Decision **PROPOSED DECISION OF ALJ HECHT** **(Mailed 10/18/2010)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking regarding policies and protocols for demand response load impact estimates, cost-effectiveness methodologies, megawatt goals and alignment with California Independent System Operator Market Design Protocols.	Rulemaking 07-01-041 (Filed January 25, 2007)

DECISION ADOPTING A METHOD FOR ESTIMATING THE COST-EFFECTIVENESS OF DEMAND RESPONSE ACTIVITIES

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1. Summary

This decision adopts a method for estimating the cost-effectiveness of most Commission-ordered demand response activities. The protocols set forth in Attachment 1 shall be used in the preparation and evaluation of future applications for approval or expansion of demand response activities. This decision also adopts a workshop process for validating and updating the models used by the protocols before filing of the periodic demand response activity and budget applications. This decision completes the work in Phase 1 of Commission Rulemaking 07-01-041; this rulemaking remains open to address issues in other phases of this proceeding.

2. Procedural Background

On January 25, 2007, the Commission opened Rulemaking (R.) 07-01-041 to address several specific issues related to the Commission's efforts to develop effective demand response programs for California's three largest investor-owned electric utilities, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE). The Scoping Memo issued on April 18, 2007, divided the major work of this proceeding into phases. Phase 1, which began in spring of 2007, focuses on the development of evaluation, measurement, and verification protocols and methodologies related to existing and possible future demand response activities. Additional phases of this proceeding address state goals for participation in and load reduction from demand response activities, integration of "emergency-triggered" demand response activities with new California Independent System Operator (CAISO) markets, and direct participation of demand response resources in new CAISO markets. This decision focuses on the development of a method for estimating the cost-effectiveness of demand response activities, within Phase 1 of this proceeding.

The April 18, 2007 Scoping Ruling required SCE, PG&E, and SDG&E (together, the utilities) and allowed other parties, to develop and submit straw proposals on load impact estimation and cost-effectiveness for consideration in this proceeding. On July 16, 2007, three straw proposals on load impact estimation and two on calculating cost-effectiveness were filed. The utilities filed joint straw proposals on both load impact estimation and cost-effectiveness, as required in the scoping memo. Ice Energy also filed straw proposals on both load impact estimation and cost-effectiveness.

On September 19, 2007, the Commission received three filings addressing the possible need for evidentiary hearings on Phase 1 issues from SDG&E and SCE (filing jointly), California Large Energy Consumers Association (CLECA), and PG&E. PG&E and CLECA each requested evidentiary hearings on certain limited issues related to the development of cost-effectiveness protocols; CLECA did not see the need for hearings on load impact issues, and PG&E suggested two issues related to the utilities' load impact protocol that might benefit from further process. CAISO and the utilities filed separate responses to CLECA's request for hearings.

An Administrative Law Judge (ALJ) Ruling issued on October 15, 2007, denied these hearing requests, but extended the Phase 1 procedural schedule to allow parties to address several cost-effectiveness issues raised in the requests through individual or joint proposals and comments. Most, but not all, active parties in the proceeding filed a joint cost-effectiveness framework proposal (referred to as the Consensus Framework)[1] in response to this ruling. Rather than answering the specific questions posed in the ruling, this Consensus Framework represented agreement by the various parties on approaches to many of the major cost-effectiveness issues previously in dispute. The Consensus Framework left many issues unresolved, which parties agreed would need to be deferred to the proceeding on the utilities' 2009-2011 Demand Response Applications.

In April 2008, the Commission adopted Decision (D.) 08-04-050 in this proceeding, resolving the load impact estimation framework portion of Phase 1 with the adoption of a set of load impact protocols. Also in April 2008, the assigned ALJ issued a ruling requesting comments on possible cost-effectiveness Protocols developed and proposed by Commission staff (2008 Staff Proposal).[2] The 2008 Staff Proposal was based on the Consensus Framework, with several modifications to address concerns of staff and parties. Party comments and reply comments raised several concerns about specific aspects of the 2008 Staff Proposal, many of which are discussed in Section 3, below.

In June 2008, the utilities submitted their applications for approval of demand response activities and budgets for 2009-2011, consolidated as Application (A.) 08-06-001 et al. In conformance with directions contained in

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[1] Joint Comments of CLECA, Comverge, Inc., Division of Ratepayer Advocates (DRA), EnergyConnect, Inc., EnerNoc, Inc., Ice Energy, Inc., PG&E, SDG&E, SCE, and The Utility Reform Network (TURN) Recommending a DR Cost-effectiveness Evaluation Framework, filed November 19, 2007 in R.07-01-041.

[2] *Administrative Law Judge's Ruling Setting Comment Period on Staff Cost Effectiveness Framework and Related Issues*, R.07-01-041, April 4, 2008.

assigned Commissioner Chong's ruling in this proceeding issued on February 27, 2008, the utilities' applications utilized the Consensus Framework to estimate the cost-effectiveness of their proposed demand response activities. Parties to A.08-06-001 et al. questioned the accuracy and consistency of the cost-effectiveness results contained in those applications. In response to a ruling in A.08-06-001 et al., the utilities filed additional information on their cost-effectiveness calculations; various parties filed comments on this additional information. A ruling in this proceeding issued on November 19, 2009, transferred these additional filings from A.08-06-001 et al. into the record of this proceeding, and allowed parties to comment on the applicability of those filings to the development of cost-effectiveness protocols in this proceeding. The filings from A.08-06-001 et al. transferred by the November 19, 2009, ruling and parties' responses to that ruling complete the record for Phase 1 of this proceeding.

Section 3 of this decision describes the major areas of disagreement among parties about technical aspects of methods for determining the cost-effectiveness of demand response activities, and the resolution of these issues in the attached final protocol. Section 4 of this decision describes the protocols adopted in this decision. Section 5 provides information on when and how these protocols should be applied, and Section 6 describes the requirements for departure from and modifications to the protocols.

3. Major Issues in the Development of Cost-Effectiveness Protocols

The development of protocols for estimating the cost-effectiveness of demand response activities was a highly technical effort, requiring expertise in both the principles of measurement and evaluation of electricity demand-side management and in the design and characteristics of existing and potential future demand response activities. Though parties agreed on several general concepts, including the desirability of basing the demand response cost-effectiveness methods on the existing cost-effectiveness methods for energy efficiency programs as adopted in the California Standard Practice Manual (SPM),[3] the specific modifications needed to apply the SPM tests to demand response activities were the subject of much debate. The cost-effectiveness protocols attached to this decision as Attachment 1 (hereafter referred to as the 2010 Protocols) are a revised form of the 2008 Staff Proposal, which was in turn developed from the Consensus Framework supported by most parties in November 2007. The 2010 Protocols modify and expand the 2008 Staff Proposal and the Consensus Framework to address concerns raised in party comments on these earlier documents. Like the Consensus Framework, these protocols use a marginal cost approach to the estimation of the cost-effectiveness of demand response activities. The 2010 protocols generally follow the same procedures and recommendations as the Consensus Framework, but include additional direction and detail to ensure consistency in calculations.

The main substantive difference between the Consensus Framework and the 2010 protocols is that these protocols replace individual utility-generated avoided cost models with one required statewide model. This change was made in response to our recognition in D.09-08-027 that parties to the demand response program and budget applications for 2009-2011 (A.08-06-001 et al.), including parties involved in development of the Consensus Framework, had considerable doubt about the accuracy of the utility-generated models and continuing

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[3] *See* drrc.lbl.gov/pubs/CA-SPManual-7-02.pdf.

concerns about their lack of transparency.[4] The concerns about the implementation of the Consensus Framework in A.08-06-001 et al. are summarized in Section 7.2 of D.09-08-027, and include the fact that the utilities used different input assumptions to compute avoided costs, making it difficult to compare the cost effectiveness of the same programs across different utilities.

As an initial test of the Consensus Framework, the 2009-2011 applications revealed the method's strengths and weaknesses. In order to incorporate this experience into the process of developing these protocols, several of the filings made in D.08-06-001 et al. relevant to the implementation of the cost effectiveness framework were added to the record in this proceeding through an ALJ ruling issued on November 19, 2009. The ruling allowed parties to comment on the usefulness of those filings in the development of cost effectiveness protocols, and parties including PG&E, Ice Energy, CLECA, TURN, DRA, and SCE filed comments. The 2010 Protocols generally avoid other changes in the basic structure of the Consensus Framework. The most contentious aspects of the protocols, and a description of how those have been resolved, are discussed in detail in this section.

