**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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

PACIFIC GAS AND ELECTRIC COMPANY FILING FOR ITS 2017 BRIDGE FUNDING PROPOSAL FOR DEMAND RESPONSE PROGRAMS FOR THE 2017 TRANSITION YEAR

SHIRLEY A. WOO
MARY A. GANDESBERY

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-2248
Facsimile: (415) 973-5520
E-Mail: SAW0@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

February 1, 2016

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In accordance with Commission's September 15, 2015, Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for 2017 Demand Response Programs and Activities Proposal Filing (September 15 Ruling), and the guidance given in Decision (D.) 15-11-042, Pacific Gas and Electric Company (PG&E) has prepared and submits its proposal for demand response programs for the 2017 Transition year.

PG&E's proposal focuses its resources on achieving market integration objectives articulated by the Commission by streamlining its demand response (DR) portfolio and improving its remaining programs and pilots. PG&E's proposal focuses primarily on integrating its Base Interruptible Program (BIP) as Reliability Demand Response Resources (RDRR) no later than May 2017 and on completing its California Independent System Operator (CAISO) market integration efforts for all other DR programs to be bid as Proxy Demand Resource (PDR) by no later than January 2018. The activities detailed in this 2017 program proposal reflect that commitment. Certain programs, demand bidding program (DBP) and the aggregator managed portfolio contracts (AMP), will not be continued in 2017 due to difficulties with effectively and efficiently integrating them as currently structured into the CAISO market, and/or to enable PG&E to focus on integration of other programs.

PG&E respectfully requests that the Commission approve its demand response program proposal for the 2017 transition year no later than the last Commission meeting in June 2016, to enable it to implement its proposals by the start of the 2017 Transition year.

Respectfully Submitted,

SHIRLEY A. WOO

By: *\/s/Shirley A. Woo*
SHIRLEY A. WOO

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-2248
Facsimile: (415) 973-5520
E-Mail: SAW0@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

February 1, 2016

ATTACHMENT

Pacific Gas and Electric Company
2017 Bridge Funding Proposal for Demand Response Programs for 2017 Transition Year

February 1, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

PACIFIC GAS AND ELECTRIC COMPANY

2017 BRIDGE FUNDING PROPOSAL FOR DEMAND RESPONSE PROGRAMS FOR 2017 TRANSITION YEAR

FEBRUARY 1, 2016

PACIFIC GAS AND ELECTRIC COMPANY
2017 BRIDGE FUNDING PROPOSAL FOR DEMAND RESPONSE PROGRAMS
FOR 2017 TRANSITION YEAR

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2017 BRIDGE FUNDING PROPOSAL FOR DEMAND RESPONSE PROGRAMS FOR 2017 TRANSITION YEAR

TABLE OF ACRONYMS

AB	Assembly Bill
AC	Air Conditioning
ADR	Automated Demand Response
ADS	Automated Dispatch System
AMP	Aggregator Managed Portfolio
B/C Ratio	Benefit/Cost Ratio
BIP	Base Interruptible Program
CAISO	California Independent System Operator
CBP	Capacity Bidding Program
CCA	Community Choice Aggregation
CE	Cost Effectiveness
CEC	California Energy Commission
CISR-DRP	Customer Information Service Request-Demand Response Provider
CPP	Critical Peak Pricing
D.	Decision
DA	Direct Access
DAM	Day-Ahead Market
DBP	Demand Bidding Program
DLA	Default Load Adjustment
DR	Demand Response
DRAM	Demand Response Auction Mechanism
DRET	Demand Response Emerging Technologies
DRMEC	Demand Response Measurement and Evaluation Committee
DRP	Demand Response Provider
DRRS	CAISO Demand Response Registration System
DRS	Demand Response System
DSM	Demand Side Management
ED	Energy Division
EM&V	Evaluation, Measurement and Verification
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute
ETCC	Emerging Technologies Coordination Council

PACIFIC GAS AND ELECTRIC COMPANY
2017 BRIDGE FUNDING PROPOSAL FOR DEMAND RESPONSE PROGRAMS FOR 2017 TRANSITION YEAR

TABLE OF ACRONYMS
(CONTINUED)

EV	Electric Vehicle
EVSP	Electric Vehicle Service Provider
GRC	General Rate Case
HVAC	Heating, Ventilating, and Air Conditioning
IOUs	Investor-Owned Utilities
IRM2	Intermittent Renewable Management Pilot Phase 2
kW	kilowatt
LBNL	Lawrence Berkeley National Lab
LC&I	Large Commercial and Industrial
LMP	Locational Marginal Prices
LMR	Load Modifying Resource
LOLE	Loss of Load Expectation
LSE	Load Serving Entity
MDMA	Meter Data Management Agent
ME&O	Marketing, Education, and Outreach
MOO	Must Offer Obligation
MRTU	Market Redesign and Technical Upgrade
MW	megawatt
NBT	Net Benefits Test
NPV	Net Present Value
O&M	Operations and Maintenance
OAT	Otherwise Applicable Tariff
OBMC	Optional Binding Mandatory Curtailment
OVGIP	Open Vehicle Grid Integration Platform
PCT	Programmable Communicating Thermostats
PDP	Peak Day Pricing
PDR	Proxy Demand Resource(s)
PFM	Petition for Modification
PG&E	Pacific Gas and Electric Company
PLS	Permanent Load Shifting
RA	Resource Adequacy
RDRR	Reliability Demand Response Resource(s)

TABLE OF ACRONYMS
(CONTINUED)

RQMD	Revenue Quality Meter Data
RTM	Real-Time Market
SA	Service Account
SB	Senate Bill
SC	Scheduling Coordinator
SLRP	Scheduled Load Reduction Program
SMB	Small and Medium-sized Business
SPM	Standard Practice Manual
SQMD	Settlement Quality Meter Data
SR	Supply Resource
SubLAP	Sub Load Aggregation Point
T&D	Transmission and Distribution
TRC	Total Resource Cost
UDC	Utility Distribution Company
VEE	Verified, Edited or Estimated

PACIFIC GAS AND ELECTRIC COMPANY 2017 BRIDGE FUNDING PROPOSAL FOR DEMAND RESPONSE PROGRAMS FOR 2017 TRANSITION YEAR

A. Introduction/Policy

1. Objectives for 2017 and the Transition to 2018

Pacific Gas and Electric Company (PG&E or the Company) is pleased to submit its 2017 Demand Response (DR) program proposal for consideration by the California Public Utilities Commission (CPUC or Commission). PG&E believes that its 2017 proposal helps to achieve the Commission's goal of DR market integration, while supporting State policies of growing renewables and limiting greenhouse gas emissions. Consistent with the Commission's September 15, 2015, *Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for 2017 Demand Response Programs and Activities Proposal Filing (September 15 Ruling)* and the guidance given in Decision (D.) 15-11-042, PG&E's proposal focuses primarily on integrating its Base Interruptible Program (BIP) as Reliability Demand Response Resources (RDRR) no later than May 2017 and on completing its California Independent System Operator (CAISO) market integration efforts for all other DR programs to be bid as Proxy Demand Resource (PDR) by no later than January 2018. The activities detailed in this 2017 program proposal reflect that commitment.

PG&E plans to focus its resources on achieving market integration objectives by streamlining its DR portfolio and improving its remaining programs and pilots. Specifically, PG&E requests to suspend its Demand Bidding Program (DBP) because it cannot effectively and efficiently integrate that program as currently structured into the CAISO market. In addition, PG&E requests to suspend the Aggregator Managed Portfolio (AMP) to minimize the number of programs in the near term so that a focused effort can be made to integrate the other programs. PG&E has decided not to continue AMP in 2017 because a new Request for Offer for a January to December 2017 contract term would not be approved for many months. The time available is too short to develop the contract, conduct the solicitation, and get regulatory approval of the contracts by 2017. PG&E expects little overall impact to its portfolio from these changes; only 1 megawatt (MW) of PG&E's DBP program is not enrolled in other PG&E DR programs and PG&E expects most AMP participants to migrate to the Capacity Bidding Program (CBP) or Demand Response Auction Mechanism (DRAM).[1] PG&E also proposes improvements to its other DR programs to better align program rules to enable market integration and/or reduce their complexity to DR participants, providers, and aggregators.

PG&E is committed to doing this work affordably. Through this proposal, PG&E requests authorization of an overall 2017 budget of $49.2 million. This request is $6.8 million less than its annualized authorized budget for 2012-2016 and specifically includes new funding for the following integration-related items:

- Approximately $6.2 million for the 2017 portion of an estimated additional $12 million needed in 2016 and 2017 for new and revised Information Technology (IT) infrastructure and business systems for market integration; and
- An estimated $7.0 million[2] in additional CBP incentives to accommodate an expected migration of AMP customers to the CBP.

Additionally, PG&E requests approval to carry over unspent 2015-2016 funds for its Permanent Load Shifting (PLS) program into 2017, rather than request additional PLS funds.

With regards to pilot programs in 2017, PG&E proposes to continue developing its Excess Supply DR Pilot to test how customers can help mitigate instances of over-generation. Additionally, PG&E plans to combine its Supply Side DR[3] and Transmission and Distribution (T&D) DR Pilots[4] into a single pilot program, the Supply Side II DR Pilot. This will allow PG&E to assess multi-use applications for Supply Resource (SR) DR resources and assess the feasibility of multi-use strategies for future SR DR program design and implementation. PG&E also plans to continue efforts begun in the T&D DR Pilot to more closely

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1 PG&E's current AMP contracts expire at the end of 2016.

2 All customer load reduction currently in AMP and not expected to go into DRAM is expected to move into CBP (~100 MW), and it is proposed that incentive payment per kilowatt (kW) be raised by 4.5 percent.

3 The Supply Side DR Pilot provides participants with access to the CAISO wholesale markets, and the ability to elect their own DR resource availability, based on their energy opportunity cost.

4 The T&D DR Pilot is focused on concerns and barriers that PG&E's Distribution Operations department encounter with the use of DR resources to support local distribution operations.

coordinate the DR department's efforts with the Company's distribution planning and operations, to better utilize DR to meet distribution needs.

PG&E is not requesting incremental funding for expanding its Rule 24 capabilities in this 2017 proposal, but requests $700,000 to cover ongoing registration support activities for the 10,000 Rule 24 registrations approved in D.15-03-042. Funds for expanding Rule 24 capabilities beyond 10,000 registrations are addressed in a Petition for Modification (PFM) filed on January 28, 2016, and will also be addressed in the February 22, 2016, testimony as directed in the January 22, 2016 Administrative Law Judge (ALJ) ruling in this proceeding.

2. Summary of PG&E's 2017 Filing

A chapter summary of PG&E's 2017 proposal is in Section 2 below. Please note that in the main body of this filing certain section headings are footnoted to designate the specific guidance from the September 15, 2015 CPUC Ruling setting forth the scope of this filing.

a. Chapter B: Enabling Market Integration

PG&E is committed to supporting the Commission's market integration goals, and plans to complete implementation for its BIP program into the RDRR product by May 1, 2017, and the remainder of its existing programs into PDR by January 1, 2018. To do this, PG&E plans to complete several key tasks in 2017, as detailed in this proposal.

First, PG&E will build the necessary IT systems to communicate with the CAISO's DR programs' respective enrollment tracking and dispatch systems and enable necessary information to be exchanged between PG&E's and the CAISO's systems.

Second, in support of market integration, PG&E also proposes to update the respective tariffs of PG&E DR programs that are not currently compatible with CAISO services to include a CAISO market award as a program trigger, align customer notification timing to meet CAISO market requirements, and comply with Commission Resource Adequacy (RA) requirements.

Third, PG&E also plans to continue work on its Excess Supply DR Pilot, which was approved by the Commission in D.14-05-025, to explore how customers can assist with renewables integration by shifting their load to periods when excess supply on the grid occurs.

Finally, PG&E plans to merge its Supply Side DR Pilot and T&D DR Pilot to form the Supply Side II DR Pilot. This pilot will test the ability of third parties and customers to provide available load relief to PG&E in a manner that not only can be used as non-wires alternative solutions for local distribution reliability issues, but also meets PG&E's RA requirements and is integrated into the CAISO markets. Participants will be able to provide the CAISO energy on a day-ahead basis, or, if needed by PG&E Distribution Operations, load reductions in real time. This multi-use strategy may provide increased value for the DR resource.

b. Chapter C: Program Improvements

1) Program-Specific Improvements

- Permanent Load Shifting: PG&E proposes no changes to this program in 2017;
- SmartAC™: PG&E will integrate this program into the CAISO market as PDR in 2018. PG&E proposes to implement (1) a default opt-out for new customers who move into a premise already equipped with SmartAC equipment; and (2) a process to follow current SmartAC participants moving into new premises that demonstrate the presence of air conditioning via meter data;
- Demand Bidding Program: PG&E will suspend DBP in 2017 due to the incompatibility of the program design with PDR and RDRR requirements;
- Base Interruptible Program: PG&E will transition BIP to RDRR by May 1, 2017, pursuant to the September 15 Ruling. PG&E proposes to resume marketing the program in 2017, subject to the megawatt cap approved in D.10-06-034, and only after the program is converted to RDRR;
- Aggregator Managed Portfolio: PG&E will not extend the existing AMP contracts, which expire in 2016, into 2017. Participating DR providers and customers will be encouraged to transition to the 2017 DRAM or the CBP. PG&E may request authority in future

program filings to utilize an AMP-type of program if market or other needs support it;

- Capacity Bidding Program: PG&E will complete the transition of this program to PDR by January 2018. PG&E proposes several changes to its CBP in 2017 to facilitate its integration into the CAISO market and improve the program; and
- Automated Demand Response (ADR): PG&E proposes several changes to the ADR program to stop the decline in program enrollments, improve cost effectiveness, and simplify customers' experiences.

2) Operations

PG&E plans to continue supporting the retail operations of its BIP, Optional Binding Mandatory Curtailment (OBMC), CBP, and SmartAC programs. Ongoing responsibilities include maintaining, operating, and enhancing both internal and vendor-supported DR systems that support the program operations and program changes.[5]

PG&E also plans to add IT systems to support the wholesale market integration activities needed for SR DR. New operational responsibilities resulting from market integration activities are numerous and implementation of the new systems and processes will be ongoing through 2017.

3) Marketing, Education and Outreach (ME&O)

PG&E plans to continue its current DR marketing, education, and outreach efforts and support the program improvements set forth in the 2017 Proposal. As stated above, PG&E proposes to resume marketing of BIP, pursuant to megawatt caps approved in D.10-06-034.

5 While the DR team also supports event day operations for PG&E's Peak Day Pricing (PDP) and SmartRate programs, the budget request for event notification activities for these is included in PG&E's 2017 General Rate Case (GRC) Phase 1, Application 15-09-001 and is therefore excluded from this proposal. Although, costs associated with Evaluation, Measurement and Validation for PDP and SmartRate™ are still included in DR program funding.

4) Cost-Effectiveness Analysis Results

PG&E performed cost-effectiveness analyses for each program individually and for its portfolio using the 2010 Cost Effectiveness Protocols, with an updated avoided cost as directed by the Commission.[6,7]

Benefits are based on forecast 2017 ex ante load impacts, shown in Table 3 below, and based on a portfolio[8] view for 1-in-2 year weather. Costs include the 2017 DR budget request plus BIP incentives[9] and $2 million of PLS costs carried over from 2016. These benefits and costs result in B/C ratios using the Total Resource Cost (TRC) test of 1.0 for BIP, CBP, and SmartAC. The TRC B/C ratios for PLS and the total DR portfolio are 0.9.

PG&E notes that a large portion of its proposed 2017 program budget ($6.2 million) is devoted to unique, one-time systems costs associated with CAISO market integration. PG&E respectfully requests that the Commission consider the B/C ratio of PG&E's DR programs excluding these implementation costs for CAISO market integration. Excluding $6.2 million from system support costs and using the same benefits results in improved TRC B/C ratios: BIP and CBP Day-Ahead have a 1.1 TRC, CBP Day-Of has a 1.2 TRC, and SmartAC has a 1.3 TRC. Although PLS's TRC remains at 0.9, the total DR portfolio TRC B/C ratio improves to 1.0.

