 200 kW	$2,641,459	$2,671,439	$0	-$2,671,439	-100%
Real Time Pricing	$70,409	$1,114,929	$0	-$1,114,929	-100%
Total Dynamic Pricing	**$2,711,868**	**$11,416,237**	**$0**	**-$11,416,237**	**-100%**
TOTAL DR Portfolio	**$191,222,391**	**$229,036,840**	**$186,182,650**	**-$42,854,190**	**-19%**

[1] Source for 2009-2011Adopted: D.09-08-027, Table 24-1, pp.198-200.
[2] Source for SCE requested DR budget: SCE-05A, Table IV-21 at p.51.
[3] Changes reflect the program specific adjustments adopted in this decision.
[4] DR contracts: 2009-2011 authorized budget incl. funding for 2012
[5] Source for SCE's IDSM budgets: EE Decision, D. 09-09-047, Section 5.9, p 213.

We reiterate the direction we provided to the Utilities in D.09-08-027 regarding the process for requesting changes or adjustments to the DR programs and budgets we approve in this decision. Changes such as requests for new DR programs, increases in the total budget for a DR program area, or changes to policies specifically adopted in this decision should be made through an Application or a Petition for Modification. We authorize the Utilities to request non-controversial changes to program tariffs and implementation procedures via a Tier 2 Advice Letter. If uncertain whether a particular change is appropriate for review through the Advice Letter process, we encourage the Utilities to consult with Energy Division staff before submitting an Advice Letter.

10. Cost Recovery

The majority of the Utilities' requests for cost recovery were non controversial and generally continue the cost recovery approach adopted for earlier demand response program budget cycles. The following discussion presents the utility cost recovery requests, party positions and the Commission adopted positions for cost recovery during the 2012-2014 budget cycle.

10.1. Utility Proposals

10.1.1. PG&E's Proposal

PG&E requests authorization to recover up to $234.3 million in expense and capital costs for the 2012 – 2014 DR program cycle. PG&E proposes to continue recovering its authorized DR revenue requirements from all customers through distribution rates included in the Distribution Revenue Adjustment Mechanism (DRAM) account.

PG&E requests the following:[417]

1. Include the forecasted costs and associated revenue for 2012-2014 in its DR application be deemed reasonable and not subject to after-the-fact reasonableness review.
2. Include the revenue requirements in the Annual Electric True-Up (AET) process and recover in rates in the same manner as other distribution costs. Moreover, revenue requirements would be subjected to the current Commission methodology for revenue allocation and rate design.
3. Eliminate the Air Conditioning Expense Balancing Account (ACEBA) and merge the costs from ACEBA into the Demand Response Expenditures Balancing Account (DREBA) beginning January 1, 2012.
4. Eliminate the Demand Response Revenue Balancing Account (DRRBA) and shift the expenses currently recorded there into the Distribution Revenue Adjustment Mechanism (DRAM) account. The DRAM a primary GRC recovery account.
5. Recover authorized capital revenue requirements in the DRAM account.
6. Record any revenues resulting from bidding PG&E's DR programs into the CAISO Market into the DRAM. Revenues recorded in the DRAM would reduce DR revenue requirements as part of the AET filing process.
7. PG&E's shareholders assume responsibility for incentive payments paid for incremental MWs beyond the emergency-triggered MWs settlement cap. PG&E would revise the DREBA to track and reconcile these as potential overpayments to authorized expenses.
8. Allow a bridge funding mechanism to continue operating PG&E's currently authorized DR programs at the level of the 2011 authorized revenue requirement.

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[417] PG&E-1 at 11-1, 11-2, 11-11.

10.1.2. SCE

SCE requests authorization to recover up to $229.037 million in program funding for the 2012 – 2014 Demand Response program cycle.[418] The DR program budget will be reflected in rates in equal amounts of $76.3 million in each of the years 2012 through 2014. SCE is not proposing any change in its currently approved DR ratemaking and plans to utilize existing balancing accounts.

D.09-08-027 authorized SCE funding for DR contracts through 2012. SCE assumes that no new funding will be requested by SCE or authorized by the Commission in response to a request by a third party for DR capacity contracts after 2012. As a result of this expectation, SCE will recover $4.5 million less from customers.[419] SCE will adjust its revenue requirement in the 2013 Energy Resource Recovery Account (ERRA) filing.

10.1.3. SDG&E

SDG&E currently records all program costs associated with its existing DR programs and its current DRP bilateral contracts in its Advanced Metering and Demand Response Memorandum Account (AMDRMA). SDG&E plans to continue using the AMDRMA account along with SDG&E's Rewards and Penalties Balancing Account (RPBA). Balances are transferred to the RPBA on an annual basis for amortization in SDG&E's electric distribution rates over 12 months consistent with SDG&E's adopted tariffs.

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418 SCE-05 at 46.

419 *Ibid.*

SDG&E requests that authorized DR program costs related to DR Operation and Maintenance (O&M) expenses, capital related costs (ie. depreciation, return and taxes), customer capacity incentive payments, and all other costs, not recovered through SDG&E's GRC be recorded in AMDRMA.

SDG&E proposes that the costs related to IT upgrades to allow applicable DR programs to participate in locational dispatch and other CAISO MRTU initiatives be recovered through its Market Redesign and Technology Upgrade Memorandum Account (MRTUMA). According to SDG&E, the purpose of MRTUMA is to record the incremental O&M and capital-related costs associated with implementing the CAISO's MRTU initiative.