3.1. Use of Confidential Data and Proprietary Models and Information

The initial straw proposal submitted jointly by SCE, PG&E, and SDG&E in the summer of 2007 proposed the use of confidential data and several software models that the utilities hold as proprietary for many aspects of the cost-effectiveness calculations. The utilities proposed using confidential data for

[4] D.09-08-027, pp. 14-15.

various costs associated with electric generation and sale, and for the proprietary models used to estimate avoided costs, including inputs to the combustion turbine simulation used to calculate avoided electric generation costs. All three utilities argue that the use of confidential data and proprietary models best capture their actual costs, and allow for more accurate cost and benefit estimates by reflecting each company's specific local and business conditions. The utilities maintain that the use of confidential and proprietary data and models is justified by the increased accuracy of the results.[5]

Several parties, particularly demand response aggregators, assert that any potential for increased accuracy through the use of confidential data and proprietary models is outweighed by the lack of transparency to other parties introduced by the use of these non-publicly available data sources. Demand Response aggregators EnerNOC, Inc., EnergyConnect, Inc., and Comverge, Inc. (together, the Joint Parties), note that "transparency in the inputs, assumptions, analysis, and ultimately evaluations resulting from the application of adopted [demand response] cost-effectiveness methods will be critical to establishing the credibility of, and creating confidence in, those results."[6] Parties note that the use of publicly available data would allow parties to confirm and, if necessary, duplicate the cost-effectiveness analysis.

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[5] Revised Straw Proposals For Demand Response Load Impact Estimation And Cost-effectiveness Evaluation Of Pacific Gas and Electric Company (U39M), San Diego Gas & Electric Company (U902E) and Southern California Edison Company (U338E), filed September 10, 2007, (http://docs.cpuc.ca.gov/efile/REPORT/72728.pdf) at 16, 89.

[6] Comments of EnerNOC, Inc., EnergyConnect, Inc., and Comverge, Inc., On the Staff Draft Demand Response Cost-Effectiveness Protocols, filed April 25, 2010 at 4.

Both the Consensus Framework and the 2008 Staff Proposal would have allowed the utilities to use confidential data and proprietary models in cost-effectiveness analyses, and consistent with the Consensus Framework, the utilities used such data instead of publicly available information in the cost-effectiveness analyses included in their 2009-11 Demand Response Applications. In D.08-06-001 et al., it became apparent that the results of the utilities' cost-effectiveness analyses were neither consistent with one another nor easily compared.[7] Use of confidential data and proprietary models for many aspects of the analysis is one among several possible reasons for this, and meant that it was difficult to follow the reasoning or methods used for the calculations and that the results were not replicable by other parties. This complicated the interpretation of the results by obscuring the specific differences between the utilities' calculations.

We find that any potential increase in accuracy that may be gained through the use of confidential data and proprietary models is outweighed by the lack of transparency introduced in the calculations through the use of these non-public data sources. As provided in Section 1C of the attached 2010 Protocols, cost-effectiveness calculations must utilize publicly available data and data sources and must generate the results using publicly available models and methods. This requirement is intended to increase the transparency of the calculations and confidence in the results. The adopted protocols specifically prohibit the use of any confidential or proprietary data "unless a clear and compelling case can be made that there are insufficient public data to perform a

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[7] D.09-08-027 at 15-16.

specific calculation."[8] A utility or party wishing to exercise this provision to use non-public data must present the case for doing so and receive written permission from Commission staff through the workshop and guidance process defined for validating and updating methods described in Section 7.1, below, in advance of the analysis utilizing that data. This exception should allow for use of confidential data in the analysis of a specific aggregator contract, for example. In addition, if permission is granted and an analysis that depends on the confidential data is done, it must be accompanied by a separate analysis utilizing publicly available data to facilitate comparisons of the results and evaluation of the data choice.[9]

3.2. Choice of a Consistent Model for Overall Cost-Effectiveness Calculations

In the utilities' initial straw proposal submitted in the summer of 2007, the utilities proposed use of their own utility-specific analytical methodologies for both the overall framework for calculation of the various cost-effectiveness tests, and calculation of specific inputs into these frameworks. In general, all three utilities argue that the use of their individual (in some cases proprietary) models best reflect their particular situations, including issues of program design, as well as each company's specific local and business conditions.

Both the Consensus Framework and the 2008 Staff Proposal specified, on a qualitative level, the inputs and considerations to be included in calculation of results from each SPM test, but allowed utilities to use their own overall

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[8] 2010 Protocols, Attachment 1, Section 1C at 9.

[9] *Id*.

frameworks for calculating the results, within the broad guidance provided. As described in Section 3.1 above, the results of the utilities' cost-effectiveness analyses were not consistent with one another or easily compared.[10] Use of different frameworks, each based on a different set of assumptions, is one among several possible reasons for this. Documents filed by the utilities during this proceeding indicated that the three utilities had made different assumptions about factors such as the lifetime of the simulated combustion turbine used to estimate avoided costs, the discount rate used to calculate the net present value of each cost and benefit, and the load impact of the programs. These documents contained little or no rationale for these choices. Like the use of proprietary models and confidential data described above, the use of inconsistent frameworks made interpretation of the results more difficult by obscuring the specific differences between the utilities' calculations. We find likewise that any potential increase in accuracy that may be gained through the use of individual or proprietary utility models for overall cost-effectiveness calculations, or for calculation of specific inputs, is outweighed by the lack of both consistency and transparency introduced by the use of these differing models.

To address this concern, the 2010 Protocols in Attachment 1 provide for use of a single framework developed by Energy Division and its consultants, to be used by all utilities, and provides for the results to be calculated with the Demand Response Reporting Template described below. This framework is non-proprietary, and will be available to all parties interested in the evaluation of demand response activities, along with non-confidential data sources, as

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[10] D.09-08-027 at 15-16.

required in Section 1C of the 2010 Protocols. This requirement for the use of consistent overall calculation frameworks, along with the use of consistent, non-confidential data sources, will increase the transparency of the utilities' cost-effectiveness calculations and results, allowing parties to better understand, and if desirable, to replicate the utilities' calculations. As a result, parties will be better able to confirm the accuracy of cost-effectiveness calculations, and potentially to suggest modifications or alternative calculations if there are disagreements about specific inputs to or results of the calculations in a given proceeding in which the cost effectiveness results are provided. For example, parties may substitute short-term for long-term avoided costs or alternative values for other inputs in the Demand Response Reporting Template for comparison with the results of the analysis performed according to the protocols.

This approach is consistent with the approach adopted in D.09-08-026 for estimating the cost-effectiveness of distributed generation, which also adopted a consistent cost-effectiveness model for use by different utilities or other Load Serving Entities (LSEs). As provided in Section 1.B of the attached 2010 Protocols, cost-effectiveness calculations shall utilize the Demand Response Reporting Template spreadsheet[11] for the calculation of results for each of the SPM tests. As discussed below, the 2010 Protocols also require the use of specific models or values for the development of many inputs into that overall framework, in order to increase consistency and therefore comparability among the utilities' results.

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[11] *See* http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm.

3.3. Calculation of Avoided Costs

One of the most contentious issues in the development of these cost-effectiveness protocols has been the calculation of the cost of the electricity that would have been used in the absence of demand response, generally called the "avoided electricity cost." Avoided electricity costs consist of the avoided costs of generation capacity (the avoided capacity costs), avoided costs of the saved energy (avoided energy costs), and avoided costs of transmission and distribution. These avoided costs comprise the major benefit of most demand response programs, and are similar to the avoided costs of other demand-side management activities such as energy efficiency and distributed generation. Because demand response programs are generally active at times of peak electricity demand, during those relatively few hours per year when electricity costs are particularly high, the avoided electricity costs used in demand response cost-effectiveness calculations must reflect the value of those peak hours. In particular, the avoided costs used for demand response must reflect the high cost of building "peaker plants" (power plants used only during those peak hours, remaining idle the rest of the year). The avoided cost calculations considered in this proceeding estimate these costs using a simulation model of a combustion turbine, which is the most common type of peaker plant. Questions remain about the best way to approximate the avoided electricity costs, but in order to avoid further delay, we adopt consistent methods to be used by the utilities to obtain the needed avoided cost inputs to their cost-effectiveness analyses. In comments on the proposed decision, DRA and TURN expressed concern that the long-term costs reflected through this method are higher than short-term prices in the bilateral Resource Adequacy market. Both DRA and TURN argue that short-term prices can be much lower when available capacity resources substantially exceed forecasted peak loads; these parties support the use of short-term prices in the cost effectiveness analysis as either the primary avoided cost input or as part of the sensitivity analysis.[12] We believe that use of long-term avoided costs are consistent with Commission energy policy for Demand Response activities, and as a result we retain the requirement for the sensitivity analysis to encompass a range defined by Energy Division around the long-term cost calculated through the Avoided Cost Calculator. Parties will have an opportunity to comment on these methods, along with other variables and data sources used in the analyses, when final cost-benefit results utilizing these protocols are submitted within Commission proceedings.

