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

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| **Application of Southern California Edison Company (U 338-E) for Approval of Demand Response Programs, Goals and Budgets for 2009- 2011.** | **Application 08-06-001 (Filed June 2, 2008)** |
| **Application of San Diego Gas & Electric Company (U 902 M) for Approval of Demand Response Programs and Budgets for Years 2009 through 2011.** | **Application 08-06-002 (Filed June 2, 2008)** |
| **Application of Pacific Gas and Electric Company for Approval of 2009-2011 Demand Response Programs and Budgets (U 39-E)** | **Application 08-06-003 (Filed June 2, 2008)** |

# PACIFIC GAS AND ELECTRIC COMPANY'S (U 39-E) PETITION FOR MODIFICATION OF DECISION 09-08-027

***(PUBLIC VERSION)***


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**April 28, 2010**

**BEFORE THE PUBLIC UTILITIES COMMISSION**
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# PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) PETITION FOR MODIFICATION OF DECISION 09-08-027

## *(PUBLIC VERSION)*

Pursuant to Rule 16.4 of the Commission's Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E) respectfully requests the California Public Utilities Commission (Commission) to modify Decision 09-08-027, in three respects.

First, PG&E requests the Commission to approve proposed amendments to two of PG&E's agreements with Aggregator Managed Portfolio (AMP) providers: EnerNOC, Inc. and Energy Connect Inc. PG&E requests the modification to: (a) increase the amount of demand response EnerNOC will provide to PG&E in 2010 and 2011; (b) replace the baseline methodology in the EnerNOC and Energy Connect agreements with the methodology adopted by the Commission in *Decision Adopting Demand Response Activities And Budgets For 2009 through 2011*, D.09-08-027 (the Decision) for other PG&E demand response programs; and (c) allow multiple participation in demand response programs by customers participating in these aggregators' portfolios, as directed by the Commission.

Second, PG&E requests the Commission modify the Decision by revising Ordering Paragraph 19 which disapproved PG&E's request to hold a competitive solicitation to obtain additional agreements to replace the AMP agreements after their expiration in 2011. Since the Decision was issued, the CAISO has clarified its rules for demand response participation in its markets. After the Federal Energy Regulatory Commission (FERC) approves the CAISO tariff, PG&E will have sufficient information to prepare a solicitation to be held in late 2010 to replace these agreements. While the direct participation phase of the Demand Response OIR (R. 07-01-041) is not concluded, it is clearly beneficial for PG&E's customers and the demand response aggregators to continue the practice of having demand response agreements for aggregators in PG&E's service area. A decision is the Direct Participation phase is not needed to establish effective new aggregator agreements.

Finally, PG&E seeks modification of Budget Table 24-2 in the Decision to move the Capacity Bidding Program (CBP), an aggregator-only program, into the aggregator category. This would allow budget shifting between aggregator programs to enable PG&E to make necessary information technology upgrades to have 10% of its demand response resources, including the CBP resources, serve as proxy demand response (PDR) as described in Advice Letter 3635-E filed on March 18, 2010 and to fund fully PG&E's administrative expenses.

## I. BACKGROUND

### A. Aggregator Managed Portfolio Agreements.

PG&E is the buyer under five AMP demand response agreements that were approved by the Commission in *Order Approving The Applications of Pacific Gas and Electric Company and Southern California Edison Company For Approval of Demand Response Agreements*, D. 07-05-029 (May 3, 2007). The aggregators for the five approved AMP agreements have participated in three event seasons, and there are two more seasons until the AMP agreements expire at the end of 2011. PG&E's request for permission to hold an additional solicitation to replace these AMP agreements after their expiration was denied by the Commission in D.09-08-027, and therefore these resources may not be available during summer 2012.

As the Commission discussed in Decision 08-06-015, the AMP agreements were awarded as the result of a competitive solicitation aimed at increasing the amount of available demand response following the 2006 heat storm:

> In Decision (D.) 06-11-049, the Commission directed Southern California Edison Company (SCE) and Pacific Gas and Electric Company (PG&E) to issue Requests for Proposals (RFPs) from third parties that could administer demand response programs and provide megawatts (MW) beyond those available from the electric utilities' own programs. PG&E's RFP resulted in five contracts with third parties that agreed to provide demand response MW to the utility by working with customers to enable them to shed load when necessary, aggregating the resulting demand response potential, and delivering it according to contract provisions. As a result of the RFP process, PG&E filed Application (A.) 07-02-032, requesting Commission approval of five agreements with demand response aggregators, also known as sellers. The Commission approved these contracts, and a similar application for additional contracts filed by SCE, in D.07-05-029, on May 3, 2007. Under the terms of the PG&E contracts, the third-party aggregators are to provide specified amounts of demand response during May through October from 2007-2011.[1/]

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1/ *Decision Modifying Decision 07-05-029 By Approving Modification of Contracts With Demand Response Providers*, D. 08-06-015, p. 2 (June 13, 2008).

In D. 08-06-015, the Commission approved amendments to PG&E's AMP agreements, and held that "[a]ny future modifications to . . . demand response contracts must be made through a petition for modification of the decision in which the contracts were adopted."[2/] In the Decision, the Commission subsequently determined that the utilities "may request . . . modifications to existing aggregator contracts through either an application or a petition for modifications of <u>this</u> decision."[3/]

**B. CAISO Develops Rules For Demand Response Participation In The CAISO Market Subsequent to D.09-08-027.**

The CAISO wholesale market structure for DR resources had not been finalized when the investor-owned utilities (IOUs) were developing their proposals and budgets for their 2009-2011 applications. For example, Proxy Demand Resource (PDR), now the primary wholesale DR product advocated by the CAISO and the IOUs, had not been advanced by the CAISO until after the IOUs filed their initial application in June 2008. By September 19, 2008, when the IOUs filed their Amended Applications, the CAISO still had not launched its Market Redesign and Technology Upgrade (MRTU) and had only begun to develop the PDR market product. Thus, PG&E, in its application, could only use general assumptions to create program proposals to integrate programs with the new markets. On February 16, 2010, CAISO filed its tariff with the Federal Energy Regulatory Commission (FERC) to allow DR resources to bid into its market utilizing PDR. On April 15, 2010, the FERC issued a letter to the CAISO requesting additional information be provided about the CAISO's PDR product. The CAISO has 30 days to

2/ *Id.*, Conclusion of Law 4.

3/ D.09-08-027, Ordering ¶ 33, (emphasis added).

respond to FERC's inquiry, which may delay approval of the CAISO tariff until mid-July 2010.

Once the CAISO tariff is approved, the IOUs will have a factual basis to move forward with the development of business systems to enable AMP customer participation in the CAISO market and for the development of a new request for proposals for third-party demand response resources. At this point, PG&E will have sufficient information to prepare a competitive solicitation to replace the expiring AMP agreements, consistent with PDR bidding rules.

### C. Decision D. 09-08-027 Denied PG&E's Proposal To Hold A Competitive Solicitation For Replacement AMP Contracts In 2011.

In its 2009-2011 Application, PG&E requested the authority to hold an additional solicitation to replace the AMP agreements after they expire in 2011. The request was denied in the Decision, both because rules for demand response participation in the MRTU market were insufficiently developed and because it was unclear whether aggregators' direct participation in the market would supplant the need for IOU contracts. PG&E's request was "denied without prejudice; PG&E may propose a similar RFP in the future, if appropriate based on market conditions."[4/]

### D. Decision D. 09-08-027 Requires PG&E To Modify Its Demand Response Programs To Allow Multiple Participation And To Serve As Proxy Demand Response Without Approving Additional, Incremental Funding.

In the Decision, the Commission required the IOUs to make up to three changes to their state-wide demand response programs. The extent of these changes were unknown to the PG&E when it submitted its original application and therefore was not fully reflected in PG&E's budget requests.

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4/ Decision, p. 119.

The Commission in Ordering Paragraph (OP) 25 of the Decision directed the IOUs to "propose modifications to one or more existing demand response programs that will make at least 10 percent of the MW enrolled in the authorized DR programs comply with the requirements of CAISO's Proxy Demand Resource." OP 25 also required the IOUs to propose these modifications within 30 days of CAISO filing its tariff modifications with the FERC.[5/] In addition, the IOUs were required to change the baseline methodology in certain state-wide demand response programs to that adopted in the Decision and to make program adjustments to allow dual participation in other DR programs.[6/]

As discussed below, implementation of each of these revisions requires changes to PG&E's business systems for the affected demand response programs.

## II. DISCUSSION

### A. The Commission Should Approve The Proposed Amendments To The EnerNOC and Energy Connect Agreements.

PG&E proposes to modify the EnerNOC and Energy Connect agreements by: (1) increasing the Commitment Level in the EnerNOC agreement, (2) changing the baseline methodology to that approved in the Decision; and (3) changing the multiple participation rules to those that will be adopted by the Commission, consistent with the Decision. Amendments incorporating these proposed revisions are attached to this Petition as Exhibits A and B, respectively.

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5/ CAISO filed its PDR tariff with FERC on Feb. 16, 2010. California Independent System Operator, http://www.caiso.com/273f/273fcac5d70.pdf.

6/ D.09-08-027 ordered the IOUs to revise its dual participation rules and establish a 10-day average settlement baseline with an optional day-of adjustment. *See* OP 30, pp. 242-243.

### 1. The Commission Should Approve The Increased Commitment Level For The EnerNoc Agreement.

The Fourth Amendment to the EnerNoc agreement, would increase the Commitment Level in the EnerNOC agreement by 25 MW in May 2010 and by 30 MW in June through October 2010 and May through October 2011. The EnerNOC agreement currently has a Commitment Level of 40 MW for May through October 2010 and 2011 and therefore the amendment would substantially increase the amount of available demand response provided by EnerNOC.[7/] The proposed amendment would increase the Commitment Level to 70 MW during June through October 2010 and May through October 2011. EnerNOC has demonstrated through its performance in AMP events and test events in 2009 that it is capable of providing reliable load reductions during demand response events and, on that basis, PG&E has agreed to the increase in Commitment Level. In 2009, during a two-hour test event, EnerNOC performed at 88.67% of its Commitment Level. During a two-hour retest event held later in 2009, EnerNOC performed at 117.02% of its Commitment Level.