10.2. Party Positions

DACC and AReM argue that because DR is functionally treated by the Commission, FERC, and CAISO as resources equivalent to generation, DR's associated expenses should be recovered through the generation revenue requirement with the sponsoring load serving entity retaining any resource adequacy or other benefits afforded by the program. Furthermore, DACC and AReM maintain that Direct Access and Community Choice Aggregator customers should not be required to pay the costs of DR programs in which they are not allowed to participate. To the extent all retail customers are required to pay the costs of utility DR programs, DACC and AReM argue that any associated benefits must be distributed equitably to all such customers. Currently, such benefits are confined to resource adequacy capacity credits, but may possibly expand in the future to environmental attributes such as potential greenhouse gas reductions credits.[420]

CLECA contends that since Direct Access and Community Choice Aggregator customers can participate in virtually all utility DR programs, they should pay for their share of the costs of these programs.

10.3. Discussion

PG&E requests the Commission to determine that forecasted costs and associated revenue for 2012-2014 be considered reasonable and therefore not subject to after-the-fact reasonableness review. We will not prejudge the deliberative process of the ERRA proceeding. PG&E's request is denied. Regarding PG&E's requests to have revenue requirements included in the AET process and to recover authorized capital revenue requirements in the DRAM account are granted. PG&E's request to eliminate the ACEBA account and transfer costs formerly tracked in ACEBA into the DREBA account is approved.

PG&E's requests the Commission to eliminate the DRRBA account and shift the costs to the DRAM account. The DRAM is a primary GRC recovery account with many accounts where DR costs may be difficult for Energy Division staff and parties to locate. The DREBA account already tracks DR expenses and has sub-accounts that accommodate both one-way and two-way balancing treatment. PG&E is directed to eliminate the DRRBA account but transfer costs recorded there into the DREBA account.

PG&E's requests to record into the DRAM any revenues resulting from bidding PG&E's DR programs into CAISO and for shareholders to assume

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[420] DAC-01 at 3.

responsibility for incentive payments paid for incremental MWs beyond the emergency-triggered MWs settlement cap are approved. PG&E's request for a DR bridge funding decision is denied without prejudice.

SDG&E and SCE propose few changes to their currently approved DR ratemaking and plan to utilize existing balancing accounts. SDG&E proposes that the cost related to IT upgrades to allow applicable DR programs to participate in locational dispatch and CAISO MRTU initiatives be recovered through its MRTUMA. SDG&E's and SCE's cost recovery mechanism as described above are approved.

CLECA focuses on the complexity of the cost allocation process and suggests that any attempt to parse out DR program cost as generation or distribution must be informed by the fact that all customers benefit from DR programs and all customers must pay for their share of these costs.[421] In its opening testimony, CLECA states that the Commission's current process of cost recovery is to include the allocation of DR costs in a GRC phase 2 proceeding or rate design window proceeding and to recover almost all costs associated with DR, as opposed to dynamic pricing, through distribution rates, which are charged to all utility delivery customers.

Although Direct Access and Community Choice Aggregator customers receive their energy from a non-utility provider, that energy is delivered across the utility distribution system. If DR programs provide distribution benefit, DA and CCA customers participate in that benefit. Without further study, the Commission finds nothing in the record to substantiate DACC and AReM's

[421] CLE-01 at 49.

assertions. Moreover, until the Commission makes a final determination about the future structure of the DR market, changing the current cost recovery and rate design process for DR is not ripe for discussion. Normally, in order for the Commission to consider DACC and AReM's proposal to restructure rates, we would require additional data and fact finding studies that are best handled in rate design. However, we agree that these issues should be considered in a consistent manner across all three utilities and thus are best handled in one proceeding, the DR Rulemaking, 07-01-041 or its successor.

11. Guidance for DR Reporting and 2015-2017 Applications

The Utilities' DR applications for the 2015-2017 program cycle shall be filed no later than January 30, 2014. We have noted several discrepancies in the applications for the 2012-2014 budget cycle which led to difficulties during the review process. We find that improved monthly reporting will assist the Commission in developing better guidance for the Utilities in preparation for the filing of future applications. We direct the Utilities to meet with the Energy Division no later than 30 days following the issuance of this decision, to develop an improved monthly reporting document. In preparation for the filing of those applications, we require the Utilities to meet with Energy Division no later than March 30, 2013 to discuss the 2015-2017 DR program and budget applications. Energy Division will provide a guidance document to the Utilities and stakeholders no later than September 1, 2013 to assist the Utilities in developing improved and thorough 2015-2017 DR program and budget applications.

12. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments are allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by CAISO, CESA, CLECA, DACC/AReM, DRA, DR Aggregators, NAPP, PG&E, SCE, SDG&E, TURN, and UCAN on November 17, 2011 and reply comments were filed on November 21 and 22, 2011 by CAISO, CESA, CLECA, DRA, DR Aggregators, PG&E, SCE, and SDG&E. Additions and revisions have been made throughout the final decision as appropriate in response to the comments received.

13. Categorization and Assignment of Proceeding

This proceeding is categorized as ratesetting. Michael R. Peevey is the assigned Commissioner and Kelly A. Hymes is the assigned ALJ in this proceeding. ALJ Hymes is the Presiding Officer.

Findings of Fact

1. A lack of budget transparency led to obstacles in the 2012-2014 demand response application review process.
2. Too much budget flexibility endangers budget transparency.
3. The Utilities provide no new information or justification in their applications for us to change our current policy on budget flexibility.
4. The Commission remains committed to the Energy Action Plan's loading order whereby energy efficiency and demand response are the preferred means of meeting California's energy needs.
5. PG&E's use of the LOLP model is consistent with the Protocols authorization of an alternate model in addition to the default E3 model.
6. PG&E provides insufficient evidence that the LOLP model is more accurate than the default E3 model for the purposes of this proceeding.
7. The Protocols consider the LOLP model to be proprietary.

8. The LOLP model used by PG&E is out of date for the purposes of this proceeding.

9. PG&E has not produced a new analysis of the LOLP since 2006.

10. SCE failed to include ME&O costs and misallocated EM&V costs in its cost-effectiveness analysis.

11. The Cost-Effectiveness Protocols do not dictate how the Commission should use the results of the cost-effectiveness tests to approve DR programs.

