APPENDIX A

2015 Demand Response Cost Effectiveness Protocols

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List of Abbreviations

AMI – Advanced Metering Infrastructure (i.e., Smart Meters)
AS – Ancillary Services
CAISO – California Independent System Operator
CCGT – Combined Cycle Gas Turbine
CEC – California Energy Commission
CPUC – California Public Utilities Commission
CT – Combustion Turbine
DG – Distributed Generation
DR – Demand Response
DRAM – Demand Response Auction Mechanism
E3 – Energy and Environmental Economics (consulting firm)
ED – Energy Division (of the CPUC)
EE – Energy Efficiency
EM&V – Evaluation, Measurement & Verification
GHG – Greenhouse Gas
IOU – Investor-owned utility (usually refers to PG&E, SCE, and SDG&E collectively)
IRP – Integrated Resource Planning
ISO – Independent System Operator
IT – Information Technology
kW – kilowatt
kWh – kilowatt-hour
LI – Load Impacts
LMP – Locational Marginal Price
LOLE/P – Loss of Load Expectation/Loss of Load Probability
LSE – Load-Serving Entity
LTTP – Long-term Procurement Plan
ME&O – Marketing, Education and Outreach
MW – Megawatt
MWh – Megawatt-hour
NOAA – National Oceanic and Atmospheric Administration
NPV – Net Present Value
NQC – Net Qualifying Capacity
NYMEX – New York Mercantile Exchange
PAC – Program Administrators Test
PG&E – Pacific Gas and Electric Company
RA – Resource Adequacy
RIM – Ratepayer Impact Measure
SCE – Southern California Edison Company
SDG&E – San Diego Gas & Electric Company
SPM – Standard Practice Manual
T&D – Transmission and Distribution
TRC – Total Resource Cost
WACC – Weighted Average Cost of Capital

SECTION 1: BASIC INFORMATION

Introduction

These 2015 revised Demand Response (DR) Cost-Effectiveness Protocols (2015 Protocols) provide a method for measuring the cost-effectiveness of demand response programs. These protocols are intended for *ex ante* evaluations of demand response programs which provide long-term resource value.

The 2015 Protocols are an updated version of the DR Cost-Effectiveness Protocols approved in 2010 in Decision (D.) 10-12-024 (2010 Protocols[1]). In addition to updating the 2010 Protocols, these 2015 Protocols incorporate the relevant sections of two guidance documents: the January 2011 Energy Division Guidance on Cost-Effectiveness[2] and the May 2012 Energy Division Guidance on Cost-Effectiveness[3].

The 2010 Protocols were based largely on three previous proposals filed in Commission Rulemaking (R.) 07-01-041: the cost-effectiveness framework submitted by the three large California investor-owned utilities (IOUs) – Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) (Joint IOU Framework),[4] the Demand Response Cost-effectiveness Evaluation Framework submitted by the Consensus Parties (Consensus Parties Framework),[5] and the Staff Draft Demand Response Cost-Effectiveness Protocols filed as Attachment A of the April 4, 2008 ruling in R.07-01-041.[6] Both the 2010 Protocols and the 2015 Protocols are designed for the three Investor-Owned Utilities (IOUs). Nevertheless, they should be applicable to demand response programs developed by any Load Serving Entity (LSE). However, LSEs other than the three IOUs are likely to require additional guidance.

These protocols have been developed with the understanding that DR is in a transitional period. Historically, DR was largely employed for reliability purposes during system emergencies in the form of interruptible programs for large industrial customers, which could be triggered when the California Independent System Operator (CAISO) would otherwise have to shed load during a system emergency or when a utility was faced with a serious distribution system emergency. These customers generally shut down all, or at least a large part, of their operations during DR events.

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[1] http://www.cpuc.ca.gov/NR/rdonlyres/B6E241E0-5B38-4E6D-AC3B-18F70EC83246/0/2010_DR_CostEffectiveness_Protocols.pdf

[2] http://www.cpuc.ca.gov/NR/rdonlyres/92C54F59-8D88-446A-846A-1747628C0F33/0/GuidanceJanuary2011.pdf

[3] http://www.cpuc.ca.gov/NR/rdonlyres/FD11FEED-C322-4164-8EFC-ABE6F188ABDA/0/GuidanceMay2012.pdf

[4] *Revised Straw Proposals For Demand Response Load Impact Estimation And Cost-effectiveness Evaluation Of Pacific Gas and Electric Company (U 39-M), San Diego Gas & Electric Company (U 902-E) and Southern California Edison Company (U 338-E)*, filed September 10, 2007 (http://docs.cpuc.ca.gov/efile/REPORT/72728.pdf)

[5] *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 (U 39-M), San Diego Gas & Electric Company (U 902-E), Southern California Edison Company (U 338-E) 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).

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

However, the deployment of advanced metering technology and development of new energy markets is enabling greater use and flexibility of demand response by all types of customers. Increasingly, customers are able to manage their loads to provide different levels of load reduction in response to price signals or other incentives. These load reductions provide value to the grid not only during emergencies, but also during times of high energy prices or in the ancillary services market. Increased use of automated technology has made DR less dependent on customer behavior and, as a result, more consistent, reliable, and easier for customers. These changes mean that DR is becoming something that more and more ratepayers can participate in, including residential customers, even when they can reduce only a small amount of load.

In addition, the increased amount of renewable generation due to Renewable Portfolio Standard (RPS) requirements means that there is increasing need to mitigate the impact of intermittent generation. Demand response resources can be used for this if they are designed to be flexible, with short notification and response times, and local availability.

Because of these emerging potential new uses of DR, the methods we use to measure its costs and benefits must be flexible enough to capture these emerging benefits.

The purpose of these cost-effectiveness protocols is to:

- Address the broad variety of DR programs, including current and future activities;
- Identify all relevant inputs that are important for determining the cost-effectiveness of DR;
- Establish methods for determining the value of those inputs; and
- Determine a useable overall framework and methods for evaluating the cost-effectiveness of each of the different types of DR activities.

The protocols presented here are not intended to address the following issues, which are more appropriately addressed in the course of the various Commission proceedings related to DR:

- Identification of proceedings where DR cost-effectiveness protocols will be used;
- The means by which the Commission will use these protocols to determine whether to pursue various DR programs, activities or policies;
- Consistency between load impact measurements for DR cost-effectiveness and the rules for determining whether a resource counts for resource adequacy; or
- Demand response program rate design and tariff terms and conditions.

The 2010 Protocols were used for the first time for the Demand Response 2012-2014 budget Applications filed by PG&E, SDG&E, and SCE in Application (A.)11-03-001 et al. The final Decision in that proceeding (D.12-04-045) found that there were some deficiencies in the 2010 Protocols, based on problems encountered during the proceeding, and directed staff to hold workshops and update the protocols accordingly. The problems found were:

- Inconsistency among the IOUs' calculation of the five adjustment factors (i.e., A, B, C, D, and E factors), particularly the A factor. This problem could be remedied by modifying the protocols to provide more specific definition of how to calculate these factors.

- Inconsistency among the IOUs' allocation of support program budgets such as ME&O, EM&V, and IT to each DR program. This problem could be remedied by modifying the protocols to provide more specific instructions of how to allocate these budgets.
- IOUs' lack of qualitative analysis of the optional costs and benefits. This is not a deficiency in the protocols, but rather lack of compliance by the IOUs. This problem could be remedied by modifying the protocols to provide more guidance on how to go about providing qualitative analysis.

The Decision also noted that there was both a lack of definition of the DR portfolio and inconsistency among the IOUs' perceptions of what should be included in the DR portfolio. The Decision asked that the Protocols be updated to include this definition. In addition, the Decision also directed that future DR Applications consolidate, as much as feasible, all DR related costs.

The modifications included in these 2015 Protocols address these, as well as other, issues in an effort to provide better guidance to LSEs. However, these modified protocols are not intended to be permanent. Our understanding of how to accurately and completely account for the costs and benefits associated with Demand Response is constantly changing. In particular, the Integrated Distributed Energy Resources proceeding (R.14-10-003) and the Distributed Resources Plan proceeding (R.14-08-013) are examining many questions related to the costs and benefits of demand-side and other distributed energy resources, especially the estimation of their avoided costs. Hence, some of the details found in these 2015 Protocols may be superseded by Decisions or Rulings in other proceedings.

Section 1.A: Intended Use of Protocols

These protocols are intended for determining the cost-effectiveness of both individual DR programs and an LSE's overall DR portfolio. As noted previously, the Commission will determine the applicability of these protocols for DR programs. LSEs are typically required to file cost-effectiveness analysis for each DR program. A DR program is defined as any demand response activity which has measurable load impacts for which the LSE is requesting budget approval. This includes DR programs of all types – event-based and non-event based, price-responsive and emergency, day-ahead and day-of. They may be used for rate programs, such as Critical Peak Pricing, to determine whether a program, given a particular rate structure, is cost-effective. They will also be used to evaluate third-party aggregation proposals, whether they are supply resources or load-modifying resources. However, only certain portions of these protocols apply to those third-party aggregation proposals designated as a supply resources, as explained below.

These protocols will be applied to supply resource demand response provided by IOUs which is integrated into CAISO markets. These protocols will be partially applied to supply resource demand response which participates in the DRAM auction mechanism. In particular, the avoided cost calculation, as discussed in Section 3.B, provides a way to benchmark both the value of DR products as compared to traditional generation and the relative value of different types of DR products, which often have different hours, days and months when they are available, different limitations on when they can be dispatched, and different participant notification requirements. Per Ordering Paragraph 16 of Resolution E-4728, the IOUs will provide an avoided cost calculation for each selected DRAM pilot contract and bid confidentially

with the Commission as part of their Advice Letters seeking Commission approval of DRAM procurement pilot contracts. That analysis will consist only of the above-described benchmark, determined by the Avoided Cost model and other methods and models, including the adjustment factors, discussed in Section 3.B. Other costs and benefits listed in these protocols will not be applied or used as part of the reasonableness review of demand response that participates in the DRAM. The DR Cost-Effectiveness Report, discussed below, will be modified to provide these avoided cost benchmarks for supply resources that participate in the DRAM.

As discussed below in Section 3.B, these protocols decline to allow avoided generation capacity costs as inputs in cost-effectiveness analyses for programs that are not either 1) integrated into the wholesale energy market, or 2) embedded in the CEC's unmanaged/base case load forecasts. This will effectively make the avoided generation capacity costs equal to zero for the purposes of cost-effectiveness analysis for programs that do not meet either of these criteria.

These protocols may not be fully applicable to permanent load-shifting programs, especially if those programs are non-dispatchable. However, until such time as a future Commission decision determines a specific cost-effectiveness method for load-shifting programs, LSEs should use these protocols. If an LSE determines that modifications to these protocols should be made to accommodate a load-shifting program, then those modifications must be clearly described and approved in writing by the Commission.

These protocols are not designed to measure "pilot" programs, which are done for experimental or research purposes, technical assistance, educational or marketing and outreach activities which promote DR or other energy-saving activities in general, although the cost of some of these programs will be considered when measuring cost-effectiveness.

Unless directed otherwise in a particular case, these protocols should be used for cost-effectiveness analysis of all DR programs, as defined above, when an LSE is seeking budget approval for a program. This includes programs proposed as part of a multi-year Demand Response application, proposed individually in an Application or Advice Letter, or as part of a proceeding that focuses on another matter, such as a General Rate Case. In general, if an LSE is requesting approval of a budget for a DR program with measureable load impacts, a cost-effectiveness analysis of that program is required in the proceeding in which the budget is being requested. LSEs may also be required to file cost-effectiveness analysis for their DR portfolio, as discussed in Section 1.H.

For the purposes of this cost-effectiveness analysis, some DR programs should be divided into sub-programs, where each sub-program is analyzed separately. Whenever parts of a program have distinctly different characteristics that would lead them to have different costs or benefits, that program should be divided into sub-programs. For example, a program which has a day-ahead and day-of option should be considered to be two separate sub-programs, and a separate cost-effectiveness analysis should be provided for each one. In practical terms, this means that there should be a separate tab on the DR Cost-Effectiveness Report for each sub-program.

We recognize that there are a wide variety of DR programs with differing attributes. Therefore, flexibility in the application of these protocols may be necessary to fully reflect the attributes of

some DR programs. The valuation of DR programs may also be affected by future Commission decisions on short-term and long-term resource adequacy, long-term procurement, avoided costs, Smart Grid or other issues, by actual program design and operations, and by emerging markets for DR that are being developed by the California Independent System Operator (CAISO). It may become necessary for the Commission or an individual LSE to update or modify methods or values in future cost-effectiveness evaluations, if doing so is necessary to provide accurate results. However, if an LSE believes any such updates or modifications are required, they must be clearly described and justified to all parties, and approved in writing by the Commission.