### 2. The EnerNOC and Energy Connect Agreements, As Modified, Are Cost Effective.

Under the proposed amendments to the EnergyConnect and EnerNOC Agreements, PG&E would continue to pay the energy and capacity prices approved by the Commission in D.07-05-029. As demonstrated in the accompanying declaration of William Gavelis, attached hereto as Exhibit C, the proposed amendments are each cost-effective and the proposed increase in the Commitment Level of the EnerNOC agreement will increase the amount of cost-effective demand response available to PG&E,

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7/ EnerNOC Agreement, Section 3.2.

consistent with the Energy Action Plan's loading order preference for cost-effective demand response resources. The proposed EnerNOC amendment will maintain (and slightly increase) the current cost effectiveness of the EnerNOC agreement. Both agreements have benefit-cost ratios exceeding one and therefore are cost-effective.[8/]

The benefit-cost ratios for the EnerNOC agreement from the Total Resource Cost, Participant, Ratepayer Impact, and Program Administrator perspectives, respectively, are set forth in Table 1 below.[9/] The net present value (NPV) for the EnerNOC amendment, separate from the original contract, is shown in Table 2. Only the 1-in-2 year weather conditions result is shown because the 1-in-10 year weather conditions result is virtually the same.

Because the non-incentive costs (e.g., administrative costs, etc.) do not change as a result of the proposed amendment, there is a slight increase in the current benefit-cost ratio of the agreement. That is, the EnerNOC amendment increases expected megawatt benefits and associated variable costs in equal proportions but does not increase the agreement's fixed costs.

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8/ The cost-effectiveness methodology used to calculate these values is consistent with the framework contained in the Joint Comments of the California Large Energy Consumers Association, Comverge, Inc., DRA, EnergyConnect, Inc., EnerNoc, Inc., Ice Energy, Inc., PG&E, SDG&E, SCE, and The Utility Reform Network Recommending a Demand Response Cost Effectiveness Evaluation Framework, filed November 19, 2007 in *Order Instituting Rulemaking,* R.07-01-041. Section B.2 of the Framework requires the utilities to evaluate DR programs and contracts using the four perspectives contained in the Standard Practice Manual: the Participant Perspective, the Ratepayer Impact Measure (Non-Participant Perspective), Total Resource Cost (TRC) Perspective and the Program Administrator Cost (PAC) Perspective (the "Framework").

9/ This result is based on hourly ex ante load impacts for residential and non-residential customers enrolled in AMP, equal to the average of megawatts to be provided from 2 to 6 p m. on system monthly peak load days. PG&E developed Ex ante load impacts for both 1 in 2 year weather conditions and 1 in 10 year weather conditions. However, the NPV of the 1 in 10 year weather conditions is only trivially greater than the 1 in 2 year weather conditions. This cost effectiveness result applies to a base case analysis and excludes any expected benefits of avoided transmission and distribution costs or avoided greenhouse gas costs.

## Table 1
**PACIFIC GAS AND ELECTRIC COMPANY**
**BENEFIT / COST RATIO BY STANDARD PRACTICE MANUAL TESTS**

**ENERNOC CONTRACT, 2010-2011**
**1-IN-2 YEAR WEATHER CONDITIONS[10/]**

| EnerNOC Contract | Filing | Time Period | Price Quote Date | Total Resource Cost Test | Partici-pant Test | Ratepayer Impact Measure Test | Program Admin-istrator Cost Test |
|---|---|---|---|---|---|---|---|
| Excluding amendment | Original | 2007-2011 | Feb.'07 [11/] | 0.84 | Not shown in A.07-02-032 | | |
| Excluding amendment | Current | 2010-2011 | Mar.'10 [12/] | 1.45 | 1.01 | 1.44 | 1.45 |
| Including amendment | Current | 2010-2011 | Mar.'10 | 1.47 | 1.01 | 1.46 | 1.47 |
| Amendment only, without original contract | Current | 2010-2011 | Mar.'10 | 1.52 | 1.01 | 1.51 | 1.52 |

**Table 2**
**PACIFIC GAS AND ELECTRIC COMPANY**
**NET PRESENT VALUE RATIO BY STANDARD PRACTICE MANUAL TESTS**

**ENERNOC AMENDMENT ONLY, 2010-2011**
**1-IN-2 YEAR WEATHER CONDITIONS[13/]**
**(in thousands)**

| | Inputs | Total Resource Cost Test | Participant Test | Ratepayer Impact Measure Test | Program Administrator Cost Test |
|---|---|---|---|---|---|
| Benefits | Reduction in Participant's Bill | – | $28 | – | – |
| | Incentive to Participant | – | [redacted] | – | – |
| | Avoided Generation Capacity Cost | [redacted] | [redacted] | [redacted] | [redacted] |
| | Avoided Energy Cost | [redacted] | [redacted] | [redacted] | [redacted] |
| Costs | Participant's Out-of-Pocket Expenses | [redacted] | [redacted] | [redacted] | [redacted] |
| | Reduction in Participants' Bills | – | – | ($28) | – |
| | Incentive to Participant | [redacted] | [redacted] | [redacted] | [redacted] |
| | Program Administrator Costs | ($0) | – | ($0) | ($0) |
| NPV | | [redacted] | [redacted] | [redacted] | [redacted] |
| B/C Ratio | | **1.52** | **1.01** | **1.51** | **1.52** |

10/ These results are applicable to both the portfolio view and the program-specific view. Results are equal when calculated on either a portfolio basis or a program-specific basis. This is because PG&E is not aware of any AMP customers participating in other demand response programs.

11/ As presented in PG&E's February 28, 2007, Application for Approval of Demand Response Agreements in A.07-02-032.

12/ This new cost effectiveness analysis uses the same methodology—albeit, implemented in a new model—as in A.07-02-032. Although the methodology PG&E used in A.07-02-032 pre-dated development of the Framework, the methodology is 100% consistent with the Framework.

13/ These results are applicable to both the portfolio view and the program-specific view.

Similarly, the updated benefit-cost ratios and net present value of the Energy Connect agreement are also higher compared to the original application, as shown in Table 3 and Table 4 below. Again, only the 1-in-2 year weather conditions result is shown because the 1-in-10 year weather conditions result is virtually the same. The increase is largely attributable to an increase in the forecast of capacity costs used to conduct PG&E's cost-effective analysis since the AMP agreements were initially negotiated.

**TABLE 3**
**PACIFIC GAS AND ELECTRIC COMPANY**
**BENEFIT / COST RATIO BY STANDARD PRACTICE MANUAL TESTS**

**ENERGYCONNECT CONTRACT, 2010-2011**
**1-IN-2 YEAR WEATHER CONDITIONS**[14/]

| Filing | Time Period | Price Quote Date | Total Resource Cost Test | Partici-pant Test | Ratepayer Impact Measure Test | Program Admin-istrator Cost Test |
|---|---|---|---|---|---|---|
| Original | 2007-2011 | Feb.'07 | 0.75 | Not shown in A.07-02-032 | | |
| Current | 2010-2011 | Mar.'10 | 1.33 | 1.01 | 1.32 | 1.33 |

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14/ These results are applicable to both the portfolio view and the program-specific view.

**Table 4**
**PACIFIC GAS AND ELECTRIC COMPANY**
**NET PRESENT VALUE RATIO BY STANDARD PRACTICE MANUAL TESTS**

**ENERGYCONNECT CONTRACT, 2010-2011**
**1-IN-2 YEAR WEATHER CONDITIONS[15]**
**(in thousands)**

| | Inputs | Total Resource Cost Test | Participant Test | Ratepayer Impact Measure Test | Program Administrator Cost Test |
|---|---|---|---|---|---|
| Benefits | Reduction in Participant's Bill | – | $24 | – | – |
| | Incentive to Participant | [redacted] | [redacted] | [redacted] | [redacted] |
| | Avoided Generation Capacity Cost | [redacted] | [redacted] | [redacted] | [redacted] |
| | Avoided Energy Cost | [redacted] | [redacted] | [redacted] | [redacted] |
| Costs | Participant's Out-of-Pocket Expenses | [redacted] | [redacted] | [redacted] | [redacted] |
| | Reduction in Participants' Bills | – | – | ($24) | – |
| | Incentive to Participants | [redacted] | [redacted] | [redacted] | [redacted] |
| | Program Administrator Costs | ($310) | – | ($310) | ($310) |
| NPV | | [redacted] | [redacted] | [redacted] | [redacted] |
| B/C Ratio | | **1.33** | **1.01** | **1.32** | **1.33** |

### 3. The Commission Should Approve The Change To The Baseline Methodology In the EnerNOC and Energy Connect Agreements.

The proposed Fourth Amendment to the EnerNOC agreement and the proposed Fifth Amendment to the Energy Connect agreement would substitute the current baseline methodology with the methodology approved by the Commission in the Decision for other PG&E demand response programs, consistent with the Commission's determination in *Decision Denying Petition for Modification of Decision 07-05-029 and Rejecting Expansion of An Existing Demand Response Contract, ,* D. 10-03-007, pp. 9 to 12 and Conclusion of Law 3.

The existing baseline methodology in both the EnerNOC and ECS agreements uses the 3 highest energy use days in the past ten similar days, aggregated on a portfolio basis. (Agreements, Section 3.6.) The methodology adopted by the Commission in the

15/ These results are applicable to both the portfolio view and the program-specific view.

Decision, by contrast, uses a "10-in-10" individual baseline with a day-of adjustment based on performance of each individual customer participating in the DR aggregators' portfolios. While the new baseline methodology was adopted for most other PG&E demand response programs that use baselines, it was not adopted for PG&E's existing agreements with DR aggregators.[16/] However, because it was approved by the Commission for use in other DR programs, PG&E believes that it is reasonable to modify the baseline methodology in the existing agreements, if requested by the DR aggregators.

#### 4. The Proposed Change To The Multiple Participation Rules in The EnerNOC and Energy Connect Agreements Are Consistent With The Commission Policy in D.09-08-027.

Section 2 of the EnerNOC amendment and Section 1 of the Proposed Energy Connect Amendment delete the existing limitations in the AMP agreements on their customers' simultaneous participation in multiple demand response programs, consistent with the policy adopted by the Commission in the Decision. PG&E filed Advice Letter 3560-E-A dated April 13, 2010 proposing multiple program participation rules compliant with the Decision. The Commission has not issued a resolution regarding the Advice Letter. Accordingly, the AMP amendments provide that the multiple participation rules that shall be in effect for these two agreements are the rules that the Commission ultimately adopts for multiple participation.

### B. The Decision Should Be Revised To Allow PG&E To Hold A Competitive Solicitation To Replace Expiring Aggregator Contracts.