12. The Cost-Effectiveness Protocols allow us to be flexible in our approach to analyzing cost-effectiveness for DR programs.

13. The TRC, PAC, and RIM tests each provide a valuable perspective in determining the cost-effectiveness of a demand response program.

14. There are deficiencies in the Cost-Effectiveness Protocols.

15. Each of the Utilities has a different approach to allocating the cost of supporting activities to the DR programs.

16. The Utilities did not comply with the Cost-Effectiveness Protocol requirement to provide qualitative analysis of optional costs and benefits.

17. The Dual Participation Rules promoted customer participation.

18. Dual Participation Rule a) did not effectively increase load reduction.

19. Allowing dual participation in a currently-defined capacity payment program and an energy payment program could result in both a loss of resource adequacy capacity value and double procurement of resource adequacy resources.

20. Dual Participation Rule b), as currently written presents two problems. If both program events overlapped, dual participation did not effectively increase load reduction. If the events did not overlap, the utility could experience double

procurement and ultimately an impact to the cost-effectiveness of dual participation.

21. In PDR and RDRP product rules, CAISO prohibits dual participation of one resource bidding into both products or within the two products.

22. Changes to the dual participation rules potentially impact currently enrolled DR customers.

23. An accurate customer baseline is important in order to properly compensate customers for their actions.

24. An accurate baseline calculation helps determine the success of a DR program.

25. The 20 percent cap for both the day-ahead and the day-of adjustment for the 10-in-10 baseline may understate load reduction and potentially underpay customers for their actions.

26. The 40 percent cap for both the day-ahead and the day-of adjustment for the 10-in-10 baseline provides a fair balance for all customers as an interim solution.

27. There is insufficient information to determine the extent of participation by DR providers in the CAISO markets.

28. The current AMP contracts are not cost-effective.

29. CAISO does not support the paradigm of a third party aggregator delivering DR resources to the CAISO system that are not integrated with the wholesale market.

30. The utilities will have an opportunity to request funding for the 2012 DR statewide marketing in the 2013 energy efficiency bridge funding request.

31. The Utilities' ME&O funding requests do not convey an adequate effort toward the Commission's policy of coordinating, reducing or eliminating program-specific budget requests in this application.

32. The Utilities provide inadequate information in their applications to fully explain and justify DR System activities and the associated funding requests.

33. Costs incurred from the DR Systems budget are spread across each DR program.

34. SCE's two $500,000 DR Systems requests for "unanticipated activities" are unreasonable and unjustifiable.

35. PG&E's Capacity Bidding Program (day-of), SCE's Summer Discount Program non-residential enhanced, and SCE's Summer Discount Program residential programs are "cost-effective."

36. PG&E only provided an estimated cost-effectiveness analysis of its Demand Bidding Program.

37. SCE's compliance procedures for its Base Interruptible Program are adequate to ensure customer compliance with this program.

38. The Schedule Load Reduction Program is legislatively-mandated.

39. PG&E's SmartAC non-residential and SCE's Capacity Bidding Program are "not cost-effective."

40. There are other options aside from the PG&E's SmartAC non residential program available to non-residential customers who want to participate in DR programs, such as the Capacity Bidding Program, the Demand Bidding Program and and dynamic rates.

41. Peak Choice, with or without Demand Bidding Program, is not cost-effective.

42. The IT system developed for the PG&E's PeakChoice program can be used to manage and operate other current and future DR programs.

43. SDG&E incorrectly performed the cost-effectiveness calculation for its Peak Time Rebate program.

44. The Utilities' proposal to divide Automated Demand Response incentive payments into an initial 60 percent payment upon project completion and a 40 percent payment a year later predicated on the customer performance demonstration is consistent with the recommendation to address customer load shed underperformance.

45. California benefits from investing in research and development that will encourage the adoption of cost-effective demand response programs.

46. The Utilities' Permanent Load Shifting proposals are cost-effective when using a 15-year amortization period in the cost-effectiveness analysis.

47. The Utility proposed incentive levels for PLS programs are approximately rate-payer neutral and within the range adequate to achieve a 5 year payback.

48. PG&E's DR-HAN Integration project is incremental to the basic HAN functionality funded in D.09-03-026 and consistent with Commission direction in that decision.

49. PG&E's requested Lab Work proposal is duplicative of work previously approved by the Commission.

50. A State Action Doctrine defense to an antitrust action exists where: (a) the challenged conduct is a result of directions clearly articulated and affirmatively expressed as state policy; and (b) there is continued active supervision of the Utilities activities in this regard.

51. Implementation of required statewide demand response activities as called for in this decision require the Utilities to work collaboratively.

52. The Utilities have not effectively used existing budgets to achieve Commission objectives to integrate demand side management programs.

53. The energy efficiency application proceeding will be delayed until 2013.

54. SCE's Integrated Demand Side Management programs have performed successfully with less than their authorized budgets.

55. The Utilities' pilot proposals do not contain detail or justification to authorize the requested budgets.

56. Improved monthly reporting will assist the Commission to develop better guidance for the Utilities in preparation for the filing of future applications.

Conclusions of Law

1. The Commission should only consider the E3 model results when reviewing PG&E's cost-effectiveness analyses in this proceeding.

2. Solely for the purposes of this proceeding, the Commission should consider "cost-effective," those programs where at least two of the TRC, PAC, or RIM tests are 0.9 or higher.

3. Solely for the purposes of this proceeding, the Commission should consider "possibly cost-effective", those programs where at least two of the cost-effectiveness tests are between 0.5 and 0.9.

4. Solely for the purposes of this proceeding, the Commission should consider "not cost-effective," those programs where two or more of the tests fall below 0.5.

5. The Commission should hold workshops immediately following the approval of these budget applications to address the deficiencies in the Protocols.

6. The Commission should adopt revised dual participation rules to avoid duplicative procurement of resource adequacy resources while continuing to promote program participation.