There are a number of different methods that could be used to determine the cost-effectiveness of demand response. Two possible methods are the business case approach, as the IOUs used in the business cases included in their Advanced Metering Infrastructure (AMI) applications, and the Integrated Resource Planning (IRP) approach. Both of these approaches could be workable for programs that have a large decremental effect on demand, but these approaches are generally not "sensitive" enough to properly measure the costs and benefits of specific demand response programs, which often have relatively small impacts. To evaluate programs with small impacts more precisely, these protocols employ a marginal cost approach. The marginal cost approach directly compares the DR resource to traditional generation from a long-term resource planning perspective. These protocols measure the cost-effectiveness of DR programs by comparing their costs and benefits to the costs and benefits of a combustion turbine (CT), which is the most common supply-side resource used to meet peak energy demand. The time period for the cost-effectiveness evaluation should be limited to the length of the program cycle (usually three years), unless it is demonstrated that a longer period of analysis is necessary. Capital investments that are expected to provide benefits beyond the current program cycle may be amortized over an appropriate period, as discussed in Section 3.E.

The methods described in these protocols should be used for *ex ante* evaluation of DR cost-effectiveness. *Ex post* evaluations of the cost-effectiveness of DR activities would not be an appropriate way to determine program approval, because one important function of demand response is to provide "insurance" against relatively low probability and/or intermittent events that can have severe consequences when they occur. If those events did not occur during a given time period, it does not necessarily mean that those demand response programs were less valuable or less cost effective *ex post*. An analogy which is often used to describe this value is to compare demand response with a homeowner's fire insurance policy, since fire insurance still provides value to the homeowner even if there is never a fire in their house. However, the expense of this insurance does need to be comparable to the value provided – to carry the analogy further, if the homeowner is paying more for fire insurance than was paid for the house itself, or is unwilling to file a claim even if a fire occurs, it is time to examine whether the insurance policy is appropriate. In addition, we recognize that while the insurance provided by demand response is valuable, it has become a less significant aspect of demand response as new technologies and markets enable DR to be used to respond to a greater variety of system needs.

Therefore, we recognize that *ex post* analysis is useful for informing assumptions or forecasts needed for *ex ante* analysis, and to better understand the relative need for and value of particular Demand Response programs. *Ex ante* cost-effectiveness evaluations should be adjusted for actual *ex post* experience from previous demand response program budgeting cycles or filings.

Thus, each cost-effectiveness test should use, to the maximum degree possible, actual program experience from previous years to ensure the new forecasts are consistent with actual experience.

Ex post analyses can thus be helpful, but are not a requirement for formal demand response cost-effectiveness filings. This issue may be taken up again in future discussions, though.

Section 1.B: Methods Used to Estimate Costs and Benefits

Previous to the adoption of the 2010 Protocols, each IOU used its own inputs and models for calculating DR cost-effectiveness. The use of separate models and data, some of which are proprietary, produced results that varied significantly, in particular for the certain aspects of the avoided cost calculations, such as gross margins and residual capacity value. Some variation would be expected due to the different characteristics of each utility system. However, as a significant portion of the IOUs' analysis and data inputs used were either held as proprietary or were not very transparent, it was extremely difficult to determine to what degree the variations reflect actual differences in the IOU service territories or were due to different underlying assumptions, input data, modeling approaches or other factors.

To address this confusion, these protocols require that all LSEs 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 cost-effectiveness results.

The avoided cost model used for DR cost-effectiveness calculations was derived from the Distributed Generation (DG) Cost-Effectiveness framework adopted by the Commission in D. 09-08-026, which specifies the use of a marginal avoided cost-based approach to distributed resource valuation. The avoided costs are calculated using the Avoided Cost Calculator, a spreadsheet tool developed by Energy and Environmental Economics (E3) as part of the DG Cost-Effectiveness framework. The Avoided Cost Calculator is now used to estimate the avoided costs of all demand-side programs. In analyzing the cost-effectiveness of resources, LSEs shall use the most recent version of the Avoided Cost Calculator that conforms with the requirements of these protocols. This may require modifications to an existing version of the calculator. More information about the calculation of avoided costs is found below in Section 3.B.

In 2009, Commission staff provided the IOUs with an Excel spreadsheet template to facilitate consistent reporting of DR program cost-effectiveness results. An updated version of that spreadsheet will be used by LSEs to report DR program cost-effectiveness and will be considered part of these protocols. This DR Cost-Effectiveness Report (previously called the DR Reporting Template) will be developed after the adoption of these Protocols, by a working group led by the Utilities, which all interested parties will be invited to join. The DR Cost-Effectiveness Report will limit the number of inputs by the LSEs to a few key fields. All the calculations and formulas pertaining to avoided costs and cost-effectiveness will be contained within the DR Cost-Effectiveness Report. This will enhance both the transparency and consistency of those calculations. The DR Cost-Effectiveness Report will include a sensitivity analysis, showing how the benefit-cost ratios vary with changes in several key inputs. In

addition to the spreadsheet portion of the DR Cost-Effectiveness Report, LSEs will be required to provide workpapers which include a written explanation where required by these 2015 Protocols. The workpapers should provide detailed explanations of all assumptions and calculations, including an explanation of how those adjustment factors not calculated in the DR Cost-Effectiveness Report were determined for each program. In addition, the workpapers must include an explanation of all other assumptions or calculations that were made to determine any of the cost and benefit inputs whose derivation is not clear.

LSEs must submit their cost effectiveness analyses by filling out the DR Cost-Effectiveness Report spreadsheet and accompanying workpapers. In the spreadsheet, a separate tab should be created for each DR program, or subprogram when necessary, and then the resulting DR Cost-Effectiveness Report spreadsheet and workpapers should be submitted with the Application or Advice Letter seeking program approval or modification. The spreadsheet file that is submitted should be named in a way that makes it obvious what it contains (e.g., "SCE DR Report.xls"). LSEs can use any part of the spreadsheet or workpapers in any section of their applications, but the spreadsheet and workpapers themselves must also be filed as part of the application.

The DR Cost-Effectiveness Report is meant to be a tool that anyone can use. All parties are encouraged to make use of it for their own analyses. For example, any party (including any LSE) can substitute a different quantity for any input and generate alternate cost-effectiveness results. These alternate results may help all parties and the Commission to understand how different conditions, assumptions, or future events might affect the cost-effectiveness of DR programs.

The report will promote the transparency of the DR evaluation process and allow for more efficient review of proposed DR programs by the Commission and stakeholders. The report will be preloaded with the following information:

1. Avoided Generation Capacity Costs
2. Avoided Energy Costs
3. Avoided Transmission and Distribution Costs for PG&E, SDG&E, and SCE
4. Avoided Environmental Costs for Greenhouse Gases (GHG)
5. Line Losses for PG&E, SDG&E, and SCE
6. Weighted Average Cost of Capital (WACC) for PG&E, SDG&E, and SCE

The LSE will specify the following quantitative information relevant to the evaluation of each program, following the procedures outlined in these protocols:

1. Load Impacts, in MW
2. Expected call hours of the program (used to determine energy savings)
3. Administrative Costs
4. Participant Costs (for only those programs which are not using a percentage of incentives as a proxy measurement)
5. Capital Costs and Amortization Period, both to the LSE and to the Participant (should be specified for each investment)
6. Revenues from participation in CAISO Markets (such as ancillary services or proxy demand resource)

- CAISO Markets Entered
- Average megawatts (MWs) and hours bid into those
- Average market price received

7. Bill reductions and increases
8. Incentives paid
9. Increased supply costs
10. Revenue gain/loss from changes in sales (usually assumed to be the same as bill reductions and increases)
11. Adjustment Factors (if not required to use default values)
    - data need to calculate Availability (A Factor)
    - Notification Time (B Factor)
    - Trigger (C Factor)
    - Distribution (D Factor)
    - Energy Price (E Factor)
    - Flexibility (F Factor)
    - Geographical/local avoided generation capacity (G Factor)

The LSE may also add the following optional inputs:

1. Social non-energy benefits, such as environmental benefits (in addition to the avoided GHG cost included in the avoided cost calculator), job creation benefits, and health benefits.
2. Utility non-energy benefits, such as fewer customer calls and improved customer relations.
3. Participant non-energy benefits, such as improved ability to manage energy use and "feeling green."
4. Market benefits, such as market power mitigation and market transformation benefits

All estimations of the MW impacts of demand response resources should be based on the Load Impact Protocols.[7] The load impacts used to determine cost-effectiveness of a DR program should be the same as the Net Qualifying Capacity (NQC) of that program used to fulfill the LSE's Resource Adequacy (RA) requirement , as determined by the RA counting rules and requirements in D.10-06-036,[8] or any subsequent RA decision, when those numbers are available. If the NQC for a particular program is not available for some or all years, LSEs can either use the program's forecast LI, as defined below, or derive the program's likely NQC using the same methods as were used to determine the program's NQC for any year in which an NQC is available. Monthly load impacts should be used to calculate DR costs and benefits to account for varying enrollment levels and avoided cost values over the course of the year. The Avoided Cost Calculator will allocate avoided cost components to individual hours to provide total or average monthly benefit values which can then be used with the monthly load impacts for benefit calculations.

[7] Decision 08-04-050 Adopting Protocols for Estimating Demand Response Load Impacts, April 24, 2008. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/81972.htm

[8] As shown in Appendix B, p.19.

The current practice for determining the NQC is to start with the load impact reported for that program in the most recent annual April Load Impact Compliance Filing. If the load impacts for a particular program were not estimated in the most recent Load Impact Compliance Filing, they should be estimated using the methods outlined in the Load Impact Protocols. The specific data which are currently used are the 1-in-2 weather year, 50th percentile *ex ante* hourly impacts, adjusted for dual participation, averaged over the RA measurement hours for DR[9] of the peak day for each month, then adjusted, as determined by Commission staff, to calculate each program's NQC. For the purpose of the sensitivity analysis, the 10th and 90th percentile values should be used as the low and high values. It is possible that all or part of this current process of calculating NQC will change in the future. The LSEs are required to use load impacts that are consistent with the RA procedures for determining the NQC that are current at the time of any cost-effectiveness filing.

All load impacts used should reflect Commission staff's adjustments, if applicable, to the underlying input assumptions used in the Load Impact Compliance Filing to calculate the NQC in the most recent RA process. These adjustments are usually made to the load impact forecasts in the IOUs' annual April Load Impact Compliance Filings to reflect factors such as past program performance or updated enrollment information, and are generally made only for one year. Hence, they might not include the years for which the cost-effectiveness analysis is being calculated. In that case, LSEs should attempt to make a similar adjustment to the estimated load impacts reported in the annual compliance filing as is done to determine the NQC for each program. This procedure should also be followed to determine the low and high values for the sensitivity analysis. However, as stated above, if the LSE cannot determine the NQC for some or all years of the program, it may use 1-in-2 weather year, 50th percentile *ex ante* hourly impacts, adjusted for dual participation, averaged over the RA measurement hours for DR of the peak day for each month, and the 10th and 90th percentile values for the sensitivity analysis.

LSEs will be permitted to adjust the energy, generation capacity and T&D capacity values taken from the Avoided Cost Calculator as appropriate to apply those values to individual DR programs with different characteristics. Utilities will input each of the adjustment factors, or the data needed to calculate them, that will be applied to the avoided costs, unless required to use the default values of the factors. Each of the factors listed above will be input as a percentage adjustment to the relevant avoided cost values. More information on how to calculate these factors can be found in Section 3.B.

Program reporting will be limited to the length of time specified in the proceeding in which the cost-effectiveness analysis is being filed, which is generally three years. LSEs may amortize capital costs over a longer period. However, since DR programs experience some level of customer turnover and technology changes rapidly, LSEs will be expected to document that installed capital equipment will actually be "used and useful" in providing load reductions over the assumed useful life.

[9] The measurement hours for January – March, November and December are 4:00 – 9:00 p.m.; for all other months the hours are 1:00 – 6:00 p.m.

LSEs must also forecast the expected number of hours each dispatchable DR program will be called and input that information in the report. LSEs should base their forecast of expected call hours on program history (when available) and explain how the forecast was made.

With the inputs described above, the DR Cost-Effectiveness Report will calculate the costs and benefits of each DR program. The DR Cost-Effectiveness Report will use each IOU's most recent after-tax Weighted Average Cost of Capital (WACC) to calculate the Net Present Value (NPV) of program costs and benefits and to amortize capital expenditures over their expected useful lifetimes. The DR Cost-Effectiveness Report will calculate the total costs and benefits, based on the Standard Practice Manual tests, for each program, following the methods specified in these protocols. The DR Cost-Effectiveness Report will also calculate the $/kW-yr costs of the kW reductions provided by each program and perform a sensitivity analysis of key inputs, as discussed in Section 1.F below.