As discussed above, the Commission denied without prejudice PG&E's request to have a new solicitation to replace the expiring AMP agreements for two primary reasons: (1) lack of certainty regarding MRTU rules for demand response; and (2) lack of

16/ D.09-08-027, pp. 140-41, fn. 181.

certainty regarding whether it would be appropriate for demand response aggregators to continue to contract with the IOUs after the development of new rules to allow direct participation by aggregators in the CAISO markets. As discussed below, neither reason should preclude a 2010 solicitation for replacement AMP agreements.

#### 1. The Proxy Demand Response Rules Will Be Sufficiently Determined This Year To Support A Competitive Solicitation For AMP.

Since PG&E filed its Amended Application in September 2009, the structure the CAISO market and for DR to participate in the CAISO markets has been substantially determined, subject only to the FERC's approval of CAISO's PDR tariff. One of the key concerns that the CPUC expressed in denying PG&E's request for an solicitation was "[i]t is not yet certain how demand response should be structured to participate most efficiently in California's future electricity market under the CAISO's new markets."[17/] This concern has been resolved by the CAISO's development of a tool for bidding PDR into its markets.

The CAISO intends to implement PDR as soon as practical after FERC approves its tariff (currently expected in July 2010). The structure for DR to bid into the CAISO market will be finally defined in sufficient time for PG&E to prepare a new solicitation by the end of the year for AMP seeking products that can be used as PDR. If FERC, however, does not approve the PDR tariff, PG&E would delay this RFP.

PG&E and DR service providers will eventually need to make significant business systems and process changes to accommodate the retail DR contracts' participation in the wholesale PDR market tariff. The DR service providers are unlikely to want to make such a significant change in their business practices for 2011 only, since

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17/ Decision, p. 118.

they know their agreements will expire and the change is not contractually required. Specifically, nominated retail DR resource commitments from the DR contracts will need to be bundled to align within the sixteen CAISO-defined SLAPS (subLAPS) where the PDR wholesale resources are bid for PG&E. It is also expected that there will be different measurement and verification and settlement requirements for PG&E and DR service providers, as well as accounting systems adjustments to ensure effective locational deployment of DR contracts, and partial dispatch. DR service providers' systems may also need to receive CAISO wholesale Automated Dispatch System commands to initiate dispatch for specific PDR resources. This dispatch signal may come directly from CAISO to the DR service provider or PG&E may relay the dispatch signal to the DR service provider through one of PG&E's systems. The scope and details of this integration change is significant. For this reason, rather than attempt to revise the AMP agreements now for 2011, PG&E proposes to hold a solicitation for agreements that are designed to be bid into the CAISO market as PDR, for up to five years beginning in 2012. PG&E would consult with the Division of Ratepayer Advocates on the form of its solicitation before it is issued. The solicitation would seek approximately 200 MW of DR (150 to 250 MW). Further, the new AMP contracts would include provisions to revise them if regulatory (e.g. market) changes agreements new issues.

### 2. It Is Appropriate To Solicit Additional AMP Agreements Even If Aggregators Will Participate Directly In The CAISO Market.

Phase Four of the Order Instituting Rulemaking regarding direct participation of aggregators into the CAISO market may not be finally determined until 2011.[18/] This phase of the OIR does not need to conclude before the new AMP solicitation should be

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18/ *See* Proposed Decision issued March 23, 2010, p. 18. (R. 07-01-041) issued and new AMP contracts to be in place. The main focus of Phase 4 will be on resolving issues related to the case where the Load Serving Entity (LSE) and Demand Response Provider (DRP) are different entities. This does not apply to AMP agreements since PG&E would continue to be the DRP for the contracts. Also, any issues between the DRP (PG&E) and other load servicing entities (LSEs), such as energy service providers, should not directly involve the AMP agreements, but will be handled by the mechanism that the Commission ultimately decides for resolving DRP/LSE issues.

Discussions with several aggregators have indicated that aggregators have a significant interest in participating in a solicitation to obtain new long-term contracts with IOUs as this provides the aggregators more certainty needed to commit resources to the California market. These resources would then allow them to then pursue additional DR that can be bid directly into the CAISO markets. If PG&E did not have these long-term contracts, it is likely there would be less aggregator participation in PG&E's service area and hence less opportunity for aggregators to also directly bid additional DR into the CAISO markets. Long-term contracts will increase the opportunity for aggregators to participate directly in the CAISO markets. This is analogous to electric generators companies who may have multi-year contracts with a utility for certain generating facilities but also bid directly into the CAISO market the output of other generating facilities.

### 3. PG&E Must Issue A Solicitation No Later Than December 2010 In Order To Obtain New, Approved Contracts For 2012.

It will take *at least* one year for PG&E to prepare an RFP, hold a solicitation, evaluate bids, negotiate contracts, and file and litigate before the Commission an application to approve the new agreements. The contracts need to be approved no later than the end of 2011 to allow sufficient time to prepare to perform in summer 2012. Any further delay in the ability to hold the solicitation will jeopardize PG&E's ability to have AMP contracts in place in 2012. For these reasons, PG&E proposes the following schedule for the AMP solicitation:

- CPUC approves solicitation – 3rd Quarter 2010
- PG&E issues solicitation – 4th Quarter 2010
- Final contracts submitted to CPUC for approval – 2nd Quarter 2011
- Commission approves contracts – 4th Quarter 2011
- New AMP contracts deliver MW – Summer 2012

Requiring PG&E to submit a new request to hold a competitive solicitation when PG&E files its application for the 2012 to 2014 portfolio, as the Decision currently allows, will by necessity create a gap in program participation for 2012. This creates a significant potential deficit in resource adequacy resources planned for 2012 as well as potential impacts to PG&E's Long Term Procurement Plan. The resources may be needed to help mitigate system emergency or price spikes in 2012, but they may not be available if the solicitation is not issued in 2010, given the amount of time it takes to prepare and hold the solicitation, evaluate bids, meet with bidders, negotiate agreements, then seek and obtain Commission approval.

### C. PG&E Requests The Commission To Transfer CBP From Category 2 to Category 3 To Enable PG&E to Shift Funds to CBP To Fund PDR.

As set forth in PG&E's Advice Letter 3635-E, dated March 18, 2010, the Capacity Bidding Program (CBP) is a good candidate for participation in CAISO's market. PG&E proposed to modify the program to allow it to participate in the wholesale market through CAISO's PDR product in 2011, pending timely approval of the PDR tariff and other regulatory actions. The implementation schedule and scope of PG&E's proposals depend upon two regulatory outcomes that have not yet occurred:

- the FERC approval of CAISO's PDR tariff; and
- the final rules for Demand Response Provider (DRP) participation in CAISO wholesale markets coming out of the Direct Participation phase of the Demand Response OIR (R.07-01-041).

Once the PDR tariff is approved and the participation rules are finalized, PG&E can finalize the program design for each program being readied for PDR and file any necessary tariff modifications as well as begin the business process and system development and the implementation work. The implementation schedule varies by the proposed program that must be readied for PDR.

Historically, CBP has proven to be a reliable program – i.e., the load reductions are predictable and consistent from event to event. As such, it is an attractive program for adaptation to the CAISO's PDR market. The program is entirely subscribed by third-party aggregators. Although these aggregators may find it difficult to participate if they must separate their portfolios geographically, PG&E does not anticipate a significant reduction in participation due to this geographical requirement. PG&E will have to make tariff modifications to CBP to allow geographical specific dispatch. PG&E finds that the event trigger currently in the tariff will be satisfactory but may consider changes to adjust the notification time for the day-of events to align with wholesale market notifications and instructions.

In addition to tariff modifications that are necessary, there are business systems and processes, including notifications, settlements and dispatch that require changes to enable CBP to participate as PDR.[19] PG&E's timeline to make CBP completely compatible with PDR is dependent upon FERC's approval of PDR, the Commission's approval of this PFM, and the final rules coming out of the DR OIR (R.07-01-041) Direct Participation phase. PG&E estimates that it will need nine months to file and receive approval of the tariff, implement the system and process changes, and communicate to customers. Funding for these modifications can be provided through shifting of funding from AMP to CBP.

In D.09-08-027, PG&E was authorized $3,615,076 for CBP from 2009-2011, 50% of which was earmarked for administrative costs, or $1,807,538, an amount which was significantly less than PG&E's original budget request. In October of 2009 $1,756,000 was transferred into the CBP budget from the CPP Budget, in compliance with the Decision's fund transfer rules between programs in the same category.

To continue to operate CBP through the 2009-2011 program cycle and make necessary IT upgrades for PDR, additional funding is required. PG&E forecasts that approximately $700,000 in additional in administrative expenditures will be required for the PDR changes. To transfer funds to CBP from other aggregator programs, PG&E requests the Commission to move the CBP from Category 2 (Price Responsive) to Category 3 (Aggregator). This request is appropriate because the Decision allowed PG&E to eliminate the direct participation option in PG&E's CBP and it is now an aggregator-only program.[20]

In the alternative, PG&E requests permission to transfer $700,000 from category 3 programs to CBP to fund these required upgrades. The cost for continued operations

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19/ *See* Section II.C.2 for budget required for CBP.
20/ Decision, p. 50.

includes implementing necessary business system adjustments to make the program capable of participating in PDR and fund PG&E's administrative expenses.

## III. CONCLUSION

For all the foregoing reasons, PG&E respectfully requests the Commission to issue a decision, approving the following:

A) the Fourth Amendment to the EnerNOC agreement;

B) the Fifth Amendment to the EnergyConnect agreement;

C) PG&E's request to hold a new demand response solicitation in 2010; and

D) PG&E's request to move the Capacity Bidding Program from category 2 to category 3 in Table 24-2 of the Decision.

Respectfully submitted,

LISE H. JORDAN
MARY A. GANDESBERY

By: ________________/s/______________________
MARY A. GANDESBERY

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Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

April 28, 2010

Pursuant to Rule 16.4, PG&E proposes the following change to Ordering Paragraph 19:

> 19. Pacific Gas and Electric Company's request~~s~~ to issue a Request for Proposal in 2011 to solicit more demand response contracts for the 2012-2014 period ~~are denied~~ is granted.

# EXHIBIT A
# EnerNOC AMENDMENT

FOURTH AMENDMENT TO
DEMAND RESPONSE PURCHASE AGREEMENT
DATED: FEBRUARY 23, 2007 BETWEEN
PACIFIC GAS AND ELECTRIC COMPANY AND ENERNOC, INC.