Table 1 shows the B/C ratios using the TRC for individual DR programs and the DR portfolio both including and excluding one-time systems implementation costs for CAISO market integration.

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6 December 3, 2015 Administrative Law Judge's Ruling Providing Clarification Regarding 2017 Demand Response Program Proposals.

7 Pursuant to D.10-12-024 and affirmed in D.15-11-042, Dynamic Rates (i.e., PDP and SmartRate) and pilot programs are not included in the cost effectiveness (CE) analysis.

8 When customers participate in more than one DR program, load impacts for CE are determined on a portfolio basis, in addition to a program-specific basis, to ensure that load reductions from overlapping programs are not double-counted.

9 BIP incentives are recovered through DRAM outside of the DR budget process.

TABLE 1
BENEFIT/COST RATIO USING TOTAL RESOURCE COST TEST
DR PROGRAMS, 2017 TRANSITION YEAR
1-IN-2 YEAR WEATHER CONDITIONS, PORTFOLIO VIEW
INCLUDING AND EXCLUDING IMPLEMENTATION COSTS FOR CAISO MARKET INTEGRATION

Line No.	DR Program	Including CAISO Market Integration Implementation Costs	Excluding CAISO Market Integration Implementation Costs
1	BIP	1.0	1.1
2	CBP, Day-Ahead	1.0	1.1
3	CBP, Day-Of	1.0	1.2
4	SmartAC	1.0	1.3
5	PLS	0.9	0.9
6	Total DR Portfolio	0.9	1.0

c. Chapter D: DR Portfolio (including budget, load impacts, and cost recovery)

PG&E's overall 2017 budget request is $49.2 million, which is $6.8 million less than the annualized authorized budget for 2012-2016. The $49.2 million request includes $6.2 million for the 2017 portion of the estimated additional $12 million needed across 2016-2017 for new and revised IT infrastructure and business systems, as well as an estimated $7.0 million in additional CBP incentives associated with customers moving from AMP to CBP. PG&E requests approval to carry over unspent 2015-2016 funds for its PLS program into 2017, rather than request additional PLS funds. PG&E's proposed 2017 budget is shown in Table 2 below.

TABLE 2
DR PROGRAMS
2017 BRIDGE FUNDING REQUEST FOR 2017 TRANSITION YEAR

Line No.		
1	**TOTAL 2017 DR Bridge Funding Request**	**$49,285,641**
2	**Category 1 - Reliability Programs**	
3	Base Interruptible Program (program admin)	$271,194
4	OBMC Scheduled Load Reduction	$42,236
5	**Category 1 Total**	**$313,430**
6	**Category 2 - Price-Responsive Programs**	
7	Demand Bidding Program	$0
8	Capacity Bidding Program (program admin.)	$327,465
9	Capacity Bidding Program (capacity incentives)	$8,323,115
10	Air Conditioning (AC) Cycling: SmartAC (program admin)	$3,270,179
11	AC Cycling: SmartAC (incentives)	$749,856
12	AC Cycling: SmartAC (capital)	$2,314,726
13	**Category 2 Total**	**$14,985,341**
14	**Category 3 - DR Provider/Aggregator Managed Programs**	
15	AMP	$30,000
16	**Category 3 Total**	$30,000
17	**Category 4 - Emerging & Enabling Technologies**	
18	Auto DR (expense)	$2,096,629
19	Auto DR (capital)	$1,538,312
20	DR Emerging Technology	$1,404,528
21	**Category 4 Total**	**$5,039,469**
22	**Category 5 - Pilots**	
23	Supply Side DR Pilot II	$2,104,617
24	Excess Supply DR Pilot	$599,921
25	**Category 5 Total**	**$2,704,538**
26	**Category 6 - Evaluation, Measurement and Verification**	
27	DRMEC	$2,900,000
28	DR Research Studies	$1,000,000
29	**Category 6 Total**	**$3,900,000**
30	**Category 7 - Marketing, Education and Outreach**	
31	DR Core Marketing & Outreach	$3,566,357
32	Education and Training	$400,000
33	**Category 7 Total**	**$3,966,357**
34	**Category 8 - DR System Support Activities**	
35	InterAct/DR Forecasting Tool	$6,204,538
36	DR Enrollment & Support	$5,437,144
37	Notifications	$4,401,306
38	DR Integration Policy & Planning	$1,603,520
39	**Category 8 Total**	**$17,646,507**
40	**Category 9 - Integrated Programs and Activities**	
41	Technology Incentives – IDSM	$0
42	Integrated Energy Audits	$0
43	**Category 9 Total**	**$0**
44	**Category 10 - Special Projects**	
45	Permanent Load Shifting (to be carried over from 2016)	$0
46	Rule 24 Operations and Maintenance (O&M)	$700,000
47	**Category 10 Total**	**$700,000**

Table 3 below shows PG&E's estimated 2017 ex ante load impacts which are based on the estimates in its April 2015 load impact reports, as amended in June 2015, adjusted to reflect the estimated effect of discontinuing AMP and DBP in 2017.

TABLE 3
ESTIMATED 2017 EX ANTE LOAD IMPACTS
DR PROGRAMS, 2017 TRANSITION YEAR

Line No.	Program	MW (August 2017)
1	BIP - Day Of Notification	246
2	CBP - Day Ahead Notification	5
3	CBP - Day Of Notification	112
4	Peak Day Pricing	82
5	Permanent Load Shift	4
6	SmartAC - Non-Residential	3
7	SmartAC - Residential	80
8	SmartRate - Residential	25
9	***All Event-Based Programs***	**553**
10	***All DR Programs***	**557**

The remainder of Chapter D discusses cost recovery-related issues as directed by the September 15 Ruling. PG&E plans to consolidate all demand response program and incentives in its forthcoming 2018-2020 DR program cycle application.[10] Beginning in 2017, as directed in D.14-12-024, PG&E proposes that DR program-related costs be recovered through distribution rates when bundled and unbundled customers are eligible to participate in a given DR Program. If a program is only available for bundled customers, the program costs would be allocated to generation rates and recovered only from the bundled customers.

d. Chapter E: Miscellaneous

1) Customer Protection

Existing PG&E DR programs meet the criteria of Public Utilities Code (Pub. Util. Code) § 380.5(a)(3), which went into effect in

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10 September 15 Ruling, page 13, Section 3c, part 4, which notes that Critical Peak Pricing (CPP) programs such as PG&E's PDP and SmartRate are not within the scope of this 2017 proposal.

January 2015, and applies to residential customer DR programs, excluding critical peak pricing rates, real-time pricing, and peak time rebate. The only PG&E DR programs subject to Pub. Util. Code § 380.5(a)(3) that are open to residential customers in 2017 are SmartAC, and the DRAM, Excess Supply DR, and Supply Side II DR pilot programs.

2) $1 million DR Funding Study

PG&E recommends that the Commission continue to authorize a $1 million total annual budget for Commission studies in 2017. Follow-up work on the Potential Study may be one use for these funds.

B. Enabling Market Integration[11]

1. CAISO Integration[12]

PG&E is committed to supporting the Commission's goals by achieving integration of its DR programs into the CAISO market as SR DR. This section describes the steps needed by PG&E to do this.

a. PG&E's Roles and Responsibilities to Facilitate Market Integration

Before discussing the work involved in integrating PG&E's DR programs, it is important to understand the different roles involved in market integration. The Demand Response Provider (DRP)[13] is the entity responsible for delivering DR, from a single or aggregated set of customers, via a PDR or RDRR that is participating in the CAISO's Day-Ahead Market (DAM) or Real-Time Market (RTM). The DRP must work with a Scheduling Coordinator (SC) to bid, receive the dispatch for, and perform financial settlements for its resources. The Meter Data Management Agent (MDMA) provides Revenue Quality Meter Data (RQMD) to the DRP, which in turn transforms the RQMD into Settlement Quality Meter Data (SQMD). The DRP submits the SQMD to the SC. The MDMA for a customer is typically also the Utility Distribution Company (UDC), the entity responsible for the

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11 References Section 3a in guidance.

12 References Section 3a:1-2 in guidance.

13 The DRP may be an aggregator. Under Rule 24, an aggregator may hire another party to perform the DRP functions. In this submittal, the term "DRP" also encompasses aggregators.

delivery of electric service to the retail customer. The UDC and the Load Serving Entity (LSE) (which may be the same or different company than the UDC and is responsible for the procurement of energy for the retail customer) have the responsibility to review and validate their respective customers, who have been registered by the DRP in a CAISO resource. For example, when a DRP submits a registration, the UDC and LSE have to confirm that it is their customer (e.g., a commercial contract or tariff is applicable to the customer and LSE), that the customer's information is correct, that there is no duplicate registration or that the customer is not currently enrolled in a utility retail DR program.[14] Upon review, the UDC and LSE each has to approve or deny the registration. If a registration is denied, the UDC and/or LSE has to provide the reason for denial so that the DRP may be able to address the issue.

PG&E fulfills each of the roles above in varying capacities. When PG&E's retail programs participate as PDR or RDRR in the CAISO market, PG&E's DR team will be responsible for delivering the load reduction and will be the DRP.

The remainder of this section describes the steps PG&E will take as the DRP to integrate its programs. It is worth noting that PG&E is the UDC for all customers in its retail programs (i.e., BIP, AMP, CBP, DBP, and SmartAC), but is only the LSE for bundled customers. Third-party LSEs will have an opportunity to reject the registration of their individual customers for DR Services via the CAISO Demand Response Registration System. This rejection would preclude PG&E from using that customer as a resource within a PDR or RDRR for its integrated programs.

1) Rule 24

Prior to the implementation of Rule 24, PG&E's DR team also was able to perform the UDC and LSE roles of reviewing and validating customer registrations at the CAISO. The competitive neutrality requirements in Rule 24, however, dictate that there must be a separate team for handling the services to the third-party DRP/aggregators under

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[14] If a customer is enrolled in PDP, PG&E will automatically disenroll the customer from PDP as per Electric Rule 24.

Rule 24, in such a way that confidential information they receive from the DRP/aggregators will not be shared with the utility staff who are responsible for discharging PG&E's roles and responsibilities as a DRP.

Rule 24 also requires PG&E to de-enroll its CPP customers (for PG&E, this is PDP and SmartRate) once a non-utility DRP includes such a customer in an approved registration. The impacts of the competitive neutrality and de-enrollment requirements on PG&E's Rule 24 activities will be discussed in PG&E's upcoming incremental funding request, as discussed in Section B.5.b.

b. PG&E as the Demand Response Provider

The feasibility of CAISO market integration for each of PG&E's DR programs was initially described in the December 2013 Olivine Report.[15] While there have been program changes since then and the participating customer composition also has changed, the report largely remains valid in (1) its assessment of which DR programs have a higher or lesser feasibility of market integration; and (2) the major changes (i.e., systems and processes) that are required to support the market integration of PG&E's DR portfolio.

To date, PG&E has focused its efforts on the integration of a subset of its programs. This has allowed PG&E to determine how to enable its internal processes to support a larger-scale SR DR portfolio, while concurrently managing the impact to enrolled customers and avoiding requests for exemptions or waivers from existing rules. PG&E does not plan to continue this small-scale program integration in 2016. Instead, PG&E will focus its resources on the large-scale objective of meeting the May 1, 2017 and January 1, 2018 deadlines. PG&E also will continue to support overall market integration efforts in 2016 through its pilots and through DRAM.

At the 2015 DR Program Review,[16] Southern California Edison Company (SCE) shared its integration efforts and described the various

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15 PG&E Testimony, PG&E-1, Volume 2, May 6, 2014, R.13-09-011.

16 Workshop held January 12, 2016 at the Commission in R.13-09-011 pursuant to ALJ ruling, regarding program revisions to enable CAISO Market Integration.

accommodations it received from the CAISO to achieve this work. As a result, the CPUC requested that each utility describe its reliance on CAISO waivers, the progress that has been made to address the issues requiring waivers, and the program impacts that should be expected if the waivers are not extended. PG&E has neither requested nor received any waivers from the CAISO to date, but anticipates that it will need to work closely with the CAISO to ensure successful integration of its DR portfolio. Therefore, this list focuses on the remaining open issues with CAISO waivers and excludes operational challenges.

- Telemetry waiver for day-ahead energy resources (PDR) greater than 10 MW or for ancillary services: Since telemetry costs make those resources not cost-effective, an option is to sub-divide day-ahead energy resources such that each resource is less than 10 MW. The implication of this is a larger number of resources will need to be registered and managed. Furthermore, PG&E needs to work with the CAISO to provide early visibility in the number of resources it will require per Sub Load Aggregation Point (SubLAP) to ensure that the CAISO has sufficient resource IDs available or is able to incorporate the new resources in the quarterly network model build. The CAISO is exploring whether it can relax or eliminate this telemetry requirement for PDR in the future; however, this change would not mitigate the issue for ancillary services.
- The use of hourly meter data for RDRR settlement in RTM: The CAISO has indicated that it may be possible for statistical sampling to be used. Use of statistical sampling would not require any change to the CAISO's Business Practice Manual or its tariff. The process by which this statistical sampling is to be implemented and the corresponding changes needed to the baseline calculation, e.g., use of control groups, need to be defined.

c. Integrating PG&E's Current DR Programs

The market compatibility varies for each DR program's tariff or contract and determines the roadmap for PG&E's market integration of its portfolio (Table 4).

1) **Base Interruptible Program**

BIP is the PG&E DR program that is most compatible with the market since its design helped inform RDRR. In order to integrate BIP, PG&E's DR systems and processes need to be updated to support dispatch in the RTM. BIP RDRR resources also need to meet the CAISO product rules for RDRR, which require that each resource be: separated by LSE; confined within one of PG&E's 16 SubLAPs; able to bid at least 500 kW per SubLAP; and less than 50 MW to employ discrete dispatch. This means that PG&E's BIP program would translate to 40+ distinct RDRRs. Once all of the CAISO product rules are applied, BIP would have several megawatts of load impact that are unable to be integrated.

2) **Aggregator Managed Portfolio**

PG&E's current AMP contracts expire at the end of 2016 and will not be extended into 2017. PG&E is proposing to incorporate some of this program's market-friendly characteristics into the CBP tariff, and work with aggregators and customers to re-enroll them in the CBP program. Encouraging PG&E's existing AMP participants to transition their resources into the CBP also provides increased ability to meet the CAISO PDR rules for DAM participation (i.e., each resource needs to be separated by LSE, be confined within one of PG&E's 16 SubLAPs, be able to bid at least 100 kW, and be less than 10 MW to avoid the telemetry requirement for PDRs).

3) **Capacity Bidding Program**

The CBP can be compatible with PDR for the DAM with some tariff modifications,[17] including the adjustment of business day-ahead notification to calendar day-ahead notification to allow a dispatch for the first business day of the week, normally Monday.

4) **Demand Bidding Program**

The DBP is not compatible with PDR since the timing for DBP event notifications (noon on the day before an event) and subsequent

[17] CPP programs will not lose their RA value per D.15-11-042.

responses (i.e., customers submit DBP bid by 4 p.m. and PG&E accepts bids by 5 p.m. on the day the event was issued) do not adhere to DAM timelines. Significant changes to the program, which would make the program substantially different than its current form, are required to transform DBP into SR DR. Due to this, PG&E proposes to suspend the DBP in 2017.

5) SmartAC

SmartAC is a direct load control program, which means that part of its design is favorable for market participation because it has a fast response time and lacks a customer notification requirement. After accounting for the CAISO PDR rules for DAM participation (i.e., each resource needs to be separated by LSE, be confined within one of PG&E's 16 SubLAPs, be able to bid at least 100 kW, and be less than 10 MW to avoid the telemetry requirement for PDRs), SmartAC's 150,000+ residential and small commercial customers can be aggregated into approximately 15-20 PDRs. However, the sheer volume of enrolled participants makes resource management, from initial registration to ongoing maintenance, challenging without automated systems that could communicate between PG&E (as the DRP) and the CAISO.[18] Settlement processes also require hourly RQMD that may not be available for a majority of SmartAC customers.[19] Therefore, PG&E is working with the CAISO on alternative solutions to acquire SQMD utilizing practices such as statistical sampling.[20]

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18 This communication platform is different from that being built by PG&E to support Rule 24, which would be supporting the firewalled group performing PG&E's roles as the UDC and LSE in reviewing and validating customer registrations.