7. The Commission should revise the 20 percent cap on the settlement baseline to a 40 percent cap on an interim basis for both the day-ahead and day-of options of the Capacity Bidding Program while the Commission continues to study the issue.

8. The Commission should not extend the AMP contracts without sufficient revisions to make the contracts cost-effective.

9. The Commission should deny PG&E's request for a RFP for new AMP contracts based on PG&E's intention that PG&E will be bidding these resources into the market.

10. The Commission should deny all DR statewide marketing funding requests for 2013 in this proceeding.

11. The Commission should deny requests for marketing Reliability programs, especially those which have few, if any, customers.

12. The Commission should decrease the marketing funds for Local DR ME&O.

13. The Utilities should focus residential and small commercial marketing efforts on motivating them to use the My Account tool as well as other available online resources.

14. The Commission should decrease the budgets in the DR Systems Support budget category to improve the cost-effectiveness of the DR programs associated with the costs in this category.

15. It is reasonable to deny approval of and funding for all options of PG&E's PeakChoice program beginning in 2013.

16. Funds to support dynamic pricing programs should be requested in general rate cases or in applications for the dynamic pricing programs.

O R D E R

IT IS ORDERED that:

1. The Division of Ratepayer Advocates' motion to file under seal the confidential Attachment A of its opening briefs is granted.

2. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall organize their demand response programs within the following ten categories: 1) Reliability-based Programs; 2) Price Responsive Programs; 3) Demand Response Provider/Aggregator-Managed Programs; 4) Enabling or Emerging Technologies 5) Pilots; 6) Evaluation, Measurement, &Verification Activities; 7) Marketing, Education and Outreach Activities; 8) Demand Response Systems Support; 9) Integrated Programs and Activities; and 10) Special Projects.

3. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company:

- May not shift funds between categories;
- May continue to shift up to 50 percent of a Demand Response program's funds to another program within the same budget category, with proper monthly reporting;
- Shall not shift funds within the "Pilots" or "Special Projects" categories without submitting a Tier 2 Advice Letter filing;
- May shift funds for pilots in the Enabling or Emerging Technologies category;
- Shall continue to submit a Tier 2 Advice Letter to eliminate a Demand Response program;
- Shall not eliminate a program through multiple fund shifting events or for any other reason without prior authorization from the Commission; and

- Shall submit a Tier 2 Advice Letter before shifting more than 50 percent of a program's funds to a different program within the same budget category.

4. The fund shifting rules are not applicable to San Diego Gas and Electric Company's funds for customer incentives approved in this decision.

5. The Energy Division shall hold one or more workshops beginning in the first sixty days after the issuance of this decision to address all deficiencies of the 2010 Cost-Effectiveness Protocols.

6. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall comply with the following revised dual participation rules for cost-effective demand response programs:

   a. Prohibit duplicative payments for a single instance of load drop. In the case of simultaneous or overlapping events called in two cost-effective Demand Response programs, a single customer account enrolled in the two programs shall receive payment only under the capacity program, not the energy payment program.

   b. Allow dual participation in up to two cost-effective Demand Response activities, if one provides energy payments based on avoided energy costs without any explicit or implicit capacity elements and the other provides capacity payments.

   c. Prohibit participation in: 1) two Demand Response programs that provide resource adequacy qualifying capacity value with the exception of the Base Interruptible and Demand Bidding Programs; 2) two cost-effective Demand Response programs that bid in California Independent System Operator's (CAISO's)wholesale Demand Response products that are prohibited under CAISO's rules ; and 3) two day-ahead cost-effective Demand Response programs or two day-of cost-effective Demand Response programs.

   d. Require that the two cost-effective programs are offered by the same demand response provider. The revised rules shall apply to all new customers beginning in 2012 and existing customers in

2013. The year 2012 shall be a transition year for customers to decide in which program they would like to participate.

7. Pacific Gas and Electric Company, San Diego Gas & Electric, and Southern California Edison Company shall submit, within 45 days, a Tier 2 Advice Letter revising, on an interim basis, the current settlement baseline for the Capacity Bidding Program day-ahead and day-of options to an individual 10-in-10 baseline with an optional 40 percent cap day-of adjustment.

8. Pacific Gas and Electric Company, San Diego Gas & Electric, and Southern California Edison Company (the Utilities) shall provide, as part of the Load Impact Annual Filing on April 1, 2012 and again in 2012 and 2014, an analysis that compares their baseline settlement result using both individual and aggregated baseline with cap percentage adjustments of 20, 30, 35, 40, 50 and no cap for the months of July, August, and September of the prior year. The Utilities shall compare the annual baseline settlement results with the Measurement and Evaluation results for the same year. The comparison analysis must include service accounts for whom the adjusted energy baseline option was selected in that nomination month as well as a second set of service accounts, assuming all service accounts select day-of adjustment.

9. Pacific Gas and Electric Company, San Diego Gas & Electric, and Southern California Edison Company (the Utilities) shall address the baseline comparison analysis as part of the annual Load Impact workshops. Prior to the workshops, the Utilities shall solicit parties' input on improving the baseline comparison studies.

10. Forty-five days following each annual load impact workshop, Pacific Gas and Electric Company, San Diego Gas & Electric, and Southern California Edison Company shall submit a joint Tier 2 Advice Letter addressing whether there is a

need to change the current baseline along with a proposed baseline comparison study for the following year.

11. Pacific Gas and Electric Company (PG&E) shall renegotiate the terms of the Aggregator Managed Programs contracts to effectively improve the cost-effectiveness so that at least two of the three cost-effectiveness tests attain at least a 0.9. Within 90 days from the issuance of this decision, PG&E shall submit a Tier 2 Advice Letter that includes the renegotiated cost-effective contracts, along with a revised cost-effectiveness analysis that provides the results of the three cost-effectiveness tests. We authorize PG&E to extend the cost-effective contracts effective 2013 through 2014.