Pacific Gas and Electric Company ("Buyer") and EnerNOC, Inc. ("Seller") agree to the following Fourth Amendment ("Fourth Amendment") to the Demand Response Purchase Agreement dated February 23, 2007 ("Purchase Agreement"), as amended in writing by the Parties on September 1, 2007, March 31, 2008, and June 3, 2008 (with the Purchase Agreement, collectively referred to as the "Agreement"):

1. Commitment Level.

The DR Commitment Level Chart in Section 3.2 of the Agreement shall be deleted in its entirety and replaced with the following:

| **Delivery Month and Year** | **2010** | **2011** |
|---|---:|---:|
| May | 65 | 70 |
| June | 70 | 70 |
| July | 70 | 70 |
| Aug. | 70 | 70 |
| Sept. | 70 | 70 |
| Oct. | 70 | 70 |

2. Dual Program Participation.

Section 2.1.2.4 of the Agreement shall be deleted in its entirety.

Section 2.1 of the Agreement is hereby amended by adding the following Section 2.1.3 thereto:
The Seller will allow an enrolled Customer to participate concurrently in one additional DRprogram that has day-ahead notification and pays for energy only pursuant to rules that shall be established and may be modified by the CPUC. In case of simultaneous or overlapping Events called in two DR programs, a single Customer enrolled in those two DR programs shall receive payment only for its performance under this Agreement..

3. Baseline Calculation.

Section 3.6 of the Agreement shall be deleted and replaced in its entirety with the following:

No later than the fifth (5th) calendar day of the month following a Delivery Month in which there was a DR Event, Seller shall provide to Buyer a valid accounting of Customer Specific Energy Baselines ("CSEB") for the preceding month, in a format consistent with Appendix I, below. A CSEB shall be valid for purposes of participation if there are at least ten (10) similar days of interval data available. CSEB calculations shall be performed at an individual Customer (i.e., Service Agreement) level. The baseline for Seller's Portfolio shall be the sum of the CSEBs of each Customer (i.e., Service Agreement) nominated in Seller's Portfolio, using those Customers' most recent ten (10) similar days prior to a DR Event. The past ten (10) similar days shall include Monday through Friday, excluding event days, NERC Holidays, and other days when the Customer reduced load under an interruptible or other curtailment program or days when rotating outages were called. For each Service Agreement in Seller's Portfolio, the ten-day baseline shall have an optional day-of adjustment, which is a ratio of: (a) the average load of certain hours before the event to (b) the average load of the same hours from the last ten (10) similar days. The adjustment shall be symmetrical (upward or downward, as indicated by usage in the window time period), is capped at plus or minus 20%, and shall be based on the first three (3) of the four (4) hours prior to the event. Each Customer's choice for the day-of adjustment shall be made no later than April 1 of each calendar year and shall remain unchanged for each of the Delivery Months of the calendar year (May 1 through October 31). If a Customer is participating in an additional DR program, the four (4) hour adjustment period will start four (4) hours prior to the beginning of the earliest DR Event. Exceptions to the baseline adjustment election frequency shall be handled on a case-by-case basis and an approval shall require the consent of both Buyer and Seller.

The Seller's CSEB shall be based on the methodology outlined above, and illustrated in Appendix I to this Fourth Amendment. Appendix I to the Agreement shall be deleted in its entirety and replaced with the Appendix I to this Fourth Amendment.

4. This Fourth Amendment shall become effective on the later of the following dates: (1) May 1, 2010; (or) (2) receipt of CPUC Approval of this Fourth Amendment. Buyer and Seller will work to obtain CPUC Approval in a timely manner. Seller and Buyer will implement Commitment Level adjustments on the first of the Delivery Month that is at least 20 days after receipt of CPUC Approval.

5. Capitalized terms used but not defined herein have the meanings ascribed to them in the Agreement.

6. Except as specifically modified and amended herein, all other terms, conditions and provisions of the Agreement are and shall remain in full force and effect.

| PACIFIC GAS AND ELECTRIC COMPANY | ENERNOC, INC. |
|---|---|
| By: [signature] | By: [signature] |
| Name: Helen Burt | Name: David Samuels |
| Title: Sr. Vice President, CCO | Title: EVP |
| Date: 3/5/2010 | Date: February 26, 2010 |

## APPENDIX I –
## CALCULATION OF CUSTOMER SPECIFIC ENERGY BASELINE
## EXAMPLE FOR ILLUSTRATIVE PURPOSES ONLY

**Event Date:** **8/28/2009**

**Event Hours:** **13:01-17:00**

| 10-IN-10 BASELINE WITHOUT MORNING ADJUSTMENT | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **DAYS** | **DATE** | **HE 10:00** | **HE 11:00** | **HE 12:00** | **HE 13:00** | **HE 14:00** | **HE 15:00** | **HE 16:00** | **HE 17:00** |
| 1 | 8/14/09 | 105.89 | 108.92 | 109.58 | 108.76 | 110.28 | 110.31 | 108.50 | 108.03 |
| 2 | 8/17/09 | 107.16 | 109.79 | 112.76 | 108.92 | 110.49 | 112.90 | 109.87 | 107.02 |
| 3 | 8/18/09 | 107.66 | 110.32 | 112.09 | 110.04 | 112.79 | 112.87 | 111.01 | 107.20 |
| 4 | 8/19/09 | 105.95 | 108.68 | 109.94 | 107.93 | 109.40 | 111.07 | 108.09 | 105.82 |
| 5 | 8/20/09 | 105.86 | 108.41 | 108.87 | 107.76 | 110.85 | 110.06 | 107.40 | 107.76 |
| 6 | 8/21/09 | 104.67 | 108.60 | 109.93 | 107.64 | 108.49 | 109.24 | 107.62 | 108.49 |
| 7 | 8/24/09 | 107.09 | 111.44 | 114.47 | 112.97 | 115.38 | 114.09 | 111.54 | 109.78 |
| 8 | 8/25/09 | 106.03 | 109.40 | 108.68 | 108.05 | 110.18 | 110.25 | 107.96 | 107.18 |
| 9 | 8/26/09 | 105.61 | 108.46 | 109.01 | 107.82 | 109.88 | 111.06 | 109.72 | 107.85 |
| 10 | 8/27/09 | 106.09 | 110.04 | 111.58 | 109.36 | 111.75 | 110.06 | 109.76 | 107.62 |
| **EVENT** | 8/28/09 | 106.79 | 110.74 | 112.18 | 108.59 | 61.39 | 65.83 | 63.67 | 61.05 |
| **10-IN-10 BASELINE** | | 106.20 | 109.41 | 110.69 | 108.92 | 110.95 | 111.19 | 109.15 | 107.68 |
| **LOAD REDUCTION** | | | | | | 49.56 | 45.36 | 45.48 | 46.63 |

| 10-IN-10 BASELINE WITH MORNING ADJUSTMENT (ADJUSTMENT FACTOR > 80%) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **DAYS** | **DATE** | **HE 10:00** | **HE 11:00** | **HE 12:00** | **HE 13:00** | **HE 14:00** | **HE 15:00** | **HE 16:00** | **HE 17:00** | | |
| 1 | 8/14/09 | 105.89 | 108.92 | 109.58 | 108.76 | 110.28 | 110.31 | 108.50 | 108.03 | | |
| 2 | 8/17/09 | 107.16 | 109.79 | 112.76 | 108.92 | 110.49 | 112.90 | 109.87 | 107.02 | | |
| 3 | 8/18/09 | 107.66 | 110.32 | 112.09 | 110.04 | 112.79 | 112.87 | 111.01 | 107.20 | | |
| 4 | 8/19/09 | 105.95 | 108.68 | 109.94 | 107.93 | 109.40 | 111.07 | 108.09 | 105.82 | | |
| 5 | 8/20/09 | 105.86 | 108.41 | 108.87 | 107.76 | 110.85 | 110.06 | 107.40 | 107.76 | | |
| 6 | 8/21/09 | 104.67 | 108.60 | 109.93 | 107.64 | 108.49 | 109.24 | 107.62 | 108.49 | | |
| 7 | 8/24/09 | 107.09 | 111.44 | 114.47 | 112.97 | 115.38 | 114.09 | 111.54 | 109.78 | | |
| 8 | 8/25/09 | 106.03 | 109.40 | 108.68 | 108.05 | 110.18 | 110.25 | 107.96 | 107.18 | | |
| 9 | 8/26/09 | 105.61 | 108.46 | 109.01 | 107.82 | 109.88 | 111.06 | 109.72 | 107.85 | **MRN SUM** | **MRN ADJ** |
| 10 | 8/27/09 | 106.09 | 110.04 | 111.58 | 109.36 | 111.75 | 110.06 | 109.76 | 107.62 | | |
| **EVENT** | 8/28/09 | **91.79** | **95.74** | **97.18** | 103.59 | 61.39 | 65.83 | 63.67 | 61.05 | **284.71** | |
| **10-IN-10 BASELINE** | | **106.20** | **109.41** | **110.69** | 108.92 | 110.95 | 111.19 | 109.15 | 107.68 | **326.30** | |
| **MRN ADJ BASELINE** | | | | | | 96.81 | 97.02 | 95.24 | 93.95 | | **0.87 (1)** |
| **LOAD REDUCTION** | | | | | | 35.42 | 31.19 | 31.57 | 32.90 | | |