Section 1.C: Confidentiality

The DR cost-effectiveness methods presented in these protocols should promote transparency by using clear and publicly available data and data sources. While accuracy and precision are critical elements of any measurement, transparency and clarity are also critical components of establishing results in which all parties can have confidence. Therefore, these protocols discourage the use of confidential or proprietary data unless a clear and compelling case can be made that there are insufficient public data to perform a specific calculation. LSEs may use confidential or proprietary data and models only with written permission from the Commission. This permission must be obtained *before* an LSE files an application or advice letter which includes the analysis. In addition, if permission is granted and an analysis that depends on the confidential data is done, it will be accompanied by a separate analysis using publicly available data. If confidential or proprietary data and analyses are used for any part of a utility's cost-effectiveness analysis, those data are entitled to the confidentiality protections recognized in Commission decisions.[10]

Section 1.D: Relationship to the Standard Practice Manual

These cost-effectiveness protocols use the tests described in the California Standard Practice Manual (SPM),[11] 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. The SPM contains four different tests, each of which measures cost-effectiveness from a different perspective. These tests are not intended to be used individually or in isolation. Rather, the tests are to be compared to each other, and tradeoffs between the tests considered. These protocols require that *all* the SPM tests, as defined below, be used to describe the cost-effectiveness of both individual DR programs and each LSE's DR portfolio.

The relative weight given to any SPM test in determining program approval will be determined within DR budget proceedings, or other Application or Advice Letter proceedings in which an LSE is requesting approval of demand response programs. Nevertheless, we expect that the TRC and PAC tests will continue to be used as the primary tests associated with program and portfolio

[10] *See* Section 454.5(g) of the California Public Utilities Code and D.06-06-066.
[11] http://www.cpuc.ca.gov/nr/rdonlyres/004abf9d-027c-4be1-9ae1-ce56adf8dadc/0/cpuc_standard_practice_manual.pdf

approval. As noted in the SPM, the Participant Test is useful for better understanding the desirability of a program, from the perspective of potential participants, and is useful for program design purposes, especially in setting incentive levels. The SPM also notes that the "Participant Test results play only a supportive role in any assessment of conservation and load management programs as alternatives to supply projects." The RIM test reflects only the potential impact on rates, and the SPM notes that the "(r)esults of the RIM test are probably less certain than those of other tests because the test is sensitive to the differences between long-term projections of marginal costs and long-term projections of rates, two cost streams that are difficult to quantify with certainty." In addition, the possibility of rate increases may be one of only many things for the Commission to consider when determining whether to invest ratepayer funds in programs which are designed to support policy goals such as GHG mitigation and reduction of pollutants.

The results of each SPM test are based on the net present value of program costs and benefits over the lifecycle of those impacts. Because the SPM is the starting point for the cost-effectiveness methods in these protocols, modifications have been made to selected elements of the SPM tests to better adapt them for use with DR.

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

DR programs avoid the need for generation capacity since they are designed to reduce customer usage during periods when supply-side resources might be unavailable, constrained or expensive, historically during peak summer afternoon hours. The amount of total capacity that the Commission requires each LSE to maintain is determined by the Resource Adequacy (RA) requirements established by the Commission. The determination of the value provided by and the cost-effectiveness of any demand response resource may be affected by any changes in the rules used to calculate RA values, as determined in the current RA proceeding (R.11-10-023), or its successor.

Section 1.F: Sensitivity Analysis

Many of the costs and benefits of Demand Response (and other) programs are based on uncertain inputs or have considerable variation among participants, LSEs and others, making them difficult or prohibitively expensive to quantify. Some costs and benefits are presented as precise quantities, but are actually *estimates* because they are dependent on assumptions and estimated inputs. Costs and benefits which cannot be easily quantified are often approximated, and if they cannot be approximated they have often been ignored in previous cost effectiveness analyses. This approach, while pragmatic, does not allow for an assessment of the true costs and benefits of these programs. In that light, the DR Cost-Effectiveness Report will perform additional types of analyses than have been done in past proceedings.

These protocols require that sensitivity analysis be performed on key variables, defined as those costs and benefits (or components thereof) which are (a) substantially uncertain and (b) likely to have a significant impact on SPM test calculations. The sensitivity analyses will be made using only the TRC test, to make it feasible for both the parties in any DR proceeding and the Commission to complete and analyze the cost-effectiveness filings in a timely manner. The variability in the TRC values calculated in the sensitivity analysis should be sufficient to demonstrate the potential variability in the other SPM tests.

A sensitivity analysis is required for each key variable. Commission staff will determine the exact range of the sensitivity analysis during the course of any particular DR proceeding. The key variables are:

1. Participant Costs
2. Avoided Capacity Cost
3. T&D Capacity Costs
4. Capital Amortization Period
5. Load Impact
6. A Factor Adjustment to the Avoided Generation Capacity Cost
7. C Factor Adjustment to the Avoided Generation Capacity Cost

Participant Costs, as discussed in Section 3.M, are equal to the sum of Transaction Costs and the Value of Service Lost. Because those two quantities are extremely difficult to quantify, other costs are used as a proxy. In the past, Participant Costs have been presumed to be equal to Participant Benefits, which are defined as the cost of customer incentives and bill reductions, minus any customer capital costs. However, this is clearly inaccurate, since it is more likely that customers participate in programs because the benefits **exceed** the costs. Hence, a more accurate assumption is that Participant Benefits are the maximum value for Participant Costs.[12] Hence, the sensitivity analysis will use the quantity Incentive Costs + Bill Reductions – Capital Costs to Participant as a **high** value, rather than as the base case value, for most DR programs. This is explained further in Section 3.M.

For **Generation Capacity Value,** the value calculated by the Avoided Cost Calculator will be considered the base case value. This value is based on the long-term Avoided Generation Capacity Costs, which are determined from the Combustion Turbine simulation. The high and low values will be some percentage greater and lesser than the base case, as determined by Commission staff. The percentage currently used is 30%.

For **T&D Capacity Value**, the values calculated by the Avoided Cost Calculator will be considered the base case values. The high and low values will be some percentage greater and lesser than the base case, as determined by Commission staff. Separate values are provided for transmission and distribution, for each of the IOUs (PG&E, SCE and SDG&E) Other LSEs may input the appropriate values for their service territories. This process may change, depending on the structure of the Avoided T&D Capacity Cost, as discussed in Section 3.B.

Each LSE should input the **Capital Amortization Period** for each long-term investment. The low value of each long-term investment for each year of the program cycle will be the annual levelized value of that investment over its expected useful lifetime. The high value will be determined by setting the Capital Amortization Period equal to the length of the program cycle

[12] This calculation is complicated by the fact that there are other participant benefits which are difficult to quantify – the Non-energy and Non-monetary benefits discussed in Section 3.J. These benefits are not considered in the simple analysis above. However, parties are encouraged to propose a different proxy value for Participant Costs, or alternate methods of calculating Participant Costs, should they have evidence that an alternative method would improve the cost-effectiveness analysis.

(usually three years) for which the cost-effectiveness analysis is being performed. The base value will be the halfway point between the calculated low and high values. As an alternative, LSEs may develop their own base values, based on estimations of dropout factors, as discussed in Section 3.E. LSEs must provide detailed descriptions of this calculation in their workpapers.

Commission staff will determine default values for **Capital Amortization Period** for different types of investments, and will use those values if none is provided by the LSE, as explained in Section 3.E.

The exact **Load Impacts** which should be used for each program are defined above in Section 1B. A sensitivity analysis will be performed using the 10th and 90th percentile values as low and high values. Note that the although this was required by the 2010 Protocols, the DR Reporting Template inadvertently applied the same method (30% higher and lower than the base value) to the sensitivity analysis of the load impacts as was used for most of the other variables. This will be corrected in the DR Cost-Effectiveness Report.

Sensitivity analysis of the adjustment factors is required for the **A factor** (discussed in Section 3.B, below). The A Factor will be determined by the new model being adopted, as discussed in Section 3.B below, and will be integrated into the DR Cost-Effectiveness Report. The high and low values will be some percentage greater and lesser than the base case, as determined by Commission staff.

Section 1.G: Qualitative Analysis

As discussed in Section 1.B, LSEs may choose to, but are not required to, add the following optional inputs in the DR Cost-Effectiveness Report:

1. Social non-energy benefits, such as environmental benefits (in addition to the avoided GHG cost included in the avoided cost calculator), job creation benefits, and health benefits.
2. Utility non-energy benefits, such as fewer customer calls and improved customer relations.
3. Participant non-energy benefits, such as improved ability to manage energy use and "feeling green."
4. Market benefits, such as market power mitigation and market transformation benefits

LSEs should include these inputs if and when it is possible to estimate quantitative values for any one of them for a specific DR program. Where it is not possible to approximate an optional input, qualitative analysis of these costs and benefits, especially when they are relevant to a specific DR program, should be provided by the LSE or by any party commenting on the analysis. Qualitative analysis is a descriptive analysis of the possible magnitude and impact of that cost or benefit. It may also include a description of any variation based on location, customer class, or any other significant factor. In addition, the qualitative analysis may reference relevant research, or propose future research.

The purpose of this qualitative analysis is not to make vague speculations about the nature of those inputs, but to better understand the impact of DR on the electric grid, and in particular to

compare DR programs to each other in those instances in which a particular DR program clearly has a different amount of a particular cost or benefit, even if that amount cannot be precisely (or even imprecisely) quantified. An example would be two programs that target different customer classes, but are otherwise the same. In this case, the customer costs and benefits will mostly be difficult to quantify, but could more easily be discussed qualitatively, allowing all parties to better understand the relative merits of the two programs.

An important goal of the qualitative analysis is to establish an ongoing dialog among DR stakeholders that can lead to better understanding of the complete range of benefits and costs of DR. For this reason, we require that LSEs put some thought into their analyses of each type of optional benefit. LSEs may argue that they believe these benefits do not exist, but no matter what belief an LSE, or other party, advocates we expect this analysis to be backed up with research, data, and thoughtful analysis.

For each of the optional inputs listed in above, and for each DR program, LSEs should determine their approach. If an LSE chooses to estimate a value for any of these inputs, an explanation of how the value was derived should be included in the workpapers. If a value cannot be estimated, the LSE shall provide in its workpapers a qualitative analysis which discusses the extent to which their DR program(s) provide non-energy or market benefits. We recognize that this type of analysis is a departure from the traditional cost-effectiveness analysis that IOUs are accustomed to. Nevertheless, we expect all LSEs to comply with this requirement. Other parties are encouraged to provide relevant information about any of the optional inputs.

The 2010 Protocols required the above qualitative analysis. However, this was not provided by the IOUs in their 2012-14 Applications. As a result, and as noted in D.12-04-045, the IOUs were out of compliance with these protocols. Hence, this analysis will be required as part of the workpapers associated with the DR Cost-Effectiveness Report. This requirement may, in the future, be modified by Decisions or Rulings in other Commission proceedings, as discussed above, as there are several proceedings currently examining the appropriate accounting of non-energy benefits and costs of demand-side and other distributed energy resources. This requirement may also be addressed via working group.

Section 1.H: Portfolio Analysis

In addition to providing cost-effectiveness analysis of each DR program, LSEs will also provide cost-effectiveness analysis of their entire DR portfolio. This should be done for each SPM test by aggregating all DR programs, and adding additional relevant costs and benefits, while correcting for any possible double-counting due to dual participation or other factors. This portfolio analysis shall include any marketing, IT, administrative, equipment or other costs associated with the LSE's portfolio of DR programs. It should **also** include costs associated with broader activities, including any DR-related activities such as customer audits; evaluation, measurement and verification; and marketing, education and outreach, or any other activity which supports or promotes DR in general rather than any one specific DR program.

Note that the portfolio analysis must include an analysis of *all* Demand Response activities, programs, and costs, whether or not the LSE is requesting budget approval for each of individual programs included in the portfolio analysis. For example, if an LSE received approval in a past

CPUC proceeding for an ongoing program which does not require re-approval in the current application (e.g., a program which is done through a long-term contract), a cost-effectiveness analysis for that ongoing program must be included as part of the portfolio analysis. As another example, the portfolio analysis must include all costs related to DR that were approved in the LSE's most recent GRC, and any other relevant proceeding. LSEs should include, as part of their workpapers, a list of *specific budget items* from their latest GRC and all other proceedings in which approval of any costs related to DR was included.

The only type of costs which can be excluded from the portfolio cost-effectiveness analysis are the costs associated with "pilot" programs, which are done for experimental or research purposes, as the benefits of these programs are generally substantial, but usually impossible to forecast. However, if an LSE is able to quantify both the costs and benefits of any particular pilot program, it must include that program's costs and benefits in its portfolio analysis. If, as will be the case for most pilots, it is not possible to estimate the benefits of the pilot project, the LSE should clearly explain this as part of the description of the pilot program.

The portfolio cost-effectiveness analysis is only one of the analyses which should be included in an LSE's DR budget application. In any individual DR proceeding, the Commission will base the approval of one or more DR programs on all information provided in an LSE's application. The Commission may approve DR programs, budgets, or activities individually, or the Commission may approve an LSE's entire portfolio, with or without modifications. The inclusion of the portfolio cost-effectiveness requirement should not be construed as an indication that the Commission intends to use portfolio cost-effectiveness, rather than program cost-effectiveness, as the basis for budget approval. These 2015 Protocols are designed to simply establish the requirements for cost-effectiveness analysis, not the policies by which program approval will be determined.