12. Contingent upon the timely submission of its Tier 2 Advice Letter regarding the renegotiated and cost-effective Aggregator Managed Program contracts, Pacific Gas & Electric Company is authorized to extend its current Aggregated Managed Programs contract for one year through December 31, 2012.

13. Subsequent to the establishment of direct participation rules and the new rules for the California Independent Systems Operator's (CAISO) wholesale Demand Response products, we will address the details related to policy issues with procurement of wholesale Demand Response resources, as part of Rulemaking 07-01-041, or its successor. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall work with CAISO, Energy Division staff and the Procurement Review Groups to develop the Request for Proposal requirements to meet future system needs, e.g., integration of renewable resources. The Utilities shall also work with the Procurement Review Groups to ensure that procurement strategies are consistent with the Loading Order.

14. One year (2012) of bridge funding for the Demand Response Statewide Marketing, Education and Outreach program in this proceeding is authorized for Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company to be used for an emergency alert campaign and the dynamic rates/Peak Time Rebate campaign.

15. During the 2012 program evaluation of Marketing, Education and Outreach activities, the Demand Response Measurement and Evaluation Committee shall review the marketing costs per enrolled customer and determine the range of appropriate costs for AC cycling programs.

16. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall consolidate all marketing funding into two categories: Marketing, Education, and Outreach (ME&O) and Integrated Demand Side Management ME&O.

17. San Diego Gas & Electric Company, and Southern California Edison Company shall re-categorize the individual Demand Response program funding requests into the Local Marketing, Education, and Outreach (ME&O) subcategory of the ME&O category.

18. Within 60 days of the issuance of this decision, the Energy Division shall hold a workshop to address Demand Response Marketing, Education and Outreach (ME&O) issues including the specific roles for Statewide and Integrated Demand Side Management ME&O and the development of marketing plans for Local DR ME&O.

19. Thirty days following the Demand Response Marketing, Education and Outreach workshop, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall submit a Tier 2 Advice Letter with a Marketing Plan for their Local Demand Response

Marketing, Education and Outreach program that provides specific details regarding the activities which will be performed, categorized to provide details in existing monthly demand response reports to the Commission; the specific programs the marketing activities will support; and marketing evaluation plans and schedules. Furthermore, the Marketing Plan shall comply with the following policies:

a. Reliability Programs are capped. Until further notice, using ratepayer funds to market these programs is prohibited.

b. The Capacity Bidding Program is administered by third party Demand Response providers. Marketing should be the role of the third party provider. Using ratepayer funds to market these programs is prohibited.

c. Programs that have few to no customers enrolled, such as the Scheduled Load Reduction and Optional Binding Mandatory Curtailment Programs, do not require marketing funds.

e. Marketing plans shall focus on price-responsive programs and permanent load shifting activities.

f. Marketing efforts for residential and small commercial customers shall focus on customer enrollment through "My Account."

g. Marketing for Peak Time Rebate shall either be done online or through highly targeted campaigns only.

h. General concept messaging for marketing Peak Time Rebate and other dynamic rate concepts shall be delivered through statewide rather than local marketing campaigns.

20. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall decrease the overall budget requested for each program approved in this decision to make their programs cost-effective.

21. Southern California Edison's overall Demand Response System Support budget is decreased by $1 million.

22. Southern California Edison's Agricultural Pumping Interruptible Program is approved. We authorize a budget of $930,023 for this program.

23. Southern California Edison's Base Interruptible Program during 2012-2014 is approved. A budget of $2,407,226 is authorized for 2012-2014.

24. San Diego Gas & Electric Company's (SDG&E) Base Interruptible Program is approved as follows. SDG&E shall decrease the administrative costs of its Base Interruptible Program by $362,179. SDG&E shall eliminate its Base Interruptible Program-Option B to conform the program to the California Independent System Operators Reliability Demand Response Product.

25. The summer month premium for San Diego Gas & Electric Company's Base Interruptible program is approved.

26. A budget of $3,816,821 is authorized for San Diego Gas & Electric Company's Base Interruptible Program during 2012-2014.

27. Pacific Gas and Electric Company's (PG&E) Base Interruptible Program is approved. PG&E shall improve the cost-effectiveness of this program by a) increasing the number of call hours from 120 to 180 hours annually,
b) decreasing the DR Systems Support budget by $3,963,399 million, and
c) decreasing the Local Demand Response Marketing, Education and Outreach budget allocated to this program by $140,704.

28. Pacific Gas and Electric Company and San Diego Gas & Electric Company shall implement the pre-enrollment qualification process and retesting for non-compliant participants in the Base Interruptible Program.

29. Budgets for the Optional Binding Mandatory Curtailment Program from Pacific Gas and Electric Company and Southern California Edison, for Rotating Outages from Southern California Edison are authorized in the amounts requested.

30. San Diego Gas & Electric Company shall terminate its Optional Binding Mandatory Curtailment Program.

31. We deny, without prejudice, the request by San Diego Gas & Electric Company to eliminate the back up generation provision from its Capacity Bidding Program and Base Interruptible Program tariffs.

32. Southern California Edison's Save Power Day Program is approved as requested. We authorize budgets as requested for this programs but with the required decreases in the Marketing, Education, and Outreach and Demand Response Systems budgets.

33. Pacific Gas and Electric Company shall not enroll new customers in its non-residential SmartAC program.

34. Pacific Gas and Electric Company (PG&E) shall migrate one half of its PeakChoice customers to other Demand Response programs by May 1, 2012 and the second half of its customers by December 31, 2012. PG&E shall terminate all options of its PeakChoice program by December 31, 2012 and adapt the information technology system developed for PeakChoice to PG&E's other demand response programs.

35. Pacific Gas and Electric Company shall submit a Tier 2 Advice Letter no later than 90 days after the issuance of this decision describing its PeakChoice transition plan.

36. We authorize a budget of $1.75 million for Pacific Gas and Electric Company to operate the PeakChoice program with one half of its customers from May 1, 2012 through December 31, 2012.