19 While most residential customers have AMI (SmartMeters) the capacity to use their interval data for RQMD does not exist for the majority of the customers.

20 The CAISO Energy Storage and Distributed Energy Resources Revised DRAFT Final Proposal, dated December 23, 2015, broadens the use of statistical sampling to day-ahead energy participation. https://www.caiso.com/Documents/RevisedDraftFinalProposal-EnergyStorageDistributedEnergyResources.pdf.

TABLE 4
PG&E'S ROADMAP FOR MARKET INTEGRATION

2015-16 Program	2017 (May)	2018 (January)
BIP	RDRR (Real-time energy market)	RDRR (Real-time energy market)
CBP	---	PDR (Day-ahead energy market)
SmartAC	---	PDR (Day-ahead energy market)

Upon completion of the changes described above (further detailed in Section C Program Improvements), most of PG&E's retail DR portfolio will be ready for SR DR.

d. Technology Improvements

In order to support a full SR DR portfolio, PG&E needs to coordinate and exchange information across multiple internal and external vendor systems that currently support the enrollment, dispatch/event notifications, and settlement of its retail programs. These, in turn, would need to be able to communicate with the DRRS and Demand Response System (DRS) to register PG&E's resources and with PG&E's Energy Procurement department's systems to facilitate the activities of the SC and enable the appropriate action, e.g., notify customers or control customers' devices, upon receipt of a market award dispatch. Coordination and information exchange with the systems of third party DRPs/aggregators participating in PG&E's DR programs also must be possible.

Due to internal PG&E and CAISO technology upgrades, PG&E's previous systems that were used for market integration[21] are not completely viable. To address this, PG&E is building technology systems to perform the following:

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21 In 2011-2012, PG&E used the PeakChoice program to participate as a DRP in the DAM.

1) **Resource Management**

- Create and manage the PDR/RDRR and registration parameters, including eligibility rules, master file characteristics, safety factor, DAM versus RTM, SubLAP, LSE, and the DRP's SC;
- Assign eligible customers into the registration based on participant and program constraints;
- Support the workflow process to review and approve the resource/registration by various entities like the CAISO, LSE, UDC, and SC;
- Interface with the DRRS and the PG&E Energy Procurement system to set up the resources and registrations; and
- Communicate and support any metering and/or configuration changes.

2) **Meter Data**

- Communicate with PG&E systems to retrieve the verified, edited, or estimated (VEE) interval meter data in various 5 minute, 15 minute, or 60 minute intervals;
- Utilize VEE interval meter data and produce SQMD;
- Support all requirements to submit both historical and ongoing SQMD to the CAISO;
- Store, transmit, and track the all data submitted to the CAISO systems;
- Forecast customer load and potential demand reduction on a daily basis based on the customer's past performance, program data, weather data, and interval meter data;
- Support standard and custom baseline calculations for past, current, and future days; and
- Support and apply various correction factors, safety factors, past event performance, and transmission loss factors to baseline calculations and forecasted load.

3) **Bidding and Scheduling**

- Create real-time/day-ahead bids for each resource based on program rules;

- Allow aggregators to submit nominations and translate the nominations to bids based on type of product, customer type, SubLAP, etc.;
- Communicate with PG&E's Energy Procurement office to submit bids and receive market awards;
- Translate market awards into a program dispatch and notify customers under program rules;
- Communicate with external systems and vendors to create the events and event notifications;
- Communicate with CAISO Automated Dispatch System (ADS) Server to read the real-time dispatch instructions related to DR and convert to appropriate dispatch orders for each DR resource;
- Communicate with and manage the available load between out-of-market and in-market events; and
- View bid and event performance for each resource.

The capabilities described above are being delivered in multiple phases since requirements will vary depending on the customer type (non-residential vs. residential) and CAISO service (day-ahead vs. real-time energy), among other reasons. PG&E's objective is to complete market integration of PG&E's DR portfolio no later than May 1, 2017, for RDRR and January 1, 2018, for PDR. This is consistent with the September 15 Ruling and D.15-11-042.

e. Dual Participation

PG&E will continue to comply with the dual participation rules for its retail portfolio.[22]

Examples of eligible dual participation include BIP and PDP, CBP Day-Of and PDP, and SmartAC and SmartRate. As programs transition to SR DR, customers may continue to participate in PG&E programs that remain as Load Modifying Resource (LMR) DR (e.g., CPP rates such as PDP or SmartRate) and in SR DR programs for which the DRP is also the utility providing the LMR DR; however, additional steps must be taken to ensure adherence to the dual participation rules. For example, if CPP

[22] D.09-08-027 at pp.152-153 and Ordering Paragraph (OP) 30.

event days occur on days when the SR DR does not receive a market award, the DRP must submit an outage to the CAISO for that resource to remove the CPP event day from the baseline calculation.

Third-party aggregators currently participating in the PG&E's retail programs (e.g., BIP[23] or CBP) will continue to follow the retail program design, in its current or future form (i.e., they manage the customer relationship and respond to the utilities' event notifications according to the tariff or contract). This role is in contrast to third parties who wish to become DRPs themselves (i.e., they register customers at the CAISO and work with an SC to bid, receive the dispatch, and perform financial settlements for its resources) under Rule 24. Per the dual participation rules outlined in Electric Rule 24/32,[24] a third party aggregator may participate in a utility DR program in which the utility is the DRP, and also directly participate in the CAISO market in which the third party is the DRP; however, it would not be able to use the same customers in both portfolios at the same time. That means that for a third-party to move customers from a PG&E program to its own DRP program, the third party must first de-enroll the customer from the utility program following the program rules, which will remove the customer from the utility's resource at the CAISO. Afterward, the third party can register this customer in its own non-utility CAISO resource. Conversely, to move customers from its DRP program to a PG&E program, the third party must remove this customer from its registered resource, after which PG&E can add the customer to its utility program portfolio.

f. Budget

The cost of IT system development and changes to enable integration of PG&E's programs into the market (i.e. activities related to resource management, meter data, bidding, and scheduling) is approximately $12 million between 2016 and 2017. PG&E plans to use the existing DR Systems Support budget (Category 8) in 2016 to begin this effort and plans

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23 BIP customers may enroll in the program directly or through an aggregator.

24 Rule 24, Section C.2.d.

to use the full authorized amount for Category 8 if granted the same level of authorized annual funding as 2012-16.

2. Pilot to Address Over-Generation[25]

In the 2015-2016 bridge funding decision D.14-05-025, the Commission authorized PG&E to conduct an Excess Supply DR Pilot, to explore how customers could help mitigate situations of over-generation, or *excess supply*, from the integration of solar and wind power supplies on the grid by shifting their load consumption to contribute to the realignment of supply and demand.

As highlighted in PG&E's DR Program Proposals for 2015 and 2016,[26] PG&E's objectives were to:

- Understand the extent to which demand-side management (DSM) can support renewable integration;
  - Measure ability and willingness of different customer segments to consume or shift load when the supply of electricity exceeds demand;
- Understand the best approaches to harness customer load during periods when the supply of electricity exceeds demand; and
  - Test different approaches that improve the ability and willingness of customers to consume or shift load in response to situations when supply of electricity exceeds demand on the grid, which may include enabling technologies, financial incentives, and other drivers of customer behavior.

During the design phase, upon further consultation with parties, PG&E determined that a preliminary foundational objective had to be added to the pilot's scope to further research what triggers consistently would be indicative of an excess supply event. This is because:

- Current DR programs for load curtailment, whether retail or wholesale, use a set of triggers (e.g., heat rate, CAISO expected load, weather, economic pricing) and associated thresholds to determine when to call forth a dispatch event. Such triggers and thresholds have not been established for excess supply events; and

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25 References Section 3a-3 in guidance.

26 See Attachment C of PG&E's Demand Response Program Proposals for 2015 and 2016, dated March 3, 2014, as part of Rulemaking (R.)13-09-011.

- Negative market energy pricing alone is not necessarily sufficient to determine whether an event should be called. Other triggers and data points such as weather and production of intermittent renewables (both utility-scale and behind-the-retail service meter generation) should be considered in conjunction with market energy prices to come up with a dependable forecast methodology to determine when to initiate an event.

PG&E therefore is in the midst of developing triggers that will be tested as part of the Excess Supply DR Pilot field demonstration, which started in late Q4 2015 and will continue until Q3 2016.

To leverage the momentum undertaken in 2015 and 2016, PG&E proposes to continue the Excess Supply DR Pilot in 2017. Besides testing further the goals laid out in the initial scope, the additional objectives for 2017 would be to:

- Ensure that, when situations of excess supply happen at the system level, the actions taken by pilot's participants to realign supply and demand do not create congestion on the distribution wires;
- Experiment with the financial incentives for customers directly enrolled and third-party aggregators for the action taken during an excess supply event, and the interaction with retail rates, such as demand charges, for non-residential customers; and
- Explore the appropriate baseline methodologies recognizing that the current methodologies were designed for DR resource load reduction and not for load consumption increase and/or shifting.

Please see Appendix A: 2017 Excess Supply DR Pilot Plan for more details on the proposed plan for 2017.

3. Other Pilot, Combining the Supply Side DR and T&D DR Pilots: Supply Side II DR Pilot

In addition to the Excess Supply DR Pilot, PG&E proposes to develop a demonstration to assess the feasibility of multiple uses for DR resources, in an environment where PG&E DR programs are not only fully integrated into the CAISO markets, but also integrated into distribution day-to-day operations. This will help further the development of non-wire alternatives for distribution system reliability issues.

To that end, PG&E proposes to combine its Supply Side DR[27] and T&D DR Pilots into one Supply Side II DR Pilot. This pilot will be offered to residential customers, non-residential customers, and third-party aggregators:

- The current Supply Side DR Pilot provides participants with access to the CAISO wholesale markets and the ability to elect their own DR resource availability, based on their energy opportunity cost;
- The current T&D DR Pilot addresses barriers that PG&E's Distribution Operations department encounters with the use of DR resources to support local distribution operations. The T&D DR Pilot is designed to direct the DR on future program designs and implementation strategies that can better support PG&E's Distribution Operations; and
- By merging the two pilots into one Supply Side II DR Pilot, participants will be able to provide the CAISO energy on a day-ahead basis, or, if needed by Distribution Operations, load reductions in real time. This multi-use strategy may provide increased value for the DR resource. The Supply Side II DR Pilot will allow PG&E to assess multi-use applications for SR DR resources and assess the feasibility of multi-use strategies for future SR DR program design and implementation.

Please see Appendix B: 2017 Supply Side II DR Pilot Plan for more details on the proposed plan for 2017.

4. Pilots' Support for Other Technologies

In 2017, PG&E will create synergies between DR and other DSM technology programs by leveraging the Excess Supply and Supply Side II DR Pilots to enable technologies behind the customer's meter, such as storage or smart devices, to serve as grid-responsive assets.

For example, both proposed DR pilots will provide a platform to enable a broad spectrum of Electric Vehicle (EV) participation, including, but not limited to, PG&E's proposed EV Infrastructure and Education Application (A.15-02-009), the Open Vehicle Grid Integration Platform developed by the

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27 Please refer to Appendix D: Initial Observations and Lessons Learned From the Implementation of Supply Side DR Pilot in 2015 for some initial observations and lessons learned to-date from the implementation of the Supply Side DR Pilot in 2015. A report providing a thorough analysis of the Supply Side DR Pilot will be made publicly available in early 2017, after the completion of the pilot, which will also run in 2016.

Electric Power Research Institute (EPRI), EV automakers and EV Service Providers (EVSP).

Pursuant to OP 17 of D.12-05-037, PG&E has verified that its pilot proposals do not duplicate projects approved in PG&E's Electric Program Investment Charge (EPIC) application (D.15-09-005) or any pending applications.

5. Support for Third-Party Market Integration

a. DRAM

D.14-12-024 authorized the Investor-Owned Utilities (IOU) to shift unspent 2015-2016 DR program dollars to implement the 2016 DRAM pilot. The IOUs proposed the non-binding cost estimates for this first phase of the DRAM ($4 million each for SCE and PG&E, and $1 million for San Diego Gas & Electric Company (SDG&E) on April 20, 2015 in PG&E Advice Letter 4618-E, which the Commission authorized in Resolution E-4728. Similarly, on October 9, 2015, the IOUs filed a joint Advice Letter (PG&E 4719-E) that provided non-binding cost estimates for the 2017 DRAM implementation costs, based on information then available. Given the lack of actual cost data available from the 2016 DRAM at the time of that filing, the 2017 estimates were based on the estimated 2016 non-binding amounts. Specifically, the joint advice letter notes that:

> By extending the 2016 DRAM estimate to cover a full calendar year of capacity payments (2016 DRAM is for June through December, while 2017 DRAM is for January through December), the IOUs can provide a non-binding estimate for the 2017 DRAM pilot year of approximately $6 million for SCE, $6 million for PG&E, and $1.5 million for SDG&E. These non-binding estimates result from increasing the original 2016 DRAM estimates by 50% (given that capacity values for January-May tend to be significantly less than June-December).

In that advice letter, the IOUs also indicated their intentions to include the 2017 DRAM funding request in the 2017 transition year submittal.

The Commission has since issued Resolution E-4754 on the October 9th joint advice letter which clarifies that the fund shifting provisions contained in D.14-12-024 applies to both years of the DRAM pilot and authorizes PG&E to use $6 million of previously approved 2015-2016 bridge funding towards DRAM 2 expenditures. PG&E will carryover the funds as authorized and will recover them consistent with

Resolution E-4754 and the Commission approval of PG&E's 2017 transition year proposal.[28]

The Commission has yet to approve the "Adoption of Residential Fee Settlement Agreement Among Comverge, EnergyHub, OhmConnect and PG&E" filed on August 6, 2015 in the Ancillary Services/Real-time Pricing phase of A.14-06-001, et seq. PG&E expects the final decision will provide guidance about whether the over-the-air meter reprogramming services[29] for residential customers should be free or subject to a fee, and if provided free, whether it should be limited to DRAM, as reflected in the Residential Fee Settlement or provided more generally for all Rule 24 participants. This guidance may affect the 2017 DRAM budget, as it could require PG&E to utilize some of its authorized DRAM funds to cover any free over-the-air meter reprogramming applicable to the 2017 DRAM.

As noted above, PG&E has been authorized to fund shift $4 million from the 2015-2016 bridge funding for DRAM in 2016. In addition, Resolution E-4754 provides the IOUs with the ability to utilize unspent 2015-2016 DR bridge funding dollars for the 2017 DRAM pilot implementation, up to $6 million. PG&E filed a Petition for Modification on January 28, 2016, to request that excess 2015-2016 DR bridge funding dollars to be used for (1) Rule 24 process improvements to enhance PG&E's ability to manage greater numbers of Customer Information Service Request (CISR)-DRP data solicitations and Rule 24 registrations; and (2) process and systems changes necessitated by the CAISO's 2016 enhancements to its DRRS.[30] These improvements facilitate DRAM

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28 PG&E expects that this funding amount will fully cover its 2017 DRAM pilot. PG&E will select bids in its ranking order according to the valuation criteria until it exhausts its funding (or meets operating limits, such as a numerical constraint on Rule 24 registrations).

29 Reprogramming meters with an hourly interval to a 15 minute interval.

30 The revenue requirement request of $49.9 million for the 2017 transition year does not include funding for these incremental improvements, above what was authorized in D.15-03-042. However, O&M costs for the 10,000 Rule 24 registrations in 2017 are included in the revenue requirement request proposal for the 2017 transition year. The incremental costs are addressed in the PFM for D.14-12-024, OP 5, filed on January 28, 2016, to "Authorize Fund Shifting to Support Increasing the Number of PG&E Rule 24 Registrations and CISR-DRPs in 2016 and Modifications to Business Process and Systems in 2016 to Meet Data and Functionality Requirements of the 2016 California Independent System Operator Demand Response Resource System Enhancements."

implementation as well as provide additional opportunity for non-DRAM entities to participate in the CAISO market in 2016 and 2017.