3.3.1. Choice of a Consistent Model for Avoided Costs

In previous cost-effectiveness analyses of demand response activities submitted by the utilities, each utility has used its own model for estimating the avoided electricity costs of demand response. Similarly, most of the potential methodologies presented throughout this proceeding, including the Consensus Framework, would allow the utilities to calculate avoided costs using their own, usually proprietary models and, in many cases, confidential data sources. Utility responses to data requests sent by Energy Division and filed in this proceeding in late 2008 include a "benchmarking" exercise in which each company provided an analysis utilizing its own avoided cost model, using a standard set of inputs,

[12] In advocating for use of short-term market costs rather than a combustion turbine proxy for estimating avoided costs, TURN's comments on the proposed decision depart from its general philosophy of deference to the Consensus Framework, given that the Consensus Framework recommended a combustion turbine proxy.

to highlight any differences in the models' outputs.[13] This benchmarking exercise showed that even using similar (and in many cases identical) inputs, the three utilities' models produced very different results for quantities such as the avoided cost of generation capacity, gross margins (net energy revenues), and the combustion turbine capacity factor.

As described above in our discussion of the need for a consistent overall framework for the cost-effectiveness analyses, we find that the lack of consistency and transparency from these differing models more than undermines any potential increase in accuracy that they may provide. In order to improve consistency and transparency, we adopt a single model that utilizes the Avoided Cost Calculator adopted for Distributed Generation in D.09-08-027, for the calculation of avoided electricity costs by the utilities, and any other LSE that uses this framework. Not only is this approach of requiring a single model consistent with the approach adopted in D.09-08-026 for estimating avoided electricity costs of distributed generation, but this decision adopts the Avoided Cost Calculator developed by Energy and Environmental Economics, Inc. (E3) and adopted in that decision, with minor modifications specified in the protocols. As provided in Section 1.B of the attached 2010 Protocols, cost-effectiveness calculations shall utilize the Avoided Cost Calculator.[14] Consistent

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[13] See: *Response of Pacific Gas and Electric Company to Administrative Law Judge's Ruling Requiring Additional Information on Cost Effectiveness Methodologies*, filed October 31, 2008; *Response of San Diego Gas & Electric Company to Energy Division DR-02,* Dated October 31, 2008, filed November 3, 2008; and *Response of Southern California Edison Company to Administrative Law Judge's Ruling Requiring Additional Information on Demand Response Cost-Effectiveness Methodologies*, filed November 3, 2008.

[14] The Avoided Cost Calculator is available at the following site: http://www.ethree.com/public_projects/cpucdr.html.

with all previous versions of the cost-effectiveness protocols, the Avoided Cost Calculator calculates separate values for the avoided generation capacity costs (the cost of building a peaker plant), the avoided energy costs (the cost of running a peaker plant), and the avoided Transmission and Distribution (T&D) costs (the cost of delivering electricity to the end-user).

3.3.2. Appropriateness of Including an Adjustment for "Gross Margins," and Calculation of Such an Adjustment

One element of the avoided cost calculation in this proceeding that has been particularly contentious is whether or not it is appropriate to adjust the avoided generation capacity cost to subtract the "gross margins," which represent revenues that the simulated combustion turbine would gain from the sales of energy when it runs during non-demand response event hours. All three utilities removed these "gross margins" from their calculated gross avoided generation capacity costs. However, the specifics of the gross margin calculations have not been transparent or easily understandable to all parties. In particular, both Commission staff and CLECA noted that the gross margin calculation seemed to be higher than expected because the utilities' models simulated a combustion turbine that operated many more hours per year than actual combustion turbines do (i.e., the simulated combustion turbines had unusually high capacity factors). As a result, both Commission staff and CLECA objected to the specific gross margin calculations and results used by the utilities both in this proceeding[15] and in A.08-06-001 et al.,[16] which focused on the demand response activities and budgets for 2009-2011.

Based on concerns over the specific methods proposed in the utilities' straw proposal for calculating gross margins, the 2008 Staff Proposal recommended that the avoided generation capacity costs calculated in the utilities' models should not be adjusted to remove gross margins (i.e., that the gross margins adjustment should be assumed to be zero). Most parties, including the three utilities and various intervenors, including consumer advocates such as DRA and TURN, objected to this recommendation, arguing that despite concerns over specific methods of calculating this value, combustion turbines do sell electricity into the electric market at non-demand response event hours, and the value of these sales should be considered in the calculation to avoid overstating the value of the avoided generation capacity costs and thereby overstating the cost-effectiveness of demand response programs.

The adoption of the Avoided Cost Calculator obviates the need for a separate, specific calculation of gross margins, because a gross margin calculation is embedded in the model. For this reason, the concerns of parties such as CLECA about the gross margin calculation proposed by the Consensus Framework and used by the utilities in A.08-06-011 et al. are no longer relevant, because the Avoided Cost Calculator specifies one consistent method for the

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15 Request of CLECA for hearings, September 19, 2007, at 9; CLECA argues that a method for calculation of gross margins recommended in the utilities' straw proposal significantly overstates electricity sales from a combustion turbine generator and therefore the gross margin number, leading to results that understate the capacity value of the combustion turbine generator and demand response that may substitute for it.

16 Filing on February 23, 2009, by CLECA at 4.

overall calculation. We believe that the consistency brought through the adoption of a single avoided cost model, and the transparency gained through the use of publicly available data, address parties' concerns about the specifics of the model originally proposed by the utilities. At the same time, the Avoided Cost Calculator calculates the gross margins value, allowing more consistent and reliable results.

3.3.3. Appropriateness of Including Transmission and Distribution Avoided Costs (and When They Should Be Included)

Another contentious issue related to the avoided cost calculation is the appropriateness of including as a benefit of demand response any costs of upgrades to electricity transmission and distribution systems that may be deferred or avoided through the use of demand response. In theory, the ability to reduce demand in specific locations could allow utilities to defer or avoid certain infrastructure investments, such as replacement or addition of substations or transformers that would otherwise be required to meet extremely high demand in those areas. In discussion of this issue in the record of this proceeding, most parties agreed that, at least in principle, demand response should be able to assist in avoiding some equipment upgrades. However, parties raised many questions related to the extent to which demand response can currently be dispatched locally to capture this benefit, as well as whether potential peak reductions due to demand response activities are considered in utility planning for such transmission and distribution upgrades.

The Consensus Framework proposed that the utilities develop a default method for estimating these transmission and distribution avoided costs, and proposes that the T&D benefit be applied only to programs that the utility or other entity performing the evaluation believes actually allow it to avoid upgrading its infrastructure. When the Consensus Framework was utilized in A.08-06-001 et al., the utilities used unclear, inconsistent and largely unexplained methods for determining the transmission and distribution avoided costs of their various demand response programs. PG&E, for example, provided an overall T&D avoided cost, but did not provide any analysis of the extent to which this benefit might be incurred by any of its demand response programs. PG&E instead provided a sensitivity analysis,[17] calculating the SPM test results for each program with and without the avoided T&D costs. At the same time, SDG&E and SCE calculated an avoided T&D cost and applied it to several demand response programs, but provided little or no explanation as to how or why. Not only do these very different methods make comparisons among the utilities' final cost-effectiveness analyses difficult, they also apparently fail to show serious consideration of the requirement that these avoided costs only accrue to activities that are actually likely to help utilities avoid infrastructure investments.

In response to these concerns, the 2010 Protocols require the utilities to define exactly how each demand response program meets the criteria for application of transmission and distribution costs. Each utility will use the avoided T&D costs for its service territory contained in the Avoided Cost Calculator[18] in applying T&D benefits to specific activities. Alternatively, if a

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[17] *See* CLECA filing in A.08-06-001 et al., filed February 23, 2009, at 2-3, and PG&E Response filed March 5, 2009, at 2-3. These filings in A.08-06-001 et al. were transferred into the record of this proceeding through an ALJ Ruling issued on November 19, 2009.

[18] The T&D values for each utility that are included in the avoided cost calculator have been adopted for use in previous Commission decisions, and may be updated through the workshop process specified in this decision for updating and validating the models and inputs in advance of the filing of periodic program and budget applications.

specific demand response activity is designed to avoid T&D costs only in a constrained region, utilities may substitute the specific regional T&D costs avoided by that project as the T&D benefit for that activity. The protocols do not prescribe a specific method for the allocation of T&D avoided costs to individual demand response programs, but provide that unless a specific rationale is given for a particular program, the avoided T&D of any program is assumed to be zero.

3.3.4. Treatment of Ancillary Services in the Avoided Cost Calculator

Several parties included discussion of the treatment of costs and revenue from ancillary services and other CAISO markets in their comments on the proposed decision. The treatment of CAISO market participation within the protocols is complicated, because revenues earned in those markets are considered in three separate calculations within the DR cost-effectiveness framework. These costs are considered in the following ways:

First, as part of the combustion turbine simulation, the Avoided Cost Calculator determines the revenue a combustion turbine would earn in energy markets, including Ancillary Services, as part of the gross margins calculation. The gross margins are subtracted from the fixed and variable operating costs of the combustion turbine to determine the "residual capacity value" which represents the avoided generation capacity cost (essentially, the cost that Demand Response, and other demand-side programs, is avoiding).