Section 1.I: Dual Participation

DR programs which allow dual participation, in which participants can enroll in more than one DR program, require special rules to accurately determine their cost-effectiveness. The 2010 Protocols required that the load impacts of any DR program that allows dual participation follow the rules described in D.09-08-027, Section 18.4. Those rules require that the load impacts of dually-participating customers be attributed to only one program so as to avoid double-counting. Dual participation rules limit participants to enrollment in one capacity program and one energy program[13], and require that the load impacts of dually-participating customers be attributed to the capacity program.

During the 2012-14 utility DR portfolio proceeding, it became evident that attributing the load impacts of dually-participating customers only to the capacity programs was resulting in underestimates of the cost-effectiveness of the energy programs, since the cost-effectiveness analysis of the energy programs included all of the costs of administering them but only part of

[13] A capacity program pays capacity incentives, in $/kW, to participants in return for the participant's willingness to reduce to a pre-set level of demand whenever needed. An energy program pays incentives in $/kWh for the energy reductions that a customer provides during DR events.

the benefits. During a subsequent demand response cost-effectiveness workshop[14], there was general consensus that this practice should change. However, there are a number of approaches, and it is not clear which will best provide the information needed to determine the cost-effectiveness of these programs. The options include:

- Requiring an additional analysis of both the capacity and the energy program combined.
- Including the dually participating customers in the separate analysis of each program, while taking care not to double-count when calculating the DR portfolio cost-effectiveness.
- Requiring an additional analysis of only the dually-enrolled customers in both the capacity and energy programs.

Determining the best approach will depend on which is the most important among the following goals: determining the cost-effectiveness of dual participation itself, of the individual programs, or of the combined programs. Requiring all three of these analyses could place an unnecessary burden on LSEs and Commission staff to provide and analyze this additional information.

Given the limited data available on the best means to capture the impact of dually enrolled customers, an additional analysis for both the capacity and the energy program combined will be required for programs that allow dual participation.

[14] held on October 19, 2012

SECTION 2: USING THE STANDARD PRACTICE MANUAL TESTS TO DETERMINE DR COST-EFFECTIVENESS

This section describes the modified SPM tests that shall be used to determine DR cost-effectiveness. These four test each reflect a different perspective. While various Commission proceedings have expressed a preference for one or the other of these four tests, these protocols do **not** do so. Each of these perspectives are significant, although the significance of each may vary for different DR programs or proceedings. The output of each test is based on the net present value of the costs and benefits, discounted over the lifetime of the relevant DR resource. Hence, the costs and benefits listed below are not simply added together to produce the SPM outputs. Rather, the costs and benefits should be calculated using the DR Cost-Effectiveness Report and Avoided Cost Calculator, using the given discount rate and the net present values, by filling out the appropriate cells of the spreadsheets. The paragraphs below provide generalized and simplified descriptions of those calculations.

Section 2.A: Total Resource Cost (TRC) Test

The TRC test calculates the costs and benefits to "society" of a demand-side resource. For the purposes of these protocols, "society" is considered to be each LSE and its customers.[15]

In the SPM, TRC benefits are limited to the LSE's avoided costs of supplying electricity and tax credits (if available). For DR programs, additional benefits include any revenue the program may earn in exchange for CAISO market participation (such as for providing ancillary services). In addition, to make the TRC test better reflect the true costs and benefits of DR to ratepayers, these additional benefits should be considered:

- Social non-energy benefits, such as environmental benefits (in addition to the avoided GHG cost included in the avoided cost calculator), job creation benefits, or health benefits.
- Utility non-energy benefits, such as fewer customer calls or improved customer relations.
- Market benefits, such as market power mitigation or market transformation benefits

From the perspective of the TRC, the costs of a demand response resource are:

- Administrative and capital costs incurred by the LSE
- Participant costs (capital costs to participant + value of service lost + transaction costs)
- Increased supply costs, if any

Each of these costs and benefits is discussed further below. These costs and benefits should be calculated as shown in the DR Cost-Effectiveness Report. For those costs and benefits which cannot be quantified, LSEs or other parties should provide a qualitative analysis of particular cost or benefit, as discussed in Section 1F.

Section 2.B: Program Administrators Cost (PAC) Test

[15] This assumes that each LSE is capturing any possible "spillover" impacts that may occur outside its service territory.

The PAC test measures cost-effectiveness from the perspective of the LSE or other entity administering the Demand Response program. The benefits are the:

- Avoided costs of supplying electricity
- Revenue the program may earn in exchange for CAISO market participation
- Utility non-energy benefits
- Market benefits

From the perspective of the PAC, the costs of a demand response resource are:

- Administrative and capital costs incurred by the LSE
- Incentives paid
- Increased supply costs, if any

Each of these costs and benefits is discussed further below. These costs and benefits should be calculated as shown in the DR Cost-Effectiveness Report.

Section 2.C: Ratepayer Impact Measure (RIM) Test

The RIM test, also called the non-participants test, measures the costs and benefits of a demand response program from the perspective of its impact on rates. The benefits considered in this test are:

- Avoided costs of supplying electricity
- Revenue from participation in CAISO Markets
- Revenue gain from increased sales, if any
- Market benefits

From the perspective of the RIM test, the costs of a demand response resource are:

- Administrative and capital costs incurred by the LSE
- Incentives paid
- Increased supply costs
- Revenue loss from reduced sales

Each of these costs and benefits is discussed further below. These costs and benefits should be calculated as shown in the DR Cost-Effectiveness Report.

Section 2.D: Participant Test

The Participant Test measures the cost-effectiveness of a Demand Response program from the perspective of a participant. For the purposes of these protocols, a participant is considered to be a ratepayer who is an end-user of electricity and participating in a DR program. From this perspective, the benefits of a DR program are:

- Bill reductions
- Incentives received

- Participant non-energy benefits
- Tax credits, if available

From the participant's perspective, the costs are:

- Bill Increases
- Capital, O&M, removal and any other costs associated with DR equipment installed
- Value of service lost (lost productivity and comfort costs)
- Transaction costs (opportunity costs associated with education, equipment installation, program application, event response management, energy audits, etc.)

Each of these costs and benefits is discussed further below. Some of these costs and benefits are difficult, if not impossible, to calculate. However, it is reasonable to assume that a customer would not voluntarily participate in a DR program if the benefits did not exceed the costs. Hence, for the purpose of DR programs in which customers have the option to enroll or not (generally referred to as "voluntary" programs), it can be assumed that the costs are less than the benefits, since a rational electricity end-user would not otherwise participate in the program. Therefore, when presenting cost-effectiveness analysis of voluntary DR programs, the LSE should simply state that the benefit/cost ratio for the Participant Test is greater than 1. Note that programs that are described as "default opt-out[16]" programs, for the purposes of this analysis, are considered to be voluntary programs.

For default programs which do not have an opt-out provision (i.e., programs in which all customers in a specific class are considered participants and opting out is not possible), a more detailed analysis must be provided. LSEs should provide an estimate for each cost and benefit which can be calculated, and any information available for other costs and benefits. However, it is understood that many, if not most, of the costs and benefits listed here are extremely difficult to quantify.

Nevertheless, there is value in trying to better understand these participant costs and benefits. The deployment of Smart Meters allows all utility customers the opportunity to better manage their electricity usage, including participation in demand response programs. However, making use of that opportunity will require an in-depth understanding of energy management. A better understanding of DR costs and benefits from a customer's perspective will better enable all parties to increase customer involvement in DR activities. While the participant test is not generally used to determine program approval, it can offer valuable information that can be used to improve program design and help predict customer enrollment, as discussed above. It is particularly important for LSEs to provide the best estimate possible of Participant Test cost-effectiveness for new programs.

[16] A default opt-out program is one in which all customers in a certain class are placed in the program as a default, but all customers have the option to opt out of participation by informing the utility during a specified time period. These programs are sometimes referred to simply as "default" programs.

SECTION 3: COSTS AND BENEFITS OF DEMAND RESPONSE

Table 1

	TRC	PAC	RIM	Participant
Administrative costs	COST	COST	COST	
Avoided costs of supplying electricity	BENEFIT	BENEFIT	BENEFIT	
Bill Increases				COST
Bill Reductions				BENEFIT
CAISO Market Participation Revenue	BENEFIT	BENEFIT	BENEFIT	
Capital costs to LSE	COST	COST	COST	
Capital costs to participant	COST			COST
Incentives paid		COST	COST	BENEFIT
Increased supply costs	COST	COST	COST	
Market benefits	BENEFIT	BENEFIT	BENEFIT	
Non-energy social benefits	BENEFIT			
Non-energy utility benefits	BENEFIT	BENEFIT	BENEFIT	
Non-energy participant benefits				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 Demand Response protocols.

Section 3.A: Administrative Costs

Administrative costs of a DR program are considered to be its operations and maintenance costs, program operational costs, IT costs, DR system operation and communication costs, the marketing and outreach costs associated with the program, evaluation, measurement, verification and reporting costs. LSEs are expected to provide budgets which detail these costs for each proposed DR program.

DR program administrative costs must include all costs that are caused by or specific to the program. All activities that are specific to a particular DR program, such as program design, development, operations, management, marketing, sales, IT infrastructure, evaluation, measurement, verification and reporting shall be included in the administrative costs of that program, even if it is budgeted separately or approved in a different proceeding than the DR program. This includes *all* costs that an LSE incurs because of the existence of DR. For example, if an LSE purchases hardware or software to upgrade their IT infrastructure, that portion of the investment that is necessitated by the existence of DR programs should be considered a cost of DR. LSEs must examine how the cost would have differed if DR programs did not exist. If that cost could would not have been incurred if DR did not exist, then the entire cost must be included in the cost-effectiveness analysis. If that cost could would have been lower if DR did not exist, then the difference between the lower cost and the actual cost must be included in the cost-effectiveness analysis.

When a program cost is budgeted separately (e.g., an IT budget which encompasses several programs), or when a program cost is part of a budget which was approved in a past CPUC

proceeding, those costs must be included as administrative costs in the cost-effectiveness analysis of an LSE's DR portfolio. In addition, those costs must be allocated to each individual DR program in the cost-effectiveness analysis of that program. Each LSE must provide, as part of their workpapers, a complete list of these two categories of costs, and include an explanation of how each budget item is used to support which DR programs. Those costs should be allocated to individual programs using the following procedure:

1. Estimation of the impact on or relationship to particular programs: For some budget items, it is possible to estimate how much of that budget will be used for particular programs. For example, EM&V costs are usually budgeted separately from program administration costs. However, it should be possible for an LSE to estimate how much of their EM&V budgets will be used to provide evaluation of each program. This is the preferred method to use for allocation of these budgets.

2. Limitation of use: For each budget listed, LSEs must provide a list of DR programs for which that budget is relevant. For example, a marketing program that targets residential customers would be relevant to only residential DR programs. This list should include all DR programs in the LSE's portfolio, whether or not program approval is being sought in the application.

3. Allocation by total budget: If it is not possible to estimate the proportion of a budget which pertains to a particular DR program, as explained in #1 above, then that budget should be allocated to each DR program that it pertains to, based on the list discussed in #2 above. The allocation should be proportional, based on the total administrative and incentive costs of the program.

The following is an example of the type of calculations and workpaper details that should be provided by LSEs. LSEs should provide similar tables and explanations in their workpapers:

Fictitious Electric Company has four demand response programs:

- Ag DR: Agricultural Capacity Response program, for agricultural customers only
- C&I DR: Base Interruptible Capacity program, for commercial and industrial customers only
- Res CPP: Summer Peaker Saver, a peak pricing program for residential customers only
- Res AC: Summer Saver Cycling, an air conditioner cycling, direct load control program for residential customers only

Fictitious Electric Company has nine budget items in its application:

Table 2

Budget Line	Description	Amount
1	Ag DR administrative costs	$100,000
2	C&I DR administrative costs	$300,000
3	Res CPP administrative costs	$250,000
4	Res AC administrative costs	$125,000
5	Res AC incentive costs	$1,000,000
6	Evaluation, Measurement & Verification (EM&V)	$200,000
7	Marketing, Education & Outreach (ME&O)	$150,000
8	Customer Notifications (Notif)	$85,000
	TOTAL	$2,210,000.00

In addition, Fictitious Electric Company has identified the following costs, which were approved in their most recent General Rate Case, as being at least partially attributable to demand response programs:

Table 3

Budget Line	Description	Amount
GRC1	Ag DR incentive costs	$1,000,000
GRC2	C&I DR incentive costs	$1,000,000
GRC3	Software Upgrade 173B*	$500,000
GRC4	Software Upgrade 84J	$400,000
	TOTAL	$2,900,000.00
	Total DR attributable	$2,600,000

*40% of the Software Upgrade 173B budget is attributable to DR

In its workpapers, Fictitious Electric Company provided a further breakdown of several budget lines:

Budget Line #6: EM&V

The $200,000 in this budget line is estimated as follows:

- $35,000 for load impact analysis of Ag DR
- $35,000 for load impact analysis of C&I DR
- $35,000 for load impact analysis of Res CPP
- $35,000 for load impact analysis of Res AC
- $30,000 for process evaluation of Res CPP
- $30,000 for process evaluation of Res AV

Budget Line #7: ME&O

The $150,000 in this budget line is estimated as follows:

- $100,000 marketing campaign to support all demand response programs
- $50,000 education campaign and materials for residential customers

Budget Line #GRC3: Software Upgrade 173B

Fictitious Electric Company estimates that 40% of the $500,000, or $200,000 of the cost of this software upgrade is attributable to demand response, and that this software is used for demand respond programs in general.