This incremental step is not a replacement for a full scale application to accommodate intermediate or full CAISO participation levels discussed by the Commission in D.15-03-042. However, the PFM fund shifting request, if granted, would allow for increasing the number of registrations in 2016 and 2017.

b. Rule 24 Operations and Maintenance

In D.15-03-042, PG&E was authorized $2.9 million to complete the Initial Implementation Step for Rule 24 registrations for 10,000 service accounts (SAs). To support the ongoing operations and maintenance for the 10,000 Rule 24 registrations, PG&E is requesting $700,000 in 2017 for the following.

1. Two Full-Time Employees to process CISRs (500 per week), support the registration review, and manage the DRP relations; and
2. O&M to maintain the Rule 24 systems and processes.

Any incremental requests beyond the Initial Implementation Step for 10,000 Rule 24 registrations are reflected in the PFM D.14-12-024 as described above, and will be in the February 22, 2016 testimony directed in the January 22, 2016 ALJ ruling.

C. Program Improvements[31]

1. Summary of All Programs

a. Permanent Load Shifting

PG&E does not propose to change PLS for 2017. For the 2017 transition year funding for PLS, PG&E requests to carry over unused and uncommitted 2015-2016 PLS budget.

b. SmartAC

PG&E proposes to improve SmartAC in 2017 to address program attrition and to prepare the program for integration into CAISO markets.

Since inception in 2007, PG&E has installed nearly 300,000 SmartAC devices, for just over 264,000 customers. At this time, 157,940 customers

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31 References Section 3b in guidance.

remain active on the program due to program attrition, which consists of customers who move, those who switch to an ineligible rate, and those who no longer wish to participate in the program.

For 2015 program year, the annual attrition rate for the SmartAC program due to customers who moved is 5.7 percent, in line with the program's historical average attrition of approximately 6 percent. Of the population that moves,[32] just under half move within PG&E's service area. To address this, the Program Year 2013 Statewide AC Cycling Programs Process Evaluation – Integrated Report by Opinion Dynamics made the following recommendation:

> When a customer moves, consider defaulting the new resident into the program: Most lapsed customers left the program due to moving out of their premises. Even when they notify the IOU, the load switch stays in place as an inactive, stranded asset. The IOUs should consider defaulting customers as participants, notifying them that they are pre-enrolled, giving them program information as well as clear information that would enable them to opt-out if they wanted. Currently, the SDG&E Summer Saver program flags vacated residential premises, and sends program information to new residents communicating to them they are an active program participant. The letter outlines the program benefits as well as provides clear information on steps and contact information should the new occupant want to opt-out of the program. This approach reduces attrition of participation due to customers moving.[33]

For 2017, PG&E proposes to follow this recommendation and:

- Pursue a default and opt-out approach for customers that move into premises with existing SmartAC equipment so that the customer moving into the premise would be notified of the existing equipment and defaulted to the program, unless the customer opts out; and
- Similarly, for existing SmartAC program participants who move within PG&E's territory to a premise that does not currently have a SmartAC device but whose meter load shape data indicates the existence of central air conditioning, have SmartAC participation follow existing

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32 Moves account for 80 percent of the attrition, resulting in approximately 85,000 SmartAC customers and approximately 43 MW of resource loss.

33 PY2013 Statewide AC Cycling Programs Process Evaluation – Integrated Report, Opinion Dynamics August 15, 2014. This report was done under the supervision of DRMEC, pursuant to OP 70 of D.12-04-045, and will be available at CALMAC.org.

participants to this new premise. Again, the option to opt-out will be provided.[34]

PG&E forecasts that both of these changes should improve retention rates and lead to decreased program costs. With a conservative estimate of a decrease in attrition rate of 50 percent (from 5.7% to 2.8%), PG&E revised its budget to decrease marketing costs to recruit new customers by roughly $400,000.

Finally, because the overall focus for program year 2017 is to operationally prepare PG&E's DR programs, including SmartAC, to transition to SR DR, PG&E is proposing to add CAISO market award/dispatch as a program trigger.

c. Demand Bidding Program

PG&E proposes to suspend the DBP for 2017 because the DBP provides few incremental megawatts to PG&E's portfolio and has different dispatch parameters than other programs, making it difficult to integrate into the CAISO market. In addition, allowing customers to opt-out when events are called makes the quality of the load reduction low and the cost/benefit ratio of the program poor. PG&E intends to work with currently enrolled DBP customers to ensure as many as possible are enrolled in another DR program.

d. Base Interruptible Program

PG&E continues to believe that the BIP is an important resource. Its fast response time, high degree of reliability and predictability, and year-round availability make it an indispensable component of PG&E's DR portfolio. As directed in the September 15 Ruling, PG&E will transition BIP to RDRR by May 1, 2017. Consequently, PG&E proposes to add market award/dispatch as an event trigger for 2017.

Given the continued importance of the BIP and its upcoming CAISO integration, PG&E requests approval from the Commission to resume marketing the program. While the marketing of BIP was prohibited in

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34 SmartAC customers are allowed to de-enroll from the program at any time after the first 12 months. The tariff will be edited to make this clear.

D.12-04-045,[35] the IOUs should be allowed to resume growing this program. PG&E is well under the cap for emergency-triggered DR that was set in D.10-06-034 and thus has room to grow this valuable program.

e. Aggregator Managed Portfolio

PG&E will allow the current AMP contracts to expire at the end of 2016. PG&E proposes not to renew the contracts, or to hold a new solicitation for 2017. This will allow PG&E to focus on integrating its other DR programs into the CAISO market. PG&E intends to preserve as many of its current AMP megawatts as possible by: (1) proposing changes to the current CBP program to encourage the AMP aggregators to move their customers to CBP; or (2) having customers participate in the DRAM.

f. Capacity Bidding Program

PG&E is seeking to enhance the current CBP rules to facilitate bidding the program into the CAISO market as PDR in 2017 and encourage as many of the current AMP participants as possible to move to the CBP. In order to improve CBP, PG&E is proposing the following changes:

- Adjust the day-ahead notification to 4 p.m. (currently at 3 p.m.) to account for instances when the DAM closes later in the day. Otherwise, resources that receive market awards may not have sufficient time to be dispatched; and
- Increase the CBP capacity prices. The current CBP capacity prices in the tariff were last updated in 2012. PG&E proposes to increase the CBP prices to account for inflation, by applying an adjustment factor of 4.5 percent[36] (see Table 5 and Table 6). This would have the added benefit of making CBP more desirable for current AMP participants.

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35 D.12-04-045, p. 87.

36 Based upon the difference between the January 2012 CPI and the October 2015 CPI (most recent available at time of analysis) from the FRED Economic Data series at the Federal Reserve Bank of St. Louis; https://research.stlouisfed.org/fred2/series/CPIAUCSL/downloaddata.

TABLE 5
DAY-AHEAD OPTION
(CURRENT TARIFF PRICE/PROPOSED PRICE PER KW)

Line No.		Current Price	Proposed Price
1	May	$3.04	$3.18
2	June	$3.71	$3.88
3	July	$15.60	$16.30
4	August	$21.57	$22.54
5	September	$13.30	$13.90
6	October	$2.17	$2.27

TABLE 6
DAY-OF OPTION
(CURRENT TARIFF PRICE/PROPOSED PRICE)

Line No.		Current Price	Proposed Price
1	May	$3.50	$3.66
2	June	$4.27	$4.46
3	July	$17.94	$18.75
4	August	$24.81	$25.93
5	September	$15.30	$15.99
6	October	$2.50	$2.61

- Update the ADR language in the tariff. While the current language indicates that "Existing AutoDR CBP shall be assigned to PG&E system-level Load Zone," there is no longer a system-level load zone.[37] System level load zones were discontinued in April 2009 with the implementation of the Market Redesign and Technical Upgrade. The proposed text would read: All ADR customers will be assigned to a specific Load Zone.

g. Automated Demand Response

ADR program improvements are addressed in Section C.5.a.

2. Operations

PG&E plans to continue supporting the retail operations of the BIP, OBMC, CBP, and SmartAC programs, in addition to the new wholesale market

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37 Electric Rate Schedule E-CBP, Sheet 3, Effective February 25, 2014.

integration activities for SR DR. Ongoing responsibilities include maintaining, operating, and enhancing both internal and vendor-supported DR systems that support these program operations and program changes:

- Online program enrollment and administration;
- Customer and device enrollment processing;
- Event management including customer management and dispatch system;
- Device group management and communication platform (e.g., SmartAC devices, and ADR technologies);
- Customer notifications;
- Forecasting and reporting capabilities; and
- Third-party portfolio management supporting CBP aggregator's ability to enroll customers, nominate monthly commitments, receive event notifications, and manage settlement.

While the DR team also supports the event day operations for PDP and SmartRate, the budget request for event notification activities are excluded in this request since it has already been included in the 2017 GRC Phase 1.

New operational responsibilities resulting from market integration activities include adding/updating locations, forming resources, managing customer registrations, forecasting and preparing resource bids, transforming a market award into a retail dispatch, and preparing settlement reports, among other functions. The implementation of the new systems and processes will be ongoing through 2017.

3. Marketing, Education, and Outreach (ME&O)

During the 2017 transition period, PG&E plans to continue the current DR ME&O efforts and to support the program improvements set forth in Section C.1, which includes resuming marketing for BIP. Through outreach, PG&E will continue to build awareness and educate customers about DR participation and how it can help them proactively manage their load during peak periods and enable them to achieve cost savings. PG&E is currently developing an educational plan (due 9/30/16) for residential, small and medium businesses in response to Assembly Bill (AB) 793[38] to inform these customer classes of incentives available for acquiring energy management technology.

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38 AB 793 and the criteria of Pub. Util. Code § 717.

PG&E's demand response section of the plan will address DR incentives for technologies such as Programmable Communicating Thermostats as part of the SmartAC program and ADR equipment for small and medium businesses. PG&E will include the DR educational aspects of the plan in its 2017 ME&O effort.

Educational efforts will also focus on building awareness of integration of DR programs in the CAISO market and societal benefits of DR, such as helping reduce greenhouse gas emissions and constraints on the grid. Marketing, education and outreach activities will address the whole of the DR portfolio, target all customer classes with appropriate and relevant DR messaging, cover coordinated core product needs, and complement integrated marketing activities.

Continued ME&O refers to work that will include:

- Ongoing DR program outreach activities and staffing to support ME&O, such as increased efforts that will be needed to handle the shift of SmartAC to be integrated in the CAISO market;
- Customer retention and ongoing education for large commercial, industrial, and agricultural DR customers including for BIP;
- SmartAC and enabling technologies-oriented program enrollment and retention efforts for residential and Small and Medium-sized Business (SMB) customers; and
- Customer research and ongoing customer satisfaction tracking studies.

These efforts support the overall megawatt goals of the DR portfolio across all relevant programs and for all customer classes, and focus on maintaining levels of customer enrollment and engagement in their respective programs.

Continued ME&O yields a long-term DR customer outreach strategy that revolves around three primary strategic objectives:

1. Increase awareness about why and how DR is a necessary component of California's energy management, and how participation impacts customers' businesses and lifestyles;
2. Educate all PG&E customers about DR programs, technology, and market integration, as well as clearly communicate options that are relevant to each customer class; and

3. Drive DR event participation and customer satisfaction with DR participation through ongoing support and education.

4. Cost-Effectiveness Protocols Applied to Program Improvements[39]

a. Background

1) Need for Cost-Effectiveness Analysis

As directed in the September 15 Ruling, PG&E presents its required CE analysis for its proposed 2017 DR portfolio.[40] The September 15 Ruling requires a CE analysis for each of the DR programs, "if proposed improvements to a program make any changes to cost-effectiveness inputs."[41] This applies to all of PG&E's 2017 DR programs because of the following reasons:

- The forecast 2012 DR load impacts is replaced with a forecast of 2017 load impacts;
- The allocation of overhead costs for Evaluation, Measurement and Verification (EM&V); ME&O; System Support Activities; and ADR to specific DR programs has changed; and
- The avoided cost inputs for the DR Reporting Template have been updated from E3's avoided cost model.[42]

2) Scope of Cost-Effectiveness Analysis

This CE analysis includes the following DR programs:

- Base Interruptible Program
- Capacity Bidding Program

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39 References Section 3b-1 in guidance.

40 Per the ED's May 11, 2012, guidance (in accordance with D.12-04-045, OP 83), the DR Reporting Templates for the cost-effectiveness analysis can be accessed at the following link: https://pgera.azurewebsites.net/Regulation/search (1) search for Public Case Documents; and (2) select "Demand Response OIR 2013" from the drop down menu; (3) select 02/01/16 and PGE as the party to narrow the search criteria; and (4) click search. Parties may request copies of the referenced DR reporting templates to: Josephine Wu, Rate Case Coordinator, Office Phone: (415) 973-3414, E-Mail: JWWD@pge.com.

41 September 15 Ruling, p. 9.

42 Per the Administrative Law Judge's Ruling Providing Clarification Regarding 2017 Demand Response Program Proposals, issued December 3, 2015, in R.13-09-011, avoided cost inputs from E3's avoided cost model identified in footnote 1 of the ruling, i.e., https://ethree.com/public_projects/cpucSGIP.php. E3's full name is Energy + Environmental Economics.

- SmartAC Program
- Permanent Load Shift

In addition to these individual DR programs, a CE analysis is presented for PG&E's entire proposed DR portfolio, which sums costs and benefits across the individual DR programs and includes all other miscellaneous DR costs requested in PG&E's application, e.g., OBMC/Scheduled Load Reduction Program (SLRP).

Based on the direction given in *Decision Adopting a Method for Estimating the Cost-Effectiveness of Demand Response Activities* in D.10-12-024 (December 21, 2010), the following items are not included in the DR CE analysis:

- Dynamic Rates, e.g., CPP, and SmartRate Programs; and
- Pilot Programs.

3) 2010 Cost Effectiveness Protocols

As directed in the September 15 Ruling, for this CE analysis, PG&E complied with the 2010 DR CE Protocols included in Attachment 1 of D.10-12-024[43] and subsequent guidance documents as listed below (the 2010 Protocols).

- Energy Division e-mails (January 21, 2011; and May 11, 2012);[44]
- Administrative Law Judge's Ruling Providing Further Guidance for Permanent Load Shifting Activities in the 2012-2014 DR Applications (April 29, 2011);
- Joint Assigned Commissioner and Administrative Law Judge's Ruling and Scoping Memo in Application 11-03-001 et al. (May 13, 2011);
- D.12-04-045, approving the 2012-2014 DR portfolios;
- Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for 2017 DR Programs and Activities

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43 http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/128596.PDF.

44 http://www.cpuc.ca.gov/NR/rdonlyres/92C54F59-8D88-446A-846A-1747628C0F33/0/GuidanceJanuary2011.pdf and http://www.cpuc.ca.gov/NR/rdonlyres/FD11FEED-C322-4164-8EFCABE6F188ABDA/0/GuidanceMay2012.pdf.

Proposal Filings in Application 13-09-011 (September 15, 2015); and

- Administrative Law Judge's Ruling Providing Clarification Regarding 2017 DR Program Proposals (December 3, 2015).

4) Standard Practice Manual Tests

Under the 2010 Protocols, PG&E reports its DR CE results—both for individual DR programs and for the entire DR portfolio—using the Commission's four Standard Practice Manual[45] (SPM) tests, as follows:

- TRC Test
- Participant Cost Test
- Ratepayer Impact Measure Test
- Program Administrator Cost Test

The results of each of these tests are expressed two ways:

- Net Present Value (NPV) i.e., the present value of future benefits, minus the present value of future costs; and
- Benefit/Cost Ratio (B/C ratio) i.e., the present value of future benefits, divided by the present value of future costs.

5) DR Reporting Template

The 2010 Protocols require the IOUs to use the public and transparent CE models provided by the Commission, as well as clear and publicly available data and data sources. The Commission provides two models, one to calculate avoided costs (the DR Avoided Cost Calculator) and one to report program results (the DR Reporting Template).[46]

The DR Avoided Cost Calculator generates avoided cost inputs for the DR Reporting Template. The DR Reporting Template spreadsheet generates an NPV and B/C ratio under each SPM test both for each DR

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45 The CPUC's "California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects" of October 2001 can be found at: ftp://ftp.cpuc.ca.gov/puc/energy/electric/energy+efficiency/em+and+v/std+practice+manual.doc.