Second, the Avoided Cost Calculator determines the Avoided Cost of Ancillary Services. This calculation determines the extent to which the use of a demand-side resource avoids the procurement of ancillary services by the CAISO. It has been determined that, at the present time, DR programs avoid little or no ancillary services procurement, since current CAISO practices do not include forecasts of DR events in the Day Ahead markets where most Ancillary Services are procured. However, this issue should be revisited in the future as CAISO practices more clearly incorporate DR into their scheduling process.

Finally, the revenues a particular DR program is expected to earn from participation in ancillary services or other CAISO markets is considered to be a benefit of that program.[19] The value of this benefit is input into the Demand Response Reporting Template, separate from the results from the Avoided Cost Calculator.

3.4. Inclusion of "Overhead" Costs such as Education and Marketing

In the past, most of the discussion of cost-effectiveness analysis of demand response has focused on calculating the avoided costs of demand response programs approved by this Commission. However, the calculation of several other costs and benefits of demand response has also been contentious. As noted by the aggregators involved in this proceeding, the utilities operate a number of programs, mostly marketing and education programs, that serve to lead customers into utility demand response programs. However the costs of these programs are not included in the calculations of the cost-effectiveness of specific demand response activities because they are funded separately. As noted by the aggregators, although the additional funding for these programs may support utility programs or lead customers to participate in utility programs, if those

[19] Considering ancillary services revenue a benefit for DR is consistent with the approach of including ancillary services Revenue in the calculation of gross margin for a CT. In both cases ancillary services revenue counts as a benefit that reduces the net cost of that resource to the utility and its ratepayers.

costs are not included in the program-level analysis this could artificially inflate the benefit-to-cost ratio of a program by underestimating program costs.[20] Aggregators express concerns that the methods adopted here could be used to assess non-utility administered programs, and if those programs are compared to utility programs that benefit from general outreach, education, and marketing associated with utility programs, non-utility activities would appear less cost effective in comparison.

To address this concern, the 2010 Protocols require that when a utility calculates the administrative costs of each program, it must include all costs attributable to the program, including those costs that may be included in a separate budget category. Costs that shall be considered in these calculations include, but are not limited to, the costs of program design, development, marketing, outreach, overhead, and information technology. Costs that promote demand response in general and are not specific to or caused by an individual program, such as statewide marketing program costs, should only be included in the evaluation of the utility's overall demand response portfolio.

In comments on the proposed decision, the Joint Parties state that the costs of the Technical Assistance/Technical Incentives program should not be included in the cost-effectiveness evaluation of DR programs because these activities are designed to encourage participation in nascent DR programs and is not intended to be a permanent incentive. PG&E and TURN respond that Technical Assistance/Technology Incentives costs should be included because

[20] Comments of EnerNoc, Inc., EnergyConnect, Inc., and ComVerge, Inc., on the Staff Draft Demand Response Cost-Effectiveness Protocols, filed in R.07-01-041 on April 25, 2008 at 7-8.

they generate load impacts. TURN specifically states that the Technical Assistance/Technology Incentives "costs are real and significant costs that are expended only to support DR programs. They should be assigned to the programs in which customers participate."

We find that Technology Incentives costs should be considered in the cost-effectiveness analysis of demand response programs. Because customers receiving rebates as part of the Technical Incentives program are required to enroll in a DR program, the cost of those rebates and other costs related to them should be included as a capital cost of the program. In contrast, the Technical Assistance program provides audits to customers who may or may not enroll in DR programs; we find that the costs of this program do not have to be attributed to individual DR programs. However, the costs of the Technical Assistance program should be included in the cost-effectiveness analysis of each LSE's portfolio.

To ensure that costs are appropriately included in the cost-effectiveness analysis of each activity, the protocols require the utilities to work with the Commission's Energy Division staff to properly categorize all administrative costs, and to disclose the allocation methodology along with all costs in the final cost-effectiveness analyses. Specific overheads and their allocation among programs will be a subject of discussion during the workshop process to validate and update the protocols in advance of the periodic demand response program and budget applications, described in Section 7.1, below. We expect this approach to ensure that the vast majority of costs that support a particular program are included in the analysis, and will minimize any advantage that the utility programs may receive from costs that are budgeted separately.

3.5. Requirements for Sensitivity Analyses and

Qualitative Analyses

The 2008 Staff Proposal contained a requirement that the utilities provide a broad array of sensitivity analyses on many of the costs and benefits that may affect the calculated SPM results, and qualitative analysis of factors that may be difficult to quantify at this time. Several parties, including the aggregators, supported the sensitivity analysis requirements included in the 2008 Staff Proposal,[21] but other parties, notably the three utilities, argued that the sensitivity requirements would be overly burdensome, and the requirements for qualitative analyses are inappropriate.[22]

The 2010 Protocols include requirements for a reduced set of sensitivity analyses that focus on the variables expected to be the key drivers of each program's cost-effectiveness. The sensitivity analysis will be performed within the Demand Response Reporting Template, and therefore will not be burdensome to the utilities. The sensitivity analysis will provide a sense of the impact of any error in the calculation of the major inputs driving the final results. Given the uncertainties inherent in many of the estimated values included in any cost-effectiveness analyses of demand response programs, we hope that the required sensitivity analyses will provide us with a picture of the range of circumstances under which the various programs would be cost effective. This should provide a more robust analysis without being overly burdensome.

We still require qualitative analysis of a few factors that are difficult to quantify, despite the concerns that these analyses may not provide useful

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[21] *Comments of EnerNoc, Inc., EnergyConnect, Inc., and ComVerge, Inc., on the Staff Draft Demand Response Cost Effectiveness Protocols,* filed in R.07-01-041 on April 25, 2008 at 2.

[22] *See*, for example, PG&E Comments filed April 25, 2010 at 2-3.

information or may inappropriately include value for these factors in the analysis. We believe that the qualitative analyses of these factors will assist us in determining if actual quantitative values for these factors can or should be included in potential future updates of the cost-effectiveness protocols. The protocols specifically invite parties other than the utilities to provide their own qualitative analyses of these hard-to-quantify factors, and encourage them to provide evidence of the value, if any, of these factors for specific demand response programs.

4. Summary of the Cost-Effectiveness Protocols

This section outlines the requirements of the 2010 Protocols.[23] The 2010 Protocols are based largely on three previous proposals filed in this Rulemaking: the cost-effectiveness framework submitted by the utilities in September 2007,[24] the Consensus Framework filed by numerous parties in November of 2007,[25] and the 2008 Staff Proposal distributed as Attachment A of the April 4, 2008 ALJ

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[23] If this discussion in this decision differs from the specifics of the protocol in Attachment 1, the full protocol is correct and should be followed.

[24] Revised Straw Proposals For Demand Response Load Impact Estimation And Cost Effectiveness Evaluation Of Pacific Gas and Electric Company (U39M), San Diego Gas & Electric Company (U902E) and Southern California Edison Company (U338E), filed September 10, 2007 (http://docs.cpuc.ca.gov/efile/REPORT/72728.pdf).

[25] Joint Comments Of California Large Energy Consumers Association, Comverge, Inc., Division Of Ratepayer Advocates, EnergyConnect, Inc., EnerNoc, Inc., Ice Energy, Inc., Pacific Gas and Electric Company (U39M), San Diego Gas & Electric Company (U902E), Southern California Edison Company (U338E) and The Utility Reform Network Recommending a Demand Response Cost-Effectiveness Evaluation Framework, filed September 19, 2007 (http://docs.cpuc.ca.gov/efile/CM/75556.pdf).

ruling in this proceeding.[26] The final 2010 Protocols incorporate numerous changes that address party comments on all of the above documents, especially the 2008 Staff Proposal. In addition, we will allow parties an opportunity to comment on these protocols, along with the inputs and results, whenever final cost-benefit analyses are submitted. At that time, we will accept suggestions for refinements or alterations to data or methods used in the analysis. The ALJ and/or assigned Commissioner may then hold further workshops or hearings as deemed necessary.

The 2010 Protocols are designed for use by the utilities. Nevertheless, these protocols may be applicable to demand response activities developed by any LSE, though LSEs other than the utilities may require additional guidance. The protocols are divided into three broad sections. Section 1 provides general guidance on the types and applicability of analyses required by the protocols. Section 2 of the protocols provides specific direction on using the modified versions of each of the tests required in the SPM. Section 3 provides a detailed discussion of each cost and benefit input to the SPM tests.

4.1. Section 1: General Guidance

In prior reporting cycles, each utility used its own inputs and models for calculating demand response cost-effectiveness. The use of separate models and data, some of which are proprietary, produced results that varied significantly. Some variation would be expected due to the different characteristics of each utility system. However, given the proprietary nature of some of the models and

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[26] *Draft Demand Response Cost Effectiveness Protocols* http://docs.cpuc.ca.gov/efile/RULINGS/80858.pdf.

input data, and the complexity of some of the models, it is extremely difficult to determine to what degree the variations reflect actual differences in the utility service territories or are due to different underlying assumptions, input data, modeling approaches or other factors.