Fictitious Electric Company also notes that budget lines #8 (Customer Notifications) and #GRC4 (Software Upgrade 84J) are both entirely attributable to demand response, and used for demand respond programs in general.

Hence, Fictitious Electric Company provided the following analysis in their workpapers:

Table 4: Budget Allocations, in thousands of dollars

Program	Admin	Incent.	Admin + Incent.	% of total	Direct EM&V	ME&O	Notif.	Software 173B	Software 84J	TOTAL
Ag DR	100	1000	1100	29%	35	29	24.5	58	116	1362.5
C&I DR	300	1000	1300	34%	35	34	29	68	136	1602
Res CPP	250	0	250	7%	65	16	6	14	28	379
Res AC	125	1000	1125	30%	65	71	25.5	60	120	1466.5
TOTAL			3775	100%	200	150	85	200	400	4810

***Note**: ME&O costs = $100,000 applied proportionally to all 4 DR programs, plus $50,000 applied proportionally to the 2 residential DR programs. Notifications and software budgets are applied proportionally.*

The sum of the application budget of $2,210,000, and the portion of the GRC budget attributable to DR of $2,600,000, is the total DR budget of $4,810,000, and is allocated to Fictitious Electric Company's four DR programs as shown in the table above.

Section 3.B: Avoided Costs of Supplying Electricity

The avoided costs of supplying electricity are the primary benefit of any demand side resource, and thus provides key information about the value of any proposed demand response resource, whether it is a load-modifying resource or a supply resource, which is bid into a CAISO market. Hence, the calculation of avoided costs will be used (1) to determine the primary benefit of load-modifying demand response resources, so as to compare those benefits to the costs of the resource (2) to determine the primary benefit of supply-side demand response resources provided by IOUs and (3) to determine an avoided cost benchmark for supply resource demand response that participates in the DRAM, which can be used to determine the reasonableness of a resource which is bid into a CAISO market.

The calculation of avoided costs differs depending on the specific characteristics of the particular resource. This is calculation is most accurate when avoided generation capacity costs, avoided energy costs, and avoided (deferred) transmission and distribution (T&D) costs are distinguished separately. DR programs can interact differently with each of these types of avoided costs, and the separation of the costs will allow such differences to be modeled in a straightforward manner. As discussed above, avoided costs will be calculated using the Avoided Cost Calculator, a spreadsheet tool developed by Energy and Environmental Economics (E3). The Avoided Cost Calculator uses a marginal cost-based approach to value each of the costs that the LSE avoided as a result of not having to deliver energy to the end-use customer.

In analyzing the cost-effectiveness of resources, LSEs shall use the most recent version of the Avoided Cost Calculator that conforms with the requirements of these protocols. Since updating the Avoided Cost Calculator has been discussed in several Commission proceedings, LSEs

should seek guidance from the Commission as to which version of the calculator is appropriate for any particular application. This may not be determined in a demand response proceeding.

The avoided costs considered include: energy purchases, generation capacity, line losses, transmission and distribution capacity, air pollution permits, offsets including CO2, ancillary services, and renewable energy purchases. The value of each of these elements is forecasted by hour and location for a 20-year period.

For demand response, the most significant avoided cost is the avoided cost of generation capacity. Avoided generation capacity costs will not be inputs in cost-effectiveness analyses for programs that are not either 1) integrated into the wholesale energy market, or 2) embedded in the CEC's unmanaged/base case load forecasts. This will effectively make the avoided generation capacity costs equal to zero for the purposes of cost-effectiveness analysis for programs that do not meet either of these criteria. The forecast of generation capacity value made by the Avoided Cost Calculator includes both a short-run and a long-run component; the transition point between the two occurs in the resource balance year. The short-run value of capacity is based on the most recent publicly-available data on actual resource adequacy value. This value is currently much lower than the long-run value, which reflects the large surplus of capacity currently available on the CAISO system. Capacity value in the years between the date of the recent publicly-available data on actual resource adequacy value and the resource balance year is calculated by linear interpolation. Beginning in the resource balance year, the value of capacity is calculated based on the cost of a simple-cycle combustion turbine (CT), as that is the first year in which new capacity resources may be needed to meet the growth of peak loads and reliability requirements. The long-run capacity value is equal to the CT's annualized fixed cost less the net revenues it would earn through participation in the real-time energy and ancillary services markets—the residual capacity value.

The use of short- vs. long-run values for generation capacity has a substantial impact on the cost-effectiveness of DR. There are two schools of thought regarding whether the short- or long-run generation capacity value is the most appropriate for valuing DR. Several parties in various demand-side proceedings have argued that in a market with excess capacity, the lower, short-run value best expresses the actual capacity costs avoided and therefore the economic benefits realized by utility ratepayers and the region as a whole.

Others argue that relying on short-run values does not appropriately reflect the position of energy efficiency and demand response at the top of the loading order[17]. DR and EE, at the top of the Energy Action Plan loading order, should not be effectively penalized because a surplus of fossil generation exists during some periods.

In addition, it is important to consider that the long-term procurement plan (LTPP) proceeding determines whether and how much additional electric generation will be needed in the future. In that calculation, the amount of future peak-demand reducing EE, DR, and DG is estimated and deducted from the additional resources that would otherwise be authorized. This results in less

[17] California's energy policy, as stated in the Energy Action Plan (http://www.energy.ca.gov/energy_action_plan/), establishes a "loading order" which requires that demand be met first by cost-effective energy efficiency and demand reductions, next by renewables, and only then by traditional generation technologies.

authorization for the IOUs to procure additional capacity than would otherwise be authorized. While many other factors can come in to play that result in an excess (or a deficit) of supply resources, these intervening factors do not change the fact that future additions of demand-side resources are factored into this LTPP "net short" calculation. As they come on line in any given year, demand-side resources are replacing supply that otherwise would have been authorized five to ten years earlier in an LTPP proceeding.

Another argument for the use only of long-term values is that DR is analyzed only over the three-year budget cycle, and not over the lifetime of an equipment purchase, as most EE programs are. Therefore, use of both short- and long-term avoided capacity costs separated by a resource balance year has a very different impact on DR than on EE. Since the resource balance year is, and will be for the foreseeable future, at least three years away, it means that the cost-effectiveness of DR would be based only on short-term costs. This is in sharp contrast to EE measures, which are analyzed over a much longer period of time, since the lifetime of most energy-efficient equipment is at least five years, necessitating the use of both long- and short-term values. Using only short-term values for DR would underestimate the real value of DR to the system. Ideally, this could be remedied by doing life-cycle analysis of DR, but that has proved to be impractical. In addition, some consistency in DR incentives is necessary to attract and retain DR participants.

Because Commission policy, as discussed at length in D.12-04-045[18], is to follow the loading order and focus on the long-term development of clean energy resources, the long-run generation capacity value will continue to be used to determine the avoided generation capacity costs of DR programs,

The approach for incorporating ancillary services (AS) avoided costs will differ from the calculation used for EE and DG. The CAISO sets procurement targets for AS resources based on load forecasts. Demand side resources such as EE reduce overall loads and therefore reduce the quantity of AS that must be procured and paid for by the CAISO and ultimately by the LSEs. The CAISO has indicated that DR would not impact the procurement of AS in the Day Ahead market. Reduced load resulting from a DR event could reduce the quantity of AS procured in the Real-Time market. However, as 85 percent or more of AS is procured by the CAISO in the Day Ahead market, and AS costs are a relatively small percentage of the overall DR benefits, the benefit of reduced AS procurement need not be included in cost-effectiveness analyses of DR programs.

On the other hand, DR programs do have the potential to earn revenue in the AS and other CAISO markets. As discussed in Section 3.D below, such revenues earned by direct participation of DR programs in CAISO markets will be counted as a benefit. However, it is important to remember that this benefit is not part of the avoided costs of DR.

Because energy is a small portion of the overall benefits of DR programs, the avoided renewable energy purchases procurement costs calculated in the EE and DG Avoided Cost framework are negligible and will not be applied to DR cost-effectiveness.

[18] see, especially, Section 7.1.4.2.1.

The 2010 Protocols did include a value for avoided GHG costs, which is also based on avoided energy and is also quite small. Because of the relatively tiny amounts associated with avoided GHG costs for DR additional adjustments to the methods used to calculate this value will not be made at this time.

To characterize the hourly marginal avoided costs of serving load, the Avoided Cost Calculator incorporates publicly available data from the following sources: CAISO, the California Energy Commission (CEC), NYMEX, NOAA, the three major California IOUs, and Synapse Consulting. These inputs are not meant to be modified by IOUs, as their uniformity across analyses provides for an "apples-to-apples" comparison of the benefits of different distributed resources.

Table 5 summarizes each of the key data sources as well as a describing the specific data obtained from each.

Table 5. Key data sources used in the Avoided Cost Calculator

Source	**Description of Data**
CEC Cost of Generation Report	Costs and operating characteristics of a new combustion turbine and combined cycle power plants
CAISO OASIS	Hourly day-ahead and real-time LMPs; hourly system loads
NYMEX	Henry Hub forwards contract prices; basis differentials between Henry Hub and California gas hubs
California IOUs	Transmission & distribution deferral values; losses factors
Synapse Consulting	Forecast of carbon prices
NOAA	Hourly weather data throughout California

Table 6 shows the key outputs calculated within the Avoided Cost Calculator that are used to assess the cost-effectiveness of DR. A more detailed description of the method used to evaluate each of these components is found below.

Table 6. Main outputs of Avoided Cost Calculator used to evaluate DR resources.

Output	**Description**
Avoided Capacity Costs (Residual capacity value)	The annualized fixed cost of a new combustion turbine, less the net revenues (gross margins) that the CT could earn operating in the real-time energy and ancillary services markets
Avoided Energy Costs	Hourly values of energy in both the day-ahead and real-time markets (the appropriate value stream depends on the DR program characteristics)
Avoided GHG Costs	The value associated with a reduction in greenhouse gas emissions resulting from avoided thermal generation
Line losses	Additional costs resulting from line losses between the point of generation and the point of retail delivery

***1) Avoided Generation Capacity Costs*:** The generation capacity costs avoided by a DR program will be based on the annual market value ($/kW-year) of the residual capacity of a new combustion turbine (CT). Throughout this proceeding several alternate methods have been proposed for determining the adjusted CT cost. While each method has its laudatory features,

we believe that transparency and simplicity are of paramount importance for these protocols. Therefore, the same method shall be used for all LSEs to determine this cost. The residual capacity value is calculated within the Avoided Cost Calculator using a method that is consistent with the California Independent System Operator (CAISO) Market Issues and Performance Annual Reports. Using cost and performance data from the CEC Cost of Generation Report, the calculator evaluates the net revenues that a new combustion turbine could expect to receive through operations in the real-time energy and other electricity markets. This net revenue is subtracted from the combustion turbine's annualized fixed costs to determine the residual capacity value. Each of these components is described in further detail below. The dispatch of the CT is similar to the approach taken by the IOUs in earlier versions of these protocols, comparing the heat rate and the resulting variable operating costs against a forecast of energy prices to determine hours in which it is economic for the CT to operate.

The first component of the generation capacity value, the annualized fixed cost of a new combustion turbine, is calculated based on cost data from the CEC Cost of Generation Report and a pro-forma tool included in the Avoided Cost Calculator. The pro-forma tool amortizes the capital and fixed operations and maintenance costs associated with a new plant over its lifetime, yielding the annualized fixed costs of a new CT. These annualized fixed costs change in each year with the inflation of capital and O&M costs.

The second component of the residual capacity value, the CT's net margin from operations, will change each year with the evolution of the CAISO real-time market and the change in gas prices. The Avoided Cost Calculator calculates the expected net margin in each year based on the historical hourly shape of the real-time market adjusted by the average annual energy price in that year. In each hour, if the real-time market price exceeds the CT's cost of operation, the CT will dispatch, increasing its net margin by the difference between the market price and the cost of operation. The total net margin is calculated by tracking the CT's operations in the real-time market over each of the 8,760 hours of the year. As a flexible generator that can ramp up and down quickly, a CT can also earn revenues through participation in the ancillary services markets. In the Avoided Cost Calculator, this additional revenue is calculated as an upward adjustment to the gross revenues earned in the real-time market based on historic data gathered from CAISO's Annual Market Reports.

The Avoided Cost Calculator then allocates the residual capacity value across the 8760 hours of the year. This process is identical to the process used to determine the A factor, discussed below. The 2010 protocols suggested doing this by allocating the residual capacity value to the 250 hours of the year in which system loads are the highest. These are the hours in which marginal changes in consumption could result in avoided capacity costs. This type of capacity allocation method is a simplified proxy for relative loss of load expectation/probability (LOLE/LOLP) models, which were used previously to the 2010 Protocols to allocate generation capacity costs. This allocation is then used to create monthly generation capacity values, which are used with the monthly load impacts in the DR Cost-Effectiveness Report to calculate monthly avoided capacity costs. The 2010 Protocols also allowed LSEs to use their LOLE/LOLP models to determine alternate monthly capacity allocations for some or all DR programs, but required that the LSE provide both sets of calculations.