46 The DR Avoided Cost Calculator is located: http://www.ethree.com/public_projects/cpucdr.html.

The DR Reporting Template is located: http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm.

program being analyzed as well as for the DR portfolio as a whole. PG&E's analysis uses the July 27, 2012, version of the DR Reporting Template. As specified in the 2010 protocols, PG&E will make available its DR Reporting Template.[47]

6) A Factor Methodology

For the PLS program, PG&E is continuing to calculate the A factor using the tabs built into the July 27, 2012, version of the DR Reporting Template. For the BIP, CBP, and SmartAC programs, PG&E calculated an A factor using the method designed by E3 and demonstrated in an October 19, 2012, DR CE workshop presentation.[48] Table 7 shows the A factors for each of PG&E's DR programs. The E3 method uses the following formula, which requires an Availability factor and a Dispatchability factor.

A Factor = Availability Factor * Dispatchability Factor.

- The Availability Factor, page 33 in the October 19, 2012, presentation, is based on month, hour, and day type. Given a DR program's restrictions on the hours when it can be dispatched, the percentages in the Loss of Load Expectation Heat Map for Availability are summed. There are tables for both weekdays and weekend days. There are also tables both including and excluding renewables. The table including renewables was used.
- The Dispatchability Factor, page 36 in the October 19, 2012, presentation, is based on the ability of a DR program to dispatch on days and hours when it would most benefit the system. A percentage can be looked up in the table based on the maximum number of hours in an event for a DR program.

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47 PG&E will provide Commission staff with an electronic copy of the DR Reporting Template on CD-ROM media and will make a copy available to any interested parties by posting it on PG&E's website, concurrently with PG&E's 2017 transition year bridge funding submittal.

48 Cost-effectiveness Workshop Four: Demand Response, hosted at the CPUC by the Energy Division on October 19, 2012. Slides at: http://www.cpuc.ca.gov/NR/rdonlyres/F8619E63-F001-4EA6-B512-EF4B6B9CD65E/0/DR_Costeffectiveness_Workshop_final.pdf (slides 27-38).

TABLE 7
A FACTOR BASED ON BOTH DEFAULT AND PG&E LOSS OF LOAD EXPECTATION
DR PROGRAMS, 2017 TRANSITION YEAR

Line No.	DR Program	AL-4164-E E3 A-factor Method[(a)]	New E3 A-factor Method		Availability Factor for new A-factor		Dispatchability Factor for new A-factor
1	BIP	53%	**55%**	=	59.6%	*	92.3%
2	CBP	47%	**63%**	=	63.5%	*	99.9%
3	SmartAC	50%	**80%**	=	80.5%	*	99.9%
4	PLS	75%	**N/A**				

(a) E3's original A factor calculation method was implied for all programs except PLS in the 2010 DR CE Protocols. For PLS, E3 added an explicit calculation of the A factor in the July 27, 2012, version of the DR Reporting Template.

7) Non-Energy Qualitative Benefits

Under the 2010 DR Cost Effectiveness Protocols, LSEs are not required to monetize in their CE analysis: (a) additional environmental benefits; (b) market and reliability benefits; and (c) non-energy and non-monetary benefits. However, there are several factors the Commission could consider when evaluating DR programs or DR portfolios. These factors and attributes include: flexibility and versatility, adaptability, integration, statewide consistency, simplicity, recognition of, and consistency with general Commission policies.

The 2010 DR Cost Effectiveness Protocols identify additional non-energy and nonmonetary qualitative benefits[49] as possible factors in determining the cost effectiveness of DR. PG&E's DR programs have

49 For example: Section 3.K: Non-Energy and Non-Monetary Benefits, p. 33 of the 2010 DR Cost Effectiveness Protocols (D.10-12-024). This category of benefits includes the benefits participants receive in lessening their impact on the environment, being good citizens by helping to prevent outages, improving their ability to manage their energy usage, having a better public image (for commercial enterprises), improving working conditions, etc. From a societal perspective, and from the perspective of LSEs, DR programs may result in non-energy benefits, such as health and safety and secondary economic benefits. Section 3.G: Environmental Benefits, pp. 29-30. Other environmental impacts that might be avoided include: "environmental justice concerns, biological impacts, impacts on cultural resources, diminishing visual resources, land use, effects on water quality/consumption, and noise pollution. Section 3.J: Market and Reliability Benefits, p. 32. This category of benefits includes increased reliability (over and above the increased reliability offered by equivalent supply-side measures, particularly when DR can provide ancillary services), increased market efficiency improvement in overall system load factors, improved market performance (e.g., decreasing price volatility), increased flexibility, portfolio benefits, and others.

attributes with similar non-energy and nonmonetary qualitative benefits, albeit these re non-quantifiable and, thus, not included in the DR Reporting Template CE analysis.

However, these non-energy and non-monetary qualitative benefits as described below should be considered by the Commission when evaluating the cost effectiveness of PG&E's DR programs.

- Local dispatch: The ability for local dispatch is planned. Local dispatch capability provides local RA credit, which supports local reliability, and allows the program to potentially participate as PDR in the CAISO market;
- CAISO market integration/adaptability: The RDRR design includes the ability to bid the megawatts in as day-ahead energy, just as if it were PDR;
- Developing third-party aggregator capabilities: PG&E's CBP is an aggregator-only program in which participating aggregators enroll retail commercial, industrial, and agricultural customers;
  - CBP offers aggregators a place to participate in the California marketplace, and "provide[s] additional innovation and services to the market, yielding additional un-captured potential benefits to DR in California."[50]
  - CBP provides opportunities for aggregators who do not have a DRAM contract to participate in PG&E's DR portfolio.
  - CBP maintains aggregator participation in California at a time when it is important to develop third-party direct participation.
- Customer participation: For DR programs like BIP where participating customers cannot opt-out of events, penalties apply for non-performance or inadequate performance, this helping to ensure the resource's reliable operation;
- Flexibility and versatility for aggregator and customer: PG&E's CBP offers flexibility in monthly aggregator nominations allowing aggregators to register new DR customers and verify their load reliability prior to committing them to a longer term commitment.

50 D.12-04-045, p. 16.

This flexibility also offers customers the ability to adjust their reduction commitments monthly in response to variations in their load and reduction capability; and

- Consistency of offerings by the IOUs: Statewide programs encourage participation in DR by businesses located in more than one IOU service area.

b. Net Present Value and Benefit-Cost Ratio Results by Standard Practice Manual Test

Table 8 shows B/C ratios by SPM test for each program and the total DR portfolio. The benefits are based on forecast 2017 ex ante load impacts based on a portfolio view for 1-in-2 year weather. The costs include the 2017 DR budget request plus BIP incentives recovered elsewhere plus $2 million of PLS costs carried over from 2016. These benefits and costs result in B/C ratios using the TRC test for each of BIP, CBP and SmartAC of 1.0. The TRC B/C ratios for PLS and the total DR portfolio are each 0.9.

However, a large portion of the proposed 2017 program budget ($6.2 million) is devoted to implementation costs for CAISO market integration. Because these implementation costs are unique and will end after CAISO market integration is completed, PG&E recommends the Commission consider approving PG&E's 2017 bridge funding request based on the B/C ratio of PG&E's DR programs excluding implementation costs for CAISO market integration. Excluding $6.2 million from system support costs and using the same benefits results in improved TRC B/C ratios. BIP and CBP day-ahead, are now 1.1, CBP day-of is 1.2 and SmartAC is 1.3. Although PLS remains at 0.9, the total DR portfolio TRC B/C ratio increases to 1.0.

Table 9 shows the improved B/C ratios of the individual DR programs excluding implementation costs for CAISO market integration.

TABLE 8
BENEFIT/COST RATIO BY STANDARD PRACTICE MANUAL TESTS
DR PROGRAMS, 2017 TRANSITION YEAR
1-IN-2 YEAR WEATHER CONDITIONS, PORTFOLIO VIEW
INCLUDING IMPLEMENTATION COSTS FOR CAISO MARKET INTEGRATION

Line No.	DR Program	Total Resource Cost Test	Ratepayer Impact Measure Test	Program Administrator Cost Test
1	BIP	1.0	0.8	0.8
2	CBP, Day-ahead	1.0	0.8	0.9
3	CBP, Day-of	1.0	0.9	0.9
4	SmartAC	1.0	1.0	1.0
5	PLS	0.9	0.6	1.7
6	Total DR Portfolio	0.9	0.8	0.8

TABLE 9
BENEFIT/COST RATIO BY STANDARD PRACTICE MANUAL TESTS
DR PROGRAMS, 2017 TRANSITION YEAR
1-IN-2 YEAR WEATHER CONDITIONS, PORTFOLIO VIEW
EXCLUDING IMPLEMENTATION COSTS FOR CAISO MARKET INTEGRATION

Line No.	DR Program	Total Resource Cost Test	Ratepayer Impact Measure Test	Program Administrator Cost Test
1	BIP	1.1	0.9	0.9
2	CBP, Day-ahead	1.1	1.0	1.0
3	CBP, Day-of	1.2	1.0	1.0
4	SmartAC	1.3	1.3	1.3
5	PLS	0.9	0.6	1.7
6	Total DR Portfolio	1.0	0.9	0.9

Table 10 presents the benefits, costs and net benefits for each DR program resulting from the cost-effectiveness analysis. A negative net benefit represents the dollar amount that would have to be removed to result in a TRC B/C ratio of exactly 1.0.

TABLE 10
NET PRESENT VALUE BY TOTAL RESOURCE COST TEST
DR PROGRAMS, 2017 TRANSITION YEAR
1-IN-2 YEAR WEATHER CONDITIONS, PORTFOLIO VIEW

Line No.	DR Program	Benefits ($million)	Costs ($million)	Net Benefits ($million)
1	BIP	22.9	23.0	(0.1)
2	CBP, Day-ahead	0.5	0.5	(0.0)
3	CBP, Day-of	12.3	11.8	0.5
4	SmartAC	10.9	10.8	0.1
5	PLS	4.4	5.1	(0.7)
6	Miscellaneous	–	4.7	(4.7)
7	**Total DR Portfolio**	**51.0**	**56.0**	**(5.0)**

Table 11 illustrates the allocation of ADR, EM&V, ME&O and System Support costs to the individual DR programs. Costs that were not directly assigned to a program were allocated proportional to DR program budgets.

TABLE 11
ALLOCATION OF NON-PROGRAM-SPECIFIC COSTS TO DR PROGRAMS
DR PROGRAMS, 2017 TRANSITION YEAR

Line No.	DR Program	Category 4: ADR	Category 6: EM&V	Category 7: ME&O	Category 8: Sys. Support
1	BIP	10%	6%	18%	33%
2	CBP, Day-ahead	2%	0%	0%	1%
3	CBP, Day-of	33%	7%	9%	27%
4	SmartAC	0%	9%	50%	27%
5	PLS	0%	5%	7%	0%
6	Portfolio	0%	26%	15%	11%
7	Not in CE	55%	46%	0%	0%
8	**Total**	**100%**	**100%**	**100%**	**100%**

5. Enabling Technology Roles and Improvement[51]

As DR evolves to address multiple and complex use cases, PG&E recognizes that automation behind the customer meter unlocks reliable and fast-acting DR, when needed. In the 2011-2012 Load Impact Evaluation of California Statewide Automated Demand Response (Auto-DR) Programs, customers participating in PG&E's ADR program provide incremental load impact that ranges from 14 percent to 27 percent more compared to customers not in ADR. PG&E believes that ultimately the role of DR Enabling Technology programs—such as ADR—is to encourage the adoption of the additional

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51 References Section 3b-2 in guidance.

enabling technology[52] modules (communications, telemetry, control), which, once embedded in the end-use appliance (e.g., heating, ventilating, and air conditioning (HVAC)/thermostat, electric vehicles, water pumping, etc.), will enable the end-use load to provide grid services through automation, once enrolled in a DR program.

a. Proposed Changes to ADR Program in 2017

In 2012-14, PG&E implemented design changes to the ADR program to address prior management and performance issues. The two main goals behind the changes were to:

1. Increase and maintain the enrollment of ADR participants into DR programs by requiring participants to enroll in a qualifying PG&E DR program for a minimum of three years. Failure to do so could trigger a request for the customer to reimburse a prorated amount of the ADR incentive previously received;
2. Increase the amount and reliability of load shed during DR events by:
   - Conducting pre-audit evaluations, prior to any application process, to understand if customer's load profile makes them likely to perform on a DR program;
   - Providing real-time coaching, during DR events, to help directly enrolled customers (i.e., excluding aggregation programs on AMP and CBP) shed load to the best of their potential;
   - Issuing performance reports typically within a week after each DR event to all ADR customers to let them know how they performed, so they might adjust their DR strategies for subsequent DR events; and
   - Moving from a 100 percent upfront incentive to paying 60 percent of the incentive after successful verification of equipment installation

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52 PG&E is using the following definitions that were provided by the Lawrence Berkeley National Laboratory during the first Technical Advisory Group meeting for the DR Potential Study ordered in D.14-12-024:

- "End-use: an appliance, centralized building service, process load, or other electricity consuming piece of equipment (e.g., HVAC, electric vehicles, water pumping, etc.)"; and
- "Enabling Technology: a set of communications, networking, telemetry, control & other systems that enable a DR end-use to provide grid service."

and testing of committed DR strategies, with the remaining 40 percent paid contingent on the customer participating in their DR program for one full season and curtailing the kilowatt load approved by the ADR program as determined by the initial engineering review, done by PG&E as part of the application process (the 60%-40% model).

Though all these measures have resulted, as intended, in enhancing ADR participants' ability to reliably shed load during DR events,[53] PG&E has consistently observed since 2013 (when the measures were implemented) a significant decline in enrollments into the ADR program itself, as can be seen in Table 12 and Table 13 below:

TABLE 12
WITH 100% ADR INCENTIVE PAYMENT UPFRONT

Line No.	Year	New ADR Enrollments	ADR Incentive Payment
1	2007	23	$2,328,291
2	2008	16	$1,460,601
3	2009	18	$3,991,728
4	2010	45	$2,656,658
5	2011	21	$3,020,847
6	2012	18	$3,961,108

TABLE 13
AFTER IMPLEMENTATION OF THE 60% - 40% SPLIT INCENTIVE MODEL

Line No.	Year	New ADR Enrollments	ADR Incentive Payment
1	2013	9	$740,198
2	2014	11	$283,168
3	2015	5	$134,490

With this information in mind, PG&E is proposing changes for 2017 that will pursue three key objectives:

1. Stop the erosion of ADR program enrollments;

53 ADR customers' load shed performance during DR events increased from less than 50 percent (prior to these changes) to 90 percent (after these changes) of their kW load approved by the ADR program.