37. San Diego Gas & Electric Company (SDG&E) Peak Time Rebate program is approved. SDG&E shall recalculate its cost-effectiveness analysis of its Peak Time Rebate program to include the customer incentives in the analysis and

submit the results in a Tier 2 Advice Letter 60 days following the issuance of this decision.

38. We approve Southern California Edison Company's (SCE) Capacity Bidding Program and authorize a budget of $661,287 for this Program. SCE's DR Systems budget is decreased by $1.7 million to reflect the majority of the $1.9 million portion of that budget which is allocated to the Capacity Bidding Program. SCE shall perform an in-depth analysis of its Capacity Bidding Program to (1) propose details of how the full-year program would work; (2) analyze the differences between Pacific Gas and Electric Company, San Diego Gas & Electric Company and SCE's Capacity Bidding Program; and (3) provide a plan for improving the Capacity Bidding Program cost-effectiveness to 0.75 in 2013 and to 0.9 in 2014. SCE shall submit this analysis in a Tier 2 Advice Letter to the Energy Division no later than 180 days following the issuance of this decision.

39. Pacific Gas and Electric Company's (PG&E) Capacity Bidding Program is approved. PG&E shall decrease the budget for this program by $1.5 million in the marketing, education and outreach budget category in order for the day-of option of this program to be cost-effective. PG&E shall submit its revised cost-effectiveness analysis with a Tier 2 Advice Letter within 45 from the issuance of this decision.

40. Pacific Gas and Electric Company's (PG&E) SmartAC residential program is approved. PG&E shall decrease the budget for SmartAC to $9,353,335. The non-residential option of SmartAC shall operate with its existing customers only.

41. San Diego Gas & Electric Company's (SDG&E) Capacity Bidding Program is approved. SDG&E shall decrease the budget for this program by $4.3 million,

including a decrease of $150,000 in the marketing, education and outreach category in order for the program to be cost-effective.

42. Southern California Edison Company's (SCE) Summer Discount Plan is approved. SCE shall decrease the budget for the Summer Discount Plan by $1.7 million in the required categories in order for the non-residential base option of this program to be cost-effective.

43. Southern California Edison Company's Demand Bidding Program is approved. We authorize a budget of $818,343.

44. Southern California Edison Company's Ancillary Services Tariff Program non-residential is denied without prejudice.

45. Pacific Gas and Electric Company's (PG&E) Demand Bidding Program is approved. PG&E shall perform an updated cost-effectiveness analysis and submit it along with a recalculated budget in a Tier 2 Advice Letter no more than 60 days from the issuance of this decision. If the results indicate less than cost-effective, we will direct PG&E to further revise its Demand Bidding Program budget. We authorize PG&E a budget of $3.216 million for its 2012-2014 Demand Bidding Program, contingent upon the receipt of the results of the resubmitted cost-effectiveness analysis.

46. All Marketing, Education and Outreach funding for the Capacity Bidding Programs is denied.

47. The Marketing, Education and Outreach (ME&O) budget in Southern California Edison Company's (SCE) Save Power Day program is recategorized to the Local Demand Response ME&O Category. The ME&O budget for this program is decreased by 50 percent. SCE's Save Power Day program is approved. A program budget of $4,707,515 is authorized for the Save Power Day program for 2012-2014.

48. Pacific Gas and Electric Company may enroll net energy metering customers in SmartAC, the Capacity Bidding Program and the Aggregator Managed Program.

49. Southern California Edison's request for funding for marketing its Critical Peak Pricing program is denied.

50. Southern California Edison's (SCE) request for funding for its Real Time Pricing to support increased ME&O efforts is denied. SCE may file a Petition for Modification within Application 10-09-002 to request these funds.

51. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities') Automated Demand Response (ADR) programs are approved with the requested modifications and direct the Utilities to fund ADR technologies that interoperate using generally accepted industry open standards or protocols. The Utilities shall develop a statewide program with common program rules and incentive levels and submit a Tier 2 Advice Letter with a proposal to Energy Division no later than October of 2013.

52. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities') Emerging Technology projects are approved as requested. The 2012-2014 Emerging Technology budgets are authorized as requested. The Utilities shall provide semi-annual reports regarding their Emerging Technology projects to the Director of the Energy Division by March 31 and September 30 of each year.

53. Permanent Load Shifting proposals for Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) are approved. The Utilities shall increase their individual budgets for the proposals as follows: $25 million for Pacific Gas and Electric Company,

$20 million for Southern California Edison Company, and $5 million for San Diego Gas & Electric Company.

54. The request for proposals and funding for the Permanent Load Shifting emerging technology programs are denied.

55. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall work collaboratively to develop and propose a standardized, statewide Permanent Load Shifting program as described in this decision. The Utilities shall jointly submit the proposal as described in this decision to the Energy Division within 90 days following the issuance of this decision.

56. Energy Division shall hold a workshop to seek feedback from interested parties and facilitate a consensus process for Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) to finalize their Permanent Load Shifting (PLS) statewide program design and rules. Within 30 days after the workshop, the Utilities shall submit the final proposal of the statewide PLS program with a Tier 2 Advice Letter to the Commission.

57. Pacific Gas and Electric Company's request for its Home Area Network (HAN) Integration project including the $3 million for the evaluation project is approved. A total budget of $20.02 million is authorized for the HAN project.

58. Pacific Gas and Electric Company shall submit a Tier 2 Advice Letter for its Home Area Network Integration project with clear descriptions for the pilot portion of the project, including a detailed schedule for the IT work and pilot execution, in order to release the $20.2 million allocated for this item. The descriptions shall follow the guidelines for "Pilots." This Advice Letter shall be submitted no later than June 30, 2012.