For this reason, we require the utilities use the same public and transparent cost-effectiveness model provided by the Commission. This approach is consistent with that used for reporting energy efficiency and distributed generation cost-effectiveness. As in those proceedings, two models will be used, one to calculate avoided costs and one to report program results. Section 1 of the 2010 Protocols describes this consistent framework and provides guidance to ensure it meets the goals of consistency, transparency, and accuracy.

4.1.1. Section 1.A.: Intended Use of the Protocols

Section 1.A. describes the purpose of the protocols and the ways in which they may appropriately be used. The protocols are intended to evaluate all types of demand response programs, regardless of the characteristics (type of trigger or notification time, for example) of the program. The protocols are not intended to evaluate programs whose primary purpose is research or education, such as pilot programs or the statewide DR marketing campaign. In the future the Commission may approve protocols or provide additional guidance for Permanent Load Shifting and Integrated Demand Side Management activities, as necessary and appropriate. The protocols acknowledge that some demand response programs may require some flexibility due to their specific characteristics, however, any modifications in the protocols, including those attempting to address particular subsets of demand response activities such as permanent load shifting, must be fully explained and receive Commission approval. We will not use these protocols for evaluation of dynamic rates, but they may be useful to provide information on the cost effectiveness of initial implementation of or additional budget requests for a dynamic rate program when the costs and load impacts of a proposed rate can be estimated.

Section 1.A also provides background on some of the possible approaches considered for estimation of the cost-effectiveness of demand response, and why certain approaches were rejected in favor of a marginal cost approach.

4.1.2. Section 1.B: Input Data and Method Used to Estimate Costs and Benefits

Section 1.B describes both the method used to estimate the costs and benefits of demand response activities, and the input data required to do so. The avoided costs will be derived using a slightly modified version of the Avoided Cost Calculator approved by the Commission as part of the Distributed Generation Avoided Cost Framework used for determining the cost-effectiveness of distributed energy generation. The Avoided Cost Calculator has been modified to be consistent with demand response programs.[27] These modifications are discussed in detail in the 2010 Protocols. The Avoided Cost Calculator generates avoided costs of generation capacity, energy, T&D, and greenhouse gas (GHG) emissions. These avoided costs will be statewide, but several adjustment factors can be used to adjust the avoided costs for individual demand response programs.

The model used to report cost-effectiveness results for each demand response program is the Demand Response Reporting Template, which is in the

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[27] http://www.ethree.com/public_projects/cpucdr.html.

form of a spreadsheet accessible through the internet.[28] This spreadsheet contains the avoided cost inputs from the Avoided Cost Calculator, along with other data such as each utility's line losses and the Weighted Average Cost of Capital (WACC).[29] Each utility's after-tax WACC will be used as the discount rate to determine the net present value of each cost and benefit.[30] The utilities and other LSEs will specify additional data for each program, such as administrative costs, capital costs and amortization period, and load impacts. The protocols also allow LSEs the option to specify five adjustment factors to the avoided costs, as well as several optional demand response benefits.

The load impacts provided by the LSEs should be based on the demand response Load Impact Protocols, and should be consistent with those used for Resource Adequacy (RA), to the extent possible. The protocols provide a detailed description of how those load impacts should be calculated. Cost-effectiveness calculations based solely on ex ante forecasts may be used for proposed new demand response activities, but may be subject to review when ex post data on program impacts become available.

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28 http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm.

29 The WACC for PG&E, SDG&E, and SCE was determined in D.07-12-049 (http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/76920.htm).

30 The appropriate WACC to use in these calculations was the subject of some dispute in the comments on the proposed decision; we find that for demand response activities, the after-tax WACC best reflects the costs borne by ratepayers for demand response activities, and is therefore the appropriate discount rate.

4.1.3. Section 1.C: Confidentiality

Section 1.C of the protocols provides for the use of public data and discourages the use of confidential data. However, if confidential data are used, they are to be accompanied by an explanation for the choice to use confidential data. If approval is received for the use of confidential data in a particular situation, the data is entitled to confidentiality protections under D.06-06-066 and applicable sections of state law.

4.1.4. Section 1.D: Relationship to the Standard Practice Manual

The attached protocols use the cost-effectiveness tests described in the SPM and originally developed to apply to energy efficiency activities to determine the cost-effectiveness of each demand response activity. There are four SPM tests, designed to measure cost-effectiveness from four different perspectives – those of society, the program administrator, the ratepayer, and the participant. The details of the SPM tests have been modified, as discussed in Section 2 of the protocols, to make them more appropriate to demand response. The protocol requires calculation of all four tests, and makes no judgment of relative importance of the various tests in making program planning decisions. The determination of which test(s) are most important for program approval and the relative weight of the tests in that determination will be made in the relevant proceedings.

4.1.5. Section 1.E: Relationship to the Planning Reserve Margin and Resource Adequacy

This section discusses the interaction between the Commission's resource adequacy requirements and the cost-effectiveness of demand response programs. The protocols note that a demand response program may avoid the need for generation capacity to the extent that it meets RA requirements established by the Commission. The protocols also provide that at this time, the value of the capacity avoided by a demand response program need not take into account whether a region already has sufficient resources to meet RA requirements, though this approach may be modified is appropriate based on future developments.

4.1.6. Section 1.F: Types of Analyses Expected

Many of the costs and benefits of demand response (and other) programs are based on uncertain inputs or are subject to considerable variation, making them difficult or prohibitively expensive to quantify. In order to begin the process of defining and narrowing these uncertainties and variations, Section 1.F of the protocols requires qualitative analysis of hard-to-quantify costs and benefits. These qualitative analyses are intended to assist in comparing demand response programs by providing information (even if qualitative) on these hard-to-quantify costs and benefits. LSEs may estimate these costs and benefits, but if they cannot they are required to describe any relevant information about costs and benefits of any demand response program, which will be considered as part of the cost-effectiveness analysis of that program. This applies particularly to environmental, market and reliability, and non-energy/non-monetary benefits. Other parties are also invited to provide evidence of the extent to which these hard-to-quantify benefits apply to individual demand response programs.

Some costs and benefits used in the analysis under these protocols are presented as precise quantities, but are actually estimates because they are dependent on uncertain assumptions and estimated inputs. For this reason, the protocols require sensitivity analysis of certain key variables such as participant costs, avoided generation capacity and T&D costs, and load impacts.

4.1.7. Section 1.G: Portfolio Analysis

In addition to providing cost-effectiveness analysis of each demand response program, Section 1.G of the protocols requires LSEs to conduct a cost-effectiveness analysis of their entire demand response portfolio. As provided in this section, the portfolio analysis will include the aggregate costs and benefits of each demand response program, as well as the costs and benefits of other demand response activities which are not program-specific, such as for general demand response marketing, education and outreach efforts and Technical Assistance activities. Most parties[31] commenting on the proposed decision contend that it is not appropriate to include the costs of pilot programs in the portfolio analysis because only the costs, and not the benefits, of pilots can be estimated in advance. We agree, and the 2010 Protocols adopted here have been clarified to show that the costs of pilot programs, which usually are evaluated separately on an ex post basis, shall not be included in the portfolio analysis, unless it is possible to estimate the pilot program's benefits as well as its costs. The portfolio analysis should correct for any possible double-counting due to dual participation or other factors.

4.2. Section 2: Calculation Framework and Input Values and Section 3: Costs and Benefits of Demand Response

Section 2 describes the modified SPM tests that will be used to determine demand response cost-effectiveness, and defines the specific costs and benefits that should be used in each of the four tests. These tests are:

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[31] DRA is the only party to argue in favor of including pilot costs in the portfolio analysis. See DRA Reply Comments, November 19, 2010 at 3.

1. the Total Resource Cost (TRC) test, which measures a program's impact on society;
2. the Program Administrators Cost (PAC) test, which measures the costs and benefits of the program from the perspective of the program administrator (usually an LSE);
3. the Ratepayer Impact Measure (RIM) test, which measures the program's impact on rates; and
4. the Participant Test, which measures the costs and benefits of the program from the perspective of a participant.

Section 3 provides detailed descriptions of each DR cost and benefit and how they are calculated. Table 1 below shows the costs and benefits that will be used as inputs for each SPM test. For each DR program, the output from each test includes a benefit/cost ratio based on the net present value of each of the costs and benefits, discounted over the lifetime of the resource. To the extent users of these protocols must use additional data beyond that contained in the prescribed models, the cost-effectiveness calculations shall be based on the most recent expected values for all inputs. The discounted costs and benefits are calculated in the Demand Response Reporting Template spreadsheet. These costs and benefits are further explained in the sections below.

The 2010 protocols do not determine or analyze the relative merits or uses of any of the four SPM tests described above, nor do they address the means by which the Commission will use the 2010 Protocols to determine whether to pursue various DR programs, activities or policies, including which SPM tests will be considered and the relative weight given to each. This determination will be made in other Commission proceedings in which DR budgets are approved.