2. Reduce ADR program cost; and
3. Improve customers' experience by simplifying ADR program options and processes.

Objective	Proposed Change for 2017	Rationale
Stop the erosion of ADR enrollments	Eliminate the 60 percent-40 percent incentive model, with all ADR incentive amount paid up front, once the technology installation is successfully completed	The ADR process evaluation report from March 2014[(a)] mentioned early findings from vendors' interviews, pointing to the reduction of the number of ADR projects completed, as a result of the change to the 60 percent-40 percent model. This decline in ADR applications has been confirmed since then by PG&E data, as shown in Table 12 and Table 13. Eliminating the split incentive should address potential participants' concerns of not being paid in full on the incentive for their ADR technology investment. The other measures (pre-audit, real-time coaching during DR events, and post-event performance reports) will remain in effect, for the full three years, in order to keep supporting ADR participants' ability to reliably shed load during DR events. The rationale for this change aligns with a recent distributed generation CPUC decision, which approved the acceleration of monthly incentive payments from a period of five years to two years, with a lump sum performance-based payment made at the end of the two years.[(b)]
Reduce ADR program cost	Reduce the ADR incentive payment cap from 100 percent to 50 percent of total project cost for Large Commercial & Industrial (LC&I) customers	This change will increase cost-effectiveness by aligning with the practice of PG&E Energy Efficiency customized incentive programs, where incentives payments are already capped at 50 percent of total project cost. PG&E believes that this lower ADR incentive cap will prompt Commercial & Industrial customers to enroll in, and stay on, a DR program, so they can make the most of their investment in Open ADR automation technology, which fulfills one of the goals of ADR to act as a recruiting agent for DR programs and increase long term enrollment in DR.
	Reduce the ADR base incentive from \$200/kW to \$150/kW	PG&E believes that this reduced ADR base incentive will prompt customers to enroll, and stay on, a DR program to get the additional DR performance incentive payment, and compensate for the reduction of the ADR base incentive per kW.
Improve customers' experience by simplifying ADR program options and processes	Offer an additional option of deemed incentives to SMB customers, for certain end uses, based on average kW reductions, to make it easier for SMBs to apply for ADR incentives	The current calculated incentive structure requires an engineering review to gather end use information, operations characteristics, and a customer's preference to then determine the proper load shed amount. This complex assessment is necessary to ensure the proper amount of kW load reduction potential for LC&I ADR projects, but requires many engineering hours that may be time and cost prohibitive for many SMB customers. SMB automation is less complicated due to simpler business operation characteristics and requires less programming to control simple end use devices, mainly AC and lighting. SMB customers could elect to have their load shed determined either by the deemed kW, which is based on customer type, end use, operation, level of participation, and climate zone (for weather sensitive load), or by the traditional calculated approach. In the former case, the incentive amount will be calculated by applying the ADR SMB incentive rate to the deemed kW. PG&E will leverage SCE's experience to create the SMB deemed offering, which has been offered to SCE's SMBs since 2012.
	Increase customers' choice by extending the list of qualifying DR programs that ADR participants can enroll in to all PG&E programs and pilots	One of the goals for ADR is to act as a recruiting agent for DR programs. By adding BIP and PG&E pilots (DRAM, Excess Supply DR, Supply Side II DR Pilots) to the existing list of qualifying DR programs, customers can enroll in the PG&E DR program or pilot that best fits their load profile and business operations.

(a) CALMAC Study ID SDG0277.01.

(b) Per D.12-15-023 dated December 17, 2015.

b. Demand Response Emerging Technologies

PG&E's Demand Response Emerging Technologies (DRET) program enables the assessment of new technologies and applications—such as "smart" devices behind customers' meters, design tools, channels, or new program features—that have the potential to enhance customers' ability to better perform on DR, and facilitate DR integration into the CAISO markets.

DRET assessments are designed to explore potential enhancements to the existing DR Portfolio, and inform the ongoing development of PG&E's DR pilots for future DR programs. For example, in the 2015-2016 bridge funding, the DRET program examined topics such as:

- Availability of technology solutions that could meet CAISO telemetry requirements for PDR, while offering the best compromise between cost and near-term feasibility;
- Accuracy of alternative baseline and settlement methodology with statistical sampling, for the integration of mass market customers into the CAISO wholesale markets; and
- Exploration of load management automation through:
  – Potential partnerships with smart thermostat manufacturers to potentially integrate into a residential ADR-enabled program, or
  – Definition of technical requirements for EV charging stations to deliver reliable and fast-response DR.

PG&E is requesting $1.4 million for the 2017 transition year, so that it may continue exploring these questions and more. PG&E will continue to provide DRET program information and updates to CPUC through the bi-annual report and the Emerging Technologies Coordination Council quarterly meetings.

6. Budget Including Reductions[54]

PG&E's funding request for program administration and incentives for 2017 is $49.2 million, which is approximately $6.8 million less than the annual funding level authorized during the 2012-2016 period. Incentives will continue to be subject to two-way balance account treatment. Per the settlement approved in

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[54] References Section 3b-3 of guidance.

D.14-08-032, the requested amounts specified below include the benefit burden costs that were formerly funded via the GRC 1.

a. Category 1: Reliability Programs

PG&E's funding request of $315,000 for its Reliability Programs is approximately $100,000 less than the amount authorized during the 2012-2016 period. PG&E requests roughly the same amount of funding to cover administrative expenses related to BIP.[55] However, due to little activity related to the OBMC program and SLRP, PG&E requests $109,000 less than the amount authorized during the 2012-2016 period.

b. Category 2: Price Responsive Programs

PG&E's funding request of $15.0 million for its Price Responsive Programs is approximately $5.3 million greater than the annual amount authorized during the 2012-2016 period. While closing DBP will reduce administrative expenses for that program, PG&E expects that this reduction in spending will be more than offset by additional incentive amounts to be paid to customers shifting from AMP into CBP. PG&E also anticipates that all participants not receiving 2017 DRAM awards will participate in CBP during 2017.[56] These two shifts will result in CBP incentive payments rising from a forecast of $1.7 million in 2016 to approximately $8.7 million in 2017.

Based on the above proposal to address attrition of SmartAC participants and expected savings of approximately $400,000, PG&E requests $6.3 million for its SmartAC program in 2017 which is roughly 5 percent less than the amount authorized during the 2012-2016 period.

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55 BIP incentives and recovery of the rate discount are handled in the GRC II cases, and are not part of the request in this case.

56 PG&E's DRAM I auction for 2017 led to a reasonable robust market response, and reasonably competitive prices. (Advice Letter 4772-E, submitted January 8, 2016, Appendix D, Independent Evaluator Report, pages 13 and 34.) Based on its experience with the DRAM I auction, PG&E anticipates that its CBP program for 2017 would not create a disincentive for third-party aggregators to participate in the DRAM II auction. The DRAM II auction and the award of contracts to winning bidders is expected to occur in the first half of 2016. (Advice Letter 4719-E, submitted October 9, 2015.)

c. **Category 3: DR Provider/Aggregator Managed Portfolio**

PG&E requests $30,000 to complete work required to suspend the DR Provider/Aggregator Managed Portfolio beyond 2016 (e.g., finish 2016 settlements, make adjustments to our APX and DR Online Enrollment systems, return collateral to aggregators, etc.).

d. **Category 4: Emerging & Enabling Programs**

PG&E requests $5.0 million in 2017 funding for Emerging & Enabling Programs, which is ~$5.3 million less than the amount authorized each year during the 2012-2016 period. PG&E requests that the level of funding for its Emerging Technology program be maintained at $1.4 million for 2017, which is consistent with the annual funding level during 2012-2016. PG&E requests $3.6 million in funding for 2017 to cover administrative expenses and incentive payments related to its ADR program. This funding request is roughly $5.3 million lower than previously requested due to the reasons cited in Section C.5.a above.

e. **Category 5: Pilots**

PG&E requests the same level of annual funding (approximately $2.7 million) for its pilots in 2017 as was authorized during the 2012-2016 period. Given PG&E's plan to consolidate the Supply Side DR Pilot and T&D DR Pilot in 2017 (to be called the Supply Side II DR Pilot), the budgets for both of these pilots should be combined into one. Therefore, PG&E requests $2.1 million for the Supply Side II DR Pilot, of which $1.375 million would be used to cover administrative expenses (including contracts for SC and other software services associated with pilot operations) and $725,000 would be used for incentive payments. PG&E requests the same level of annual funding for its Excess Supply DR Pilot (approximately $600,000) as was authorized for 2015-2016. $400,000 of this amount would be used to cover administrative expenses (including contracts for software services associated with pilot operations), and $200,000 would be used for incentive payments. In addition, PG&E requests that the incentive budgets for the Supply Side II DR Pilot and the Excess Supply DR Pilot be converted into a two-way balancing account, so that greater than expected interest can be accommodated if it should materialize.

f. **Category 6: Evaluation, Measurement and Verification**

PG&E requests $3.9 million in 2017 funding for EM&V, which is approximately $540,000 less than the annual funding level authorized during 2012-2016. This reduction is largely driven by the elimination of DBP and AMP.

g. **Category 7: Marketing, Education and Outreach**

PG&E requests $4.0 million in 2017 bridge funding for ME&O, which is $870,000 less than the annual funding level authorized during 2012-2016. The reduction in this funding request is driven by the expectation that approval of PG&E's request to allow participation in SmartAC to follow participants on an opt-out basis when they move will reduce customer acquisition costs. Closure of DBP will also reduce marketing expenditures. Partially offsetting these reductions, PG&E requests a relatively small increase ($135,000) in authorized funding for Education and Training efforts due to the need to train PG&E's Energy Sales and Service team and PG&E contractors on the proposed program changes (DBP and AMP closure and market integration).

h. **Category 8: DR System Support Activities**

PG&E requests approximately $17.6 million[57] in 2017 funding for DR System Support Activities to support PG&E's commitment to integrating its demand response programs into the CAISO wholesale market. This request is $2.9 million greater than the annual level of funding approved for Category 8 during the 2012-2016 period. Details of this increase in funding can be found in Section B.1.

i. **Category 9: Integrated Programs and Activities Including Technical Assistance**

PG&E does not request funds for Integrated Programs and Activities—including Technical Assistance because these funds ($3,264,000) were requested and authorized in Energy Efficiency D.14-10-046.

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57 This amount excludes the cost of PDP and SmartRate notifications, for which funds have been requested in the 2017 GRC Phase 1.

j. Category 10: Special Projects

PG&E asks that it be allowed to utilize unspent 2015-2016 funds from the PLS program to pay for PLS administrative and incentive expenses in 2017.

PG&E also requests $700,000 for the ongoing operations and maintenance related to 10,000 registrations under Rule 24, as described in detail in Section B.5.b.

D. DR Portfolio[58]

1. Complete Budget for 2017 Portfolio by the 10 DR Funding Categories[59]

Details of PG&E's 2017 budget request by category are shown in Table 14 below. Per the settlement approved in D.14-08-032, the requested amounts shown in the table below include the benefit burden costs that were formerly funded via the GRC.

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[58] References Section 3c in guidance.

[59] References section 3c-1 in guidance.

TABLE 14
PG&E'S 2017 DR BUDGET REQUEST COMPARED TO THE AVERAGE ANNUAL DR FUNDING AUTHORIZED DURING THE 2012-2016 PERIOD

Line No.	Program	Annualized 2015-2016 Authorized Budget** (a)	2017 Request (b)	Comparison** (b-a)
1	*Category 1: Reliability Programs*			
2	Base Interruptible Program	$268,569	$271,194	$2,625
3	Optional Binding Mandatory Curtailment/ Scheduled Load Reduction (OBMC/SLRP)	$152,152	$42,236	$(109,916)
4	**Category 1 Total**	**$420,721**	**$313,430**	**$(107,291)**
5	*Category 2: Price-Responsive Programs*			
6	Demand Bidding Program	$580,575	$–	$(580,575)
7	Capacity Bidding Program	$2,443,877	$8,650,580	$6,206,703
8	AC Cycling: SmartAC	$6,668,169	$6,334,761	$(333,408)
9	**Category 2 Total**	**$9,692,621**	**$14,985,341**	**$5,292,720**
10	*Category 3: DR Provider/Aggregator Managed Programs*			
11	Aggregator Managed Portfolio	$472,253	$30,000	$(442,253)
12	**Category 3 Total**	**$472,253**	**$30,000**	**$(472,253)**
13	*Category 4: Emerging & Enabling Programs*			
14	ADR	$8,935,370	$3,634,941	$(5,300,428)
15	DR Emerging Technology	$1,404,528	$1,404,528	$–
16	**Category 4 Total**	**$10,339,898**	**$5,039,469**	**$(5,300,428)**
17	*Category 5: Pilots*			
18	Supply Side II DR Pilot	$2,104,617	$2,104,617	$–
19	Excess Supply DR Pilot	$599,921	$599,921	$–
20	**Category 5 Total**	**$2,704,538**	**$2,704,538**	**$–**
21	*Category 6: Evaluation, Measurement, and Verification*			
22	DRMEC	$4,442,699	$3,900,000	$(542,699)
23	**Category 6 Total**	**$4,442,699**	**$3,900,000**	**$(542,699)**
24	*Category 7: Marketing, Education, and Outreach*			
25	DR Core Marketing and Outreach	$4,571,168	$3,566,357	$(1,004,811)
26	Education and Training	$264,945	$400,000	$135,056
27	**Category 7 Total**	**$4,836,113**	**$3,966,357**	**$(869,756)**
28	*Category 8: DR System Support Activities*			
29	InterAct/DR Forecasting Tool	$4,987,045	$6,204,538	$1,217,493
30	DR Enrollment & Support	$5,437,144	$5,437,144	$–
31	Notifications	$2,736,872	$4,401,306	$1,664,434
32	DR Integration Policy & Planning	$1,603,520	$1,603,520	$–
33	**Category 8 Total**	**$14,764,580**	**$17,646,507**	**$2,881,927**
34	*Category 9: Integrated Programs and Activities (Including Technical Assistance)*			
35	Technology Incentives – IDSM	$2,025,770	$–	$(2,025,770)
36	Integrated Energy Audits	$1,275,231	$–	$(1,275,231)
37	**Category 9 Total**	**$3,301,001**	**$–**	**$(3,301,001)**
38	*Category 10: Special Projects*			
39	Permanent Load Shifting	$5,064,144	$–	$(5,064,144)
40	Rule 24 O&M[2] for 10,000 registrations	$–	$700,000	$700,000
41	DR Auction Mechanism[3]	$–	$–	$–
42	**Category 10 Total**	**$5,064,144**	**$700,000**	**$(4,364,144)**
43	**Total**	**$56,038,566**	**$49,285,641**	**$(6,7582,925)**

** Per the settlement approved in D.14-08-032 both 2015-2016 annualized Authorized budgets and proposed 2017 budgets have been adjusted for benefit burden that was funded out of the GRC before 2015.

2/ This is separate from the $2.9 million authorized in D.15-03-042 for the Initial Implementation Step for Rule 24 for 10,000 SAs.

3/ As authorized in Resolution E-4754, DRAM is funded by unspent funds authorized for 2015-2016.

2. Megawatt Impact for Each Program[60]

Table 15 is a summary of PG&E's portfolio-adjusted load impact for August 2017 under the 1-in-2 weather conditions under the PG&E peak. (A table that shows the load impacts for each month of 2017 can be found in Appendix C: PG&E's Portfolio-Adjusted Load Impacts for PG&E Peaks Under 1-in-2 Weather Conditions for 2017.) PG&E made its 2015 annual load impact filing on April 1, 2015, and the filing was later amended on June 12, 2015. For the purpose of this 2017 proposal, the forecast here is based on the amended load impact filing but with the following changes:

- AMP will not be extended for 2017, and the existing load impacts have been moved to CBP;[61]
- DBP will be eliminated; and
- SmartAC load impacts will largely remain, given an updated *net* attrition rate of less than 1 percent (where net attrition is attrition minus expected replacement) and the proposed changes in Section C.1.b.

Other than these specific changes, PG&E expects the proposed program improvements for 2017 would have minimal impacts—if any—on the aggregate load reduction, as they do not materially alter the assumptions PG&E made in the last load impact filing. Some program modifications may affect customer experience in some way. However, it is highly uncertain how they will affect load reduction. In the absence of additional evidence to suggest one way or the other, the ex ante load impacts filed in June 2015 remain a reasonable basis for the 2017 projection.

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60 References Section 3c-2 in guidance.

61 As of the time of this filing, it is unknown if existing AMP contracts will move to the 2017 DRAM as the sellers have not yet submitted bids or been awarded contracts. Therefore, PG&E assumes all AMP megawatts will move to CBP for the purposes of load impact analysis.

TABLE 15
PG&E'S PORTFOLIO-ADJUSTED, 1-IN-2 LOAD IMPACTS UNDER PG&E MONTHLY PEAK FOR AUGUST 2017

Line No.	Program	MW (August 2017)
1	BIP - Day Of Notification	246
2	CBP - Day Ahead Notification	5
3	CBP - Day Of Notification	112
4	Peak Day Pricing	82
5	Permanent Load Shift	4
6	SmartAC - Non-Residential	3
7	SmartAC - Residential	80
8	SmartRate - Residential	25
9	***All Event-Based Programs***	**553**
10	***All DR Programs***	**557**

3. Cost Recovery

a. Demand Response Programs and Incentives

As directed by the September 15 Ruling, PG&E provides Table 16 below to identify "all programs and incentives provided through demand response but established external to the 2012-2014 demand response application proceeding."[62]

62 September 15 Ruling, p. 13. Also, for 2017, if a program is only available for unbundled customers to participate, the costs would be recovered only from unbundled customers. D.14-12-024 and D.14-05-025.