59. San Diego Gas & Electric Company's Small Customer Technology Deployment program is approved with the following changes: (1) limit participation in this program to Peak Time Rebate customers only; (2) combine the two programs, (3) within 30 days of the issuance of this decision submit a Tier 2 Advice Letter to the Energy Division that includes an updated cost-effectiveness analysis of the combined programs, and (4) 30 days after the completion of the Residential Automated Control Technology Pilot, submit a Tier 2 Advice Letter with updated details of the Small Customer Technology Deployment program informed by the results of this pilot. Energy Division shall review the Advice Letter as a condition for release of the authorized budget for this program.

60. We authorize the Demand Response Measurement and Evaluation Committee (DRMEC) to continue to perform evaluations of statewide and individual utility Demand Response activities. We direct the DRMEC to continue to report its findings at annual public workshops.

61. The Demand Response Measurement and Evaluation Committee shall ensure that Evaluation, Measurement & Verification activities are jointly planned and implemented to achieve the core objectives as adopted in D.09-09-047: 1) Load Impact Evaluations; 2) Process Evaluations; 3) Demand Response Potential, Market Assessment and Technology Studies; 4) Policy and Planning Support; and 5) Financial and Management Audits.

62. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall conduct statewide impact evaluations when possible.

63. The Demand Response Measurement and Evaluation Committee (DRMEC) shall submit a detailed process evaluation plan, as described in this

decision that lists all Demand Response programs to be evaluated during 2012-2014 along with an explanation of the necessity of each evaluation. The DRMEC shall submit the process evaluation plan to the Energy Division no later than 45 days following the issuance of this decision.

64. Evaluation, Measurement and Verification budgets are authorized as follows: $15,721,000 for Pacific Gas and Electric Company, $7,604,147 for Southern California Edison Company, and $5,715,000 for San Diego Gas & Electric Company.

65. The Executive Director may hire and manage one or more contractors to perform tasks as described in this decision for the purpose of performing studies that advance the goals of the Commission's Demand Response activities. The Executive Director may spend up to $1 million during each of the three fiscal years beginning July 1, 2012 to be paid for by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) through their Evaluation, Measurement and Validation budgets. PG&E and SCE shall each be responsible for 40 percent of the costs and SDG&E shall be responsible for the remaining 20 percent of the costs.

66. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall work collaboratively to implement Demand Response statewide activities as ordered in this decision.

67. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company may request funding for post-2012 Integrated Demand Side Management activities in their request for 2013 energy efficiency bridge funding.

68. Pacific Gas and Electric Company's (PG&E) Integrated Demand Side Management (IDSM) budget for 2012 is authorized except for the $2.7 million Technology Incentive funding. PG&E's request for 2013 IDSM funding is denied.

69. Southern California Edison Company's (SCE) 2012 Energy Leaders Partnership Program is approved. A budget of $868,031 for the Energy Leaders Partnership Program is authorized. A budget of $4.107 million is authorized for SCE's other requested Integrated Demand Side Management (IDSM) activities for 2012. We deny SCE's request for IDSM funding for 2013.

70. San Diego Gas & Electric Company's Technical Assistance Integrated Demand Side Management program is approved as requested.

71. San Diego Gas & Electric Company's request for the Microgrid project is denied.

72. A budget of $4,305,359 is authorized for San Diego Gas & Electric Company's Integrated Demand Side Management programs.

73. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall submit a Tier 2 Advice Letter that includes a Proposed Pilot Plan for each of the pilots proposed in this application. All future Demand Response applications shall include a Pilot plan for every Demand Response Pilot proposed. The Advice Letter shall be submitted no later than six months before the anticipated start date of the pilot or 60 days after the issuance of this decision. Each Pilot Plan shall contain the following elements:

- A problem statement;
- How the pilot will addresses a DR goal or strategy;

- Specific objectives and goals for the pilot;
- A clear budget and timeframe;
- Relevant standards or metrics;
- Methodologies to test the cost-effectiveness of the pilot;
- An Evaluation, Measurement and Verification plan; and
- A strategy to identify and disseminate best practices and lessons learned.

74. The following budgets for Demand Response pilots are authorized, contingent upon the submittal and approval by Energy Division of the required Pilot Plan: $7.96 million for Pacific Gas and Electric Company, $1.8 million for Southern California Edison Company, and 1.5 million for San Diego Gas & Electric Company.

75. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company (the Utilities) shall implement the modifications to policies and program rules affecting existing Demand Response programs and activities adopted in this decision by January 1, 2012 or upon Energy Division approval of the Advice Letter implementing the change. For those programmatic changes not associated with another Advice Letter , the Utilities shall submit a Tier 1 compliance Advice Letter within 45 days of the issuance of this decision updating its tariffs to be consistent with the requirements of this decision and specifying the date on which those changes will take place.

76. For all compliance submissions ordered in this Decision which require cost-effectiveness analyses, Energy Division shall provide further guidance to the parties on the format and assumptions to be used for the cost-effectiveness

analyses. Energy Division shall provide that guidance within 15 days of the issuance of this decision.

77. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall meet with the Energy Division no later than 45 days following the issuance of this decision to develop an improved monthly Demand Response Program Reporting document.

78. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company (the Utilities) shall file 2015-2017 Demand Response Applications no later than January 31, 2014. In preparation for the filing of future applications, the Utilities shall meet with Energy Division no later than March 30, 2013 to discuss the 2015-2017 DR Program and Budget applications. Energy Division shall provide a guidance document to the Utilities and other stakeholders no later than September 1, 2013 to assist the Utilities in developing improved and thorough 2015-2017 DR Program and Budget applications.

79. Applications (A.) 11-03-001, A.11-03-002, and A.11-03-003 are closed.

This order is effective today.

Dated __________________________, at San Francisco, California.