(1) Adjustments below 80% would cap at 80%

| 10-IN-10 BASELINE WITH MORNING ADJUSTMENT (ADJUSTMENT FACTOR < 120%) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| DAYS | DATE | HE 10:00 | HE 11:00 | HE 12:00 | HE 13:00 | HE 14:00 | HE 15:00 | HE 16:00 | HE 17:00 | MRN SUM | MRN ADJ |
| 1 | 8/14/09 | 105.89 | 108.92 | 109.58 | 108.76 | 110.28 | 110.31 | 108.50 | 108.03 | | |
| 2 | 8/17/09 | 107.16 | 109.79 | 112.76 | 108.92 | 110.49 | 112.90 | 109.87 | 107.02 | | |
| 3 | 8/18/09 | 107.66 | 110.32 | 112.09 | 110.04 | 112.79 | 112.87 | 111.01 | 107.20 | | |
| 4 | 8/19/09 | 105.95 | 108.68 | 109.94 | 107.93 | 109.40 | 111.07 | 108.09 | 105.82 | | |
| 5 | 8/20/09 | 105.86 | 108.41 | 108.87 | 107.76 | 110.85 | 110.06 | 107.40 | 107.76 | | |
| 6 | 8/21/09 | 104.67 | 108.60 | 109.93 | 107.64 | 108.49 | 109.24 | 107.62 | 108.49 | | |
| 7 | 8/24/09 | 107.09 | 111.44 | 114.47 | 112.97 | 115.38 | 114.09 | 111.54 | 109.78 | | |
| 8 | 8/25/09 | 106.03 | 109.40 | 108.68 | 108.05 | 110.18 | 110.25 | 107.96 | 107.18 | | |
| 9 | 8/26/09 | 105.61 | 108.46 | 109.01 | 107.82 | 109.88 | 111.06 | 109.72 | 107.85 | | |
| 10 | 8/27/09 | 106.09 | 110.04 | 111.58 | 109.36 | 111.75 | 110.06 | 109.76 | 107.62 | | |
| EVENT | 8/28/09 | 126.79 | 130.74 | 124.18 | 116.59 | 61.39 | 65.83 | 63.67 | 61.05 | 381.71 | |
| 10-IN-10 BASELINE | | 106.20 | 109.41 | 110.69 | 108.92 | 110.95 | 111.19 | 109.15 | 107.68 | 326.30 | |
| MRN ADJ BASELINE | | | | | | 129.79 | 130.07 | 127.68 | 125.96 | | 1.17 (2) |
| LOAD REDUCTION | | | | | | 68.40 | 64.24 | 64.01 | 64.91 | | |

(2) Adjustments above 120% would cap at 120%

**End of Appendix I**

# EXHIBIT B
# ENERGY CONNECT AMENDMENT

FIFTH AMENDMENT TO
DEMAND RESPONSE PURCHASE AGREEMENT
DATED: FEBRUARY 26, 2007 BETWEEN
PACIFIC GAS AND ELECTRIC COMPANY AND ENERGY CONNECT, INC.

Pacific Gas and Electric Company ("Buyer") and Energy Connect, Inc. ("Seller") agree to the following Fifth Amendment ("Fifth Amendment") to the Demand Response Purchase Agreement dated February 26, 2007 ("Purchase Agreement"), as amended in writing by the Parties on October 24, 2007, December 20, 2007, March 31, 2008 and June 3, 2008 (with the Purchase Agreement, collectively referred to as the "Agreement"):

1. Dual Program Participation.

Section 2.1.2.4 of the Agreement shall be deleted and replaced in its entirety with the following:

The Seller will allow an enrolled Customer to participate concurrently in one more demand response program that has day-ahead notification and pays for energy only pursuant to rules that shall be established and may be modified by the CPUC. In case of simultaneous or overlapping events called in two demand response programs, a single customer enrolled in those two programs shall receive payment only for its performance in the aggregator managed portfolio program.

2. Baseline Calculation.

Section 3.6 of the Agreement shall be deleted and replaced in its entirety with the following:

No later than the fifth (5th) calendar day of the month following a Delivery Month in which there was a DR Event, Seller shall provide to Buyer a valid accounting of Customer Specific Energy Baselines ("CSEB") for the preceding month, in a format consistent with Appendix I, below. A CSEB shall be valid for purposes of participation if there are at least ten (10) similar days of interval data available. CSEB calculations shall be performed at an individual Customer (i.e., Service Agreement) level. The baseline for Seller's Portfolio shall be the sum of the CSEBs of each Customer (i.e., Service Agreement) nominated in Seller's Portfolio, using those Customers' most recent ten (10) similar days prior to a DR Event. The past ten (10) similar days shall include Monday through Friday, excluding event days, NERC Holidays, and other days when the Customer reduced load under an interruptible or other curtailment program or days when rotating outages were called. For each Service Agreement in Seller's Portfolio, the ten-day baseline shall have an optional day-of adjustment, which is a ratio of: (a) the average load of certain hours before the event to (b) the average load of the same hours from the last ten (10) similar days. The adjustment shall be symmetrical (upward or downward, as indicated by usage in the window time period), is capped at plus or minus 20%, and shall be based on the first three (3) of the four (4) hours prior to the event. Each Customer's choice for the day-of adjustment shall be made no later than April 1 of each calendar year and shall remain unchanged for each of the Delivery Months of the calendar year (May 1 through October 31). If a Customer is participating in an additional DR program, the four (4) hour adjustment period will start four (4) hours prior to the beginning of the earliest DR Event. Exceptions to the baseline adjustment election frequency shall be handled on a case-by-case basis and an approval shall require the consent of both Buyer and Seller.

The Seller's CSEB shall be based on the methodology outlined above, and illustrated in Appendix I to this Fifth Amendment. Appendix I to the Agreement shall be deleted in its entirety and replaced with the Appendix I to this Fifth Amendment.

3. Capitalized terms used but not defined herein have the meanings ascribed to them in the Agreement.

4. This Fifth Amendment shall become effective on the later of the following dates: (1) May 1, 2010; (or) (2) receipt of CPUC Approval of this Fifth Amendment. Buyer and Seller will work to obtain CPUC Approval in a timely manner.

5. Seller and Buyer will implement Commitment Level adjustments on the first of the Delivery Month that is at least 20 days after receipt of CPUC Approval.

6. Except as specifically modified and amended herein, all other terms, conditions and provisions of the Agreement are and shall remain in full force and effect.

| **PACIFIC GAS AND ELECTRIC COMPANY** | **ENERGY CONNECT, INC.** |
|---|---|
| By: ______________________________ | By: ______________________________ |
| Name: ______________________________ | Name: ______________________________ |
| Title: ______________________________ | Title: ______________________________ |
| Date: ______________________________ | Date: ______________________________ |

# APPENDIX I –
# CALCULATION OF CUSTOMER SPECIFIC ENERGY BASELINE
# EXAMPLE FOR ILLUSTRATIVE PURPOSES ONLY

**Event Date:** **8/28/2009**

**Event Hours:** **13:01-17:00**

| 10-IN-10 BASELINE WITHOUT MORNING ADJUSTMENT | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **DAYS** | **DATE** | **HE 10:00** | **HE 11:00** | **HE 12:00** | **HE 13:00** | **HE 14:00** | **HE 15:00** | **HE 16:00** | **HE 17:00** |
| 1 | 8/14/09 | 105.89 | 108.92 | 109.58 | 108.76 | 110.28 | 110.31 | 108.50 | 108.03 |
| 2 | 8/17/09 | 107.16 | 109.79 | 112.76 | 108.92 | 110.49 | 112.90 | 109.87 | 107.02 |
| 3 | 8/18/09 | 107.66 | 110.32 | 112.09 | 110.04 | 112.79 | 112.87 | 111.01 | 107.20 |
| 4 | 8/19/09 | 105.95 | 108.68 | 109.94 | 107.93 | 109.40 | 111.07 | 108.09 | 105.82 |
| 5 | 8/20/09 | 105.86 | 108.41 | 108.87 | 107.76 | 110.85 | 110.06 | 107.40 | 107.76 |
| 6 | 8/21/09 | 104.67 | 108.60 | 109.93 | 107.64 | 108.49 | 109.24 | 107.62 | 108.49 |
| 7 | 8/24/09 | 107.09 | 111.44 | 114.47 | 112.97 | 115.38 | 114.09 | 111.54 | 109.78 |
| 8 | 8/25/09 | 106.03 | 109.40 | 108.68 | 108.05 | 110.18 | 110.25 | 107.96 | 107.18 |
| 9 | 8/26/09 | 105.61 | 108.46 | 109.01 | 107.82 | 109.88 | 111.06 | 109.72 | 107.85 |
| 10 | 8/27/09 | 106.09 | 110.04 | 111.58 | 109.36 | 111.75 | 110.06 | 109.76 | 107.62 |
| **EVENT** | 8/28/09 | 106.79 | 110.74 | 112.18 | 108.59 | 61.39 | 65.83 | 63.67 | 61.05 |
| **10-IN-10 BASELINE** | | 106.20 | 109.41 | 110.69 | 108.92 | 110.95 | 111.19 | 109.15 | 107.68 |
| **LOAD REDUCTION** | | | | | | 49.56 | 45.36 | 45.48 | 46.63 |

| 10-IN-10 BASELINE WITH MORNING ADJUSTMENT (ADJUSTMENT FACTOR > 80%) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **DAYS** | **DATE** | **HE 10:00** | **HE 11:00** | **HE 12:00** | **HE 13:00** | **HE 14:00** | **HE 15:00** | **HE 16:00** | **HE 17:00** | | |
| 1 | 8/14/09 | 105.89 | 108.92 | 109.58 | 108.76 | 110.28 | 110.31 | 108.50 | 108.03 | | |
| 2 | 8/17/09 | 107.16 | 109.79 | 112.76 | 108.92 | 110.49 | 112.90 | 109.87 | 107.02 | | |
| 3 | 8/18/09 | 107.66 | 110.32 | 112.09 | 110.04 | 112.79 | 112.87 | 111.01 | 107.20 | | |
| 4 | 8/19/09 | 105.95 | 108.68 | 109.94 | 107.93 | 109.40 | 111.07 | 108.09 | 105.82 | | |
| 5 | 8/20/09 | 105.86 | 108.41 | 108.87 | 107.76 | 110.85 | 110.06 | 107.40 | 107.76 | | |
| 6 | 8/21/09 | 104.67 | 108.60 | 109.93 | 107.64 | 108.49 | 109.24 | 107.62 | 108.49 | | |
| 7 | 8/24/09 | 107.09 | 111.44 | 114.47 | 112.97 | 115.38 | 114.09 | 111.54 | 109.78 | | |
| 8 | 8/25/09 | 106.03 | 109.40 | 108.68 | 108.05 | 110.18 | 110.25 | 107.96 | 107.18 | | |
| 9 | 8/26/09 | 105.61 | 108.46 | 109.01 | 107.82 | 109.88 | 111.06 | 109.72 | 107.85 | | |
| 10 | 8/27/09 | 106.09 | 110.04 | 111.58 | 109.36 | 111.75 | 110.06 | 109.76 | 107.62 | **MRN SUM** | **MRN ADJ** |
| **EVENT** | 8/28/09 | 91.79 | 95.74 | 97.18 | 103.59 | 61.39 | 65.83 | 63.67 | 61.05 | 284.71 | |
| **10-IN-10 BASELINE** | | 106.20 | 109.41 | 110.69 | 108.92 | 110.95 | 111.19 | 109.15 | 107.68 | 326.30 | |
| **MRN ADJ BASELINE** | | | | | | 96.81 | 97.02 | 95.24 | 93.95 | | 0.87 (1) |
| **LOAD REDUCTION** | | | | | | 35.42 | 31.19 | 31.57 | 32.90 | | |