During the 2012-14 DR portfolio proceeding, a simplistic method of allocating the residual capacity value to the 250 hours of the year in which system loads are the highest was used. This approach resulted in wildly varying allocations and A factor estimates for similar programs at different IOUs. As a result, D.12-04-045 stated the need to improve the method used for these calculations[19]. During the course of the 2012-14 DR portfolio proceeding, subsequent cost-effectiveness workshops, and more recent staff research, a large number of options have emerged:

1. Loss of load probability or loss of load expectation (LOLP/LOLE) models: Each IOU has an LOLP/LOLE model which they use for planning purposes. The IOUs have provided testimony that they believe that using LOLP/LOLE models will result in more precise and accurate values. Other stakeholders have protested the use of LOLP/LOLE models for various reasons, including that these models use proprietary software, the inputs include confidential data, and the models are run infrequently. The CPUC has determined that "transparent" models, which use only publicly-available software and data, are preferred.

2. E3 default (simple) model: This is a fairly simple model, which spreads the residual capacity value over the 250 hours of the year with the highest demand. This method was used during the IOUs 2012-14 budget application. There was some variation between the IOUs in how exactly how the allocation among the 250 hours was made.

3. E3 default (simple) model using fewer hours: In the IOUs 2012-14 budget application, SDG&E argued that using the same method, but spreading the value over the top 100, rather than 250, hours was more accurate.

4. R factor model[20]: At a workshop in October 2012 on Demand Response cost-effectiveness, the IOUs suggested a mathematical function, called the "R factor," which mimics their LOLE output.

5. E3 RECAP model[21]: At a workshop in October 2012 on Demand Response cost-effectiveness, E3 suggested using a Effective Load Carrying Capacity model. This model was later updated and is now called the RECAP model.[22]

6. Probabilistic reliability modeling: This model is under development in the Resource Adequacy proceeding (R.11-10-023)[23]. This probabilistic reliability model, run by Energy Division, could be used to allocate the residual capacity value to each hour of the year, as well as determine some of the adjustment factors. This would likely be a superior method because at least some demand-side programs (i.e., those that are

[19] Section 6.2.4.3
[20] See, for example, SCE's comments at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M029/K556/29556665.PDF, pp. 7-8, Figure II-2.
[21] E3 ELCC model was first proposed at a workshop on Demand Response Cost-effectiveness on October 19, 2012: http://www.cpuc.ca.gov/NR/rdonlyres/F8619E63-F001-4EA6-B512-EF4B6B9CD65E/0/DR_Costeffectiveness_Workshop_final.pdf (slides 27-38).
[22] E3's Recap model can be found at https://ethree.com/public_projects/recap.php .
[23] http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/Probabilistic+Modeling.htm

dispatchable such as Demand Response) could be included in the model along with supply-side options.

While the preferred method is to use option #6, until such time as this model has been approved by the Commission the LSEs shall use option #5 for both allocation of the residual capacity value and the determination of the A factor, as discussed below. The DR Cost-Effectiveness Report will be adjusted accordingly. Further review of this model will be provided at future workshops. The Commission will issue guidance at a later date on which methodology LSEs should use regarding the A factor.

Adjustments to the generation capacity value: Because DR reduces end-use load, it also reduces the reserve margin of operating generation facilities that provide reserve generation to respond to system contingencies. The applicable adopted reserve margin will be used to adjust the generation capacity value upward when applied to the MW impacts of the DR program. In addition, CTs incur a heat rate efficiency penalty when operating during the hot summer on-peak periods when the capacity is needed the most. This CT Summer Peak Performance Penalty reduces the energy produced by the CT and therefore reduces both energy production and energy revenues. The Peak Performance Penalty, in the form of a percentage reduction of the generating capacity of the CT during the summer months, will also be applied to adjust the capacity value upward. The calculation of avoided capacity costs will also take into account avoided line losses.

Adjustments for individual DR programs: The generation capacity value of a DR program without usage or availability constraints would be equivalent to the full CT residual capacity cost. Therefore, this cost will be the maximum capacity value. To the extent that a DR program has usage and availability constraints, this maximum value should be adjusted downward. Three adjustment factors for avoided capacity cost were included in the 2010 Protocols: Availability (A Factor), Notification Time (B Factor) and Trigger (C Factor). Two additional factors are being added to these 2015 Protocols. The F factor is an optional adder (i.e., greater than 100%) that can be applied to those DR resources that are flexible enough to be useful to the system operator to mitigate the effects of intermittent generations. The G factor is also an adder, which reflects the additional value of a DR program that can be called locally in a constrained area. The adjustment factors are designed to reflect the program characteristics that constrain or add to the optimal use of DR dispatching. These factors are discussed below.

The A Factor is intended to represent the portion of capacity value that can be captured by the DR program based on the daily and monthly availability of the program, and the frequency and duration of calls permitted. A program that could be called in every hour that a generation capacity constraint might be experienced by the utility would have an A Factor of 100%. As discussed above, a placeholder for the RECAP model created by E3 is temporarily adopted for this calculation to determine the A factor.

For **the B factor** calculation LSEs were directed to examine past DR events to determine how often the additional information available for shorter notification times would have resulted in different decisions about events calls. In other words, decisions about when to call day-ahead events are based on the best available information the day before the event occurs. However, the need for DR is based on conditions (particularly weather), which can change in the course of 24

hours. By examining past events, an estimate can be made of how often a curtailment event would have been accurately predicted, not predicted but needed, or predicted but not needed in advance of the notification time required by a particular program. As an example, such an analysis would identify when load and weather forecasts would have initiated a DR call a day ahead as compared to when DR curtailments were actually needed in real-time. However, in the 2012-14 DR portfolio proceeding the IOUs were able to only apply this method to distinguishing between day-of and day-ahead programs. The three IOUs had slightly different results, and Commission staff subsequently provided guidance[24] to the IOUs to use a B Factor of 100% for all day-of programs and 88% for all day-ahead programs.

It is difficult to determine the exact, relative value of the various notification times. As it becomes more common for Demand Response to be bid into CAISO markets it will be easier to quantify these values. In addition, this issue of the relative value of different notification times has been discussed in R.14-10-010, a Resource Adequacy proceeding, so we will defer to the Resource Adequacy process to provide future guidance. IHowever, until a more exact measurement can be made, LSEs are instructed to use the following B Factors:

Table 7

Notification Time	B Factor
30 minutes or less	100%
Day Of, greater than 30 minutes	94%
Day Ahead or greater	88%

The C factor should account for the triggers or conditions that permit the LSE to call each DR program. LSEs consider customer acceptance and transparency in establishing DR triggers. However, in general, programs with flexible triggers have a higher value than programs with triggers that rely on specific conditions. Therefore, a C factor should be determined so that programs with less flexible triggers can be de-rated. In the past, each LSE was directed to propose a method for determining the C factor, and to clearly explain the method used and each step of the process described. In the 2012-14 DR portfolio proceeding PG&E used a C Factor of 95% for its air conditioner cycling programs and its Base Interruptible Programs, and 100% for all other DR programs, while SDG&E and SCE used a C Factor of 100% for all programs. The January 2011 Guidance on Cost-effectiveness instructed the IOUs to use a 'C factor' of 95% for any program which cannot be triggered at the discretion of the utility, and to otherwise use 100%. LSE's should continue to follow this guidance for C factor calculations until further notice.

LSEs should keep in mind that D.10-06-034 issued in Phase 3 of R.07-01-041 adopted a multi-party settlement and reduced the amount of reliability-based and emergency-triggered demand response programs that count for Resource Adequacy from 3.5% of system peak in 2010 to 2% of system peak in 2014. Although the settlement adopts caps the MWs that count for Resource Adequacy, the settlement removed the enrollment caps on reliability-based and emergency-triggered demand response program. Any C Factor analysis applied to emergency based DR

[24] January 2011 Energy Division Guidance on Cost-Effectiveness, available at http://www.cpuc.ca.gov/NR/rdonlyres/92C54F59-8D88-446A-846A-1747628C0F33/0/GuidanceJanuary2011.pdf

programs should make a clear distinction between enrolled MW up to the 2% cap and enrolled MW over and above the 2% cap. To the extent a utility applies a capacity value to emergency based DR above the 2% cap, the utility must clearly demonstrate that the impact of the emergency based DR above the 2% cap actually reduces the identified capacity needs used for utility and CAISO capacity and RA planning and leads to a commensurate reduction in capacity or RA procurement.

The F Factor is an adder which provides additional value for those DR resources which are particularly flexible, and can provide the CAISO with added value in that they are particularly useful for responding to intermittent generation. Characteristics of flexible DR may include programs which are:

- Capable of making economic bids into CAISO markets and subject to a must-offer obligation according to the Flexible Resource Adequacy Must Offer Obligation,
- Capable of ramping or sustaining output for three consecutive hours,
- Capable of providing ancillary services, and/or
- Capable of responding to over-supply conditions.

A technical working group will be convened, headed by the Utilities, in order to establish a proposal for the proper means of valuing the F Factor.

The G Factor accounts for those DR resources which can be called locally in geographical regions that are resource-constrained. Starting with these 2015 Protocols, LSEs may propose this adder for any DR program which can be called locally in any region which is facing constraints that put it at a higher than normal risk of experiencing generation capacity shortages. LSEs must include any proposals to use this geographical adder in their workpapers. The proposals should include an explanation of why the adder is needed, and an analysis of how the magnitude of the adder was determined. LSEs should file their cost-effectiveness analyses in the DR Cost-Effectiveness Report of affected DR programs, and their DR portfolios, both with and without the G Factor.

In the event that an LSE does not submit a G factor for some or all of their programs, the default G factor values will be as follows:

For SDG&E, the default G factor adder shall be 10%, thus the G Factor will be 110%.

For SCE:

- For DR programs that can only be dispatched in SCE's entire service territory, the default G factor adder shall be 0%, thus the avoided capacity cost will be unaffected.

- For DR programs that can be dispatched locally in the local resource adequacy areas of Big Creek-Ventura or the L.A. Basin, the default G factor adder shall be 5%, thus the G Factor will be 105%

For all other LSEs other than SDG&E and SCE, the default G factor adder shall be 0% and no adjustments will be made to the avoided capacity costs based on locational value at this time.

The specific values of this adder above are based on current local Resource Adequacy values, and as such are likely to change over time. Future changes in the methods used to determine the Avoided T&D capacity cost, which includes the transmission constraints which may affect local RA values, could potentially result in double-counting if the G Factor is used, in which case its use will be reconsidered. Hence, Commission staff may issue further guidelines about this adjustment in the future.

2) Avoided Energy Costs: The Avoided Cost Calculator calculates hourly avoided costs of energy in both the day-ahead and real-time markets based on historic hourly shapes and a forecast of the average value of wholesale energy in each year. These hourly energy values serve as the basis for the valuation of energy savings resulting from demand reductions. The hourly shapes of the day-ahead and real-time markets are derived from historical CAISO data. Hourly historical Locational Marginal Prices (LMPs) at the each of the load aggregation points are normalized by daily gas spot prices to adjust for the underlying volatility of the gas market. The resulting shapes provide a representative snapshot of the dynamics and trends in each market that is used to shape the average market price in each year.

The annual average market price is based on market forwards for electricity contracts at NP15 and SP15 obtained from Platts. Between 2010 and 2014, these forwards are used directly as the annual value of energy. Beyond 2014, the average market price is calculated as the product of the average market heat rate, which is assumed to remain level after 2014, and the forecast of burnertip gas price in California. The annual average market price calculated in this manner serves as the annual average for both the day-ahead and real-time markets.

The calculation of avoided energy costs will take into account avoided line losses. The incremental cost of any additional generation resulting from a load-shifting program will be taken into consideration based on the expected electricity prices during the time that the additional electricity is used.

The DR Cost-Effectiveness Report estimates energy benefits based on the straightforward product of on-peak energy avoided costs, loss factor, and avoided energy usage. This value estimate is supplemented by an adjustment factor that allows parties to value DR under alternate energy price scenarios. LSEs are required to use the simple evaluation approach presented herein, but are allowed to apply an Energy Adjustment Factor (E Factor). LSEs may use the energy adjustment factor to reflect the correlation between electricity prices and the times when DR program events are expected to occur, based on the times in which the program will be available, constraints on the use of the program, and the probability distribution of and correlations between the trigger conditions under which events can be called under that program. The derivation of the E factor must be provided in the workpapers.

In the past, parties have discussed the use of option pricing models to value DR. While this has theoretical value, such an approach is far from an easily understood and transparent approach.

LSEs may, however, incorporate an option pricing approach in the "E Factor" analysis. In that case, however, the LSE shall provide justification for the adjustment factor in their workpapers provided as part of the cost-effectiveness analysis. Such justification will include all input data and modeling in spreadsheets that will allow Commission staff and interested parties to replicate the LSE's results.