TABLE 16
2012-16 DEMAND RESPONSE PROGRAM COSTS BY PROCEEDING
($ MILLIONS)

Line No.	Programs	Proceeding	2012	2013	2014	2015	2016	Total
1	DR Program Costs and Incentives (excluding BIP and AMP incentives)	A.11-03-001 R.13-09-011	$60.6	$60.6	$60.6	$50.3	$50.3	$282.4
2	BIP Incentives	A.10-03-034 A.13-04-012	$19.1	$21.0	$23.9	$25.4	$23.9	$113.3
3	AMP Incentives	A.07-02-032 A.12-09-004	$15.8	$19.0	$20.5	$12.4	$8.4	$76.1
4	**Total**		**$95.5**	**$100.6**	**$105.0**	**$88.1**	**$82.6**	**$471.8**

b. Schedule to Consolidate All DR Programs and Incentives

The September 15 Ruling directs the IOUs to propose a "schedule to consolidate all demand response programs and incentives into one demand response portfolio."[63] As noted in the table above, only BIP and AMP incentives are approved outside the 3-year DR program cycle proceeding. For 2017, PG&E is proposing to not extend the current AMP contracts. PG&E would, therefore, recommend that BIP costs (and AMP if the Commission were to reject PG&E's proposal to not extend AMP for 2017) be consolidated in PG&E's 2018-2020 DR program application to be filed in November 2016.

c. Cost Recovery

Beginning in 2017, PG&E proposes that all DR program-related costs be recovered through distribution rates when bundled and unbundled customers are eligible to participate (as directed by D.14-12-024). If a

63 *Ibid*.

program is only available for bundled customers to participate, the costs would be recovered only from the bundled customers.[64]

E. Miscellaneous[65]

1. Customer Protection[66]

The September 15 Ruling providing guidance for the utilities' 2017 transition year submissions directed the utilities to include in their 2017 proposals recommendations regarding customer protection and Senate Bill (SB) 1414. Existing PG&E residential DR programs meet the criteria of Pub. Util. Code § 380.5(a)(3) and (b), which went into effect in January 2015, and PG&E proposals for 2017 will continue to be compliant. The statute says that utilities should not impose a charge on residential customers "for not enrolling in the program." PG&E does not levy a charge on residential customers for not enrolling in PG&E's DR programs. DR program costs are recovered among all customers through normal allocation and rate design, as the Commission directs, but there is no charge for not electing to be in a PG&E DR program. Furthermore, imposition of charges for not enrolling would require a specific, billable charge levied on a customer. A separate charge "for not enrolling" in a program is also different from penalties that may be incurred by customers in the program who do not perform under the terms of the program.

PG&E's DR programs comply with the customer protections described in this new statute.

a. SmartAC

PG&E's SmartAC program provides customers an incentive ($50) for allowing PG&E to install a load control receiver (switch), which allows PG&E to cycle the customer's air conditioner when a DR event is called. There is no charge to the customer for the switch or its installation. A

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64 Currently, AMP incentives are recovered via generation rates per D.07-05-029. Had PG&E decided to continue the AMP program beyond 2016, AMP incentives would be recovered via distribution rates beginning in 2017, as the AMP program is available to both bundled and unbundled electric customers. SmartRate and PDP are the only programs where participation is limited to bundled customers. Cost recovery for SmartRate and PDP, however, is not requested in this case for these programs after 2016. Instead SmartRate and Peak Day Pricing cost recovery is requested in PG&E's 2017 GRC I proceeding.

65 References Section 3d in guidance.

66 References Section 3d-1(a-c) in guidance.

customer in the SmartAC program may opt-out of specific SmartAC events by going to www.pgesmartac.com and de-enrolling for the specific day's event, or by calling the call center that supports the program. Customers can also leave the SmartAC program any time after the first 12 months, at no cost to the customer. PG&E is proposing to remove the 12 month clause from the current tariff language. Currently, the customer does not receive any additional or ongoing incentive for their participation in the SmartAC program. The SmartAC program does not involve third-party aggregators. PG&E provides the following education and outreach materials to its SmartAC customers:

- Direct mail recruitment materials include a brochure with many FAQs, eligibility requirements, the website address, and the call center toll-free number for more information;
- The SmartAC website provides a simple graphic demonstration of the way the program works, eligibility requirements, explanations of the technology, program basics, an "Already Enrolled" link to manage their device which is used to opt-out of an event, and provides the toll-free number to the call center;
- A "welcome kit" door hanger is left with every customer where a SmartAC device is installed. This provides customers with additional information about incentive delivery timing, tells them what to do if their AC isn't working properly and reiterates program basics. It also includes the website address and the toll-free number to the call center. It offers written and graphic detail descriptions of how a customer can opt-out of a DR event for that day either via the toll-free number or the website; and
- On DR event days, the main page of PG&E's website and the SmartAC page have banners indicating there is a SmartAC event and how a customer can opt-out of the event for the day.

b. DRAM Pilot

The Commission approved the 2016 and 2017 DRAM pilots in D.14-12-024, and Resolutions E-4728 and E-4754 (Pending). In this pilot, PG&E contracts with its DRAM Sellers to pay them for participating directly in the CAISO market using PG&E's retail customers to provide DR through

CAISO products like PDR and RDRR. In return, PG&E receives RA tags for the capacity under the DRAM contract. The DRAM pilot is open for bundled and unbundled, residential and non-residential customer participation. Under resolution E-4728, PG&E is required to contract for at least 2 MW, or 20 percent of the capacity under contract (whichever is larger), for residential customer participation in both the 2016 and 2017 DRAM pilots.

The DRAM Sellers must register as a DRP with both the Commission, pursuant to Rule 24, and the CAISO, pursuant to their Business Practice Manual. Under Rule 24, Section C.7, Formal Notification for Residential and Small Commercial Customers, the DRAM seller must also provide notification to its residential and small commercial customers, in hard copy or through electronic means consistent with the "Customer Notification Form Letter" as approved in resolution E-4630, or a more recent Commission approved successor.[67] This requirement will apply to DRAM Sellers registering residential customers under Rule 24.

PG&E believes that this requirement in Rule 24 satisfies Pub. Util. Code § 380.5(a)(3). Since PG&E is not entitled to know the terms and conditions of the relationships between the DRAM Sellers and the retail customers they have under contract to meet their DRAM contract obligations, the utility cannot have any responsibility for the consumer protection requirement under the code section beyond the Rule 24 requirement that the Commission Energy Division will be administering.

c. Excess Supply and Supply Side II DR Pilots

PG&E pilot proposals for 2017 programs open to bundled and unbundled residential customers will be compliant with SB 1414 and the criteria of Pub. Util. Code § 380.5(a)(3) and (b). PG&E's DR pilot programs will not levy a charge on residential customers for not enrolling in PG&E's DR programs. Residential customers who wish to participate in the Excess

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67 Under Rule 24, Section C.7, the non-Utility DRP must provide a Customer Notification Letter to each residential and small commercial customer explaining the DRP's terms and conditions of participating in the DRP's DR Service. The Form Letter must be provided to the customer before placing its service account in a Registration in the CAISO DR System. This notification letter will provide any grace period in which the customer can cancel the DR Service enrollment without any charges or penalties.

Supply DR Pilot and/or Supply Side DR II Pilot programs can only participate through third party aggregators at this time. PG&E will create a pilot agreement form between PG&E and third party residential aggregators, requiring that all third party residential aggregators send a notification similar to the notification required under Rule 24, Section C.7 to each of their residential customers. Similar to Rule 24, the notification would be subject to approval by the CPUC's Energy Division. The notification letter would explain the aggregator's terms and conditions for the customer to participate with the aggregator in the pilot. A copy of the Rule 24 notification letter template is in Appendix E: Rule 24 Notification Letter Template, and will be modified as appropriate for the pilots.

PG&E believes that the required notification to each residential customer approved by ED (and required under the aggregator pilot agreement) would be in compliant with SB 1414 and would satisfy Pub. Util. Code § 380.5(a)(3).

2. $1 million DR Funding Study[68]

In D.12-04-045, the Commission designated $1 million in annual statewide funding for the Executive Director to hire contractors to perform studies that advance the goals of the Commission's DR activities.[69] The ED initially created the DR Research Project Coordination Group to develop a study plan for this funding. No final determinations resulted from this group so the funding carried over each year. When the Commission decided to conduct a DR Potential Study scheduled for completion in 2016, this funding was earmarked for this task.

PG&E recommends that the Commission continue to authorize a $1 million total annual budget for Commission studies in 2017. Follow up work on the Potential Study may be one use for these funds. It will ensure there is a funding vehicle available for the Commission if future additional DR studies are found to be necessary. However, to ensure that this funding does not languish if it is not used, the Commission should impose a requirement that any unused funds must be returned to ratepayers if not used within a reasonable period of time.

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68 References Section 3d-2 in guidance.

69 D.12-04-045, OP 72.

PG&E recommends a deadline of June 2019 for the Commission staff to notify the IOUs about the projects to be funded, to coincide with the period when the IOUs will likely begin work on their DR program applications for the period beginning in 2021. This will allow for a reasonable period of time for any study needs to be determined based on the initial performance of the IOUs' 2018-2020 DR portfolios.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

2017 EXCESS SUPPLY DR PILOT PLAN

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APPENDIX A
2017 EXCESS SUPPLY DR PILOT PLAN

A. New and Innovative Program Design

Continuation of an existing pilot testing demand side resource assisting with renewables integration.

B. Problem Statement

Wind and solar power supplies are largely insensitive to customer demand for energy on the grid, and this misalignment can lead to situations of over-generation on the grid.

In this context, the main goal of PG&E's Excess Supply DR Pilot is to explore how customers can help mitigate situations of over-generation, or excess supply, by shifting their load consumption to contribute to the improved alignment of supply and demand.

At this time, there are still unanswered questions around what should trigger an excess supply event, the effects to customer rates, the effects to local distribution operations, and the interaction with other DR programs that provide demand and energy reductions. The pilot will study these issues.

C. How the Pilot Will Addresses a DR Goal or Strategy

PG&E envisions that the Excess Supply will be a program offering, with a targeted date of 2019, that will assist during excess supply conditions. The pilot as proposed will help with identifying and evaluating the programmatic rules and interaction with third-party aggregators and customers.

The pilot proposed for 2017 will help identify and evaluate the potential programmatic rules and interaction with participants in connection with grid challenges. PG&E envisions that there will be a program offering for Excess Supply, with a targeted date of 2019 that will assist during excess supply conditions on the grid.

The Excess Supply DR Pilot is open to third parties that aggregate retail customer loads, and to retail bundled and unbundled customers who wish to enroll directly in the pilot, for both residential and non-residential segments (participants). Retail customers can include PG&E bundled retail customers as well as customers who receive energy procurement services from Community Choice Aggregation (CCA) or Direct Access (DA) providers.

1. Enablement of New Technologies

The Excess Supply DR Pilot will also provide a pathway for new technologies. PG&E believes that technologies adopted behind the customers' meters, such as storage or smart devices, have a vital role to serve as grid-responsive assets. DR programs will act as gateways for participants to provide their demand and energy shifts that are tied to when excess supply is occurring. Results of the Excess Supply DR Pilot will help PG&E and the CPUC assess the benefits of DR as a gateway to grid needs and benefits and, in addition, provide an in-depth understanding of the benefits of technologies, like EVs.

The objective of the PG&E's Excess Supply DR Pilot is to inform the design of a future program, by determining appropriate trigger conditions, and conducting the field testing of the actions required from PG&E, customers, and third-party aggregators so that load can be increased when excess supply conditions exist:

- Currently, there are no sets of practical triggers and associated thresholds that PG&E can rely on to predict excess supply conditions. Looking at the CAISO's Locational Marginal Prices (LMP) in both day-ahead and real time markets is not sufficient to determine whether an event should be called. DAM does not normally indicate which hours excess supply condition would occur and real time prices can result in short duration calls with multiple start-ups. PG&E is looking at assessing what other triggers, other than pricing, can be used to help call events at earlier times so it can then notify participants to start shifting;
- Further experimentation surrounding compensation to participants is still needed in 2017. With the 2015-2016 Excess Supply DR Pilot, all retail customers were eligible and PG&E provided a capacity incentive for participation. PG&E recognizes that the retail rates, especially demand charges, will be a challenge. In 2017, PG&E will tackle this issue more specifically and explore future compensation structure;

- Ensure that, when situations of excess supply happen at the system level, the actions taken by participants to realign supply and demand do not create congestion on the distribution wires; and
- Explore the appropriate baseline methodologies. Today's baseline methods, like the 10-in-10 with morning adjustment, reflect the performance of a DR resource when asked to reduce load. The 10-in-10 baseline with morning adjustment predicts what the load could have been if the DR event was not called. PG&E would evaluate if the same method leads to understanding the performance of a DR resource that is asked to shift and consume more energy.

D. Specific Objectives and Goals for the Pilot

The objective of the PG&E's Excess Supply DR Pilot is to inform the design of a future program, by conducting the field testing of the actions required from PG&E, customers, and third-party aggregators so that load can be increased when excess supply conditions exist:

- Currently, there are no sets of practical triggers and associated thresholds that PG&E can rely on to predict excess supply conditions. Looking at the CAISO's LMPs in both day-ahead and real time markets is not sufficient to determine whether an event should be called. The DAM does not normally indicate which hours excess supply condition would occur and real time prices can result in short duration calls with multiple start-up and endings. PG&E is looking at assessing what other triggers, other than pricing, can be used to help call events at earlier times so it can then notify participants to start shifting;
- Further experimentation surrounding compensation to participants is still needed in 2017. With the 2015-2016 Excess Supply DR Pilot, all retail customers were eligible and PG&E provided a capacity incentive for participation. PG&E recognizes that current standard retail electric rates may present conflicting price signals that will need to be addressed in the context of this pilot.[1] In 2017, PG&E will tackle this issue more specifically and explore future compensation structures;

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[1] Also, see, Rulemaking 15-12-012 – Order Instituting Rulemaking to Assess Peak Electricity Usage Patterns and Consider Appropriate Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments, issued December 28, 2015.

- Factor the local distribution constraints systematically in the pilot's operations to ensure that, when situations of excess supply happen at the system level, the actions taken by participants to realign supply and demand do not create congestion on the distribution wires; and
- Explore the appropriate baseline methodologies. Today's baseline methods, like the 10-in-10 with morning adjustment, reflect the performance of a DR resource when asked to reduce load. The 10-in-10 with morning adjustment is predicting what the load could have been if the DR event was called. PG&E would evaluate if the same method leads to understanding the performance of a DR resource that is asked to shift and consume more energy.

E. Budget and Timeframe

PG&E requests the same level of annual funding for its Excess Supply DR Pilot (approximately $600,000) as was authorized for 2015-2016. $350,000 of this amount would be used to cover administrative expenses (including contracts for software services associated to pilot operations), and $200,000 would be used for incentive payments. In addition, PG&E requests that the incentive budgets for the Excess Supply DR Pilot be converted into a two-way balancing account, so that greater than expected interest can be accommodated if it should materialize.

Field Pilot

Id #	Task Name	Start	Finish
1	Continue to provide existing service as part of the pilot (Event signals will be sent for existing participants)	January 2017	December 2017
2	Pilot workshop to introduce program elements to new interested 3rd parties and customers	January 2017	January 2017
3	Continuously recruit customers from various segments and rate schedule classes	February 2017	July 2017
4	Finalize data collection and post-evaluation assessment process. Develop report.	November 2017	December 2017
5	Publish findings Provide any findings that would tie to this pilot becoming a program offering targeted for 2019	December 2017	December 2017

F. Standards and Metrics

PG&E will benchmark relevant programs by other utilities and program administrators on their efforts to address this system condition. PG&E will keep track of the following as it relates to this initiative:

- Customer satisfaction with the different types of DR usage

- Performance of customer response
- Areas of opportunities to increase load
- Forecasted versus actual budgets

G. Methodologies to Test the Cost-Effectiveness of the Pilot

PG&E believes that evaluating the pilot's cost-effectiveness is not appropriate at this time. One of the goals of the Excess Supply DR Pilot is to determine the costs and benefits of having third parties and customers respond if and when needed.