Table 1: Costs and Benefits Considered in the Four SPM Tests

	TRC	PAC	RIM	Participant
Administrative costs	COST	COST	COST	
CAISO market participation revenue	BENEFIT	BENEFIT	BENEFIT	
Avoided costs of supplying electricity	BENEFIT	BENEFIT	BENEFIT	
Bill Increases				COST
Bill Reductions				BENEFIT
Capital costs to LSE	COST	COST	COST	
Capital costs to participant	COST			COST
Environmental benefits	BENEFIT			
Incentives paid		COST	COST	BENEFIT
Increased supply costs	COST	COST	COST	
Market benefits	BENEFIT	BENEFIT	BENEFIT	
Non-energy/monetary benefits	BENEFIT			BENEFIT
Revenue gain from increased sales			BENEFIT	
Revenue loss from reduced sales			COST	
Tax Credits	BENEFIT			BENEFIT
Transaction costs to participant	COST			COST
Value of service lost	COST			COST

Shaded rows indicate those costs and benefits which are not included in the SPM but have been added to these protocols for demand response.
(Cells are left blank when the particular cost or benefit is not used in a given test).

Several of the costs and benefits used in the 2010 Protocols have generally accepted definitions and need not be explained in detail here. The protocols provide detailed definitions of each of these costs and benefits so that it is clear which budget items should be included in each category and calculation when an LSE files its cost-effectiveness analysis. Major costs and benefits defined in the protocols but not discussed in detail here include:

- Administrative costs
- Bill increases and reductions
- Capital costs to LSE
- Capital costs to participant
- Incentives paid
- Revenue gain from increased sales and revenue loss from reduced sales
- Tax credits

Costs and benefits included in the 2010 Protocols that are less accepted or less clearly defined are discussed in the sections below.

4.2.1. Avoided Cost Values

The largest benefit of demand response comes from avoiding the cost of supplying the electricity that would have been needed in the absence of the demand response. The avoided costs of electricity consist of the following three categories:

1. Avoided costs related to generation capacity, the so-called "avoided generation capacity costs," which represent the cost of building the facilities that would be needed to generate the electricity that would be used if demand response were not available.
2. Avoided costs related to production of the electricity for which demand response is substituted, the so-called "avoided energy costs," which represent the cost of unused fuel, labor, and other resources needed to operate the generation plants which provide the electricity that would have been generated if a demand response event had not occurred.
3. Avoided costs related to the T&D of energy, the so-called "avoided T&D costs," which represent the cost of moving electricity from the location at which it is produced to the point at which it would have been used had it not been replaced by demand response.

The following subsections describe how these avoided electricity costs will be calculated under the 2010 Protocols.

4.2.1.1. Avoided Generation Capacity Costs

The avoided generation capacity costs are determined by the Avoided Cost Calculator discussed in Sections 3.3.1, 3.3.2, and 3.3.3 above. This model uses publicly available data from sources such as the CAISO Market Issues and Performance Annual Reports as inputs to model the costs of a new Combustion

Turbine. The model estimates the hourly marginal costs of avoided new generation capacity for each hour of the year. The avoided generation capacity cost is then modified for each individual demand response program with three adjustment factors (called the A, B, and C factors), which are determined by each LSE for each demand response program. The A factor adjusts the avoided generation capacity cost for an individual demand response program, based on the probability that the program will be available when needed. The B factor takes into account the varying notification times associated with different demand response programs. Because programs with shorter notification times are more valuable, the B factor is used to reduce the value of programs with longer notification times. The C factor determines the relative value of programs with different triggers, de-rating those with less flexible triggers to reflect their lower value.

4.2.1.2. Avoided Energy Costs

The avoided cost of energy is also determined by the Avoided Cost Calculator. This is the cost of generating the electricity that would have been needed had a demand response event not been called. For current demand response programs, this cost is generally relatively small in comparison with the avoided cost of generation capacity. The Avoided Cost Calculator determines the avoided cost of energy by modeling hourly market price shapes for energy for each hour of the year. The 2010 Protocols also allow LSEs to apply an Energy Adjustment Factor to the avoided energy cost, to reflect their own calculations of the expected avoided energy costs.

4.2.1.3. Avoided Transmission and Distribution Costs

Avoided T&D costs reflect the deferred or reduced capacity investments in electric transmission and distribution systems that occur when demand response is available in local areas that would otherwise require such investment. The avoided T&D cost for each utility included in the Avoided Cost Calculator will reflect the average cost for T&D upgrades in the utility's service territory.

T&D capacity value is allocated to individual hours based on the hourly temperatures in each climate zone. This approach results in an allocation of T&D value to several hundred of the hottest (and likely highest local load) hours of the year. The originally proposed Demand Response Reporting Template used a weighted average of the hourly allocation of T&D value by climate zone to calculate a system-wide average T&D capacity value to each month in the Demand Response Reporting Template. In response to the comments of several parties, IOU specific T&D capacity values will be used. These values will also be reported separately for sub-transmission and for distribution. As with the avoided generation capacity costs, the monthly T&D capacity values will be used with the monthly load impacts to calculate program benefits.

2012 T&D Avoided Cost Values

	Transmission and Sub-Transmission	Distribution
PG&E	19.58	57.03
SCE	23.85	30.71
SDG&E	21.50	53.28

Under the 2010 Protocols, the utility or other entity performing the evaluation will then apply the calculated T&D costs to each program to the extent that that program may actually alleviate congestion in a particular area. Unless a specific rationale is provided for a given program, the avoided T&D of the program is assumed to be zero.

4.2.2. Costs Specific to Participants

The costs that a ratepayer must incur to participate in demand response programs include the capital costs of equipment, transaction costs, and the value of service lost. While the calculation of capital costs is straightforward, calculation of the other participant costs is not. However, participant costs must be determined for the purpose of calculating the TRC and Participant tests.

As described more fully in the 2010 Protocols, transaction costs are the opportunity costs associated with education, equipment installation, program application, energy audits, developing and managing a load shed plan, and other activities required for participation in a specific program. Examples of transaction costs are the personnel costs associated with time spent on activities such as filling out a demand response program application, making decisions about whether or how to install demand response equipment, and shutting off equipment during a demand response event.

The value of service lost through participation in demand response includes any losses in productivity that occur because of demand reductions, as well as "comfort costs," which are the losses in comfort participants may experience or perceive when particular end-uses become unavailable. Examples of lost productivity costs are revenue losses incurred when a business is shut down during a demand response event. Examples of comfort costs include having to walk further to use a copy machine, feeling too hot or too cold because of changes in a thermostat setting, and the cost of having to change one's work hours.

These value-of-service costs may be significant to the participant, but are difficult to quantify. The protocols acknowledge that estimates of these costs are likely to be highly uncertain. Because it is necessary to calculate participant costs for the purposes of the TRC test, the utilities have in the past used incentives paid plus bill reductions minus capital costs as a proxy for measurement for participant costs. However, as explained in the protocols, this is not an accurate estimate of participant costs because it assumes that participant benefits are equal to participant costs. Instead, the protocols establish the quantity

incentives + bill reductions – capital costs

as the **maximum** value for the total of transaction and lost value of service costs. Because the value of these costs is uncertain, the 2010 Protocols require a sensitivity analysis to show how the different possible values of these participant costs affect the final results. The value calculated above shall be used as the maximum value for the purpose of the sensitivity analysis, with a lower value used as the standard value for this quantity.

4.2.3. Revenue from CAISO Market Participation

Revenue, if any, from participation in CAISO markets,[32] should be included as a benefit in the TRC, RIM, and PAC tests. Revenue from CAISO market participation refers to any revenue that a demand response program receives in return for providing demand response services to the CAISO, for example as Ancillary Services or a Proxy Demand Resource. In order to qualify as ancillary services under CAISO rules, a program must be available to be called

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32 For example, from provision of ancillary services or Proxy Demand Resource services.

on short notice (usually with less than 10 minutes notice) and the load drop from the program must be accompanied by certain required telemetry, consisting of specific communications and measurement equipment that ensures performance. Proxy Demand Resource activities similarly provide information to CAISO about the load drop in a particular situation. This benefit is not listed in the original SPM tests, but payment received by a demand response program (or a generator) that provides such services is an additional revenue stream that will be considered as a benefit in the cost-effectiveness calculation.

4.2.4. Increased Supply Costs

Increased supply costs may occur if a demand response program results in an overall increase in electricity consumption, requiring an increase in fuel, operations, and maintenance costs to support that increased generation to meet that consumption. Because demand response programs generally decrease electricity consumption, the value for this cost in most cases will be zero. In certain cases, however, demand response may result in increased electricity consumption, particularly if load is shifted from a peak time into a different time, and the program's costs and benefits are measured in different time periods. For example, an air conditioning load control program may encourage customers to pre-cool their homes or businesses before the peak time, which could actually increase electricity usage, and therefore supply costs, in the time-period immediately before a demand response event.