(1) Adjustments below 80% would cap at 80%

| 10-IN-10 BASELINE WITH MORNING ADJUSTMENT (ADJUSTMENT FACTOR < 120%) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **DAYS** | **DATE** | **HE 10:00** | **HE 11:00** | **HE 12:00** | **HE 13:00** | **HE 14:00** | **HE 15:00** | **HE 16:00** | **HE 17:00** | **MRN SUM** | **MRN ADJ** |
| 1 | 8/14/09 | 105.89 | 108.92 | 109.58 | 108.76 | 110.28 | 110.31 | 108.50 | 108.03 | | |
| 2 | 8/17/09 | 107.16 | 109.79 | 112.76 | 108.92 | 110.49 | 112.90 | 109.87 | 107.02 | | |
| 3 | 8/18/09 | 107.66 | 110.32 | 112.09 | 110.04 | 112.79 | 112.87 | 111.01 | 107.20 | | |
| 4 | 8/19/09 | 105.95 | 108.68 | 109.94 | 107.93 | 109.40 | 111.07 | 108.09 | 105.82 | | |
| 5 | 8/20/09 | 105.86 | 108.41 | 108.87 | 107.76 | 110.85 | 110.06 | 107.40 | 107.76 | | |
| 6 | 8/21/09 | 104.67 | 108.60 | 109.93 | 107.64 | 108.49 | 109.24 | 107.62 | 108.49 | | |
| 7 | 8/24/09 | 107.09 | 111.44 | 114.47 | 112.97 | 115.38 | 114.09 | 111.54 | 109.78 | | |
| 8 | 8/25/09 | 106.03 | 109.40 | 108.68 | 108.05 | 110.18 | 110.25 | 107.96 | 107.18 | | |
| 9 | 8/26/09 | 105.61 | 108.46 | 109.01 | 107.82 | 109.88 | 111.06 | 109.72 | 107.85 | | |
| 10 | 8/27/09 | 106.09 | 110.04 | 111.58 | 109.36 | 111.75 | 110.06 | 109.76 | 107.62 | | |
| **EVENT** | 8/28/09 | 126.79 | 130.74 | 124.18 | 116.59 | 61.39 | 65.83 | 63.67 | 61.05 | 381.71 | |
| **10-IN-10 BASELINE** | | 106.20 | 109.41 | 110.69 | 108.92 | 110.95 | 111.19 | 109.15 | 107.68 | 326.30 | |
| **MRN ADJ BASELINE** | | | | | | 129.79 | 130.07 | 127.68 | 125.96 | | 1.17 (2) |
| **LOAD REDUCTION** | | | | | | 68.40 | 64.24 | 64.01 | 64.91 | | |

(2) Adjustments above 120% would cap at 120%

## <u>End of Appendix I</u>

# EXHIBIT C

# DECLARATION OF WILLIAM GAVELIS

**(PUBLIC VERSION)**

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

| | |
|---|---|
| Application of Southern California Edison Company (U 338-E) for Approval of Demand Response Programs, Goals and Budgets for 2009-2011. | Application 08-06-001<br>(Filed June 2, 2008) |
| Application of San Diego Gas & Electric Company (U 902 M) for Approval of Demand Response Programs and Budgets for Years 2009 through 2011. | Application 08-06-002<br>(Filed June 2, 2008) |
| Application of Pacific Gas and Electric Company for Approval of 2009-2011 Demand Response Programs and Budgets (U 39-E) | Application 08-06-003<br>(Filed June 2, 2008) |

**DECLARATION OF WILLIAM GAVELIS IN SUPPORT OF PACIFIC GAS AND ELECTRIC COMPANY'S (U 39-E) PETITION FOR MODIFICATION OF DECISION 09-08-027**

***(PUBLIC VERSION)***

LISE H. JORDAN
MARY A. GANDESBERY

Pacific Gas and Electric Company
77 Beale Street, MSB30A
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San Francisco, CA 94120
Telephone: (415) 973-0675
Facsimile: (415) 973-5520
E-Mail: magq@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

April 28, 2010

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

| | |
|---|---|
| Application of Southern California Edison Company (U 338-E) for Approval of Demand Response Programs, Goals and Budgets for 2009-2011. | Application 08-06-001 (Filed June 2, 2008) |
| Application of San Diego Gas & Electric Company (U 902 M) for Approval of Demand Response Programs and Budgets for Years 2009 through 2011. | Application 08-06-002 (Filed June 2, 2008) |
| Application of Pacific Gas and Electric Company for Approval of 2009-2011 Demand Response Programs and Budgets (U 39-E) | Application 08-06-003 (Filed June 2, 2008) |

**DECLARATION OF WILLIAM GAVELIS IN SUPPORT OF PACIFIC GAS AND ELECTRIC COMPANY'S (U 39-E) PETITION FOR MODIFICATION OF DECISION 09-08-027**

***(PUBLIC VERSION)***

I, William H. Gavelis, declare as follows:

1. I am a senior analyst in the market design and analysis department of the energy policy planning and analysis organization within the energy procurement function at Pacific Gas and Electric Company ("PG&E"). I submit this Declaration in support of the cost effectiveness ("CE") of the proposed modifications to the EnerNOC and Energy Connect demand response contracts ("Modifications") included in PG&E's Petition for Modification of Decision 09-08-027 ("Petition to Modify"). I have personal knowledge of the matters set forth herein, and could and would competently testify truthfully thereto.

2. My responsibilities as a senior analyst include modeling cost effectiveness of demand response ("DR") programs, developing avoided generation capacity cost modeling inputs, and analyzing alternative pricing formulae for qualifying facilities.

3. Based on my knowledge and experience, I make this declaration that the Modifications each have a benefit-cost ratio exceeding one[1/] using Standard Practice Manual[2/] ("SPM") tests and therefore are cost-effective, consistent with the demand response cost effectiveness guidelines contained in the *Joint Comments of the California Large Energy Consumers Association, Comverge, Inc., DRA, Energy Connect, Inc., EnerNoc, Inc., Ice Energy, Inc., PG&E, SDG&E, SCE, and The Utility Reform Network Recommending a Demand Response Cost Effectiveness Evaluation Framework*, filed November 19, 2007 in Order Instituting Rulemaking, R.07-01-041 (the "Framework").

## A. Introduction

### 1. Cost Effectiveness Overview

PG&E developed a cost-effectiveness model ("CE Model") to evaluate DR programs, such as the aggregator managed portfolio ("AMP") contracts, including these Modifications.[3/] Under the Framework, PG&E and the other investor-owned utilities agreed to report the results of four SPM tests for their respective DR programs.[4/]

a. Total Resource Cost ("TRC") Test

b. Participant Test

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1/ This result is based on hourly *ex ante* load impacts for residential and non-residential customers enrolled in AMP, equal to the average of megawatts to be provided from 2 to 6 p.m. on system monthly peak load days. PG&E developed *Ex ante* load impacts for both 1 in 2 year weather conditions and 1 in 10 year weather conditions. Results are equal when calculated on either a portfolio basis or a program-specific basis. This is because PG&E is not aware of any AMP customers participating in other demand response programs. This cost effectiveness result applies to a base case analysis and excludes any expected benefits of avoided transmission and distribution costs or avoided greenhouse gas costs.

2/ 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>.

3/ In Decision 06-11-049, the Commission directed PG&E to issue RFPs to third-party aggregators to seek bilateral contracts for new demand response (Conclusion of Law 21). PG&E issued an RFP and agreements were negotiated with five successful bidders and the resulting contracts (AMP contracts) were approved by the Commission on May 3, 2007 in Decision 07-05-029.

4/ An additional ruling in Rulemaking 07-01-041 dated April 4, 2008, requested an example calculation of the cost effectiveness of the Capacity Bidding Program from each IOU. PG&E's methodology for calculating CE in this chapter follows the example that PG&E filed on April 25, 2008, in response to that ruling. Data inputs have been updated, as appropriate, to be used in this application.

c. Ratepayer Impact Measure Test

d. Program Administrator Cost Test

The results of each of those tests can be expressed in either of two ways:

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

**2. Cost and Benefit Categories**

PG&E's CE evaluation took into account the costs and benefits defined in the Framework. These costs and benefits include:

- Benefit of Avoided Generation Capacity Cost
- Benefit of Avoided Energy Cost
- Benefit of Deferred/Reduced Transmission and Distribution ("T&D") Capacity Investment, if applicable
- DR programs Costs
- Costs Incurred by Non-Participating Customers
- Participating Customer Costs, including changes in enrolled customers' electricity bills due to the DR programs
- Incentives Received by DR programs Participants

To apply the SPM tests for this CE analysis, PG&E updated its CE Model[5/] from what was used in the original AMP filing for the EnerNOC and Energy Connect contracts.[6/] This update included updated *ex ante* load impacts as reported to the CPUC in 2010 under the protocols for estimating *ex ante* load impacts for demand response programs, as adopted in D.08-04-050 ("*Ex Ante* Impacts"). It also includes an updated

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5/ PG&E's CE Model—created subsequent to the original EnerNOC filing—is referred to as DREEM, which stands for "Demand Response, Energy Efficiency Model." It adheres to the guidelines of the Framework.

6/ PG&E's February 28, 2007 Application for Approval of Demand Response Agreements (A.07-02-32).

calculation of avoided generation capacity costs and avoided energy costs using more recent forward market prices. The *Ex Ante* Impacts of the Modifications were allocated in proportion to the megawatts specified in each contract or amendment. The fixed program administration costs[7/] were allocated equally to each of the five contracts in AMP.[8/] PG&E's CE Model estimated these future costs and benefits and attributed them to the party that will incur those costs and/or enjoy those benefits, e.g., society, the program administrator, participants and non-participants in the program.

Estimating participant costs is problematic because these are costs that only participants know. Because of this, the Framework recommends the following:

> For DR programs where participation is voluntary and it is difficult to reliably measure participating customers' costs, the incentive received by the participating customer will be treated as offsetting the costs incurred by the participating customer, including any loss in business earnings or personal inconvenience (value of service loss).[9/]

Customers voluntarily participate in AMP. Therefore, for purposes of this CE analysis, the value of the incentive payments received by a participating customer under AMP is considered to be equal to the value of the customer's costs incurred, including any loss in business earnings or personal inconvenience, e.g., value of service loss.