PG&E intends to work with Energy Division and the Demand Response Measurement and Evaluation Committee (DRMEC) to understand the cost and benefit drivers.

H. Evaluation, Measurement and Verification Plan

PG&E will work with DRMEC to prepare and conduct a plan to evaluate the performance of some aspects of the Pilot to Assess Potential for DR to Address "Excess Supply" Situations. PG&E expects that the evaluation will include, but not be limited to, the following:

- Evaluation of DR incentive structures;
- Evaluation of triggers to call an excess supply event;
- Evaluation of DR customer forecasting and baseline tools that may be developed or used as part of this pilot; and
- Evaluation of the impact and satisfaction of participating DR customers.

I. Strategy to Identify and Disseminate Best Practices and Lessons Learned

PG&E will conduct quarterly meetings with the Energy Division throughout the pilot period. The meetings will include current work, budgets, and foreseeable next steps to ensure parties are well informed.

This report will be published and be made publicly available on a designated public internet site by PG&E and/or DRMEC.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX B

2017 SUPPLY SIDE II DR PILOT PLAN

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2017 SUPPLY SIDE II DR PILOT PLAN

A. New and Innovative Program Design

The Supply Side II DR Pilot will be the first to test the feasibility of multi-use applications for Supply Side DR resources. Under the Supply Side II DR Pilot PG&E will assess Supply Side DR program design and implementation strategies that allow the same resources to be used to support local distribution system reliability needs as well as local area and system resource adequacy needs. The insights gained from the Supply Side II DR Pilot will be used to inform future multi-use Supply Side DR program design and implementation.

B. Problem Statement

PG&E requests combining the current Supply Side DR and T&D DR pilots into one Supply Side II DR Pilot, offered to residential and non-residential customers, both bundled and unbundled, and third-party aggregators, to tackle programmatic questions around multiple use applications for a Supply Side DR resource.

PG&E believes that the value of a DR resource can be increased if it can be structured to provide a range of services spanning from the CAISO wholesale markets to localized grid services for the UDC:

- The current Supply Side DR Pilot provides participants with access to the CAISO wholesale markets, and the ability to elect their own DR resource availability, based on their energy opportunity cost;
- The current T&D DR Pilot is focused on ways in which DR can be designed, implemented and operated at the local area level to support PG&E's T&D Operations; and
- By merging the two pilots into one Supply Side II DR demonstration, participants will be able to provide the CAISO energy on a day-ahead basis, and, if needed by Distribution Operations, load reduction in the day of, with the possibility of combining multiple performance payments for participating customers.

C. How the Pilot Will Addresses a DR Goal or Strategy

For 2017, PG&E requests approval to develop and implement the Supply Side II DR Pilot to assess the feasibility of multiple uses for DR resources, and test the practicability of a future vision where PG&E DR programs are not only fully integrated into the CAISO markets, but also integrated into distribution day-to-day operations to provide non-wire alternatives for PG&E's Distribution Operational local system reliability issues.

1. Program Structure

The Supply Side II DR Pilot is open to third parties that aggregate retail customer loads, and to retail customers who wish to enroll directly in the pilot, for both residential and non-residential segments (participants). Retail customers can include PG&E bundled retail customers as well as customers who receive energy procurement services from CCA or DA providers.

Under the 2015-2016 Supply Side DR Pilot, participants were able to access the CAISO's day-ahead and real time markets to provide energy and non-spinning reserves. The pilot also allowed participants to provide their DR resource assessment of availability and opportunity cost. While these options are important to maintain, PG&E recognizes that the Supply Side II DR Pilot will need to add options that tie into RA - Must Offer Obligation (MOO). As such, participants that elect to adhere to RA - MOO will receive a higher performance payment for their resource.

In addition to providing CAISO market-based services, the Supply Side II DR Pilot will enable the option for DR resources to be called to address local distribution reliability issues for the distribution grid.

For the 2017 pilot, PG&E's Customer Energy Solutions department will coordinate with PG&E's Electric Asset Management and Strategy department to identify local distribution areas where load is projected to be near existing capacity constraints. These highly loaded local distribution areas will then be cross-referenced to participants in the Supply Side II DR Pilot to identify a subset of local distribution areas, which will then be used to demonstrate the feasibility of multiple uses of Supply Side II DR Pilot resources for both CAISO markets and distribution operations.

2. Enablement of New Technologies

The Supply Side II DR Pilot will also provide a pathway for new technologies. PG&E believes that technologies behind the customer meter, such as storage or smart devices, have a vital role to serve as grid-responsive assets. DR programs will act as gateways for participants to provide their demand and energy reduction that is tied to the needs of the CAISO and distribution operations. Results of the Supply Side II DR Pilot will help PG&E and the Commission assess the benefits of DR as a gateway to grid benefits and, in addition, provide an in-depth understanding of the benefits of technologies, like EVs.

D. Specific Objectives and Goals for the Pilot

PG&E is committed to the integration of DR resources into the CAISO market as a viable economic resource. PG&E is also committed to developing and expanding the role of DR resources in other operational channels like the UDC reliability.

The objective set for the Supply Side II DR Pilot is to maximize the value of DR in all possible channels to assist with multiple grid needs, to provide maximum benefit to all retail customers.

E. Budget and Timeframe

PG&E requests $2.1 million for the Supply Side II DR Pilot, of which $1.4 million would be used to cover administrative expenses (including contract for SC and other software services associated to pilot operations), and $700,000 would be used for incentive payments. In addition, PG&E requests that the incentive budgets for the Supply Side II DR Pilot be converted into a two-way balancing account, so that greater than expected interest can be accommodated if it should materialize.

Field Test

Id #	Task Name	Start	Finish
1	Continue to operate and provide existing services as part of the pilot program	January 2017	December 2017
2	Pilot workshop to introduce new service offerings; real time energy, day ahead and real time A/S to all interested parties Introduce the new option for distribution level services	January 2017	January 2017
3	Design and Implement new program options that serve distribution services Work with distribution department to identify characteristics such as (but not limited to) needs, locations and duration of load curtailment	January 2017	March 2017
4	Release new distribution service option	April 2017	December 2017
5	Finalize data collection and post-evaluation assessment process. Develop report.	November 2017	December 2017
6	Publish findings Provide any findings that would tie to this pilot becoming a program targeted for 2019	December 2017	December 2017

F. Standards and Metrics

PG&E will benchmark relevant programs by other utilities and program administrators on their efforts around flexible ramping and regulation services. PG&E will keep track of the following as it relates to this initiative:

- Third party and customer satisfaction with the program structure;
- Performance of DR resources versus forecasted response;
  - Forecasted versus actual budgets;
  - Load reduction, by interval-by hour; and
- Number and duration of events partitioned between CAISO and Distribution calls.

As the Supply Side II DR Pilot proceeds, new standards and metrics may be developed and the ones proposed herein may no longer be relevant. Any changes to the standards and metrics will be communicated with Energy Division as part of the quarterly meeting.

G. Methodologies to Test the Cost-Effectiveness of the Pilot

PG&E believes that evaluating the pilot's cost-effectiveness is not appropriate at this time. One of the main goals of the Supply Side II DR Pilot is to determine the costs and benefits of having DR resources provide services to the CAISO and PG&E's UDC operations.

A CE analysis, after the pilot is completed, on the expected costs and benefits of a full program that offers these services may be meaningful to explore the necessary program attributes needed for future DR programs. PG&E intends to work with the Energy Division and the DRMEC on this potential program cost-effectiveness analysis at the conclusion of the pilot.

H. Evaluation, Measurement and Verification Plan

PG&E will work with DRMEC to prepare and conduct a plan to evaluate the performance of some aspects of the Supply Side II DR Pilot. PG&E expects that the evaluation will include, but not be limited to, the following:

- An evaluation of any forecasting and baseline tools developed or used as part of this pilot;
- An evaluation of the impact and satisfaction of DR resource owners participating;
- An evaluation of the impact of the number of calls between CAISO and PG&E's UDC operations;
- If applicable, an evaluation of what type of loads were participating in various services;
  - Study and further evaluation of the type of enabling technologies needed to facilitate load as a flexible resource.

I. Strategy to Identify and Disseminate Best Practices and Lessons Learned

PG&E will conduct quarterly meetings with the Energy Division throughout the pilot period. The meetings will include current work, budgets and foreseeable next steps to ensure parties are well informed.

This report will be published and be made publicly available on a designated public internet site by PG&E and/or DRMEC.

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APPENDIX C

PG&E'S PORTFOLIO-ADJUSTED LOAD IMPACTS FOR PG&E PEAKS UNDER 1-IN-2 WEATHER CONDITIONS FOR 2017

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APPENDIX C
PG&E'S PORTFOLIO-ADJUSTED LOAD IMPACTS FOR PG&E PEAKS UNDER 1-IN-2 WEATHER CONDITIONS FOR 2017

Line No.	Load Impacts (MW) of DR Resources	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	BIP - Day Of Notification	199	212	211	237	218	237	241	246	238	232	212	205
2	CBP - Day Ahead Notification	0	0	0	0	5	6	6	5	5	5	0	0
3	CBP - Day Of Notification	0	0	0	0	111	112	112	112	112	111	0	0
4	Peak Day Pricing – Non-Residential	28	27	28	65	65	82	82	82	79	65	31	28
5	Permanent Load Shift	0	0	0	0	3	4	4	4	3	3	0	0
6	SmartAC - Non-Residential	0	0	0	0	2	3	3	3	2	1	0	0
7	SmartAC - Residential	0	0	0	0	52	83	83	80	73	37	0	0
8	SmartRate - Residential	0	0	0	0	13	25	24	25	22	11	0	0
9	All Event-Based Programs (incl. PDP)	226	240	238	302	466	547	550	553	531	463	243	232
10	All DR Programs (incl. PDP)	226	240	238	302	470	551	554	557	534	466	243	232

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APPENDIX D

INITIAL OBSERVATIONS AND LESSONS LEARNED FROM THE IMPLEMENTATION OF THE SUPPLY SIDE DR PILOT IN 2015

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APPENDIX D
INITIAL OBSERVATIONS AND LESSONS LEARNED FROM THE IMPLEMENTATION OF THE SUPPLY SIDE DR PILOT IN 2015

Implementation of the Supply Side DR Pilot started in 2015, and will continue through 2016. The Supply Side DR Pilot is the continuation of an earlier PG&E pilot, the Intermittent Renewable Management Pilot Phase 2 (IRM2), which was designed to study the feasibility of demand-side resources to participate into the CAISO wholesale market as PDRs. A project report summarizing the lessons learned from IRM2 was published by LBNL.[1]

There will be a thorough analysis of the Supply Side DR Pilot after the completion of the pilot, and a similar report will be made publicly available in early 2017. In the meantime, PG&E shares some initial observations and lessons learned to-date:

1. The Supply Side DR Pilot has given customers and aggregators the freedom to elect their own DR resource availability and price.
   - Participants have bid during a wide range of periods, making DR available well beyond its traditional summer, 12 p.m. – 6 p.m. period. For instance, PG&E has observed activity across all months, later in the day, and early in the morning;
   - DR is capable of performing in the Real Time market; and
   - DAM participation is still most popular for participants and can be valuable to the wholesale market.
2. The Supply Side DR Pilot has allowed for the identification of wholesale market integration issues before they are encountered in other programs.
   - The Supply Side DR Pilot has tested PDR market participation flow, including bidding, award notification, performance calculation, and settlement. When issues in the wholesale market systems were uncovered, the CAISO has worked closely with PG&E to resolve these;

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1 http://drrc.lbl.gov/sites/all/files/lbnl-179019_intermittent_renewable_management_pilot_phase_2.pdf.

- The Supply Side DR Pilot is being used to improve the customer experience with mass-market recruitment and enrollment. PG&E will continue to work with stakeholders in 2016 to improve processes; and
- The Default Load Adjustment (DLA) is not dependent on either the bid or award in the DAM, which means that an LSE can incur a DLA even if the day-ahead bid is above the Net Benefits Test (NBT). This results in questions about the value of the NBT as a bid floor price in the DAM.

3. Additional observations on bidding behavior are:
   - Participants have been actively bidding into wholesale energy markets using PDR. DAM participation has been available since April 2015; between April and the end of 2015 there were over 2,300 bids and 400 awards in the day-ahead energy market;
   - There has generally been an increase in bidding activity. This may be attributable to participants becoming more familiar and comfortable with participation in the CAISO market and to participants fine-tune bidding habits; and
   - Real-time energy market participation for non-residential participants has been available since August 2015. There has been active participation, both bids and awards, in the CAISO RTM.

Finally, PG&E notes that changes were made to Supply Side DR Pilot bidding requirements and capacity payments in 2015 to see how participants would respond and additional changes may be tested in 2016. The Supply Side DR Pilot also will allow PG&E to test additional methodologies for settlements and performance measurement, such as the use of statistical sampling for DAM participation, which will be utilized for residential participation in 2016.

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APPENDIX E

RULE 24 NOTIFICATION LETTER TEMPLATE

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APPENDIX E
RULE 24 NOTIFICATION LETTER TEMPLATE

DIRECT PARTICIPATION DEMAND RESPONSE

CUSTOMER NOTIFICATION FORM LETTER

FOR NON-UTILITY DEMAND RESPONSE PROVIDERS SERVING RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS

[***Date***]

Dear Customer,

[***DRP Name***] sends this letter by the order of the California Public Utilities Commission ("Commission" or "CPUC") to all residential and small commercial customers[1] who have expressed interest in enrolling in Demand Response ("DR") Services with a non-utility DR Provider (DRP). You have the right to choose to enroll in DR Service(s) with a non-utility DRP. This is only a summary and may not fully convey the terms and conditions of your contract.

SUMMARY OF YOUR DR SERVICE CONTRACT

Terms and Conditions

Incentive payment(s)	*Insert whether the payment is fixed, e.g., $/customer/yr. or mo. or $/kW/yr. or mo., and/or variable, e.g., energy payments, etc.*
Response to a DR Event	*Insert what is required of the customer; indicate whether the response is mandatory or voluntary; indicate the minimum duration of the event if applicable.*
Event Notification	*Insert the time in advance for customer to be notified about an event, e.g., real time, 5, or 30 min. etc.*
Event Criteria	*Insert the list of criteria for which an event will be triggered.*
Event Period	*Insert the season and monthly/weekly/daily hours that an event will be triggered.*

1 D.12-11-025, OP 17.

Number of Events	*Insert the limit or estimated number of events/month/week/day if applicable including 'unlimited.'*
Term(s) of DR Service	*Insert the start and end dates of the enrollment.*
Installed Equipment	*Insert what equipment is needed at the customer's site and the costs to the customer if any.*
Meter Data Access	*Insert what and how the DRP will access customer usage and other account data.*
Penalties for non-performance	*Insert if there are any penalties for non-performance and describe how the penalties will be calculated.*
Your right to cancel	*Insert the grace period in which the customer can cancel the enrollment without any charges or penalties.*
Estimated Incentive Payments	*Provide the estimated incentive payments based on the customers' load and the terms and conditions on an annual basis or the total if the enrollment is less than a year.*
Additional Information	*Insert additional details describing the terms and conditions.*

[For customers enrolled in PG&E's event-based demand response program(s):]

We would like to inform you that upon the enrollment in our {DR Service} as of [date], PG&E will automatically disenroll your service account from Peak Day Pricing and place it under an Otherwise Applicable Tariff (OAT). You should be aware that you may lose your bill protection under Peak Day Pricing. Please contact PG&E for more details on Peak Day Pricing obligations and OAT provisions.

Attached please find additional customer information and a summary of CPUC rules on DR Services.

Sincerely yours,

[*DRP Signature block*]
/s/_________________