4.2.5. Benefits that are Currently Difficult to Quantify

The following types of demand response benefits are difficult to quantify. Because of the difficulty quantifying these benefits, the Commission is not requiring that an LSE include values for these benefits in their cost-effectiveness calculations according to the 2010 Protocols at this time, with the exception of avoided GHG emissions costs, which will be calculated by the Avoided Cost Calculator. However, we require the LSEs to submit qualitative descriptions of the following benefits, when relevant for a particular demand response program:

- Environmental benefits
- Market and reliability benefits
- Non-energy and non-monetary benefits

Parties are strongly encouraged to provide relevant information about any of the optional inputs, and to comment on the estimates and qualitative discussions provided by the LSEs.

5. Purpose and Use of the New Protocols

The 2010 Protocols adopted in this decision shall be used for evaluation of the cost-effectiveness of existing and proposed demand response activities in future program development, planning, and evaluation activities. Cost-effectiveness analysis of voluntary demand response activities included in future demand response program activity and budget applications, including the demand response applications for 2012-2014, due to be filed in January 2011,[33] shall use the adopted protocols. These protocols should also be used to estimate cost-effectiveness of demand response activities proposed in free-standing applications such as for new programs or aggregator contracts, and in expansions of existing programs done via advice letter or another method.

In comments on the proposed decision, PG&E suggested that utilities should be able to use their own utility-specific avoided costs and other data for the evaluation of offers received in competitive solicitations. DRA's reply comments noted that "[i]t is not the internal process by which a utility uses to

[33] D.09-08-027, Ordering Paragraph 41.

evaluate and select the final bids that are important, but rather whether the end product resulting from that process—the final contracts—meet the Commission's requirements for cost-effectiveness based on the adopted protocols."

We find that like other demand response programs, proposed contracts must be subject to cost-effectiveness review based on the adopted protocols. LSEs are free, as DRA points out, to use any methods they want to evaluate offers received in completive solicitations to determine which offers they will pursue. However, if an LSE decides to seek Commission approval for those offers, they then are subject to Commission-approved cost-effectiveness analysis.

We recognize that aspects of these protocols may be changed and improved as demand response activities evolve and more information becomes available on best practices in measurement and evaluation of demand response; however, with the exception of the regular validation and update process required in Section 7.1, below, these protocols shall remain in place until modified or superseded by new direction from this Commission. The most recent, validated version of the Avoided Cost Calculator and Demand Response Reporting Template shall be accessible through the Commission's Web site at http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm, and shall be used for all cost effectiveness calculations done according to the protocols. The Commission may review these protocols in a future proceeding if modifications are made to the SPM or another source referenced in the protocols. The Commission may also review or amend the protocols as needed to address new developments, including those raised in future demand response applications.

The protocols adopted here may require adjustments for use with Permanent Load Shifting. These protocols are not designed to measure technical assistance, pilot projects designed for research or experimental purposes, or education, marketing and outreach activities which promote demand response or other energy-saving activities in general, though the cost of some of those programs will be considered when measuring the cost-effectiveness of a utility's entire demand response portfolio, as discussed in the protocols.

It may become necessary for the Commission or an individual utility to update or modify methods or values in future cost-effectiveness evaluations. However, if a utility believes any such updates or modifications are required, they must be clearly described and justified to all parties, and approved by the Commission, as described in Section 6, below.

6. Departures from and Modifications to the Protocols

The 2010 Protocols require that any changes or modifications to the protocols or use of confidential data be approved in writing by staff in the Commission's Energy Division.

In addition, the 2010 Protocols suggest several areas of research that would be required to more accurately estimate values for a number of demand response costs and benefits, particularly the so-called "difficult-to-quantify" benefits. The Commission may, in a future proceeding, establish a procedure for carrying out this research, and invites parties in their comments on the utilities' future cost-effectiveness analyses to make proposals for carrying out this needed research. One such area that has been identified as needing additional study is in the use of backup generators during demand response events. While future proceedings will address this issue, at this time the Commission strongly encourages the utilities to develop methods to collect data from demand response participants about ownership and usage of backup generators during demand response events.

7. Guidance for the Use of the Protocols in the 2012-2014 Demand Response Applications

D.09-08-027 in A.08-06-001 et al., the utilities' last three-year applications proceeding, requires the utilities to file their new applications not later than January 30, 2011, and a ruling describing general requirements for the format and contents of those new applications was issued in R.07-01-041 on August 27, 2010. That ruling required the use of the Consensus Framework as the basis of cost effectiveness estimates contained in the new applications. With the adoption of this decision, we instead require the utilities to use the 2010 Protocols to calculate the cost effectiveness estimates for demand response activities included in the 2012-2014 Demand Response Applications. These protocols shall be used for all activities included in the applications for which the utilities are requesting a set budget and for which load impacts can be estimated using the load impact protocols, with the exception of Permanent Load Shifting activities. Further guidance on calculations of cost effectiveness for Permanent Load Shifting Activities may be issued before the applications are filed.

Because evaluation of all IDSM activities other than bridge funding for 2012 are being deferred to the Energy Efficiency program applications for 2013-2015, we do not require use of these protocols to estimate the cost effectiveness of those activities for the full 2012-2014 period in the forthcoming Demand Response applications.

As discussed in Section 7.1, below, we are adopting a regular validation process to ensure that the analysis contained in each set of three-year applications utilizes current values and reasonable assumptions for all inputs. The models reflecting the most current assumptions to be used in the three-year applications shall be kept accessible through the Commission's Web site at http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-

Effectiveness.htm, and shall be used for all cost effectiveness calculations done according to the protocols, including those contained in stand-alone program applications or advice letters.

Various commenters expressed concerns about the fact that these protocols are being adopted shortly before the due date established in D.09-08-027 for the 2012-2014 applications, which could complicate the preparation of those applications. In order to ensure that validated models are available for an adequate period of time to allow utilities to prepare their applications, we delay the due date of the next set of program and budget applications from January 30, 2011, as required in D.09-08-027, to March 1, 2011. This extension of time should allow for approximately six weeks of preparation time for the applications after completion of the initial validation process described below.

7.1. Establishment of a Regular Workshop Process for Validating and Updating the Protocols and Models

In order to ensure that the specific inputs and assumptions contained in the Avoided Cost Calculator and Demand Response Reporting Template are accurate and current when the utilities prepare their three-year program and budget applications, we establish a workshop process to validate and update the models regularly, with input from interested parties. This validation process will ensure that the models referenced in the protocols continue to accurately reflect the protocols as circumstances and conditions change.

Energy Division staff shall hold workshops in advance of the filing of each new set of the utilities' demand response program and budget applications. These workshops shall be noticed on all parties on the most recent service list for this proceeding (R.07-01-041) and for the most recent demand response program applications proceeding (currently A.08-06-001 et al.). Utilities may request to use confidential data or otherwise depart from certain aspects of the protocols by providing a written explanation and justification of those departures to Energy Division staff, with copies to all parties noticed of the workshop, at least three days in advance of the workshop. Utilities shall also send a copy of these requests by electronic mail at drprotocols@cpuc.ca.gov. These workshops shall serve two purposes: first, they will include an opportunity for parties to validate the Avoided Cost Calculator and Demand Response Reporting Template models by identifying any potential errors or suggesting updated inputs for use in future cost effectiveness analyses of demand response. Discussion of items such as the inputs to the combustion turbine pro-forma financials, the modeling of the combustion turbine dispatch and resulting capacity factor, gross margin calculations, and appropriate T&D avoided cost values may be addressed in the workshop. In addition, the workshop will allow parties and Energy Division staff to discuss requested departures from these protocols contained in the utilities' pre-workshop filings (if any). Based on discussion at the workshop, Energy Division staff shall make technical updates to the models to reflect current values for any inputs or assumptions that may have changed since the previous versions, or to correct any errors found by parties at the workshop. Energy Division staff will also prepare and circulate to all workshop participants and the appropriate service lists their guidance on the instances in which utilities may depart from specific requirements of the protocols, if any, based on the utilities' written requests and parties' comments at the workshop. Staff may provide additional technical information responding to parties' questions in their post-workshop guidance along with a list of any corrections made to the models.

Because the utilities' next three-year demand response applications are due in early 2011, we expect Energy Division to hold the pre-application workshop as soon as possible after the adoption of this decision, with final technical guidance based on that workshop issued within 2 weeks after the workshop. For future application cycles, we require Energy Division staff to initiate this workshop process at least three months before the due date of the applications, and issue final technical guidance at least 45 days in advance of the application due date. If necessary, the Demand Response Measurement and Evaluation Committee shall make funds, not to exceed $50,000, available to support the validation process and related model maintenance, and utilities may request additional funding to support future validation and update activities in future demand response program and budget applications.