## B. Cost Effectiveness Evaluation Period for DR programs

The Framework states that the cost effectiveness evaluation period for a DR program:

> will ordinarily cover either the expected economic life of the major investment under that DR program or the period in which benefits will occur due to the costs that will be incurred during the DR program cycle.[10/]

7/ Based on guidance from the demand response department, the fixed program costs used in this cost effectiveness analysis are unchanged from those received in May 2008.

8/ The five contracts within AMP are: EnerNOC, Energy Connect, CPower (formerly ASC), Alternate Energy Resources (formerly Comverge) and Energy Curtailment Specialists.

9/ The Framework, Section B.3 (p. 2).

10/ *Id.,* Section B.4 (p. 2).

To evaluate the cost effectiveness of the Modifications, PG&E included the remaining period of those agreements, i.e., from May 1, 2010, through December 31, 2011.

## C. Net Present Value and B/C Ratio Results by SPM Test

Cost effectiveness results were discounted to March 31, 2010,[11/] using a 7.6 percent discount rate—PG&E's after-tax, weighted average cost of capital ("WACC"). These calculations are for *Ex Ante* Impacts for both 1-in-2 year weather conditions and 1-in-10 year weather conditions. The results shown are applicable for both a portfolio view as well as a program-specific view.[12/]

Table 1 provides the B/C Ratio by SPM test for the EnerNOC contract under 1–in–2 year weather conditions, both including the proposed amendment and not including the proposed amendment.

**TABLE 1**
**PACIFIC GAS AND ELECTRIC COMPANY**
**BENEFIT / COST RATIO BY STANDARD PRACTICE MANUAL TESTS**

**ENERNOC CONTRACT, 2010-2011**
**1-IN-2 YEAR WEATHER CONDITIONS**[13/]

| EnerNOC Contract | Filing | Time Period | Price Quote Date | Total Resource Cost Test | Partici-pant Test | Ratepayer Impact Measure Test | Program Admin-istrator Cost Test |
|---|---|---|---|---|---|---|---|
| Excluding amendment | Original | 2007-2011 | Feb.'07 [14/] | 0.84 | Not shown in A.07-02-032 | | |
| Excluding amendment | Current | 2010-2011 | Mar.'10 [15/] | 1.45 | 1.01 | 1.44 | 1.45 |
| Including amendment | Current | 2010-2011 | Mar.'10 | 1.47 | 1.01 | 1.46 | 1.47 |
| Amendment only, without original contract | Current | 2010-2011 | Mar.'10 | 1.52 | 1.01 | 1.51 | 1.52 |

11/ This analysis uses PG&E's proprietary forward price curves for the cost of natural gas and the price of electricity based on this same date.

12/ When customers participate in more than one demand response program, load impacts for cost effectiveness 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. However, PG&E is not aware of any AMP customers participating in other demand response programs.

13/ These results are applicable to both the portfolio view and the program-specific view.

14/ As presented in PG&E's February 28, 2007, Application for Approval of Demand Response Agreements in A.07-02-032.

15/ This new cost effectiveness analysis uses the same methodology—albeit, implemented in a new model—as in A.07-02-032. Although A.07-02-032 pre-dated development of the Framework, its methodology is 100% consistent with the Framework.

The original AMP application reported a B/C Ratio for the EnerNOC contract of 0.84 for the TRC test over the period 2007-2011 using avoided costs based on February 2007 prices. When the TRC is recalculated for the original EnerNOC contract—using avoided costs based on March 31, 2010 prices and consistent with the Framework—the B/C Ratio increases to 1.45. With the added MW in the proposed amendment—without additional program administration costs—the B/C Ratio improves to 1.47. In fact, if a B/C Ratio is calculated for only the MW in the EnerNOC Amendment, separate from the original contract, the result is 1.52.

Table 2 provides the B/C Ratio by SPM test for the EnerNOC contract under 1–in–10 year weather conditions, both including the amendment and not including the amendment. Although the 1-in-10 year B/C Ratios appear equal to the 1-in-2 year B/C Ratios, they are actually higher, albeit, in the fourth decimal place.

**TABLE 2**
**PACIFIC GAS AND ELECTRIC COMPANY**
**BENEFIT / COST RATIO BY STANDARD PRACTICE MANUAL TESTS**

**ENERNOC CONTRACT, 2010-2011**
**1-IN-10 YEAR WEATHER CONDITIONS**[16/]

| EnerNOC Contract | Filing | Time Period | Price Quote Date | Total Resource Cost Test | Partici-pant Test | Ratepayer Impact Measure Test | Program Admin-istrator Cost Test |
|---|---|---|---|---|---|---|---|
| Excluding amendment | Original | 2007-2011 | Feb.'07 | 1-in-10 year results not shown in A.07-02-032 | | | |
| Excluding amendment | Current | 2010-2011 | Mar.'10 | 1.45 | 1.01 | 1.44 | 1.45 |
| Including amendment | Current | 2010-2011 | Mar.'10 | 1.47 | 1.01 | 1.46 | 1.47 |
| Amendment only, without original contract | Current | 2010-2011 | Mar.'10 | 1.52 | 1.01 | 1.51 | 1.52 |

Table 3 provides the B/C Ratio by SPM test for the Energy Connect contract under 1–in–2 year weather conditions.

16/ These results are applicable to both the portfolio view and the program-specific view.

**TABLE 3**
**PACIFIC GAS AND ELECTRIC COMPANY**
**BENEFIT / COST RATIO BY STANDARD PRACTICE MANUAL TESTS**

**ENERGY CONNECT CONTRACT, 2010-2011**
**1-IN-2 YEAR WEATHER CONDITIONS**[17/]

| Filing | Time Period | Price Quote Date | Total Resource Cost Test | Partici-pant Test | Ratepayer Impact Measure Test | Program Admin-istrator Cost Test |
|---|---|---|---|---|---|---|
| Original | 2007-2011 | Feb.'07 | 0.75 | Not shown in A.07-02-032 | | |
| Current | 2010-2011 | Mar.'10 | 1.33 | 1.01 | 1.32 | 1.33 |

Table 4 provides the B/C Ratio by SPM test for the Energy Connect contract under 1–in–10 year weather conditions. Although the 1-in-10 year B/C Ratios are lower than the 1-in-2 year B/C Ratios in the third decimal point—1.3235 vs. 1.3274—the NPV of the TRC test is actually higher—$[redacted]

**TABLE 4**
**PACIFIC GAS AND ELECTRIC COMPANY**
**BENEFIT / COST RATIO BY STANDARD PRACTICE MANUAL TESTS**

**ENERGY CONNECT CONTRACT, 2010-2011**
**1-IN-10 YEAR WEATHER CONDITIONS**[18/]

| Filing | Time Period | Price Quote Date | Total Resource Cost Test | Partici-pant Test | Ratepayer Impact Measure Test | Program Admin-istrator Cost Test |
|---|---|---|---|---|---|---|
| Original | 2007-2011 | Feb.'07 | 1-in-10 year results not shown in A.07-02-032 | | | |
| Current | 2010-2011 | Mar.'10 | 1.32 | 1.01 | 1.32 | 1.32 |

Table 5 shows NPV by SPM test for just the EnerNOC amendment by itself—not including the original contract—under 1–in–2 year weather conditions.

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17/ These results are applicable to both the portfolio view and the program-specific view.
18/ These results are applicable to both the portfolio view and the program-specific view.

**Table 5**
**PACIFIC GAS AND ELECTRIC COMPANY**
**NET PRESENT VALUE RATIO BY STANDARD PRACTICE MANUAL TESTS**

**ENERNOC AMENDMENT ONLY, 2010-2011**
**1-IN-2 YEAR WEATHER CONDITIONS**[19/]
**(in thousands)**

| | Inputs | Total Resource Cost Test | Participant Test | Ratepayer Impact Measure Test | Program Administrator Cost Test |
|---|---|---|---|---|---|
| Benefits | Reduction in Participant's Bill | – | $28 | – | – |
| | Incentive to Participant | [redacted] | [redacted] | [redacted] | [redacted] |
| | Avoided Generation Capacity Cost | [redacted] | [redacted] | [redacted] | [redacted] |
| | Avoided Energy Cost | [redacted] | [redacted] | [redacted] | [redacted] |
| Costs | Participant's Out-of-Pocket Expenses | [redacted] | [redacted] | [redacted] | [redacted] |
| | Reduction in Participant's Bill | – | – | ($28) | – |
| | Incentive to Participant | [redacted] | [redacted] | [redacted] | [redacted] |
| | Program Administrator Costs | ($0) | – | ($0) | ($0) |
| NPV | | [redacted] | [redacted] | [redacted] | [redacted] |
| B/C Ratio | | **1.52** | **1.01** | **1.51** | **1.52** |

Table 6 shows NPV by SPM test for the Energy Connect contract, under 1–in–2 year weather conditions.

**Table 6**
**PACIFIC GAS AND ELECTRIC COMPANY**
**NET PRESENT VALUE RATIO BY STANDARD PRACTICE MANUAL TESTS**

**ENERGY CONNECT CONTRACT, 2010-2011**
**1-IN-2 YEAR WEATHER CONDITIONS**[20/]
**(in thousands)**

| | Inputs | Total Resource Cost Test | Participant Test | Ratepayer Impact Measure Test | Program Administrator Cost Test |
|---|---|---|---|---|---|
| Benefits | Reduction in Participant's Bill | – | $24 | – | – |
| | Incentive to Participant | [redacted] | [redacted] | [redacted] | [redacted] |
| | Avoided Generation Capacity Cost | [redacted] | [redacted] | [redacted] | [redacted] |
| | Avoided Energy Cost | [redacted] | [redacted] | [redacted] | [redacted] |
| Costs | Participant's Out-of-Pocket Expenses | [redacted] | [redacted] | [redacted] | [redacted] |
| | Reduction in Participant's Bill | – | – | ($24) | – |
| | Incentive to Participant | [redacted] | [redacted] | [redacted] | [redacted] |
| | Program Administrator Costs | ($310) | – | ($310) | ($310) |
| NPV | | [redacted] | [redacted] | [redacted] | [redacted] |
| B/C Ratio | | **1.33** | **1.01** | **1.32** | **1.33** |

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19/ These results are applicable to both the portfolio view and the program-specific view. Results for 1-in-10 year weather conditions are more positive, but by a very small amount.

20/ These results are applicable to both the portfolio view and the program-specific view. Results for 1-in-10 year weather conditions are more positive, but by a very small amount.