3) Avoided Transmission and Distribution Costs: As a result of DR programs, utilities may defer and/or reduce transmission and/or distribution capacity investments (and thus avoid T&D costs) in local areas experiencing load growth or other system constraints. The 2010 Protocols used avoided T&D values submitted in each IOU's General Rate Case as the basis for the avoided T&D calculation. These values were allocated to individual hours based on the hourly temperatures in each climate zone. This approach resulted in an allocation of T&D value to several hundred of the hottest hours of the year. This information was then used to determine a monthly avoided T&D cost, which when combined with each program's monthly load impacts, determines the potential monthly avoided T&D cost of the program.

Since that time, a new model for avoided T&D capacity costs was developed by E3 for use in the California Net Energy Metering Ratepayer Impacts Evaluation[25]. This model separately calculates transmission avoided costs for subtransmission "downstream" of the CAISO and distribution system avoided costs, for each IOU.

Subtransmission-level avoided costs are based on transmission avoided costs in $/kW-year filed by the IOUs in GRC or other recent proceedings. This cost is allocated over the hours in the year in which the transmission systems would be likely to experience constraints, based on both system peak and substation demand levels.

The model for distribution-level avoided costs is more complex. The IOUs must provide confidential lists of distribution system project upgrades which are planned for the next five to ten years. Using this information, forecasts of load growth, and known capacity constraints in the project areas, E3 calculates the costs savings that could occur if the projects are deferred. This "Present Worth" method is more accurate than the previous method. However, it does have the disadvantage that it uses confidential data to determine results. While the Commission normally discourages the use of confidential data in cost-effectiveness analysis, an exception may be made in this case because of the difficultly in determining reasonable and consistent values for avoided T&D costs, until and unless another method emerges which uses only publicly-available data.

The accuracy of this model depends on the provision of detailed, accurate and timely information from the IOUs. The IOUs are expected to comply with the need for this information so that accurate avoided T&D capacity costs can be determined. The process for developing this model may be discussed in future workshops. As an interim solution, the Protocols will continue to use the GRC method described in the 2010 Protocols for determining avoided T&D cost estimates.

Parties have expressed a preference for deferring the determination of avoided T&D costs to the ongoing Distributed Resource Plans under discussion in R.14-08-013. While the Commission

[25] http://www.cpuc.ca.gov/PUC/energy/Solar/nem_cost_effectiveness_evaluation.htm. See Appendix C, p. 40.

agrees that this is the preferred approach, it is not certain that a model will emerge from this proceeding in a timely enough manner to be adopting for use by DR. However, if and when possible, the methods which are developed in R.14-08-013 may be adopted and used in place of the existing methodology. Commission staff may issue further guidelines about this process, based on the any Decisions in R.14-08-013 or as the result of workshops held after the adoption of these Protocols.

LSEs other than the IOUs should continue to use the method described in the 2010 Protocols to determine this avoided cost. For all LSEs, the avoided cost of T&D capacity will be increased to account for line losses.

The avoided T&D capacity cost must be matched with the characteristics of individual DR programs by using the "D factor," which adjusts the T&D value for each program. Throughout the years that demand response stakeholders have discussed the concepts related to cost-effectiveness, the terms "right time", "right place", "right certainty" and "right availability" have been used to describe the match of allowable DR operations to utility T&D system needs and avoided costs. The various criteria are intended to limit the application of the avoided T&D costs to programs that actually avoid or defer T&D investment. A specific method for calculation of the D factor is not proposed here, but LSEs are expected to base their D factors on the criteria below, and explain in their workpapers how the D factor for each DR program was determined.

The D factor for each DR program should be based on the following criteria:

Right Time: DR is or can be in place in time to defer some or all of the costs of planned or needed distribution system upgrades (i.e., before local conditions become severe enough to require upgrades)

Right Place: DR programs exist in areas where additional distribution capacity is needed and can be relied upon for local T&D equipment loading relief (e.g., can be dispatched just in the local area, not only system-wide, and are located in areas where load growth would result in a need for additional delivery infrastructure but for DR).

Right Certainty: There is sufficient certainty that DR can provide the long-term demand reductions to defer upgrade costs. For example, there must be a sufficient number of customers and the appropriate types of DR to provide a reasonable level of certainty that needed demand reductions can be provided.

Right Availability: DR will be available when needed. This is a similar calculation as for the A factor, although specific to T&D needs. It should take into account that for DR to be able to avoid sub-transmission and distribution investment, it must be possible to call the program to reduce circuit loading when it may occur, which may or may not be at times when the system is experiencing a generation peak event.

The default value of the D factor will be 0%. In other words, it will be assumed that a given DR program does not avoided or defer any transmission or distribution upgrades unless LSEs can

show otherwise, at both the sub-transmission and distribution levels. LSEs must provide, in their workpapers, an explanation of how the above criteria apply to each DR program.

Section 3.C: Bill Increases and Reductions

Bill increases and reductions are included only in the Participant Test. They are calculated from the perspective of end-users who participate in DR programs. However, because they occur only in the Participant Test it is only necessary to calculate them for default DR programs which do not have an opt-out provision.

This calculation can be complex because end-users generally switch from one rate to another when signing up or defaulting onto a DR program. Hence, a participant's bill reduction (or increase) is the difference between the actual bill received by the participant, *less any incentives paid*, and the bill the participant would have received had the participant not signed up for DR.

For example, in a program which changes the participant's rates but does not provide any incentives, such as CPP, the bill reduction (or increase) would be the difference between the actual bill and the bill the participant would have received had the participant stayed on the previous rate. For a program which does not change the rates but simply provides an incentive structure on top of the existing rate structure, such as an Air Conditioner Cycling Program, the bill reduction (or increase) is simply the total load drop (or increase) during DR events multiplied by the participant's rate. For a program which both changes rates and provides incentives, the incentives must be subtracted from the actual bill before the difference between the actual bill and the bill that would have been received under the old rates is calculated.

DR programs which provide new customers with bill protection should be able to generate this information fairly easily. However, for other programs, the expense of accurately calculating these bill reductions and increases may be very large, and not worth the cost given the relatively small values likely for this data. Hence, when assessing default DR programs which do not have an opt-out provision, the utilities may, if necessary, approximate these values using load impacts estimated using the established Load Impact Protocols, and a reasonable and transparent method. It may also be easier for the utility to calculate one number that is the sum of customers' bill reductions and incentives paid, which is acceptable for the participant test. However, a separate value for the incentives paid must still be calculated for the PAC and RIM tests.

Section 3.D: CAISO Market Participation Revenue

The CAISO currently has three products available that allow for DR to participate directly in wholesale energy markets. These are the Proxy Demand Resource, Participating Load and Reliability Demand Response Resource products. Product specifications and must-offer requirements for flexible capacity, which DR will be eligible to provide, are currently in development. Any revenues earned by an LSE or third party DR provider from CAISO markets through direct participation of DR should be counted as a benefit in cost effectiveness calculations using these protocols. No utility DR programs have been designed with the explicit intention of bidding or self-scheduling into these markets[26], but such program are anticipated in the future. For those DR programs that can participate directly in CAISO markets, LSEs should provide information regarding how that program will be bid into the CAISO markets. Such

[26] PG&E's IRM2 pilot is an exception. It commenced bidding into CAISO energy markets in 2014.

information should include which services can be provided, the anticipated number of hours and MWs that will be bid into each market, any rules or agreements that limit or enhance the ability of the utility to bid DR into these markets, and how CAISO market revenues will be shared between the utility, customer and, if applicable, aggregator. The rules and bidding strategies for DR participation in these markets may be complex. Nevertheless, the computation of these revenues should be presented in a clear and transparent manner.

Section 3.E: Capital Costs to LSE

This cost includes the fixed (capital) costs actually incurred by the LSE for equipment, IT and other investments which are required for particular DR programs and have a useful lifetime that is **greater than** the period of time over which the cost-effectiveness analysis is done (i.e., the reporting period, which is usually a three-year budget cycle). Any investments which have a useful lifetime of less than the reporting period should be considered administrative costs. Capital costs will be amortized over the lifetime of the investment as well as over the reporting period, to determine the low and high values, respectively, which will be used in the sensitivity analysis. For each investment, the LSE shall explain the details of the cost (e.g., types of equipment purchased, type and use of the IT investment) and how the lifetime was determined. Note that all capital costs must be included in the cost-effectiveness analysis of each DR program, even if those costs are budgeted elsewhere.[27]

For each DR program which requires capital investment, LSEs should submit a separate Capital Amortization Period for each investment, which will be used as part of the calculation of the high, low and base case values for the annual cost of each capital investment. If it is not possible to determine a Capital Amortization Period for a particular program, a default value determined by Commission staff will be used. The default value is currently 10 years for DR equipment and 5 years for IT equipment and software.

For each capital investment, the maximum cost of that investment occurs when the equipment is used only during the reporting period and then discarded. The minimum cost occurs when the equipment is fully used by all participants, none of whom drop out of the program, for each year of its useful lifetime. Accordingly, we will use these two values for the high and low values in the sensitivity analysis, respectively. For the high value, the total cost of the investment will be amortized over the reporting period (usually three years), and for the low value, the investment will be amortized over its useful lifetime, based on the value supplied by the LSE. If the LSE does not submit a value for the useful lifetime of each investment, the default value of 10 years (or 5 years for IT) will be used.

The base value of each capital investment will estimated as the halfway point between the low and high values. The formula for this calculation is:

[27] For example, if a customer receives an equipment rebate or other assistance as part of a rebate program such as Auto DR, and subsequently enrolls in a critical peak pricing program, the costs of the equipment rebate are considered capital costs of the critical peak pricing program. For customers who have received equipment rebates but have not yet enrolled in a DR program, a reasonable estimate should be made, based on program history, of the proportion of those customers who will ultimately enroll in each DR program.

Base value = low value + ½ * (high value – low value)

As an alternative, LSEs may develop their own base values. Using the low value as a starting point, LSEs may derive reasonable estimates of the most probable base value of each capital expenditure, based on estimations of dropout factors (for equipment or IT investment related to number of participants); useful lifetime of other, similar or previous investments, etc. LSEs must provide detailed descriptions of this calculation, including evidence that the lifetime of the investment is accurate (i.e., that the equipment or IT investment will be used and useful for the entire lifetime) in their work papers. For the purpose of sensitivity analysis, the high and low values will remain the same even if the LSE has chosen to derive an alternate base value.

Section 3.F: Capital Costs to Participant

This cost includes the fixed (capital) costs actually incurred by a program participant when installing equipment designed to facilitate the participant's ability to provide demand reductions. It also includes operations and maintenance cost of that equipment, as well as removal costs (less salvage value), and any other equipment-related costs associated with DR-enabling equipment installed by the participant. If a participant receives full or partial rebates for DR-enabling equipment purchases from the utility or any other known source, the cost of those rebates must be subtracted from the purchase price to determine the total capital costs incurred by the participant[28]. Note that capital costs do *not* include costs such as the participant's time spent in arranging the installation, or other indirect costs which are more properly accounted for as participant transaction costs or value of service lost. Note that all capital costs must be included in the cost-effectiveness analysis of each DR program, even if those costs are budgeted elsewhere.

As with the Capital Costs to LSE above, for each DR program, LSEs should submit a Capital Amortization Period for each investment, which will be used as part of the calculation of the high, low and base case values for the annual cost of each capital investment. If it is not possible to determine a Capital Amortization Period for a particular program, a default value determined by Commission staff will be used. All calculations for Capital Costs to Participant remain the same as for Capital Costs to LSEs.

As an alternative, LSEs may develop their own base values, based on estimations of dropout factors, as discussed in Section 3.E. LSEs must provide detailed descriptions of this calculation in their work papers.

Section 3.G: Incentives Paid

This category consists of the total amount of all capacity and energy incentives paid by the utility to participants for "pay for performance" programs. In the case of contracts between a utility and a third-party aggregator, the incentives paid are considered to be the total amount of all capacity and energy incentives paid by the utility to the third-party aggregator.

[28] For example, if a customer purchases a piece of equipment for $1200, receives a rebate for $400, pays $100 for equipment installation, and there are no operations, maintenance or removal costs, then the capital cost to the participant is $1200 - $400 + $100 = $900.

The cost of incentives paid to participating customers should be determined consistent with the forecasted usage of the DR program, determined from the Load Impact protocols, that is used to calculate avoided generation capacity and energy benefits. LSEs should calculate the expected cost of incentives, consistent with the program's Load Impacts and Expected Call Hours. This may differ from the budgeted cost of the DR program's incentives, which may be based on a maximum, rather than expected, number of call hours.

Most DR incentives are received by participants in the form of bill credits, although separate payments made directly from an LSE to a participant do occur. For the purposes of cost-effectiveness, the protocols do not distinguish between direct incentive payments and bill credits, and refer to either as "incentives."