Energy Division may make small technical corrections or updates to data in the Avoided Cost Calculator and Demand Response Reporting Template outside of the periodic workshop review process described here, if necessary to ensure that calculations accurately reflect the protocols consistent with recent Commission decisions and other current conditions. Updates may include data such as updated electricity forward prices, natural gas prices and CAISO market price data, among other possible items. Energy Division will notify the most recent service list in this proceeding and the most recent demand response applications proceeding of any changes to the models, and will ensure that the most current versions of the models remain accessible to all parties.

8. Categorization and Assignment of Proceeding

This proceeding is categorized as ratesetting. The assigned Commissioner is Dian Grueneich and the assigned ALJs for Phase 1 are Darwin Farrar and Jessica T. Hecht.

9. Comments on Proposed Decision

The proposed decision of ALJ Hecht in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. CLECA, DRA, the Joint Parties, PG&E, SCE, SDG&E, and TURN filed comments on the proposed decision on November 12, 2010. DRA, the Joint Parties, PG&E, SCE, SDG&E, and TURN, filed reply comments on November 19, 2010. Comments ranged from requests for a further process to validate inputs into the demand response reporting template to suggestions for technical corrections to several aspects of the protocols. Technical corrections and changes have been made as appropriate throughout the decision and the protocols in response to the comments.

Findings of Fact

1. The cost-effectiveness protocols adopted in this decision use the tests described in the California SPM (which was developed to measure the cost-effectiveness of energy efficiency programs), to provide the basis for comparing the costs and benefits of demand response.

2. Modifications and additions have been made to selected elements of the SPM tests to better adapt them for use with demand response.

3. Use of publicly available data will increase both the transparency and consistency of the calculation of demand response costs and benefits.

4. Use of common models to determine both the avoided costs and the cost-effectiveness of demand response based on non-proprietary data will enhance both the transparency and consistency of the calculation of demand response costs and benefits.

5. Avoided electricity costs, which include energy, capacity, and potentially other costs, are the most significant benefit of demand response.

6. Because demand response programs are mostly active at times of peak electricity demand, when electricity costs tend to be high, the avoided electricity cost values used in demand response cost-effectiveness calculations should reflect the value of electricity in those peak hours.

7. The Avoided Cost Calculator, created by E3 to determine the avoided costs of distributed generation, as modified in the 2010 Protocols, provides a reasonable estimate of avoided electricity costs at peak hours when demand response is likely to be needed, as well as at non-peak hours when demand response might be needed.

8. The Avoided Cost Calculator explicitly calculates gross margin values, obviating the need for a separate, specific calculation of gross margins, and allows for more consistent and reliable results across utilities.

9. The Avoided Cost Calculator calculates the avoided costs of T&D.

10. The avoided costs of T&D are a benefit of demand response, and should be considered in cost-effectiveness calculations, as appropriate.

11. The load impacts used to determine cost-effectiveness should be consistent with RA requirements, to the extent possible.

12. Certain general activities such as administration, education, and marketing may support utility programs, even if the funding for those activities is not listed within the program's approved budget.

13. Program costs are correctly captured in the cost-effectiveness calculation only if all costs attributable to a particular program, whether they are included in the program's budget or a separate category, are considered in the cost-effectiveness analysis of that program.

14. Sensitivity analyses on key variables will illustrate the range of circumstances under which programs may be cost effective.

15. Qualitative analyses of factors that may affect the cost-effectiveness of a program but are difficult to quantify will improve our understanding of those factors and inform future decisions on the importance of quantifying those factors.

16. The cost-effectiveness protocols adopted in this decision are designed for use by the utilities in analyzing Commission-approved demand response activities and potential future demand response activities.

17. The cost-effectiveness protocols adopted in this decision may be suitable for use by other LSEs, including small utilities and demand response aggregators, in analyzing existing and potential future demand response activities.

18. A workshop and guidance process to validate the Avoided Cost Calculator and Demand Response Reporting Template models in advance of the filing of new demand response program and budget applications will ensure that the models accurately reflect the protocols at the time of the analysis.

19. Energy Division may make small technical corrections or updates to data in the Avoided Cost Calculator and Demand Response Reporting Template models outside of the periodic workshop review process described here, if necessary to ensure the models accurately reflect these protocols and remain consistent with current conditions.

Conclusions of Law

1. It is reasonable to require that cost-effectiveness calculations of Commission-approved demand response activities utilize publicly available data and data sources to the extent feasible.

2. It is reasonable to require that cost-effectiveness calculations of Commission-approved demand response activities use consistent and non-proprietary models and methods.

3. The Avoided Cost Calculator adopted in this decision is consistent with the approach adopted in previous Commission decisions for similar analyses of cost-effectiveness.

4. It is reasonable to require that any changes or modifications to the protocols or use of confidential data in calculations by the utilities be approved in advance through the workshop and guidance process for validating and updating the protocols and models before filing of regular 3-year program and budget applications for demand response activities.

5. If confidential or proprietary data and analyses are used for any part of a utility's cost-effectiveness analysis, those data should be entitled to the confidentiality protections recognized in Commission decisions.

6. Each of the SPM tests should be used to describe the cost-effectiveness of both individual demand response programs and each utility's demand response portfolio.

7. It is reasonable to require the utilities to use the adopted cost-effectiveness protocols in analyses of existing or proposed demand response activities presented to this Commission.

8. The relative weight given to any Standard Practice Manual test in determining program approval or modification should be determined within demand response budget proceedings, or other application or advice letter proceedings in which a utility is requesting approval of a demand response resource.

9. The 2010 Demand Response Cost-Effectiveness Protocols found in Attachment 1, referred to as the "2010 Protocols," which summarize costs and benefits and input variables for each of the adopted cost-benefit tests, should be adopted to guide cost-benefit calculations for demand response activities, subject to future modification by this Commission.

10. It is reasonable for Energy Division to oversee the cost-benefit analysis work done according to the adopted protocols to ensure that the analyses apply the cost-benefit models adopted in this decision and the most recent data available.

11. It is reasonable to require the utilities to work with Energy Division to ensure that all costs attributable to a program, including administrative and other costs that may not be captured in the program's budget, are included in the cost-effectiveness analysis of each program.

12. It is reasonable to require sensitivity analyses on key variables, in order to illustrate the range of circumstances under which programs may be cost effective.

13. It is reasonable to require qualitative analyses of factors that may affect the cost-effectiveness of a program but are difficult to quantify.

14. It is reasonable to require Energy Division to work with parties to validate the Avoided Cost Calculator and Demand Response Reporting Template models in advance of the filing of new demand response program and budget applications, and to issue specific technical guidance on the application of the protocols, including the possibility of departures from the protocols' requirements.

15. It is reasonable to allow Energy Division staff to make technical corrections to the Avoided Cost Calculator and Demand Response Reporting Template if

necessary to ensure that they reflect the most accurate and current information available.

16. It is reasonable to require the Demand Response Measurement and Evaluation Committee to provide funding not to exceed $50,000 to support validation activities related to use of the Avoided Cost Calculator and Demand Response Reporting Template for the 2012-2014 Demand Response Program and Budget Applications.

O R D E R

IT IS ORDERED that:

1. Demand response activities supported by incentives and rate exemptions funded by ratepayers of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, shall be analyzed using the four cost-effectiveness tests described in this decision, namely, the Participant Test, the Total Resource Cost Test, the Ratepayer Impact Measure, and the Program Administrator Cost Test, and the tests shall be run with the input variables and data sources set forth in Attachment 1.

2. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall use the cost-effectiveness protocols described in and attached as Attachment 1 to this decision in all future cost-effectiveness analyses of their demand response activities, until directed otherwise. These utilities shall file their Demand Response Program and Budget Applications for 2012-2014 utilizing these protocols not later than March 1, 2011.

3. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall use the Avoided Cost Calculator to

calculate the avoided costs used in all future cost-effectiveness analyses of their demand response activities.

4. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall use the Demand Response Reporting Template to calculate the cost-effectiveness estimates for their demand response activities.

5. If Pacific Gas and Electric Company, San Diego Gas & Electric Company, or Southern California Edison Company want to depart from any of the requirements contained in Attachment 1 to this decision in a particular application, they may request such approval in writing in advance of the workshop scheduled for validating and updating the protocols and models held before the filing of the three-year program and budget application for demand response. These workshops shall be held as provided in Section 7, above.

6. Energy Division shall oversee the cost-effectiveness analyses of demand activities according to the protocols in Attachment 1.

7. Energy Division shall notify the most recent service list in this proceeding and the most recent demand response applications proceeding of any technical changes to the Avoided Cost Calculator and the Demand Response Reporting Template, and will ensure that the most current versions of the models remain accessible to all parties.

8. The Demand Response Measurement and Evaluation Committee shall make funds, not to exceed $50,000, available to support the validation process and related model maintenance for the cost effectiveness models used in the 2012-2014 application period.

9. This decision resolves all remaining issues in Phase One of Rulemaking 07-01-041.

10. This proceeding remains open to deal with pending issues in its second and fourth phases.

This order is effective today.

Dated ______________________________, at San Francisco, California