APPENDIX A

List of Acronyms and Abbreviations

APPENDIX A – List of Acronyms and Abbreviations

A.	Application
AB	Assembly Bill
AC	Air Conditioning
ADR	Automated Demand Response
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
AMP	Aggregator Managed Programs
Application(s)	Applications filed inA.11-03-001 et al.
AReM	Alliance for Retail Energy Markets
BUG	BackUp Generation
CAISO	California Independent System Operator
CALMAC	CALMAC Manufacturing Corporation
CEC	California Energy Commission
CESA	California Energy Storage Alliance
CLECA	California Large Energy Consumers Association
CSM	Cafeteria Style Menu
D.	Commission Decision
DACC	Direct Access Customer Coalition
DR	Demand Response
DRA	Division of Ratepayer Advocates
DRMEC	Demand Response Measurement and Evaluation Committee
DSM	Demand Side Management
E3	Energy and Environmental Economic Consultants
EM&V	Evaluation, Measurement and Verification
EV	Electrical Vehicle

FERC	Federal Energy Regulatory Commission
GRC	General Rate Case
Guidance Ruling	8/27/2010 Ruling from ALJ Jessica Hecht
HAN	Home Area Network
HVAC	Heating, Ventilation and Air Conditioning
IDSM	Integrated Demand Side Management
IOU	Investor Owned Utility
IRM 2	Intermittent Resource Management Pilot Phase 2 (PG&E)
IT	Information Technology
kW	Kilowatt
LDR	Locational Demand Response Pilot (SDG&E)
LOLP	Loss of Load Probability
M&E	Measurement and Evaluation
ME&O	Marketing, Education and Outreach
MRTU	Market Redesign Technology Upgrade
MW	Megawatt
NAPP	North America Power Partners
NCDR	New Construction Demand Response Pilot (SDG&E)
OP	Ordering Paragraph
PAC	Program Administrator Cost
Partnership Program	Energy Leaders Partnership Program (SCE)
PDR	Proxy Demand Resource
PG&E	Pacific Gas and Electric Company
PLS	Permanent Load Shifting
PLS Study	Statewide Joint Investor-Owned Utility Study of PLS
Protocols	2010 Cost-Effective Protocols
R	Rulemaking

RDRP	Reliability Demand Response Product
RIM	Ratepayer Impact Measure
SCE	Southern California Edison Company
Scoping Memo	May 13, 2010 Scoping Memo in A.11-03-001 et al.
SDG&E	San Diego Gas & Electric Company
Settlement Agreement	Joint Motion Settlement Agreement
SPM	Standard Practice Manual
Strategic Plan	California Long Term Energy Efficiency Strategic Plan
T&D	Transmission and Distribution
TRC	Total Resource Cost
TURN	The Utility Reform Network
UCAN	Utility Consumers Action Network
Utilities	PG&E, SDG&E, and SCE, collectively

(END OF APPENDIX A)

APPENDIX B

Utility Ex Ante Load Impacts for 2012 through 2014

Appendix B

PG&E
Portfolio Adjusted Ex Ante Load Impact (MWs) for
July under 1-in-2 Weather Year Condition

DR Programs	**2012**	**2013**	**2014**
Base Interruptible Program (BIP)	205	221	234
Smart AC - Non Residential	3	4	5
Smart AC – Residential	99	100	97
DBP - Day Ahead	8	0	0
Peak Day Pricing (PDP) - Non Residential *	29	88	75
Peak Day Pricing (PDP) - Residential *	9	7	7
PeakChoice: Committed Load- Day of	20	21	22
PeakChoice: Committed Load - Day Ahead	4	5	6
PeakChoice: Best Effort - Day of	2	2	3
PeakChoice: Best Effort - Day Ahead	1	8	8
Capacity Bidding Program (CBP) - Day Ahead	25	25	25
Capacity Bidding Program (CBP) - Day Of	30	30	30
Aggregator Managed Portfolio - Day Ahead	40	40	40
Aggregator Managed Portfolio - Day of	149	149	149
Permanent Load Shift (PLS)	7	16	29
Total - PG&E	**631**	**716**	**730**

Source: PGE-5, pg 8, not including TOU rates.
Load impact for PDP reflects the delay in the implementation schedule.

SDG&E
Portfolio Adjusted Ex Ante Load Impact (MWs) for
July under 1-in-2 Weather Year Condition

DR Programs	**2012**	**2013**	**2014**
BIP	10	13	16
Summer Saver	15	15	15
CPPD - Medium C&I (20-200 kW)*	0	26	26
CPPD - Large C&I (>200 kW)*	12	12	12
PTR- Residential*	69	70	71
CBP-DA	10	11	11
CBP-DO	22	24	26
Permanent Load Shift (PLS)	2	4	5
Small Customer Technology Deployment	6	10	12
Total - SDG&E	**146**	**185**	**194**

Source: SGE-13, pg LW\KS-12

SCE
Portfolio Adjusted Ex Ante Load Impact (MWs) for
July under 1-in-2 Weather Year Condition

DR Programs	2012	2013	2014
Base Interruptible Program (BIP) -15 min.	129	131	134
Base Interruptible Program (BIP) -30 min.	417	425	432
Agriculture Pumping Interruptible (AP-I)	40	43	47
Summer Discount Plan (SDP) : Base- commercial	19	21	24
SDP: Enhance - commercial	42	45	47
SDP: Option A - residential	398	407	431
SDP: Option B - residential	101	137	157
DBP	12	16	18
CPP-L	25	23	26
CPP-M	47	161	61
CPP-S	14	35	13
Ancillary Service Tariff (AST)	0	4	10
Capacity Bidding Program (CBP) - Day Ahead	1	1	2
Capacity Bidding Program (CBP) - Day Of	19	20	21
DR Contracts - Day Ahead	25	0	0
DR Contracts - Day of	80	0	0
Real Time Pricing (RTP)	13	20	26
Permanent Load Shift (PLS)	6	13	19
Save Power Day (Peak Time Rebate)	332	371	356
Total - SCE	**1,720**	**1,873**	**1,824**

Source: SCE-5, pg 19

(END OF APPENDIX B)