Section 3.H: Increased Supply Costs

Increased supply costs are any costs incurred by the utility in providing additional electricity to ratepayers as the result of a DR program. These costs would normally be zero, as DR generally decreases electricity consumption. However, there may be programs in which electricity consumption might increase, especially during certain time periods, such as load shifting programs. In these cases, it may be appropriate to calculate this cost.

Section 3.I: Market Benefits

This category of benefits includes the increased market efficiency improvements resulting from DR, such as improved overall system load factors, improved market performance (e.g., decreasing price volatility), increased overall system flexibility, and portfolio diversity benefits. Most of these benefits are difficult to quantify, and there is disagreement as to whether some of them exist at all. The exact nature of these benefits may become clearer as new research emerges and new markets for DR become available.

Electricity markets are constantly changing, and potential developments such as a capacity market could alter the methods and benefits used to value DR. However, more study is needed of these potential benefits before they can reasonably be included in DR cost-effectiveness. The benefits that should be considered include the factors mentioned above as well as:

- **Innovation in retail markets.** Providing a DR framework can result in new retail product and pricing innovations, ultimately benefiting the customer through increased choice and a better matching of the customers' needs with choices offered by electric markets.
- **Incentive for development of efficient controls and end-use technologies.** The customer's potential for cost savings through load shifting creates a new market for technology that now has an appropriate value proposition and business case.
- **Reduced market power on peak days.** Tight supplies and/or transmission constraints that can exist on days when DR is likely to be called can lead to an excess of market power. Since most generation is already committed, generators not yet committed may have greater market power for meeting the remaining peak demand (i.e., there is less competition once most generation has already been committed).
- **Overall productivity gains by better utilizing industry investment.** Better pricing and the interaction of demand and supply can produce overall productivity gains by better utilizing

the fixed investment that comprise one of the largest capital investments made in a region. Improved capacity factors should result in improved electric system efficiency.

Although LSEs will not be required at this time to estimate these additional market benefits in their cost-effectiveness calculations for DR programs, qualitative analysis of these benefits should be provided, as discussed in Section 1.G above. It is important that LSEs provide this analysis, even if they believe that these benefits do not apply to their DR programs.

Section 3.J: Non-Energy and Non-Monetary Benefits

Utilities, demand response program participants, and society as a whole receive non-energy benefits from participation in DR programs. These benefits are also referred to as non-monetary benefits.[29] There may also be non-energy or non-monetary costs, which can be included in this category as a decrement, or negative benefit, in any calculations. These benefits, by their nature, are difficult – if not impossible – to quantify. However, a considerable amount of work has been done to quantify some of these benefits for low income energy efficiency programs.[30] This work can be used as a starting point for understanding the non-energy benefits of DR.

Non-energy benefits (NEBs) are usually divided into three categories:

- Social non-energy benefits, such as environmental benefits (in addition to the avoided GHG cost included in the avoided cost calculator), job creation benefits, and health benefits.
- Utility non-energy benefits, such as fewer customer calls and improved customer relations.
- Participant non-energy benefits, such as "feeling green," being good citizens by helping to prevent outages, improved ability to manage energy use, and having a better public image (for commercial enterprises).

Social NEBs include "environmental benefits," which in the 2010 Protocols were listed as a separate category of benefits. Social NEBs can be included as benefits in the calculation of the TRC test. They may not be included in the PAC, RIM or Participant Test.

Criteria emission pollutant-related costs that can be avoided by DR programs are already reflected in estimates of the generation capacity costs avoided by that DR program, to the extent that pollutant limits are required by current environmental regulation. However, environmental regulations are enacted to limit pollutants, not to limit the abatement of pollutants. There are residual benefits of avoiding criteria pollutants above and beyond the level of existing environmental regulation.

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[29] Non-energy benefits are somewhat different than non-monetary benefits, in that non-energy benefits may include monetary gains such as lower labor costs. Either concept may be used to provide a basis for analysis for this category of benefits, as our understanding of this type of benefit is still emerging.

[30] More information about the use of non-energy benefits to evaluate Low Income programs can be found in the revised final report " *Non-Energy Benefits: Status, Findings, Next Steps, and Implications for Low Income Program Analyses in California*" issued May 11, 2010. http://www.liob.org/docs/LIEE%20Non-Energy%20Benefits%20Revised%20Report.pdf

There are several other environmental impacts that might be avoided depending on the specific type(s) of capacity – generation, transmission, or distribution – that the DR program is expected to defer or avoid. These potential environmental impacts include the avoided costs of criteria pollutants associated with avoided generation capacity, as discussed above. Additional impacts include, but are not limited to:

- decreased health care costs associated with lower emission levels, especially decreased air pollution;
- additional GHG mitigation benefits (over and above the avoided GHG costs)
- quantitative or qualitative job creation benefits resulting from DR programs;
- environmental justice improvements, particularly for supplying electricity in urban areas
- biological impacts;
- impacts on cultural resources;
- diminishing visual resources (e.g., due to power plant stacks or transmission towers);
- land use, including impacts of energy infrastructure on local ecosystems;
- effects on water quality/consumption; and
- noise pollution.

Utility NEBs can be included in the TRC, PAC and RIM tests, but should not be included in the Participant Test. Utility NEBs consist of any indirect change in costs that an LSE experiences as a result of its DR programs. This includes any changes in the number of complaint calls or service requests, any changes in customer perception or relationship to their LSE, and changes in the number of delinquent bills or disconnections. All utility NEBs included in the cost-effectiveness analysis must be documented.

Participant NEBs is a broad category which includes the intangible benefits that DR participants often perceive when they agree to reduce their demand during DR events. Some of these specific benefits are listed above. While these benefits are important to the participants, they should not be included in the TRC, PAC or RIM tests, since these benefits accrue only to a small number of ratepayers. These benefits should be included *only* in the Participant Test.

Although LSEs are not required to include NEBs in their cost-effectiveness calculations for DR programs, either LSEs or other parties are invited to submit evidence of the magnitude of the benefits or costs of Demand Response. However, only evidence supported with data, rather than based on speculation, to be accepted by the Commission.

In addition, qualitative analysis of these benefits is required, as discussed in Section 1.F above. An example of this type of analysis would be a discussion of the additional benefit provided by a new residential DR program which is designed to be integrated with energy efficiency and customer generation programs. Because this program provides benefits that other DR programs do not, a qualitative analysis can be made, describing the additional benefits of offering customers integrated load management solutions, as compared to the traditional approach of separate programs for energy efficiency, demand response and customer generation. The analysis should discuss the possibility of increased customer participation, reduced participant transaction costs, and possible utility cost savings in their marketing and administrative budgets.

Section 3.K: Revenue Gain or Loss from Sales Increases or Decreases

These revenues are calculated only for the RIM test. For the most part, a DR program will result only in revenue loss, rather than revenue gain, but there may be programs in which electricity consumption might increase, especially during certain time periods. Also, even if a DR program results in a net revenue loss due to a DR reductions, it may make more sense to calculate this quantity separately for different time periods. In many current DR programs, there is a revenue gain during non-peak periods due to load-shifting activities.

Revenue loss (or gain) from any one utility customer is the change in consumption due to the DR program multiplied by the customer's rate, and the total revenue loss (or gain) is of course the sum of this amount for all program participants. However, like the category "bill increases and reductions" above, this calculation is complicated by the fact DR participants often move from one rate to another when joining a DR program. It is further complicated because DR participants often receive incentives, making it impossible to calculate these revenues simply by examining customer bills.

Revenue loss (or gain) should be calculated in a similar manner as bill increases (or reductions), as discussed above, so that incentives are eliminated and any change in the participant's rate structure is accounted for. Also similar to the category above, utilities are not expected to go to great expense to accurately calculate revenue gains (or losses). Hence, when calculating these values for the RIM test, the utilities may simply approximate these values, using a reasonable and transparent method, if a more precise measurement is not available. For example, LSEs usually assume that revenue losses and gains are equivalent to bill reductions and increases.

Section 3.L: Tax Credits

Tax credits are not presently available for DR programs. In the event that they are available in the future, they should be considered a benefit in the TRC and Participant tests. This includes any and all federal, state or local tax credits which may become available to participants for DR equipment installation or any other cost incurred in providing demand reductions.

Section 3.M: Transaction Costs and Value of Service Lost

These two categories include all of the costs to the participant, other than bill increases and equipment costs, of participating in a DR program. Transaction costs are the opportunity costs associated with education, equipment installation, program application, energy audits, developing and managing a load shed plan, etc. Examples of transaction costs are the personnel costs associated with time spent on activities such as filling out a DR program application, making decisions about whether or how to install DR equipment, developing and testing a load-shed plan, and enacting that plan during DR events.

Value of service lost 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 an end-use become unavailable. Examples of lost productivity costs are revenue losses incurred when a business is shut down during a DR event, or the cost of food which spoils in a non-working refrigerator. 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 or an equipment outage, or the cost of having to change one's work hours.

These costs are significant to the participant, but difficult to assign a monetary value to. Even individuals who experience the loss of comfort generally cannot state with any certainty what monetary value they place on, for example, feeling warmer than preferred, and even when monetary values can be determined, as they often can for productivity costs, they vary widely from one person, company or industry to the next. This makes it extremely difficult to estimate these costs for the purpose of estimating DR cost-effectiveness. Direct estimation of value of service lost or productivity losses would require extensive research and customer surveying, which is likely to be expensive and yield results that are highly uncertain. For this reason, a proxy variable is used to estimate these costs.

The benefits to a participant of participating in a DR program are, for the most part, easy to estimate – they are simply the total amount of the incentives paid to the participant.[31] It is reasonable to assume that participants in voluntary DR programs perceive their costs as being less than the benefits, or at the very least participants perceive that they are "breaking even." Therefore, the maximum possible value of their costs is equal to the value of the benefits. Hence, the maximum possible value of a participant's bill increases + equipment costs + value of service lost + transaction costs is equal to the value of the benefits received. This deduction leads logically to using the amount of the incentives as a proxy measurement for participant costs, where:

Total Participant Costs =
Transaction Costs + Value of Service Lost + Capital Costs to Participant + Bill Increases

Total Participant Benefits =
Incentives + Non-Monetary/Energy Benefits + Tax Credits + Bill Reductions

Total Participant Costs ≤ Total Participant Benefits

Transaction Costs + Value of Service Lost + Capital Costs to Participant + Bill Increases ≤
Incentives + Non- Monetary/Energy Benefits + Tax Credits + Bill Reductions

Tax credits and bill increases will generally be zero, and non-monetary/energy benefits are accounted for elsewhere. Hence, the net result is:

Transaction Costs + Value of Service Lost ≤
Incentives + Bill Reductions – Capital Costs to Participant.

Hence, for the purpose of calculating values for the TRC test, *for voluntary DR programs only,* LSEs should assume that the *maximum possible* value of the transaction costs and value of service lost can be approximated as the value of all incentives paid to customers plus the customers' total estimated bill reductions minus any participant capital costs. Because this is the *maximum* value possible for this quantity, it will be used as the high value in the sensitivity

[31] While there are other benefits, such as the decreased cost of energy consumption during DR events (if energy is conserved rather than shifted), the benefit of feeling like a "good citizen," and the benefit of feeling "green," these benefits are already included in the category of non-energy benefits discussed above.

analysis for most DR programs. The base value of 75% of this quantity and a low value of 50% will be used for most DR programs, as discussed below.

There are some DR programs or customers for which more precise estimates can be made. For example, evaluations of residential air conditioner cycling programs indicate that most participants do not notice any loss of comfort when their air conditioners are turned off during an event[32]. There are few, if any, productivity losses, and the transaction costs are relatively low – participants have to apply to the program, and arrange for a technician to install a switch or communicating thermostat on their premises, but do not have any continuing costs. For these reasons, these protocols will use 35% of incentives as base value of the proxy measurement for value of service lost and transaction costs for AC cycling programs, 60% of incentives for the high value, and 10% for the low value.

For DR programs which are not considered voluntary (i.e., those with no opt-out provision), LSEs will have to expand on the above analysis, and to the best of their abilities, provide estimates of the values of participant transaction costs, lost productivity costs and comfort costs. This type of analysis will be extremely challenging, and it would be reasonable to make estimates for these costs based on the known customer benefits, using the method above for voluntary programs as a starting point. Other possible starting points for this analysis might be suggested in the literature on partial outage costs, or based on customer participation rates in programs which have transitioned from opt-in to opt-out. As an alternative, LSEs may calculate the maximum Participant Costs as shown above for voluntary programs, and allow Commission staff to determine the base case amount.

For all other DR programs, the protocols assign a value of 75% of incentives as a proxy measurement of the base value of service lost and transaction costs, 100% of incentives as the high value, and 50% of incentives as the low value.

LSEs and other parties are encouraged to submit alternate methods for the analysis of participant costs, should they have evidence that an alternative method would improve the cost-effectiveness analysis. Alternate methods may include direct calculation of value of service lost and/or transaction costs or inclusion of quantifiable non-energy benefits.

[32] See, for example, http://www.calmac.org/publications/Final_report_for_California_DLC_Program_Comparison.pdf, which found that only about one third of participants noticed that an event had occurred.