The forecast of total costs for the Modifications are shown in Table 7, for 1-in-10 year weather conditions. The forecast total costs for 1-in-2 year weather conditions are about 1 percent less.

**TABLE 7**
**PACIFIC GAS AND ELECTRIC COMPANY**
**FORECAST OF TOTAL COSTS**

**ENERNOC AND ENERGY CONNECT AGREEMENTS**
**NET PRESENT VALUE, 2010-2011**
**1-IN-10 YEAR WEATHER CONDITIONS**
**(in thousands)**

| Agreement | Program Administration | Capacity Incentives | Energy Incentives | Total Costs |
|---|---|---|---|---|
| EnerNOC, excluding amendment | $ 310 | [redacted] | [redacted] | [redacted] |
| EnerNOC, including amendment | $ 310 | [redacted] | [redacted] | [redacted] |
| Energy Connect | $ 310 | [redacted] | [redacted] | [redacted] |

## D. Cost Effectiveness Model Design

The benefit and cost inputs for the CE Model are a composite of values. Estimates of the program costs, including program incentives, and *Ex Ante* Impacts all come from the PG&E program manager. Other benefit and cost inputs for the CE Model, such as bill impacts or avoided costs, are determined by the CE Model based on customer rate schedule(s) and/or PG&E's estimate of forward electricity prices, respectively.

The bulk of the benefits provided by DR programs are from avoided generation capacity costs and avoided energy costs. To determine the value of these benefits, the CE Model takes as inputs:

- Estimates of the avoided annual cost of generation capacity, obtained from PG&E's avoided generation capacity cost ("ACC") model, based on forecasts of the annual economic carrying charge for the net capacity cost of a new combustion turbine ("CT").

- Estimates of forward energy prices.
- Program-specific information including:
  - Estimates of *Ex Ante* Impacts.
  - The rate categories that contain the rate schedules for the various types of customers enrolled in the DR program.
  - The structure of the DR program, including identification of events, limits on event duration, customer incentives, and the profiles of the customers within each rate class.

The base-case of this cost effectiveness analysis does not include two other types of potential benefits: (1) benefits due to deferred or reduced T&D capacity investments; and (2) benefits due to avoided greenhouse gas ("GHG") emissions.

The Framework states that avoided T&D costs should be included in the analysis if the DR program meets the "right place," "right certainty" and "right time" criteria.[21/] Because PG&E does not have sufficient, geographically-specific load information to apply these criteria correctly, benefits from avoided T&D costs are not included in the base-case, cost-effectiveness analysis of the DR programs.

Likewise, forecast benefits from avoided GHG emissions also are not included in the base-case cost effectiveness analysis of the DR programs, both for simplicity and due to its *de minimus* affect on the outcome.

**1. Avoided Cost Input Assumptions**

**a. Avoided Capacity Cost Assumptions**

The methodology PG&E used to estimate annual avoided generation capacity cost for the Modifications is consistent with the Framework.[22/] PG&E assumed that the generation capacity cost avoided each year will be from a new CT. A necessary component of the avoided generation capacity cost calculation is the deduction—of the

21/ The Framework, Section E.2 (p. 4).
22/ The Framework, Section C.1 (p. 3).

present value of the "gross margin" a CT would be expected to earn selling energy when market prices exceed its marginal cost of generation—from the present value of the total fixed plant cost.[23/] In computing those present values, PG&E used a discount rate equal to PG&E's after-tax WACC.

Consistent with recent studies,[24/] PG&E's assumptions for CT installed capital cost, heat rate, fixed O&M and variable O&M are as follows:

(1) Installed capital cost of a new CT is $1,000 per kilowatt (kW) in 2007 dollars, increasing at the rate of 2.145 percent per year.

(2) New CT heat rate of 9,266 British thermal unit per kilowatt-hour (kWh).

(3) Fixed O&M cost for a new CT is $14/kW-year in 2007 dollars, increasing at 2.145 percent per year.

(4) Variable O&M cost for a new CT $4/megawatt-hour (MWh) in 2007 dollars, increasing at 2 percent per year.

**b. Avoided Energy Cost Assumptions**

The analysis also uses PG&E's proprietary forward price curves for electricity and natural gas as of March 31, 2010. This information is confidential under CPUC Decision 06-06-066. As a result, PG&E's estimate of avoided costs appears only in confidential workpapers. To calculate avoided energy costs from the Modifications, the forward energy prices are multiplied by the average hourly *Ex Ante* Impacts of MW demand reductions.

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23/ Gross margin is the energy sales revenue minus variable fuel and variable operations and maintenance (O&M) cost. I am informed and believe the expected gross margin is estimated using a spark spread call option model. A CPUC decision whether or not to include gross margins in the calculation of avoided capacity cost is still pending in Rulemaking 07-01-041.

24/ The values for CT costs used in this analysis are consistent with those in the California Energy Commission's Comparative Costs of California Central Station Electricity Generation Technologies, Final Staff Report, December 2007, CEC-200-2007-011-SF and Integrated Energy Policy Report.

### 2. Load Impact Estimation

The *Ex Ante* Impacts for the AMP program were determined consistent with CPUC Decision 08-04-050, which adopted protocols for estimating load impacts for demand response programs. The *Ex Ante* Impacts of the Modifications were allocated in proportion to the megawatts specified in each contract or amendment.

The *Ex Ante* Impacts were determined on both a portfolio and a program-specific basis. This ensures that reductions in loads of EnerNOC and Energy Connect customers are not "double counted" with the load reductions of other DR programs. However, PG&E is not aware of any AMP customers that participate in other demand response programs. Thus, the load impacts are the same for both the portfolio view and the program-specific view.

### 3. Program Event Estimation

In order to perform the CE analysis, it was necessary to estimate when the Modifications will be called or triggered in 2010-2011. The Modifications are modeled as being triggered at PG&E's discretion based on market prices consistent with the principles of least-cost dispatch. To emulate the likelihood this resource would be used, the CE Model runs an optimization looking at the value of energy from calling the program at various times of the month. The CE Model then allocates the allotted monthly hours into the periods that would return the highest avoided energy value based on projected electricity prices and estimated load impacts. This method models the most efficient use of the Modifications given the constraints built into the contracts.

### 4. Benefit and Cost Calculations

#### a. Benefit of Avoided Capacity Cost

Consistent with the Framework[25/] the overall avoided generation capacity value of the Modifications is equal to the annual sum of the following five factors:

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25/ The Framework, Section C.2 (p. 3).

(1) The fraction of annual hours in which the Modifications are available to alleviate lost load in a month. This is equivalent to the fraction of annual capacity value fairly attributable to a given month as compared to a resource available consistently all year.

(2) The capacity of the Modifications in a month, in megawatts, determined by the average of the hourly *Ex Ante* Impacts that would occur.

(3) PG&E's estimate of the annual market value of capacity in that month, in $/kW-month.

(4) PG&E's estimate of maintaining a required 15 percent reserve margin on the additional generation capacity that will be avoided by the Modifications, (i.e., a multiplier of 1.15 on demand reductions on monthly peak load days).

(5) An upward adjustment for the electric line losses that are avoided by customer meter-level demand reductions provided by the Modifications.

**b. Benefit of Avoided Energy Cost**

By reducing usage during times of high demand, the Modifications avoid the procurement of high-cost electricity and so provide a benefit of avoided energy cost. We can determine the value of the total benefit by estimating total triggered hours, determining how much energy the contract saves per hour, and multiplying by the market price of energy.

These avoided energy costs are modeled by simulating which hours of the year when DR events would be triggered pursuant to the contract. Then, for each applicable hour, the estimated *Ex Ante* Impacts, in megawatts, on the peak-load day in that month under 1-in-2 year weather conditions and 1-in-10 year weather conditions, are multiplied by the option value of a block of energy, in $/MWh, over those same hours, as estimated by forward prices.

These hourly avoided energy cost values are then summed across the applicable hours to generate an annual avoided energy cost for the Modifications. Typically, the avoided energy costs in DR programs such as the Modifications tend to be much smaller than the avoided generation capacity costs.

**c. Avoided Electric Line Losses**

The CE Model also adjusts avoided energy costs for electric line losses that are avoided by demand reductions at the customer meter (i.e., the electricity losses that would be associated with providing power to the customer in addition to the power the customer would consume). Because electric line losses vary depending on the voltage level of the customer, this calculation is performed separately for demand reductions at each voltage level and then summed according to those weights.

**d. DR programs Cost and Incentives**

The cost of administering the Modifications and the cost of customer incentives are included in the CE analysis. Based on guidance from the demand response department, the fixed cost of administering the Modifications were modeled with no increase from the May 2008 forecast. The fixed program administration costs/ were allocated equally—20% each—to each of the five contracts in the AMP program. The impact of the Modifications on customers' electricity bills is also included. Finally, the customer incentive paid during actual demand reductions is also included in the CE analysis.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge.

Executed this 28th day of April 2010 at San Francisco, California.

/s/
WILLIAM H. GAVELIS

CERTIFICATE OF SERVICE BY ELECTRONIC MAIL OR U.S. MAIL

I, the undersigned, state that I am a citizen of the United States and am employed in the City and County of San Francisco; that I am over the age of eighteen (18) years and not a party to the within cause; and that my business address is Pacific Gas and Electric Company, Law Department B30A, Post Office Box 7442, San Francisco, CA 94120.

On the 28th day of April, 2010**,** I served a true copy of:

**PACIFIC GAS AND ELECTRIC COMPANY'S PETITION FOR MODIFICATION OF DECISION 09-08-027 (PUBLIC VERSION)**

[**XX**] By Electronic Mail – serving the enclosed via e-mail transmission to each of the parties listed on the official service list for **A. 08-06-001, A. 08-06-002 and A. 08-06-003** with an e-mail address.

[**XX**] By U.S. Mail – by placing the enclosed for collection and mailing, in the course of ordinary business practice, with other correspondence of Pacific Gas and Electric Company, enclosed in a sealed envelope, with postage fully prepaid, addressed to those parties listed on the official service list for **A. 08-06-001, A. 08-06-002 and A. 08-06-003** without an e-mail address.

I certify and declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on this 28th day of April 2010, at San Francisco, California.

/s/

PAMELA J. DAWSON-SMITH

# THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
# EMAIL SERVICE LIST

Last Updated: April 27, 2010

## CPUC DOCKET NO. A0806001; -002; -003

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Last Updated: April 27, 2010

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Last Updated: April 27, 2010

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